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Case No. EO-2025-0154
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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. EO-2025-0154

DIRECT TESTIMONY

OF

BRADLEY D. LUTZ

ON BEHALF OF

EVERGY MISSOURI METRO AND EVERGY MISSOURI WEST

Kansas City, Missouri
February 2025

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DIRECT TESTIMONY

OF

BRADLEY D. LUTZ

Case No. EO-2025-0154

Q: Please state your name and business address.

A: My name is Bradley D. Lutz. My business address is 1200 Main, Kansas City, Missouri 64105.

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

A: I am employed by Evergy Metro, Inc. I serve as Director, Regulatory Affairs for Evergy Metro, Inc. d/b/a as Evergy Missouri Metro ("Evergy Missouri Metro"), Evergy Missouri West, Inc. d/b/a Evergy Missouri West ("Evergy Missouri West"), Evergy Metro, Inc. d/b/a Evergy Kansas Metro ("Evergy Kansas Metro"), and Evergy Kansas Central, Inc. and Evergy South, Inc., collectively d/b/a as Evergy Kansas Central ("Evergy Kansas Central") the operating utilities of Evergy, Inc. ("Evergy")

Q: On whose behalf are you testifying?

A**:** I am testifying on behalf of Evergy Missouri Metro ("EMM") and Evergy Missouri West ("EMW") (collectively the "Company" or "Applicants").

Q: What are your responsibilities?

A: My current responsibilities are focused on rates, regulatory operations and customer issues, providing support and oversight for a wide range of regulatory work including determination of retail revenues, load analysis, rate design, class cost of service, tariff administration, compliance reporting, response to customer complaints, docket

management system administration, general tariff administration, and relationship development for Evergy's regulatory activities in the Missouri and Kansas jurisdictions.

Q: Please describe your education, experience and employment history.

A: I hold a Master of Business Administration from Northwest Missouri State University and a Bachelor of Science degree in Engineering Technology from Missouri Western State University.

I joined Evergy, then Kansas City Power & Light Company, in August 2002 as an Auditor in the Audit Services Department. I moved to the Company's Regulatory Affairs group in September 2005 as a Regulatory Analyst where my primary responsibilities included support of our rate design and class cost of service efforts. I was promoted to Manager in November 2010 and was promoted to my current position in March 2020.

Prior to joining Evergy, I was employed by the St. Joseph Frontier Casino for two years as Information Technology Manager. Prior to St. Joseph Frontier Casino, I was employed by St. Joseph Light and Power Company for nearly 14 years. I held various technical positions at St. Joseph Light and Power Company, including Engineering Technician-Distribution, Automated Mapping/Facilities Management Coordinator, and my final position as Senior Client Support Specialist-Information Technology.

Q: Have you previously testified in a proceeding before the Missouri Public Service Commission ("Commission" or "MPSC") or before any other utility regulatory agency?

A: Yes, I have testified multiple times before the Commission concerning tariff, class cost of service and rate design topics as part of various recent proceedings. Additionally, I have testified multiple times before the Kansas Corporation Commission ("KCC").

Q: What is the purpose of your Direct Testimony?

A: The purpose of my Direct Testimony is to address the mechanics of how the Company's large customer load strategy, known as the Large Load Power Service ("LLPS") Rate Plan, will be implemented. As part of my testimony, I sponsor the following:

- Proposed Schedule LLPS Tariff – This is a new tariff offering for customers with demand greater than 100 MW. I explain the mechanics of this new tariff, including eligibility, pricing, the associated service agreement, and the terms and conditions.
- New and Voluntary Riders – I discuss the complementary riders to the LLPS tariff that will apply either on a mandatory or optional basis for Schedule LLPS customers.
- New and Voluntary Renewable Energy and Demand Response ("DR") Programs – I discuss the existing and Company's proposed programs and tariff offerings for Schedule LLPS customers who wish to procure renewable and/or carbon free energy or participate in an interruptible DR program to help support customers' sustainability goals.
- Ancillary Tariff Revisions to Support LLPS Rate Plan – I summarize other tariff changes that will need to be made to support and integrate the Company's LLPS Rate Plan.
- Billing Example – I present an illustrative bill for an LLPS customer.
- LLPS Rate Plan Support – I provide analytical support for the broader system and customer benefits that the LLPS Rate Plan will deliver and explain why this plan is reasonable and in the public interest.

Q: Are you sponsoring any attachments to your testimony?

A: Yes, I sponsor the following attachments (collectively, "Schedule BDL-1"):

- New Tariffs - Base Tariffs to the LLPS Rate Plan
  - Schedule LLPS (Large Load Power Service)

- New Tariffs – Complementary Riders to the LLPS Rate Plan
  - Schedule SR (System Support Rider)
  - Schedule CCR (Customer Capacity Rider)
  - Schedule DRLR (Demand Response & Local Generation Rider)

- New Tariffs – Renewable/Carbon Free Attribute Procurement Riders Within the LLPS Rate Plan
  - Schedule CER (Clean Energy Choice Rider)
  - Schedule RENEW (Renewable Energy Program Rider)
  - Schedule AEC (Alternative Energy Credit Rider)
  - Schedule GSR (Green Solution Connections Rider)[1]

- Modified Tariffs to accommodate LLPS Rate Plan
  - Schedule LPS (Large Power Service)
  - Schedule SIL (Special Rate for Incremental Load Service)[2]
  - Rules and Regulations Section 2 and Section 8

I. EVERGY'S LLPS RATE PLAN, LARGE LOAD POWER SERVICE TARIFF (SCHEDULE LLPS)

Q: What is the purpose of this section of your Direct Testimony?

A: In this section of my Direct Testimony, I review the background and strategy behind the development of the LLPS Rate Plan, then discuss the more specific mechanics of the LLPS tariff. As I explain, Schedule LLPS is intended to complement the Company's existing commercial and industrial ("C&I") rates, and thus was crafted based on a similar general

[1] The Green Solutions Rider is currently before the Commission in Case No. EA-2024-0292, *In re Application of Evergy Missouri West for Permission and Approval of Certificates of Public Convenience and Necessity Authorizing It to Construct, Install, Own, Operate, Manage, Maintain and Control Two Solar Generation Facilities* (filed Oct. 25, 2024). The Company is proposing the same rider for EMM in this filing.
[2] For EMW only.

structure as the existing Large Power Service ("LPS")[3] rate, while adding a number of distinct provisions intended to protect non-participants. The LLPS Rate Plan also includes a variety of voluntary customer choice options to secure renewable and/or carbon free attributes, among other large customer program offerings.

Q: Please summarize the Company's existing large customer load strategy which resulted in the development of the LLPS Rate Plan presented in this filing.

A: As Company witnesses Kevin Gunn and Jeff Martin explain, Evergy embarked on a multi-faceted and cross-functional approach to evaluating both the current national and state landscape with respect to large customer load. As part of this effort, the Company also assessed its current programs and offerings for large and large load customers. To begin this effort, the Company's leadership team evaluated the opportunities and challenges for the system and customers that today's large load pipeline creates. Evergy then developed a series of key principles intended to guide its overall large load customer strategy. These principles include developing a structure that:

(1) is equitable and fair, with particular consideration and protection given to existing and non-large load customers;

(2) promotes economic development and continues to attract large customers to Missouri;

(3) is efficient, both for the Company and large customers, and one that is also transparent and understandable;

(4) affords large customers choice and flexibility to procure renewable energy/carbon free attributes and participate in other eligible utility programs; and,

[3] The Large Power Service rates are similar in EMM and EMW. Both are four-part designs with blocked demand charges and hours-use energy charges. The rate design for EMW retains elements of the Annual Base Demand ("ABD") structure. Initial steps were taken in an earlier EMW rate case, No. ER-2022-0130 to remove the ABD structures.

(5) treats the power grid as a shared resource, while enabling customers with aggressive clean energy goals the ability to pay incrementally more to support those objectives.

Once these principles were established, Evergy collaborated with a variety of internal business units, external stakeholders, and industry experts to craft the tariff proposals included in this filing, cumulatively known as the LLPS Rate Plan. Company witness Jeff Martin provides a more complete description of these collaborative efforts.

Q: How did the LLPS Rate Plan develop?

A: The LLPS Rate Plan efforts began with internal teams. Initial design plans were formulated by Evergy representatives from Regulatory, Legal, Accounting, Energy Resource Management, Energy Solutions, Customer Operations, and Customer Solutions. We then sought insight from others in the energy industry. Working with The Brattle Group, we conducted a scan of large load efforts, seeking to compare them with our design plans. We also worked specifically to focus on large load rate designs or rate-related agreements approved in other jurisdictions or agreed to by large load customers, looking for best practices and ensuring all aspects of large load customer service were being accounted for in the designs. With this information we prepared initial drafts of the LLPS tariff and the associated riders. Versions of these tariffs and riders were shared and meetings held with the Staff of the MPSC, Staff of the KCC, the Office of the Public Council, the Kansas Citizens Utility Ratepayer Board, and prospective large load customers to discuss the details of the designs. This interaction and feedback helped with the refinement of all parts of the LLPS Rate Plan.

Q: Please describe the LLPS Rate Plan.

A: The LLPS Rate Plan centers around a new base rate tariff: Large Load Power Service, Schedule LLPS tariff ("Schedule LLPS"). This tariff is complemented with several new riders to accommodate the unique needs and capabilities of large customers, specifically:

- System Support Rider, Schedule SR;
- Customer Capacity Rider, Schedule CCR; and,
- Demand Response & Local Generation Rider, Schedule DRLR.
- The LLPS Rate Plan is also designed to offer large customers access to several riders to procure renewable or carbon-free attributes to meet their corporate sustainability goals. These other new riders include:
- Clean Energy Choice Rider, Schedule CER;
- Green Solution Connections Rider, Schedule GSR;[4]
- Renewable Energy Program Rider, Schedule RENEW; and,
- Alternative Energy Credit Rider, Schedule AEC.

Finally, the Applicants propose modifications to a number of existing tariffs, riders, and Company rules and regulations to harmonize the new tariffs and riders included in the LLPS Rate Plan. It should be noted that Evergy has filed a very similar version of this LLPS Rate Plan with the KCC to create a consistent approach for more broadly addressing large load customers seeking to location within the region.

Q: Please describe the types of customers the LLPS Rate Plan will serve.

A: The Company anticipates that the LLPS Rate Plan, and Schedule LLPS in particular, will allow the Company to respond appropriately to the influx of new customers considering

[4] Being proposed for EMM only with this filing.

locating in Missouri who are significantly larger than any of Evergy's current large customers. As Mr. Gunn notes, Evergy currently has a pipeline of over 20 customers totaling more than six gigawatts ("GW") of new, incremental demand. While a considerable amount of interest to date has been from large customers in the data center/data processing space, the Company has also received interest from other technology and advanced manufacturing customers. Examples of such customers include battery and microchip manufacturers, industrial manufacturers, and agricultural processing. While these large customers are beneficial from an economic development perspective, a distinct electric utility benefit from data center customers is that they stand to bring significant system value as data centers tend to have exceptionally high load factors, which can create benefits for all customers on the Company's grid. I discuss this in more detail later in my testimony.

Q: When do you anticipate these new large loads in the pipeline will come onto Evergy's system in Missouri?

A: Customers are here now. Evergy has been working with two large load customers since 2019, and many more are seeking to locate in Evergy's service territory area now. In the Company's experience, large customers are ready to develop projects quickly to address their critical concerns. In many cases, large customers are prepared to bring greenfield sites to market in as little as two years, but only if they have confidence in their utility service provider and its ability to accommodate their electricity needs. Specifically, the key elements that will enable large customers to bring their projects to market quickly include: (a) transparency and clarity in the queue process, (b) constructiveness of the regulatory environment, (c) well designed tariffs, and (d) resource procurement processes

that provide large customers with certainty that the necessary utility infrastructure (*i.e.*, capacity) will be available to provide them with the energy they need.

Q: How prepared is the Company to accommodate the potential load in its pipeline?

A: Based on its experience of bringing large customers onto its system, the Company has capable personnel and processes to manage the provision of service to them. It also has existing tariffs that establish terms and pricing for commercial and industrial ("C&I") customers including large load customers. However, it is clear that today's customers and their level of growth are distinct from past growth the Company has experienced. The size of this load growth is massive — multiples of what the Company has historically managed in a given year. More uniquely, many of the large customers seeking service are very knowledgeable in their understanding of energy and utility ratemaking. They bring new levels of sophistication and demands to the interconnection process. Some even maintain their own portfolio of renewable resources to support their comprehensive corporate sustainability goals. Therefore, the Company cannot rely solely on its past practices to address this phenomenon. Leading up to this filing, Evergy spent significant time evaluating its current approach to large customer load growth, taking into account many facets, including ratemaking and rate design, tariffs, commercial terms and conditions, customer relations, and the planning of generation, distribution, and transmission systems. The result is the LLPS Rate Plan proposed in this filing.

Q: How has the Company historically set pricing for large customers?

A: The most common approach was to use the Company's existing large customer tariffs, specifically the Large Power Service tariffs[5] (collectively, "LPS rates"). These tariffs are

[5] EMW Large Power Service, Sheet 149 through 149.6 and EMM Large Power Service, Schedule LPS, Sheet 14 through 14E.

applicable to larger C&I customers,[6] which represented loads less than 50 MW. The Company also has special contract tariffs,[7] which were used in a limited fashion approximately 20 years ago. These special contract tariffs allow the Company to meet specific competitive threats while preserving some contribution to margin through customer retention. The tariffs can also be used to serve customers who require a service structure not found in the Company's standard tariffs. The purpose of these special contracts tariffs has somewhat been replaced by economic development riders and generally these are not the option of choice for customers. Evergy has more experience with special contracts in its Kansas jurisdiction and while the special contracts are useful, they can result in asymmetric terms for customers. The process requires significant negotiation time to reach a mutually favorable result, considerable effort for regulatory approval, as well as significant Company effort to administer and maintain the special contract during the term. Most recently, the Company has implemented special rates in an effort to serve these larger loads.

Q: Please describe these special rates.

A: The first rate established to address larger load customers was EMW's Special Rate for Incremental Load Service, Schedule SIL ("SIL").[8] This special rate is available to customers with new, incremental load who have a facility whose primary industry is the

[6] Absolute demand thresholds for service do not exist for the EMM or EMW rates. If selecting service under EMW LPS, a customer will be billed a minimum demand of 500 kW. If selecting secondary voltage service under EMM Schedule LPS, a customer will be billed a minimum demand of 980 kW. Customers served at higher voltages have higher minimum demands. These rates do not currently have a maximum limit.

[7] EMW Special Contract Rate, Sheet 141 through 143 and EMM Special Contract Service, Schedule SCS, Sheet 29 through 29B.

[8] Schedule SIL was approved by the Commission on November 13, 2019, in Case No. EO-2019-0244. The rate was proposed to provide service to a large steel manufacturing customer nearing completion of construction and offered pricing similar the special rate allowed under the provisions of Section 393.355, RSMo. This rate is not available to customers in the EMM jurisdiction.

smelting of aluminum and primary metals, the production or fabrication of steel, or the operation of a facility with an increase in load equal to or in excess of 50 MW. Furthermore, a customer seeking service under Schedule SIL must demonstrate competitive need and show economic development benefits to the State of Missouri. The rate relies on a separate contract to establish rate terms but is required to recover the incremental cost of service for the customer. The main design feature of the Schedule SIL rate is integration of a renewable energy resource. The customer load will be served primarily by renewable energy resources separate from the resources used to serve general customers of the Company.

Q: Have any customers received service under the SIL rate?

A: Yes. One customer is receiving service under Schedule SIL.

Q: Does the Company have any other tariffs that could be applicable to large load customers?

A: Yes. The Company currently offers the Special High-Load Factor Market rate, Schedule MKT ("MKT")[9] to non-residential customers who operate a facility with a load equal to or in excess of a monthly demand of 150 MW or is reasonably projected to be at least 150 MW within five years of receiving service from Company. The customer must be able to demonstrate and maintain an annual load factor throughout the year of 0.85 or greater.[10] The MKT rate is an incremental cost design, meaning the rate paid by the customer receiving service is set only on the incremental cost of its service. The customer is not responsible for other embedded costs associated with the Company full cost of service.

[9] Schedule MKT was effective on August 28, 2022, under Docket EO-2022-0061 for EMW and was effective on June 23,2023, under Docket EO-2023-0022 for EMM. The tariffs are largely identical in design and purpose.

[10] During initial startup or commissioning, not to exceed five years, the Customer must be able to demonstrate and maintain an average annual load factor throughout the year of 0.85 or greater.

The MKT rate includes a demand charge set at the full cost of incremental capacity obtained to serve the customer. The energy charge is set at the Southwest Power Pool's ("SPP") hourly nodal price. By linking to the SPP nodal energy pricing an MKT customer who owns renewable resources within the SPP can better align its energy costs from the Company with revenues obtained by the renewable resource. Green attributes from the renewable resource could also be applied to the customer's load to meet any customer-established sustainability goals. These rates were established to accommodate two large load customers who have located in Evergy's Missouri jurisdictions.

Q: Have any customers received service under the MKT rates?

A: No. Only one eligible customer has become operational since the MKT rate was approved, but it is receiving service under the EMW Large Power Service rate, Schedule LPS.

Q: Why did the Company establish the MKT rates?

A: In what has now been recognized as a precursor of the current large load interest in the region, the Company was responding to interest from prospective data center customers. These customers had identified the region as suitable for building new data centers that represent loads expected to be approximately 200 MW and were seeking rates for service. At that time, the market for renewable resources had changed, making the Schedule SIL rate uncompetitive. The other Company rates were also not well suited to offer appropriate pricing to these customers.

Q: Why were the Schedule SIL and MKT rates unable to serve the large load customers seeking service today?

A: The LPS rates, special contracts, or Schedule SIL and MKT rates worked when there was a smaller pipeline of interested customers. However, with the significant number of new

large customers interested in locating in Missouri, it has become uneconomic, administratively burdensome, and inefficient to administer these legacy approaches, especially when today's customers are seeking so many novel programs and options. Specifically, the idea of applying incremental cost rates to a large number of customers is contrary to the nature of the shared electric grid and increasingly unsustainable. The Company also wants a fair and uniform process that is broadly applicable to all large load customers, and mechanically consistent with shared, embedded cost ratemaking, thus promoting transparency and fairness. Finally, it is important to deploy safeguards and protections that will avoid undue risk to non-participants and to ensure large load customers provide long-term benefits to the system and to Missouri.

Q: Why did the Company develop the LLPS Rate Plan for large load customers over 100 MW?

A: Evergy developed the LLPS Rate Plan for customers who are much larger than typical "large" customers of just a few years ago. Beyond size, as noted earlier, today's large load customers are actively engaged in energy matters. Some large customers own portfolios of renewable resources, and others have established aggressive renewable and sustainability goals. Some of these customers actively participate in setting energy policy at state legislatures, regulatory commissions, and regional transmission organizations ("RTOs"). These large load customers are highly aware of their energy needs and have sustainability goals that relate to their energy supply and service. As the Company monitored approaches developing across the industry and through direct engagement with a variety of large load customers, it determined that an entirely new tariff, Schedule LLPS,

along with related new riders, would be needed to accommodate the needs of these large load customers and to ensure proper protections are in place for all other customers.

Q: Why did the Company establish 100 MW as the eligibility requirement for Schedule LLPS?

A: To determine the appropriate size threshold for Schedule LLPS, the Company reviewed the size and attributes of existing large customers, as well as prospective large load customers. We also considered the thresholds used for the Schedule SIL and MKT rates. In doing so, Evergy realized that 100 MW appeared to emerge as a reasonable threshold between its existing and prospective large load customers. The 100 MW threshold will ensure that any large customers who enroll in Schedule LLPS are new customers and will limit the need to convert existing customers to a new tariff. In addition to customer size, this threshold level captures efficiencies and economies of scale that can be leveraged to create rates that are fair and equitable based on the unique needs of these large load customers.

Q: How will this work for large customers with a load that may initially be less than 100 MW?

A: If a customer seeks service and is reasonably expected to remain below 100 MW for the next 15-year period, the Company recommends the customer choose the LPS rates. Later, if the situation changes and the customer expects to grow above the 100 MW threshold, the Company, relying on Customer Solutions personnel assigned to support large customers, will work with the customer to transition them to the Schedule LLPS tariff. The Company will also guide the customer through the Path to Power process as needed, which Evergy witness Jeff Martin discusses in his testimony. Evergy will follow a similar process

for working with new customers, though will likely first start with the Path to Power interconnection process.

Q: What are the key features of the Company's proposed Schedule LLPS?

A: Schedule LLPS is intended to complement Evergy's existing C&I tariffs. While Schedule LLPS follows a similar rate structure to existing LPS tariffs, it adds a number of distinct terms and conditions intended to protect existing customers, while affording a variety of customer choice options. Below is a summary of the key features of the Schedule LLPS tariff:

- **Availability:** Available to new or expanding customers with a load forecast reasonably expected to have a maximum monthly demand equal to or above 100 MW, and who take service at a substation or transmission-level voltage. When a customer meeting this load expectation requests service, it will define its expected annual capacity requirements for the term within a formal Service Agreement. This process will help confirm applicability. A transitional load period, referred to as a ramp period, can be accommodated for within that term, but is limited to five years. As a contingency, provisions for a special contract are being retained to address unique needs that might occur as part of a state-sponsored economic development program.
- **Term:** Schedule LLPS customers will be required to take service for a term of 15 years. Service shall remain in effect thereafter unless cancelled, modified, or the customer selects and is qualified to receive service under another applicable Company rate schedule.

- **Service Agreement:** Customers enrolled in Schedule LLPS must execute a Service Agreement that will be used to specify detailed commercial provisions related to their electric service, including, but not limited to, load characteristics and load ramp, customer-specific terms, applicable construction cost recovery terms, and other service details, including definition of pertinent operating procedures. A series of exhibits will be used within the Service Agreement to document the load forecast for the 15-year term, and the customer-specific pricing terms driven by the Schedule LLPS customer, in addition to customer-specific terms in the pertinent riders and voluntary programs the customer is enrolled in. The Company may update these exhibits as needed, including any pricing changes resulting from rate case decisions. The Company anticipates making individual Service Agreements available to the Commission on request, although confidentiality protections may need to be addressed on a case-by-case basis depending on the terms and conditions of each Service Agreement and each customer's relevant commercial concerns. I discuss additional details of the Service Agreement in more detail later in my testimony.
- **Customer Charge**: Schedule LLPS customers will be billed a monthly charge to recover costs for metering, billing, and customer support. Initially, this charge will mirror the LPS rate but may be subject to future review or modification as part of a ratemaking or other appropriate filing.

- **Grid Charge**: Schedule LLPS customers will be billed a monthly charge established to recover substation and transmission-related costs. The charge will be based on the Customer's highest monthly demand in the last 12 months.
- **Demand Charge**: LLPS customers will be billed a monthly charge established to recover production-related costs. The billing demand is the highest demand indicated in any 15-minute interval measured during the month. Demand pricing levels are set by season and subject to a minimum demand amount. The minimum demand ensures that each month customers will pay for 80 percent of the contract capacity amount, as defined in the customer Service Agreement.
- **Energy Charge**: LLPS customers will be billed a monthly charge to recover energy-related costs based on metered kWh consumed, with pricing levels to vary by season.
- **Reactive Demand Adjustment**: LLPS customers will be billed a monthly charge to recover costs associated with managing any reactive demand introduced on the system by the customer.
- **Interim Capacity Charge**: This is an optional element in the tariff that provides a method to recover specific capacity procurements needed to serve a Schedule LLPS customer prior to fully incorporating its load into an Integrated Resource Plan ("IRP"). This will be billed as a per kW charge. If the existing system cannot meet a customer's load requirements or load timing needs, the Company, after reaching an agreement with the customer,

may enter into specific market contracts to provide interim capacity to the customer. In such case, the Company will charge the customer an additional demand charge reflecting the cost of this temporary capacity as a direct pass-through charge to the Schedule LLPS customer. Interim capacity and the related charge will not be utilized for all Schedule LLPS customers. Billing-related details concerning the Interim Capacity will be documented in the Service Agreement.

In addition to the foregoing provisions, Schedule LLPS includes a number of customer protections. These provisions are intended to help ensure that load deviations, facility closures, or the failure of a large load customer to meet certain terms do not cause undue impacts to other customers. These provisions are:

- **Minimum Monthly Bill**: Customers will be subject to a minimum monthly bill requirement. Under Schedule LLPS, the minimum monthly bill will require payment of the non-energy components of the tariff, specifically, the sum of the Customer Charge, Grid Charge, Demand Charge, and Reactive Demand Adjustment. Demand elements will be based on the Minimum Demand amounts and the customer capacity forecast detailed in the Service Agreement.
- **Early Termination Fee**: If a customer chooses to terminate service under Schedule LLPS or seeks service under another available rate schedule prior to the end of the 15-year term, it must provide written notice 36 months prior to the requested date of termination or schedule change, and pay an exit fee equal to their minimum charges over the remaining term or for 12

months, whichever is greater. If the customer switches to another rate schedule for which it qualifies, it will not be required to pay an exit fee. Should the customer seek to terminate service with less than 36 months' notice, an additional early termination penalty equal to the minimum charge multiplied by two for each month less than the required 36-month required notice will apply. Within the termination language of the tariff, any interim capacity in place at the time of termination request must be resolved prior to exit. This could be in the form of either the Company recovering the remaining costs of such capacity from the customer or the Company retaining the capacity to serve other customers if it has a need and at the Company's discretion.

- **Collateral Requirements**: In addition to the standard credit terms under the Company's rules and regulations, and any applicable requirements established related to construction, the Company proposes additional collateral requirements to ensure the creditworthiness of new large load customers, given the size of their monthly bills and the unique risks associated with such large transactions. The Company will require the customer to post sufficient collateral in an amount equal to two years of minimum monthly bills, as calculated by the Company. The collateral requirement will be re-calculated annually. To enroll, a customer with a credit rating of at least A- from Standard & Poors and A3 from Moody's, and liquidity greater than ten times the **c**ollateral requirement will be required to post 50 percent of the Collateral Requirements, with the 50

percent discount not to exceed $150 million. A customer that does not have an A- credit rating from S&P and an A3 rating from Moody's, but maintains liquidity greater than ten times the Collateral Requirement (which can be shown by providing quarterly financial statements and a third-party certification) will be exempt from 40 percent of the Collateral Requirements, with the 40 percent discount not to exceed $125 million. The collateral requirement must be provided at the time of the Service Agreement execution and must be a guarantee from the ultimate parent or a corporate affiliate of the customer for the full collateral requirement, a standby irrevocable letter of credit for the full collateral requirement, or cash for the full collateral requirement. Any collateral posted by a customer shall not accrue interest while held by the Company.

- **Contract Capacity Reductions**: The customer may request to reduce the Contract Capacity at any time after the first five years of the term by up to 10 percent, in total, by giving the Company at least 36 months written notice prior to the beginning of the year for which the reduction is sought. The customer may reduce its Contract Capacity beyond 10 percent at any time after the first five years of the term by giving the Company at least 36 months written notice prior to the beginning of the year for which the reduction is sought, subject to payment of a Capacity Reduction Fee. The Capacity Reduction Fee will be calculated as the nominal value of the remaining Minimum Charge for the terminated/reduced capacity in excess of the 10 percent allowed reduction. The Capacity Reduction Fee will be

due and payable to the Company upon the effective date of the capacity reduction. Following receipt of notice, the Company will use reasonable efforts to mitigate the Capacity Reduction Fee amount owed by the customer by evaluating the opportunity to re-assign the reduced capacity.

Q: Will the recovery riders that are applicable to the existing LPS tariff also apply to Schedule LLPS?

A: Yes. All jurisdictional recovery riders will apply, such as the Fuel Adjustment Clause, Demand Side Investment Mechanism, Tax Adjustment, any applicable Renewable Energy Standard Rate Adjustment Mechanism, and any applicable Securitization Charge. In the future, should any new riders be implemented to address other needs or mandates, the Company expects that they will apply to Schedule LLPS customers as they would the LPS rates. The Company agrees to evaluate the effect of any such new riders on a case-by-case basis as circumstances warrant.

Q: How did the Company develop the pricing included in Schedule LLPS?

A: The effort began by examining the pricing of the current LPS rates and the associated cost support provided by Class Cost of Service ("CCOS") Studies. Using the current, Commission-approved pricing and the Company CCOS Studies from the most recent rate cases, Evergy priced the large load customers under the existing rates which provide a point of alignment for the further rate development. I would summarize the effort in three steps: (1) establishing a baseline from the current rates, (2) using CCOS to establish pricing relationships, and (3) designing the final Schedule LLPS pricing. I will discuss each of these steps.

Q: Do you consider this a traditional approach to establishing pricing?

A: No. In most cases a rate pricing is developed by dividing cost components by annual billing units. In this case we only have prospective customers, and billing units are not available. The Company has instead established pricing based on the existing, most similar rate and its related cost components. Going forward, as customers receive service under the Schedule LLPS rate, there will be opportunities to adjust pricing if cost analysis deems it necessary.

Q: Are you certain that this approach will result in a just and reasonable rate for large load customers?

A: Yes. Based upon my knowledge and experience in developing rates that have been approved by the Commission, I am confident that the rate design and rate pricing proposed in this case is just and reasonable.

Q: Why is this important to establish a baseline from the current rates as the first step in developing pricing?

A: After assessing the current rates, examining industry approaches, and considering our goals for the LLPS Rate Plan, the Company determined that the Schedule LLPS rate should align with the current LPS Rates to form a baseline. This alignment would serve two purposes. First, it would help ensure the pricing of the initial rate would be an extension of the current, Commission-approved pricing. Second, it would ensure an appropriate level of revenue recovery from these new customers. As noted earlier, because Evergy does not have billing determinants to inform its rate design, this baseline will give the Company a reasonable starting point for its pricing.

Q: How did the Company develop the baseline pricing?

A: The Company calculated the annual monthly billing for a representative customer under the current LPS Rate. The representative customer was assumed to be a 728 MW load at 85 percent Load Factor that is served at the Transmission Voltage Service and operates at full, annual load with no ramp. This annual, monthly billing was used to produce an average price per kWh. The Company then calculated another monthly billing scenario, using the same customer assumptions but operating at 100 percent load factor. The resulting annual, monthly billing was used to produce another average price per kWh. These average prices represented the best average cost that could be provided with the existing rates and became the base rate target for the Schedule LLPS design. The following Table 1 details the current and best rates determined for EMW and EMM.

Table 1

Company	Rate Schedule	Load Factor	Average Rate ($ per kWh)
EMM	Schedule LPS	85%	$ 0.05783
		100%	$ 0.05299
EMW	Schedule LPS	85%	$ 0.06393
		100%	$ 0.06095

Q: Why was it important to establish this base rate target?

A: If the Company designs its Schedule LLPS rate to be proximate to this best rate target, it can reasonably ensure that the new Schedule LLPS customers pay a rate that delivers a similar return to the current LPS rates.

Q: Why is the second step of using CCOS Studies to establish pricing relationships important?

A: After assessing the current rates, examining industry approaches, and considering our goals for this Rate Plan, the Company determined that the Schedule LLPS rate should be built

using pricing that closely aligns with the cost of service. The Company is aware that its current LPS rate pricing does not align well with cost of service. Deviations from cost are the result of past rate case outcomes (Commission orders or settlement agreements) and other policy related steps that were used to manage impacts or achieve specific goals. The decision to seek better alignment was driven by the expected design features to leverage interim or customer capacity. By aligning capacity pricing closely with cost, this will provide a more appropriate structure to support the expected addition of or substitution of capacity.

Q: Did the Company produce a new CCOS study or rely on existing CCOS studies?

A: The Company chose to rely on existing CCOS studies to inform this work. Having recently completed rate cases, the available studies provide a reasonable basis for this introductory pricing. Evergy recognized that it did not have a study regarding the impact of new large load customers on the cost of service. Therefore, it took steps to refine the data modeled in the CCOS study, one for EMM and one for EMW, during the last general rate case proceedings and made appropriate adjustments to include a representative large load customer to examine the effect on the CCOS study results. This pro forma large load CCOS analysis ("Large Load CCOS Study") included a hypothetical 384 MW non-coincident peak ("NCP") demand customer receiving service at the transmission voltage with 90 percent coincidence factor with system peak and an 85 percent monthly load factor. This is intended to approximate the characteristics of an existing customer and falls near the middle of the range of loads that are likely to be on Evergy's system.

Q: How was this representative customer incorporated into the Large Load CCOS Study?

A: To develop the Large Load CCOS Study, the Company first took the CCOS study from its last general rate cases (No. ER-2022-0129 for EMM and No. ER-2024-0189 for EMW), and adjusted certain accounts and allocators to reflect the customer addition. Specifically, the projected NCP of 384 MW was added to the current LPS class's NCP. Based on the assumed 85 percent load factor, the customer would add approximately 2.9 million megawatt hours ("MWh") per year to the LPS class. These assumptions and Evergy's current LPS tariff pricing were then used to calculate the customer's base rate revenue additions. Turning to the cost elements of the study, it was assumed that any new infrastructure required to serve the customer will be paid for by the customer. Based on this assumption, no infrastructure additions and other correlated costs specifically to serve the customer have been added to rate base. For Operating Expenses, two separate changes were made to FERC Account 555 (Purchased Power expense) based on assumed changes in power supply and operating capacity costs. To account for an increase in capacity costs, the 384 MW were added (valued at the system average cost of capacity). To account for fuel and/or purchased power, the approximately 2.9 million kWh were added at $0.025 per kWh. This amount is based on a separate study analyzing the incremental pricing impact of adding additional large loads in Evergy's jurisdiction.

The Company also considered a second CCOS view where it was assumed that Evergy will build a new combined cycle gas turbine ("CCGT") and will add 400 MW to its jurisdictional rate base to serve the customer. To account for the new plant in rate base, $629 million was added to FERC Account 344 (Generators). The $629 million is based

on an estimated 400 MW share of a CCGT. Multiple adjustments to operating expenses have been made based on the addition of the CCGT. These include changes to depreciation expense, fixed operation and maintenance ("O&M") expense, variable O&M expense, property insurance expense, and property tax expense.

Q: How were the CCOS results used to support the Company's Schedule LLPS pricing structure?

A: The Company's CCOS model includes a view of the class cost data that compiles the unit cost for each rate element (customer, demand, and energy costs) for each class. The following Table 2 for EMW and Table 3 for EMM contain the key unit costs resulting from the initial scenario where the customer is added without generation.

Table 2

Unit Costs at Present Rates			
Large Power Service Unit Costs	TY Original Values	Including LPS Test Customer	Change
Customer Costs	$49.25	$55.24	$5.99
Excluding Local Facilities	$37.70	$41.71	$4.01
Average Cost per kWh	$0.03037	$0.02881	($0.00156)
Demand Cost Per Billing kW	$14.75	$12.44	($2.31)
Production Demand	$6.13	$6.00	($0.14)
Transmission Demand	$4.84	$4.62	($0.22)
Distribution Demand	$3.77	$1.82	($1.95)

Table 3

Unit Costs at Present Rates			
Large Power Service Unit Costs	TY Original Values	Including LPS Test Customer	Change
Customer Costs	$118.95	$126.14	$7.19
Excluding Local Facilities	$108.63	$115.14	$6.50
Average Cost per kWh	$0.02708	$0.02988	$0.00280
Demand Cost Per Billing kW	$21.26	$19.34	($1.92)
Production Demand	$14.62	$13.37	($1.25)
Transmission Demand	$2.45	$2.19	($0.26)
Distribution Demand	$4.19	$3.78	($0.42)

Q: Were there similar results produced for the second scenario where generation was added?

A: Yes. The following Table 4 for EMW and Table 5 for EMM, provide the same rate elements for the second scenario.

Table 4

Unit Costs at Present Rates			
Large Power Service Unit Costs	**TY Original Values**	**Including LPS Test Customer**	**Change**
Customer Costs	$49.25	$52.91	$3.66
Excluding Local Facilities	$37.70	$40.18	$2.48
Average Cost per kWh	$0.03037	$0.02877	($0.00160)
Demand Cost Per Billing kW	$14.75	$12.79	($1.96)
Production Demand	$6.13	$6.728	$0.59
Transmission Demand	$4.84	$4.355	($0.49)
Distribution Demand	$3.77	$1.71	($2.06)

Table 5

Unit Costs at Present Rates			
Large Power Service Unit Costs	**TY Original Values**	**Including LPS Test Customer**	**Change**
Customer Costs	$118.95	$125.81	$6.86
Excluding Local Facilities	$108.63	$114.88	$6.25
Average Cost per kWh	$0.02708	$0.02999	$0.00291
Demand Cost Per Billing kW	$21.26	$19.30	($1.96)
Production Demand	$14.62	$13.38	($1.24)
Transmission Demand	$2.45	$2.19	($0.27)
Distribution Demand	$4.19	$3.74	($0.45)

Q: Which values were used to set the rates?

A: The Company considered both scenarios in setting the rate and chose a price within the range of these results. In the case of EMM, some consideration was given to the age of the data represented by these results and the range was adjusted accordingly.

Q: Does the CCOS study also provide any insight on how the additional large load customer impacts the other customer classes?

A: Yes. The class rate of return is a measure of the returns related to the costs that can help to assess this impact. When at equilibrium, the class rate of return will match the

jurisdictional rate of return. Classes producing a rate of return less than the jurisdictional rate of return are, in effect, subsidized by classes that have rates of return higher than the jurisdictional rate of return. The rate of return results are examined later in this testimony.

Q: Regarding the last step to design the final Schedule LLPS pricing, what did this step rely on?

A: As with the earlier steps, in the Company's assessment of its current rates, examination of industry approaches, and the goals for this Rate Plan, Evergy determined that the Schedule LLPS rate should be a four-part rate design consisting of a customer charge, grid charge, demand charge, and an energy charge. This structure provides suitable detail regarding the pricing and aligns with structures used in most Evergy jurisdictions. The Company further determined that the rate design pricing should be seasonally differentiated. This is also a common attribute of pricing in Evergy's jurisdictions.

Q: What other, more advanced pricing structures were considered for the Schedule LLPS rate?

A: The Company examined similar rates used in the industry, as well as approaches being promoted more locally. We did not find significant variation from the basic designs in our industry assessment, but we were aware of interest in time-varying designs within the Evergy's jurisdictions. Utilizing a time of use design for energy pricing was considered. However, given that most customers who will seek the Schedule LLPS rate are high load factor energy users (often in excess of 80 percent load factor) the Company concluded that the time of use pricing would offer little benefit at this time.

Q: How did the Company develop the Schedule LLPS pricing?

A: The final pricing was determined by creating a pricing model that contained the desired structure and the initial pricing from the CCOS. Using monthly billing determinants for a representative Schedule LLPS customer, the Company produced the expected revenue and the resulting average price per kWh. The Company then adjusted the pricing to align the Schedule LLPS average price per kWh with the rates calculated under the LPS rate schedules. Grid Charge pricing between the substation and transmission voltages were further informed by data from the CCOS. Provisions are in place to support further seasonal differentiation as actual large load customer data becomes available. Table 6 details the proposed pricing for the Schedule LLPS tariffs.

Table 6

Schedule LLPS Initial Monthly Pricing				
Charges	Missouri Metro		Missouri West	
	Summer	Winter	Summer	Winter
Customer	$ 1,181.28	$ 1,181.28	$ 675.00	$ 675.00
Grid ($/kW) Substation Voltage	$ 3.003	$ 3.003	$ 4.811	$ 4.811
Grid ($/kW) Transmission Voltage	$ 2.200	$ 2.200	$ 4.750	$ 4.750
Demand ($/kW)	$ 14.000	$ 12.000	$ 10.000	$ 8.000
Energy ($/kWh)	$ 0.02988	$ 0.02988	$ 0.02881	$ 0.02881

II. COMPLEMENTARY RIDERS TO SCHEDULE LLPS

Q: Please describe this portion of your testimony.

A: In this section, I elaborate on each of the new tariffs developed as part of the LLPS Rate Plan, which are intended to complement Schedule LLPS. These complementary riders to Schedule LLPS are available on either on a mandatory or optional basis, as summarized below:

Rider	Relationship to Schedule LLPS	Description	Nature of Charge
System Support Rider (Schedule SR)	Mandatory	An additional, non-by passable charge paid by Customers receiving service under Schedule LLPS to ensure appropriate recovery of costs incurred to serve Schedule LLPS customers, and to reflect the acceleration of resource investment required to serve large loads that join the Company's system	$/kW demand charge
Customer Capacity Rider (Schedule CCR)	Optional	Evergy credits customers for using their existing capacity as SPP-accredited capacity	$/kW-month bill credit for capacity contribution
Demand Response Generation Rider (Schedule DRLR)	Optional	Customers use their onsite generation to provide demand response services to Evergy	Bill credit based on demand response commitment and performance

In the remainder of this section, I will discuss each rider in more detail.

System Support Rider (Schedule SR)

Q: What is the System Support Rider (Schedule SR)?

A: The System Support Rider is a new tariffed charge to customers receiving service under Schedule LLPS. This rider is designed to ensure appropriate recovery of costs incurred to serve Schedule LLPS customers, and 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.

Q: How will the System Support Rider ensure appropriate recovery of costs incurred to serve Schedule LLPS customers?

A: The cost recovery component will be calculated based on comparing the Schedule LLPS customer's estimated rate revenue and estimated revenue prior to applying the Customer Capacity Rider, the Demand Response & Local Generation Rider, and the Clean Energy Choice Rider. Should the Schedule LLPS customer's estimated revenue fall below the customer's estimated rate revenue, an amount, expressed in a dollar per kW ($/kw) charge, will be added to the customer bill as an SR charge. This comparison will be completed annually.

Q: What is the effect of this cost recovery component?

A: The cost recovery component will ensure the Schedule LLPS customer's rate is set to recover the cost of service established in the Schedule LLPS rate design. If a Schedule LLPS customer is participating in the Customer Capacity Rider or the Demand Response & Local Generation Rider, the customer will have other options available to reduce its effective rate as a result of contributing positively to the shared grid. That said, the SR charge will not be subject to any otherwise applicable Economic Development Rate discount, as discussed in more detail by Evergy witness Jeff Martin.

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

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

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

Evergy identified 10 years as its timeframe based on a comparison of its normal load growth and the growth it expects with these large load customers. To aid in billing, the SR charge will be expressed in the form of dollars per kW ($/kW) and will be added to

the Schedule LLPS customer's bill. For this rider, the kW amount used for determining the charge will be the billed KW reduced by any capacity provided by the customer through the Customer Capacity Rider, Schedule CCR. The acceleration component will be calculated and updated as part of each Company rate proceeding.

Q: Is the System Support Rider designed to recover the cost of a 700MW CCGT?

A: No. 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.

Q: How will the System Support Rider revenue be used to protect other customers?

A: The Company proposes that during a general rate proceeding and as part of the CCOS study conducted in a general rate case, the revenues produced by Schedule SR will be allocated to the non-LLPS classes. This additional revenue contribution will serve to offset the additional accelerated generation costs expected to flow to those classes. As a result, these allocated revenues will promote fairness and mitigate the risk of undue cross-subsidization by non-LLPS customers.

Q: Why did the Company choose to implement these features within a rider instead of incorporating them into the Schedule LLPS tariffed rate?

A: The Company chose a rider approach to keep such costs and revenues separate from base rates and the normal calculation of any applicable base rate discounts. Evergy believes that this approach will also promote transparency and fairness.

Q: Is there any way for a Schedule LLPS customer to opt-out or otherwise remove the charge?

A: Yes. 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.

Customer Capacity Rider (Schedule CCR)

Q: What is the Customer Capacity Rider ("Schedule CCR")?

A: The Customer Capacity Rider is a new, optional rider applicable to Schedule LLPS that is designed to allow large load customers who own generating resources to contract that capacity to the Company and have that capacity apply to their service. Under the proposed design, all contracting is subject to Company's capacity need and its complete discretion, and must be for capacity amounts no less than a monthly average of 10,000 kilowatts (kW) per year. These controls will ensure that the capacity agreement is beneficial operationally and economically for the Schedule LLPS customer, all other customers, and the Company.

Q: Why might large load customers be interested in participating in Schedule CCR?

A: A number of large customers are actively procuring and maintaining portfolios of renewable generation to support their corporate clean energy goals. Because the energy and capacity from the renewable generation is often sold into the market, the CCR rider benefits large customers by allowing them to contract that capacity to the Company helping satisfy their load. In a situation where the Company needs to build or acquire capacity, using this existing customer-owned capacity could allow customers to achieve higher loads faster. It is also expected that contracting for customer-owned capacity could be more economic for the Schedule LLPS customer and the Company.

Q: Please explain how the Customer Capacity Rider will function.

A: The key mechanism to the Customer Capacity Rider is that it is a bilateral contractual agreement between the Company and customer. This agreement transfers all rights to the Company with provisions that are not limited to the capacity amount, the capacity accreditation, capacity price, deliverability terms, and any other term necessary to define the expected capacity to be received. The accredited capacity amount will be determined by seasonal capacity accreditation (annually for both summer and winter), as determined by SPP's methodology and will be reduced by the applicable SPP planning reserve margin. The Company anticipates this agreement will be similar to other capacity agreements that it has executed. Within the contract and the contracting process, steps will be taken to ensure the customer's capacity is deliverable to the appropriate Company load node. The customer will be responsible for all SPP determined transmission deliverability costs to provide the capacity to Evergy's load node. Details concerning the amount of capacity

contracted, and the negotiated price will be memorialized in the Schedule LLPS Service Agreement.

For each accredited kW of contracted customer capacity, reduced by the applicable SPP planning reserve margin, the customer will receive a credit equal to the price difference between the Schedule LLPS Demand Charge price and the negotiated pricing in the capacity contract. To ensure the customer delivers the amount of capacity contracted, an annual reconciliation will be performed to compare the capacity delivered to the contracted amounts. If customers provide less than their full committed capacity, they will be required to pay a "shortfall penalty" based on a formula set forth in the Company's tariff. If the customer's resource provides more than the committed capacity, the customer will be compensated for each additional kW at the negotiated price.

Q: Please explain how the Company will calculate the value of the Customer Capacity Rider credit.

A: The credit value will be customer specific and will be the difference between the tariffed Demand Charge price and the negotiated price in the capacity contract. The amount of capacity contracted and the negotiated price will be stated in the customer's Service Agreement. The customer's capacity will also be used to reduce the billed demand in applying the System Support Rider charge.

Q: What happens if the customer terminates service or moves to another Company rate schedule where Schedule CCR is not applicable?

A: If the customer terminates service with the Company or moves to another Company rate schedule where Schedule CCR is not applicable, the Company and customer will take the

necessary steps to terminate the capacity contract or revise the contract to allow continued receipt of the capacity by the Company.

Demand Response & Local Generation Rider (Schedule DRLR)

Q: What is the Demand Response and Local Generation Rider, Schedule DRLR?

A: The Demand Response & Local Generation Rider ("Schedule DRLR") provides a new rider option for Schedule LLPS customers to be compensated for using load flexibility or local generation to provide demand response services to the Company when needed. This option provides customers with the ability to reduce their energy bill while providing the Company with the system benefits of having demand response resources that can increase headroom on the Company's system or reduce energy costs for all customers at times of high demand. Under the tariff, the Company may call demand response events for a variety of reasons, including to improve system reliability by reducing customer load during peak and grid condition periods, to address resource adequacy, to offset forecasted system peaks that could result in future generation capacity additions, and/or to reduce costs based on market conditions.

Q: What type of Schedule LLPS customers might be interested in this option?

A: Many large load customers have flexible operations and onsite generation that could be used to curtail power when there are grid alerts or system outages, or when system capacity is constrained. With growth in large load customers, they offer the power of scale to provide hundreds of megawatts of potential demand reduction capacity that could be used to support system reliability. Because not all large load customers have the tolerance or ability to interrupt their operations, the Company proposes this as an optional rate. For customers whose operations can be interrupted, this provides a win-win in terms of

customer and system value. Evergy has decades of experience with various interruptible rates and demand response programs within its jurisdictions to that have provided these benefits.

Q: Are there options within Schedule DRLR that large load customers can choose?

A: Yes. Customers have two options. Under the first option, interruptions for participating customers will be limited to the summer (from June 1 to September 30) and the winter (from December 1 to March 31) for the hours 6:00 a.m. to 10:00 p.m., Monday through Friday excluding holidays. Under the second option, a customer can be interrupted at any time. Customers who enroll in the latter option receive higher compensation. The compensation rate varies monthly and will be paid per kilowatt of measured demand reduction. All specific terms and conditions are further set by the terms of an individual customer participation agreement.

Q: How are the compensation rates calculated and applied to large customers?

A: The Company will use a calculated baseline load or "CBL" method to determine the participant's estimated hourly load. A CBL is an estimate of a customer's hourly or sub-hourly usage patterns or load shape during peak hours. CBLs utilize average load from days prior to demand response events. CBLs use two to 10 qualifying days when selecting which days are utilized for averaging, excluding weekends, holidays, and weather anomalies that may adversely impact the CBL. The baseline is then compared to actual metered average hourly demand during the curtailment event which is used to calculate the hourly kW impact of the event. The Company will then compensate for the level of reduction achieved in a bill credit.

Q: How is the incentive credit calculated?

A: The Company proposes the incentive credit, referred to in the tariff as the "Reduction Credit," be set at a rate of $54 per kW-year for customers enrolled in the unconstrained interruption program. For customers enrolled in the constrained interruption program, the Company proposes the credit be set at a rate of $43 per kW-year for each kW successfully delivered. The tariff sets forth the Company's proposed credit schedules which are differentiated by month. Customers will also be subject to a demand response earnings opportunity fee to recover any foregone earnings from demand response realized capacity reduction and an administrative charge to support the delivery and implementation of the Schedule DRLR program.

Q: Will the Company provide notice to customers of a system curtailment event?

A: Yes. The Company will notify customers in advance of a curtailment event. At a minimum, the Company will notify a customer no less than 10 minutes prior to an event. It should be noted this minimum is associated with automated alerts sent to customer energy control systems. Typically, the Company expects customers will receive notification two to four hours in advance on same day curtailments and a day ahead notice where possible.

Q: Are there limits on how many events the Company can call?

A: Yes. The minimum number of events that the Company will call is one event per season. This event could be an actual curtailment or a test. The constrained and unconstrained curtailment options each have monthly availability hours, and the maximum number of

hours in which an event can be called in each month. Those maximum hours are listed in the tariff and will be noted in participant agreements.

Q: Does the Company plan to use a third-party evaluator to monitor the program?

A: Yes. The Company will hire a third-party evaluator to perform evaluation, measurement, and verification of the participant performance, as well as develop an SPP accreditation report.

Q: How does Schedule DRLR compare to existing demand response programs for large customers?

A: Schedule DRLR is similar in structure to existing Missouri Energy Efficiency Investment Act ("MEEIA"), Commission-approved demand response programs (specifically, Business Demand Response). However, Schedule DRLR differs in the rate code eligibility and slightly in the incentive rate due to that larger MW scale and event call availability.

Q: If this program is similar, why is the Company proposing this rider?

A: The similarities in tariff design between the existing Business Demand Response program and Schedule DRLR program are driven by the Company's desire for a consistent approach toward demand response across all C&I customer classes. The approach is based on a participant's delivered performance and contributions through demand response to reduce system peak and support grid reliability. The distinction between these designs is scale and impact. Large loads present an exponentially greater opportunity to support local and regional reliability based on their individual capacity contributions. The Company has crafted Schedule DRLR so to align load availability of participants to the monthly periods that represent the top percentile of annual system load hours. This approach creates a direct

correlation and opportunity to incentivize customers for their system peak and reliability contributions, thus benefitting all customers.

III. RENEWABLE/CARBON-FREE PROGRAMS WITHIN THE LLPS RATE PLAN

Q: What renewable or carbon-free programs are offered under the LLPS Rate Plan?

A: There are four optional riders developed as part of the LLPS Rate Plan that will enable large customers to procure renewable/carbon free attributes from the Company to help meet their corporate sustainability goals. Many large customers have aggressive corporate clean energy goals and desire energy options that allow them to manage the energy mix that serves them. These optional riders to Schedule LLPS are summarized below:

Rider	Relationship to Schedule LLPS	Description	Nature of Charge
Renewables Rider (Schedule RENEW)	Optional	Unbundled REC offering that provides attributes from Evergy's local generation fleet or attributes procured on the customer's behalf.	Incremental $/kWh charge for applicable attributes
Green Solution Connections (Schedule GSR)	Optional	Unbundled REC offering that provides multi-term current and future year renewable attributes from Evergy's IRP resources.	Incremental $/kWh charge for applicable attributes
Alternative Energy Credits (Schedule AEC)	Optional	Unbundled AEC offering that provides carbon free attributes from Evergy's Wolf Creek nuclear facility.	Incremental $/kWh charge for applicable attributes
Clean Energy Choice Rider (Schedule CER)	Optional	Option to provide customers with a means to influence Evergy's integrated resource plan for clean resource generation	Negotiated installment payment.

Q: Does the Company have existing renewable program offerings where customers can procure renewable attributes?

A: Yes. Evergy offers the Renewable Energy Rider ("Schedule RER") in both Missouri jurisdictions.[11] These tariffs provide non-Residential Customers a voluntary opportunity to purchase renewable energy, in addition to service provided through a generally available rate, from renewable energy sources that the Company contracts. Participants will receive an additional charge or credit to their standard bill based upon the sale of the metered output of the renewable resource into the wholesale market. As part of the tariffs, participating customers also receive the associated renewable attributes associated with their subscription. As resources are identified for the Schedule RER program, the Company expects that Schedule LLPS customers may find value in those programs and may participate. Additionally, as I discuss below, the Company is requesting that the Renewable Energy Program Rider ("Schedule RENEW") be approved for use in the Missouri jurisdictions.

Q: Why is it important for Evergy to provide optionality for customers to secure renewable attributes or consider options to secure carbon free attributes for its customers?

A: It was important for Evergy to consider the changing large load and general C&I customer's carbon free needs in the development of these options to meet the largest of its customers' needs but also realizing that no one program design may meet all customers'

[11] EMW Renewable Energy Rider, Schedule RER, Sheet 139 through 139.7 and EMM Renewable Energy Rider, Schedule RER, Sheet 40 through 40H.

needs. Renewable energy credits ("RECs")[12] are sought by large C&I customers, but to varying degrees. Some large customers prefer a simple historical REC option that is unbundled, meaning that the energy has been disassociated with the REC. Schedule RENEW is an example of an unbundled REC program. Businesses can buy unbundled RECs in one area of the country and apply them to their energy usage in another area of the country, making it difficult to assess the environmental impact. Alternatively, businesses may seek a bundled REC where the RECs are sold together with the physical electricity and part of the same contract where the energy and REC price is fixed for a determined period. Schedule RER is an example of a bundled REC program. Bundled RECs are most often associated with a purchased power agreement ("PPA"). RECs can also be obtained directly from the electric provider, which offers a closer matching of a business' energy use with the production of a given renewable resource. If customers are unable to receive the energy that is associated with a renewable asset, they then seek generation resources that deliver the renewable energy or carbon-free energy ("CFE") to the same balancing authority in which their facility is located. Typically, a bundled REC is more expensive than an unbundled REC. In the LLPS Rate Plan Evergy has developed new programs that will add to its existing renewable customer solutions programs with an eye toward what elements may not be ready now but will be considered for future program offerings. I describe below the new programs to secure renewable/carbon free energy that Evergy proposes as part of the LLPS Rate Plan.

[12] Under Section 393.1025(4), a REC is defined as a tradeable certificate of proof that one megawatt-hour of electricity has been generated from renewable energy sources. I understand that RECs are a market-based instrument that represents the property rights to the environmental, social, and other non-power attributes of renewable electricity generation.

Renewable Energy Program Rider (Schedule RENEW)

Q: Please explain the Renewable Energy Program Rider being proposed by the Company.

A: The Renewable Energy Program Rider ("Schedule RENEW") is a program that has been in place for years in Evergy's Kansas Central territory. Currently, about 21,000 Evergy Kansas Central customers participate in the program. Schedule RENEW provides customers the option to purchase unbundled RECs at a fixed price that is adjusted annually. As this program has been working effectively, Evergy decided to propose expansion of this program to its Missouri territory customers as part of the LLPS Rate Plan.

Q: What does Schedule RENEW offer to customers?

A: Under this program, the Company agrees to generate renewable energy, purchase renewable energy, or purchase RECs in an amount at least equal to the amount contracted for by participants enrolled in Schedule RENEW. Participants may subscribe up to 100 percent of their annual energy usage. During the initial sign up, the customer will designate its desired subscription percentage in increments of 10 percent. Pricing for the RECs is defined in the tariff and is subject to annual price adjustments updates to reflect the market values of the attributes. RECs are retired annually by the Company on behalf of the customer.

Q: How does the Company intend to treat Schedule RENEW program revenues from a ratemaking perspective?

A: Revenues collected from the sale of the historical renewable attributes through Schedule RENEW will be recognized in the associated resource's jurisdictional fuel adjustment clause ("FAC") for the benefit of all respective jurisdictional customers.

Green Solution Connections Rider (Schedule GSR)

Q: Please explain the Green Solution Connections Rider being proposed by the Company.

A: The Green Solution Connection Rider ("Schedule GSR") is a voluntary subscription-based program for C&I customers that will offer eligible customers the opportunity to subscribe to future renewable energy attributes associated with new Company-owned wind and/or solar generation acquired as a result of the Company's IRP process, but which are not needed to meet the Company's compliance obligations. Under this program, customers may subscribe to forward-looking renewable energy attributes for a term of 10 or 15 years based on the associated resource. Revenues collected from the sale of those attributes will offset fuel costs in the associated resource's jurisdictional FAC for the benefit of all respective jurisdictional customers. This program is being proposed for EMM in this filing. The same program has been proposed for EMW in Case No. EA-2024-0292. Company Witness Kimberly H. Winslow offers testimony on Schedule GSR in that proceeding.

Q: Who will be eligible for this program?

A: The Green Solution Connections Program will be available to all non-residential customers, including Schedule LLPS customers, with an average monthly peak demand greater than 200 kW. Subject to Company approval, customers that have an aggregate peak demand of at least 2.5 MW based upon peak annual demand and an average of 200 kW or greater per account are eligible. Additionally, Governmental or Municipal accounts are eligible to aggregate their separate accounts to participate, which is an important distinction I discuss later in my testimony. The program is not restricted but is limited to the REC available from the respective renewable resource.

Q: Please describe the design of Schedule GSR.

A: This program is designed to leverage newly constructed renewable resources, giving subscribers access to RECs that represent additional and regional renewable generation. An eligible C&I customer will subscribe to Schedule GSR and will pay monthly for the cost of renewable attributes generated from the resource at a specified annual price per kilowatt-hour based on the customer's subscribed amount for a fixed term. A customer may subscribe to the percentage of the renewable asset output (kW) needed to match up to 100 percent (in single percentages) of the customer's eligible annual usage to align with the renewable asset's estimated annual generation.

Q: Please discuss the pricing strategy for the renewable attributes offered through Schedule GSR.

A: Fundamentally, Evergy is seeking Commission approval to sell the future renewable attributes tied to future renewable energy generated from renewable assets that it is seeking approval to build as part of its IRP. Evergy currently sells historical, unbundled RECs from its existing renewable generation, ensuring first that all requirements for tariffs, mandatory and voluntary Renewable Portfolio Standards are met prior to consideration of selling. The Company sells these historical renewable attributes to customers, separate from their retail energy service, referred to as unbundled RECs. The sale of historical, unbundled RECs is credited against the respective asset's jurisdictional FAC. Evergy is proposing a 10-year and 15-year contract term option for the GSR Program, with Commission approval to sell the future renewable attributes at a known, or fixed price, over a specific period of time.

Q: Does a market exist to support this pricing?

A: No. While there is an established market for the sale of unbundled RECs, the longest term available in the Green-E/Voluntary North American REC market for National GE Wind/Solar is a five-year term. To adequately price the forward renewable attributes and overcome this limitation, Evergy developed a pricing strategy for the GSR Program that considers two main elements. First, the Company generally understands that C&I customers prefer long-term, fixed-price certainty. Therefore, the GSR Program provides participating customers the option of choosing a 10-year or 15-year agreement. This is an inherent value to C&I customers for long-term price certainty but also comes with risk that Evergy must consider and reflect in its pricing strategy. Second, it is also anticipated that C&I customers will place a higher value on the renewable attributes generated from these assets given that these are: (1) new, carbon-free resources; (2) the solar assets deliver CFE to the same balancing authority that Evergy's Missouri customers are located; and (3) that the Program will retire the renewable attributes on the GSR Program participant's behalf. These three elements formulate the basis for the Program pricing strategy.

Q: Based on this strategy, how is the pricing developed?

A: Evergy developed a pricing approach that sets that basis for forward pricing. The pricing includes the ask price, asset backed premium, market-risk premium, and administrative charge, as summarized below:

- Ask price or basis for unbundled market value:
  - For the near-term, Evergy will rely upon the Green-E/Voluntary National GE Wind/Solar "ask price" as the basis of the unbundled

market value for the renewable attributes (e.g., a forward market "ask price" is provided through 2029)

- For the mid-term, Evergy will rely upon the Electric Reliability Council of Texas ("ERCOT") Texas GE Wind market (*e.g.*, a forward market "ask price" is provided through 2031)
- Evergy will extrapolate pricing for the remainder of the contract length (10 or 15 years)

- Asset-backed premium – this reflects the higher value of the renewable attributes from the specific IRP-related renewable assets: new, carbon-free resources that deliver CFE to the same balancing authority that Missouri customers are located.
  - For years 1-5, the asset-backed premium is 50 percent of the market ask price; and,
  - For Years 6-15, the asset-backed premium is 25 percent of the market ask price given that more renewables are expected to be available, and the premium is likely to lessen.
- Market-risk premium – this will account for pricing variability over the duration of the subscriber's term
  - Beginning in year 5 of the term, Evergy will apply a premium on 10 percent of the market ask for Years 6-15.
- Administration cost – this will reflect the costs of tracking, reporting and retiring renewable attributes on a subscriber's behalf

- The administration cost will apply annually for Years 1-15 and escalate at two percent.

Evergy proposes to reverse the forward pricing curve so that subscribers pay a higher up-front cost in the early years to reflect the long-term financial hedge.

Q: Can you further elaborate on why Evergy is proposing both a 10-year and 15-year agreement for renewable attributes?

A: Yes. Evergy has had significant discussions with the Department of Defense ("DOD"), understanding the requirements of Executive Order 14057,[13] and how it applied to other governmental agencies, such as the National Nuclear Security Administration ("NNSA"). The DOD has significant load in the Missouri service territory. While Executive Order 14057 was rescinded on January 20, 2025, understanding DOD's requirements and limitations was a priority while it was in effect. From these discussions, Evergy learned that 40 U.S. Code § 501 limits public utility contracts to 10 years. Therefore, it was important to construct an agreement that could meet the needs of the federal government to meet their goals, but also provide an opportunity for customers who would want longer, price certain renewable attributes.

Q: Please summarize the benefits of the GSR Program to subscribers.

A: The GSR Program represents an ideal balance to provide subscribers with an option to meet their sustainability goals. The GSR Program fulfills several goals that Evergy seeks to meet C&I customer demand: (a) the Program is designed to be flexible and aligned with

[13] Exec. Order No. 14057, 86 Fed. Reg. 70935 (Dec. 8, 2021) https://www.federalregister.gov/documents/2021/12/13/2021-27114/catalyzing-clean-energy-industries-and-jobs-through-federal-sustainability. This Executive Order affirms that it is the policy of the United States that "the Federal Government [] lead[s] by example in order to achieve a carbon pollution-free electricity sector by 2035 and net-zero emissions economy-wide by no later than 2050. Through a whole-of-government approach, [the United States] will demonstrate how innovation and environmental stewardship can protect our planet, safeguard Federal investments against the effects of climate change, respond to the needs of all of America's communities, and expand American technologies, industries, and jobs." *Id.* at Sec. 101.

large customer demands and desires; (b) it provides the opportunity to acquire renewable energy attributes with long-term price certainty; and (c) it includes renewables that are local and positively impacts non-participants. The program has other specific customer benefits that buying unbundled RECs does not provide, such as predictable pricing, support for the local economy, or improved environment through lower carbon emissions. The pricing of the GSR Program is not tied to the broader wholesale energy market whereas unbundled RECs have that exposure, thus future fluctuations in energy pricing could translate to higher unbundled REC prices.

Q: What are the benefits of the GSR Program to non-participating customers?

A: The sale of these future attributes will provide known benefits over the term of the customer agreements. Revenue collected from subscribing customers for the renewable attributes in this phase will be treated for the benefit of all customers where that resource is planned to meet customer's generation needs.

Q: You refer to "phase" in the prior response - does the Company anticipate more phases of this Program?

A: Yes. This program complements renewable projects within the IRP very well by providing a product that our large customers are requesting. It will also provide benefits to all customers in the jurisdiction where the renewable resource is being developed. However, just because an IRP may add a renewable resource in the future, it does not automatically dedicate its renewable attributes to this program. The Company will evaluate plans to expand the program to include additional phases of the program in future predetermination filings for renewables, which will also be dependent on the needs of our large customers. If the Company deems that the renewable attributes of a resource are not needed for

compliance and that it would like to expand the program, at that time, the Company may seek approval from the Commission to update the pricing for forward renewable attributes associated with those planned IRP renewable assets.

Q: Will the subscriber pay for these renewable attributes through their retail bill?

A: No. The Company is proposing that subscribing customers be invoiced "off-bill" and *via* a separate commercial contract for the program. The approach is used in other transactions involving unbundled REC purchases from Evergy. Subscribers in the GSR Program will be invoiced monthly for the portion of the energy generated based on their subscription times the GSR rate for the corresponding year that the energy was generated. Because the renewable attributes are discretionary purchases by the customer, the Company has opted to provide a separate invoice to participants to keep the customer's electric bill void of extra costs unrelated to the provision of electric service.

Q: How does the Company propose to treat program revenues from a ratemaking perspective?

A: Schedule GSR includes the process that the Company will undertake to allow Evergy's Missouri customers to subscribe to the renewable attributes and how revenue collected from EMW or EMM subscribing customers for the renewable attributes will be treated for the benefit of all customers where that resource is planned to meet customer's generation needs. Revenue collected from the Program will be treated for the benefit of all jurisdictional customers by crediting those revenues to the FAC.

Alternative Energy Credits (Schedule AEC)

Q: Please explain the Alternative Energy Credits Rider the Company is proposing.

A: The Alternative Energy Credit Program ("Schedule AEC") is a new, voluntary tariff that will provide all C&I customers, including Schedule LLPS customers, access to carbon free attributes, referred to as Alternative Energy Credits ("AECs"), which are related to energy produced from the Company's Wolf Creek Nuclear Generating plant ("Wolf Creek"). The tariff allows C&I customers the ability to include these carbon-free credits, also referred to as zero emission credits, in their own clean energy portfolios to support their sustainability needs and decarbonization goals. As part of this program and because the registries used by the Company do not yet manage these credits, the Company will track AECs based on the output of Wolf Creek and will retain a third party to independently certify the attributes on an annual basis.

Q: How do interested customers subscribe?

A: Similar to the other programs in the LLPS Rate Plan, customers will enter into a participation agreement and designate a subscription level in single percentage increments up to 100 percent of their annual usage. The participation agreement will be for a term of one, three, or five years. The Company will require the customer be in good standing to participate in this program. If a customer has received a disconnection notice within 12 months of submitting a participation agreement, it will not be able to subscribe.

Q: How are the pricing terms established for Schedule AEC?

A: The Company has developed a baseline price from other emissions free energy credits (specifically RECs) and used that to develop a rate for AECs, including a minimal administrative charge for validating and retiring the AECs on the customer's behalf. The

final pricing will depend on the term of the agreement. Table 7 details the Company's proposed pricing.

Table 7

AEC Rate Pricing			
Designated Resource	One Year Agreement Term	Three Year Agreement Term	Five Year Agreement Term
Wolf Creek	$0.00866 per kWh	$0.00827 per kWh	$0.00788 per kWh

Q: Are there any other limits to participation?

A: Currently, the only resource designated for this program is Wolf Creek. Should the AECs associated with this facility be insufficient to meet the sum of the annual subscriptions during a calendar year, the Company 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 alternative energy subscribed generation.

Q: How does the Company propose to treat program revenues from a ratemaking perspective?

A: Revenue collected from the program will be treated for the benefit of all jurisdictional customers by crediting those revenues through the Company's FAC mechanism.

Clean Energy Choice Rider (Schedule CER)

Q: What is the Clean Energy Choice Rider?

A: Some large load customers have corporate sustainability or decarbonization goals that seek not only to ensure that the energy they consume meets their energy goals, but also to influence the overall renewable or carbon-free energy generation supply portfolio that serves the jurisdiction(s) where they choose to locate. The Company's Schedule CER is a new rider designed to facilitate this interest by providing a means for LLPS customers to

sponsor and accelerate new clean energy acquisitions through the Company's IRP process. If a Company's IRP Preferred Plan is modified as requested (referred to as a "Clean Energy Preferred Resource Plan"), the requesting customer will fund the incremental costs associated with that portfolio and the acceleration costs associated with that plan. The requesting customer will also have the renewable/carbon-free attributes associated with the modification retired on its behalf.

The Company developed this voluntary program based on feedback and engagement with prospective large load customers and their interest in having: (1) utility-scale generation options that support new, incremental clean energy resource acquisitions on the Company's system; (2) a process by which a customer can request and pay for the incremental costs of specific clean energy resources which are developed and/or owned by the utility; and (3) a process that enables a customer to claim the attributes associated with the modification.

Q: Please explain the mechanics of the Clean Energy Choice Rider.

A: The CER Rider is designed to interact with the Company's IRP process. As the Company performs its triennial resource planning process, it establishes a Preferred Resource Plan under the Commission's IRP Rule, 20 CSR 4240-22.070(1). This Preferred Resource Plan is designed to represent the Company's preferred resource deployment, based on lowest cost and alignment with Company goals, and state and federal legal and regulatory requirements. Schedule CER provides the opportunity for an eligible customer to notify the Company of its interest in sponsoring modifications to the Company's Preferred Resource Plan. The Company will engage with the customer to understand its desired clean resource modifications, will study the alternative resource scenarios, and may then develop

a Clean Energy Preferred Resource Plan. In doing so, the Company will provide the customer with an indicative cost for the desired clean resource modifications. Should the requesting customer request multiple clean resource modifications, the Company may model some or all of them at its discretion. The Company will ensure that any Clean Energy Preferred Resource Plan meets the Company's obligation to provide safe, reliable, and efficient service for all customers.

The requesting customer shall indicate its support for the Clean Energy Preferred Resource Plan and execute an agreement detailing that support and willingness to pay all actual costs associated with the associated cost differential. The resulting Clean Energy Preferred Resource Plan will be submitted to the Commission as part of the Company's IRP process and will be subject to Commission review, and any other appropriate Commission/stakeholder review processes.

Q: How can a requesting customer advocate for a specific resource under Schedule CER?

A: For example, if the Company's Preferred Resource Plan identifies the construction of one or more natural gas resources, a large customer could request the Company to deploy a renewable resource combined with battery storage in lieu of the natural gas resources.

Q: If the Clean Energy Preferred Resource Plan is consistent with the IRP process, what occurs next?

A: The Company will follow good utility practices to execute its Clean Energy Preferred Resource Plan and obtain any necessary Commission approvals to carry out the goals of a Clean Energy Preferred Resource Plan.

Q: How will the differential in cost between the Preferred Plan and a Clean Energy Preferred Resource Plan be calculated and recovered?

A: As cost estimates are developed and following the determination of the final cost of the clean resource development that resulted in the Clean Energy Preferred Resource Plan, the cost differential will be updated to reflect actual costs. An installment payment price will be calculated, inclusive of any contribution in aide of construction taxes, and paid by the requesting customer over a term that is no greater than the expected life of the clean energy resource selected in the Clean Energy Preferred Resource Plan. The Company will bill the requesting customer on its monthly bill until payment of the cost differential is complete. This charge will not be discounted by any applicable economic development rider.

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

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

Q: Will the Company entertain requests from multiple customers for consideration in a single resource plan?

A: Yes. Multiple requests may be modeled to the extent they are mutually compatible within the plan and ensure the Company's ability to provide safe, reliable, and efficient service for all customers. In such a scenario, the cost differential for the Clean Energy Preferred Plan will be shared among the requesting customers based on factors such as requesting customer load share, cost impacts of requested clean resource technologies, or other factors that will be evaluated by the Company. Concerning the renewable attributes, these will be

allocated to the requesting customers on the equivalent basis as the cost differential, as applicable.

Q: What will occur if a Schedule LLPS customer chooses to terminate service or seek service under a rate where the Schedule CER Rider is not available?

A: Should a requesting customer terminate its service at any point after the Company has implemented a Clean Energy Preferred Resource Plan for a specific customer and before the cost differential of the Clean Energy Preferred Resource Plan, or allocated portion, has been fully paid, the customer shall be required to pay the outstanding cost differential as a single payment. The customer agreement will contain terms that set forth these commercial obligations.

IV. OTHER TARIFF CHANGES

Q: Please summarize whether the Company has identified any other tariff changes that need to be made to support the LLPS Rate Plan.

A: In order to implement and accommodate the LLPS Rate Plan, the Company is proposing several additional changes related to its existing tariffs and its Rules & Regulations governing its terms of service. It is possible that additional modifications will be identified through the course of this proceeding, which the Company will present to the Commission and the parties as appropriate.

Q: What additional modifications to existing tariff sheets does the Company propose at this time?

A: The additional modifications proposed are reflected in the redlined tariffs provided as schedules to my testimony, and include:

- EMW Large Power Service and EMM Large Power Service, Schedule LPS will be updated to reflect the 100 kW demand ceiling, above which customers would receive service under Schedule LLPS.
- Section 2 regarding Service Agreements for EMW and EMM will be expanded to add details about the prescribed process for all customers with expected loads greater than 25 MW to request and receive service from the Company. This process is known as the Path to Power which Company witness Jeff Martin discusses in his Direct Testimony. The Path to Power describes the Company's interconnection study process which will allow the Company to guide customers through the process of receiving service and selecting the appropriate rates for their facility.
- Section 9, Extension of Electric Facilities for EMM, and Section 7, Extension of Electric Facilities for EMW. will be expanded. They will clarify that the LLPS Rate Plans is not applicable to the extension of substation or transmission voltage facilities and that all costs (other than Network Upgrades required by SPP) are payable by the requesting customer. These terms will ensure that large customers requesting line extensions are responsible for all costs associated with any of Evergy's dedicated facilities.
- The EMW Special Rate for Incremental Service, Schedule SIL, will be frozen. The need for Schedule SIL was reduced by approval of Schedule MKT. The Company will keep the rate in place to support service provided to the one customer on Schedule SIL rate.

- Fuel Adjustment Clause, Rider FAC for both EMW and EMM, will be revised to recognize the revenues produced from the Renewable Energy Program Rider, Green Solutions Connections Rider and Alternative Energy Credit Rider flowing those benefits back to all customers.

V. ILLUSTRATIVE LARGE CUSTOMER BILLS

Q: Has the Company considered how the components of the LLPS Rate Plan will interact to provide service to a Schedule LLPS customer?

A: Yes. In preparing this filing, the Company has drawn from its considerable experience with C&I customers and has added key elements that Evergy has become acquainted with during the past few years from discussions with existing and prospective large load customers. Schedule LLPS was largely designed to align with and expand on the Company's existing LPS rate structure. The Company then established a design and approach which helps to ensure that a large load customer makes a positive contribution to cost of service, while mitigating cost impacts and providing benefits to all stakeholders. Finally, the Schedule LLPS tariff is complemented with a series of customer-centric options to help large load customers achieve their energy goals.

Q: What will a bill for a Schedule LLPS customer look like?

A: The following examples, shown in Figures 1 through 3, show what a hypothetical customer taking service under Schedule LPS and Schedule LLPS would likely see in its bill. For these examples, I have used the Evergy Missouri Metro bill print format, but an Evergy Missouri West bill would be similar. Figure 1 is for a hypothetical Schedule LPS customer.

Figure 1

Illustrative Bill Example – Current Schedule LPS

Billing Details - service from 12/09/2024 to 01/09/2025

Customer Chg	$1,181.28
Facilities Chg 980.0000 kW at $3.956 per kW .	$3,876.88
Demand Chg 980.0000 kW at $10.433 per kW	$10,224.34
Energy Chg 939.6000 kWh at $0.07737 per kWh	$72.70
Energy Chg 939.6000 kWh at $0.04934 per kWh	$46.36
Energy Chg 1,743.9600 kWh at $0.02577 per kWh	$44.94
DSIM Chg 12-10-2024-01-09-2025 for 3,623.1600 kWh at $0.00187 per kWh	$6.78
FAC Chg 12-10-2024-01-09-2025 for 3,623.1600 kWh at $0.00087 per kWh	$3.15
Subtotal	$15,456.43
City Franchise Fee	$813.50
Missouri State Sales Tax @ 4.225%	$653.03
County Sales Tax @ 1.25%	$193.21
City Sales Tax @ 2.25%	$347.77
Current Charges	**$17,463.94**

Figure 2 is an example of a Schedule LLPS bill. This example assumes the customer needs interim capacity associated with its service. Also, the rate pricing, taxes, and totals would be likely different to reflect the Schedule LLPS pricing. This was left unchanged from the Schedule LPS to reduce less relevant edits and for ease of understanding.

Figure 2

Illustrative Bill Example – Proposed Schedule LLPS

Billing Details - service from 12/09/2024 to 01/09/2025

Customer Chg	$1,181.28
Facilities Chg 980.0000 kW at $3.956 per kW .	$3,876.88
Demand Chg 980.0000 kW at $10.433 per kW	$10,224.34
Interim Demand xxkW at $x.xxx per kW.....	**$x,xxx.xx**
Energy Chg 939.6000 kWh at $0.07737 per kWh	$72.70
Energy Chg 939.6000 kWh at $0.04934 per kWh	$46.36
Energy Chg 1,743.9600 kWh at $0.02577 per kWh	$44.94
DSIM Chg 12-10-2024-01-09-2025 for 3,623.1600 kWh at $0.00187 per kWh	$6.78
FAC Chg 12-10-2024-01-09-2025 for 3,623.1600 kWh at $0.00087 per kWh	$3.15
SR Chg 05-01-2024-05-13-2024 for xxx.xxx kW at $xx.xxx per kW	**$x,xxx.xx**
Subtotal	$15,456.43
City Franchise Fee	$813.50
Missouri State Sales Tax @ 4.225%	$653.03
County Sales Tax @ 1.25%	$193.21
City Sales Tax @ 2.25%	$347.77
Current Charges	**$17,463.94**

Finally, Figure 3 reflects a hypothetical Schedule LLPS customer who chooses to participate in a number of the programs offered in the LLPS Rate Plan. Specifically, this example adds the Customer Capacity Rider, the Alternate Energy Credit Rider, and the Clean Energy Choice Rider. As customers select various riders within the LLPS Rate Plan, the bill would be adjusted to reflect their choices.

Figure 3

Illustrative Bill Example – Proposed Schedule LLPS with expanded Rider application

Billing Details - service from 12/09/2024 to 01/09/2025	
Customer Chg	$1,181.28
Facilities Chg 980.0000 kW at $3.956 per kW .	$3,876.88
Demand Chg 980.0000 kW at $10.433 per kW	$10,224.34
Interim Demand xxkW at $x.xxx per kW.....	**$x,xxx.xx**
CCR Credit xxxx.xxxx kW at $xx.xxx per kW .	**$x,xxx.xx**
Energy Chg 939.6000 kWh at $0.07737 per kWh	$72.70
Energy Chg 939.6000 kWh at $0.04934 per kWh	$46.36
Energy Chg 1,743.9600 kWh at $0.02577 per kWh	$44.94
DSIM Chg 12-10-2024-01-09-2025 for 3,623.1600 kWh at $0.00187 per kWh	$6.78
FAC Chg 12-10-2024-01-09-2025 for 3,623.1600 kWh at $0.00087 per kWh	$3.15
SR Chg 05-01-2024-05-13-2024 for xxx.xxx kW at $xx.xxx per kW	**$x,xxx.xx**
AEC Chg 05-01-2024-05-13-2024 for xxx.xxx kWh at $xx.xxx per kWh	**$x,xxx.xx**
CER Chg Installment Payment at $x,xxx.xx	**$x,xxx.xx**
Subtotal	$15,456.43
City Franchise Fee	$813.50
Missouri State Sales Tax @ 4.225%	$653.03
County Sales Tax @ 1.25%	$193.21
City Sales Tax @ 2.25%	$347.77
Current Charges	**$17,463.94**

Q: Please provide more details regarding the role of the Schedule LLPS Service Agreement.

A: A Service Agreement is common to the utility business, and in Evergy's case is identified in the Company's Rules & Regulations. Its purpose is to define the interaction between the Company and the customer, and to address non-rate terms and conditions, but normally is not executed in contract form. With customers under the Schedule LLPS tariff, the

Company plans to use the Service Agreement to clearly link service under the new rate with the requirements of the Rules & Regulations while adding additional terms to address operational conditions unique to the respective customer and to memorialize customer specific pricing.

The Service Agreement will be used to specify certain provisions of their electric service, including, but not limited to, load characteristics, customer-specific terms, applicable construction cost recovery terms, and other service details, including defined operating procedures. One of the key operational aspects detailed in the Service Agreement is the customer's contract capacity. As discussed earlier in my testimony, the purpose of the contract capacity is to define the customer's annual peak load forecast. This information will be used by the Company to support its resource planning efforts and to support billing under Schedule LLPS. The example, Figure 4, illustrates what the contract capacity forecast may look like in an exhibit to the Service Agreement. The actual form of such an exhibit or numbering and format may be subject to modification.

Figure 4

EXHIBIT A
Contract Capacity
(with Load Ramp within first five years of initial term, if applicable)

Date	Annual Peak Load (kW)
Year 1: XXXX	
Year 2: XXXX	
Year 3: XXXX	
Year 4: XXXX	
Year 5: XXXX	
Year 6: XXXX	
Year 7: XXXX	
Year 8: XXXX	
Year 9: XXXX	
Year 10: XXXX	
Year 11: XXXX	
Year 12: XXXX	
Year 13: XXXX	
Year 14: XXXX	
Year 15: XXXX	

Q: How will the Service Agreement be used to document customer-specific pricing?

A: Given the variety of optional rates and program offerings available to an LLPS customer, the elements included on a given customer's bill will inherently vary from customer to customer. Further, the pricing within these elements is also unique from customer to customer. To address this variability, the Company proposes to use a dedicated exhibit within the Service Agreement to document the pricing for each. As an illustration, Figure 5 shows what the pricing portion of the Service Agreement is expected to look like. This version includes sections to accommodate the Interim Capacity provision of the Schedule LLPS rate, commitments from the Customer Capacity Rider, and terms from the Clean Energy Choice Rider. Note that the exact exhibit/attachment numbering and format may be subject to modification.

Figure 5

EXHIBIT D
Summary of Customer-Specific Pricing

Interim Capacity					
Description	Summer Amount (kW)	Winter Amount (kW)	Summer Price	Winter Price	Term
Customer Capacity Rider					
Description	Summer Amount (kW)	Winter Amount (kW)	Summer Price	Winter Price	Term
Clean Energy Choice Rider					
Description			Modified Plan Cost		Term
System Support Rider – Cost Recovery Component					
Description			Component Value ($ per kW)		Date
Other					

Q: How will the Company keep the Commission aware of these terms?

A: The Company anticipates making individual Service Agreements available to the Commission and the parties as requested, although confidentiality protections will likely need to be addressed on a case-by-case basis, depending on the terms and conditions of each Service Agreement and each customer's commercial concerns.

Q: As the Company's proposed tariffs contemplate a number of customer agreements, how will they relate to each other?

A: The LLPS Rate Plan will rely on a variety of contracts and agreements that are designed to complement the various LLPS Rate Plan tariffs. Evergy will ensure that there is an opportunity to address the unique needs and considerations of each customer, while preserving commercial remedies for the Company if a customer breaches the terms of an agreement. Below is a summary of some of the topics that will likely be covered by separate agreements:

- Construction & Planning – These agreements are at the earliest stages of customer interaction and generally align with the Path to Power processes which include interactions with SPP and construction activities.
- Capacity – These agreements are in the form of bilateral contracts or other market-level contracts typically used by the Company's_marketing and origination functions. The interim capacity provision within Schedule LLPS and the Customer Capacity Rider agreement are examples.
- Participation Agreements – These are customer agreements that set terms for participating in an optional program or rider. These agreements are common to other existing Company programs for energy efficiency and demand response. All the renewable riders in the LLPS Rate Plan will have a related participation agreement. With respect to the Clean Energy Choice Rider, given the relatively long period of time associated execution of the IRP planning process, the agreement will be especially important to define commitments by the customer and the Company.
- Billing – The Service Agreement and the illustrative Exhibit D in Figure 5, will be useful in defining the key terms from the various agreements and used to support billing.

The Company expects, consistent with many of its current practices and obligations, to execute these contracts and administer them going forward. These agreements will be available within rate cases or other Commission proceedings to inform and support steps taken in performing the commitments of the tariff and riders and then execution of the related customer billing.

VI. LARGE LOAD CUSTOMER BENEFITS

Q: In summary, what are the benefits of adding large load customers to the Company's system?

A: If appropriate risk parameters are developed, adding new large load customers will be beneficial to all customers and the State of Missouri. While Company witnesses Kevin Gunn and Jeff Martin discuss the economic development benefits, there will be ratemaking benefits as well. Notably, the ratemaking construct is firmly based on energy sales. As additional customers are added to the system and our retail load, the amount of energy consumed will enable the Company to spread the fixed costs of utility service across more kilowatt-hours, in turn reducing the average costs for all customers. The key to making this successful is adding customers at an average or above-average cost to serve. This benefit is reinforced due to the nature of the large load energy consumption. Most large load customers tend to be high load factor customers, meaning their energy consumption is more stable relative to their peak demand. Data centers often have load factors of 80 to 95 percent, which is well above the typical customer load factor.

Q: Has the Company attempted to model any of these benefits?

A: Yes. The CCOS model is one way to show this effect. Using the same CCOS models described earlier to support the base rate pricing, the Company explored the effect on all customer classes, this time focusing on the class Rates of Return. The class Rate of Return is a measure of the class Net Operating Income as a percentage of the class Total Rate Base. In traditional rate design, comparing the class Rates of Return will help identify classes that are producing more revenue or less revenue as compared to each other class's share of allocated costs or the jurisdiction as a whole. The goal of ratemaking is to have all classes show a positive Rate of Return, equal to the jurisdictional Rate of Return.

Recalling the process I described earlier, the Company included a representative large load customer[14] into the Company CCOS study from its most recent rate cases in this jurisdiction, No. ER-2022-0129 for EMM and No. ER-2024-0189 for EMW. This customer addition adds revenue, based on the current LPS rates and adds Purchased Power Capacity and Purchased Power Energy to align with the new load. The Company also modeled additional details to represent execution of the LLPS Rate Plan. Specifically,

- The addition of a 400 MW Combined Cycle Gas Turbine ("CCGT") generating unit to test the class impacts with added plant investment; and,
- Estimated revenues produced by the acceleration component of the System Support Rider and allocated to other classes.

In its modeling, the Company approximated the impact of this added load and added investment. Table 8 and Table 9 show the collective results in all scenarios for EMW and EMM respectively.

Table 8

Class	Rates of Return at Present Rates				
	Test Year Original Values	No Generation Investment		With CCGT Investment	
		Including LPS Test Customer	Change	Including LPS Test Customer	Change
Residential	2.64%	3.94%	1.30%	3.38%	0.74%
Small General Service	9.29%	11.42%	2.13%	9.54%	0.25%
Large General Service	7.58%	9.88%	2.31%	8.12%	0.54%
Large Power Service	5.94%	13.23%	7.29%	10.21%	4.27%
Thermal	0.00%	0.00%	0.00%	0.00%	0.00%
Special Contracts	9.00%	8.99%	0.00%	8.99%	0.00%
Electric Vehicle	-59.93%	-60.04%	-0.11%	-58.76%	1.17%
MO West Retail	**4.64%**	**7.34%**	**2.70%**	**6.12%**	**1.48%**

[14] The representative customer has a projected NCP of 384 MW with an 85 percent load factor. The representative customer will add approximately 2.9 million megawatt hours (MWh) per year to the current class.

Table 9

Class	Rates of Return at Present Rates				
	Test Year Original Values	No Generation Investment		With CCGT Investment	
		Including LPS Test Customer	Change	Including LPS Test Customer	Change
Residential	2.04%	4.03%	1.99%	3.51%	1.47%
Small General Service	9.08%	12.19%	3.11%	10.39%	1.31%
Medium General Service	10.11%	14.09%	3.98%	11.65%	1.54%
Large General Service	10.33%	14.34%	4.01%	11.84%	1.51%
Large Power Service	9.63%	10.23%	0.60%	8.48%	-1.14%
Lighting	9.62%	11.45%	1.83%	10.64%	1.02%
CCN	-55.49%	-56.25%	-0.77%	-53.78%	1.71%
MO Metro Retail	**5.88%**	**8.57%**	**2.69%**	**7.26%**	**1.38%**

Comparing the class Rates of Return relative to the Test Year Original Values in these examples shows that under the Schedule LLPS approach (specifically with the LLPS rate priced at a similar level to the current LPS rates and combined with the System Support Rider) will provide benefits in nearly all scenarios examined.

Starting with the EMW results in Table 8, under the "no generation investment" scenario, the rate of return increases for all primary customer classes.[15] Under the "with CCGT" scenario, the rate of return similarly increases, but at a smaller rate as the addition of the CCGT plant increases the EMW rate base. Additional revenue produced by the System Support Rider and allocated to the non-LPS classes provides the main benefit.

Turning to the EMM results in Table 9, the potential addition of the representative large load customer benefits the EMM system and its customer classes in both the "no generation" and the "with CCGT" scenarios except for the LPS class under the "with CCGT" scenario. The return on rate base at present rates decreases from 9.63 percent to 8.48 percent, indicating that the LPS class is slightly harmed by adding the Customer under this set of assumptions and inputs. The decrease in the LPS rate of return is a result of the additional costs being predominantly allocated on the basis of energy. As the new customer

[15] There are no customers in the Thermal Class and the Special Contract Class includes only one customer.

has a very high load factor (85 percent), more costs are pulled into the class through the allocation process.

Q: Does the Company's CCOS modeling reflect that Schedule LLPS will support a positive or neutral impact on all customers from a ratemaking perspective?

A: Yes. The CCOS modeling shows that all non-LPS class customers should benefit or be held harmless from a ratemaking perspective as new Schedule LLPS customers are added. Expressed another way, the effects of adding a large load customer, with or without added generation, produce benefits under the proposed LLPS rate design. This occurs through the addition of high load factor customers through comparably priced rates and supplemented by the additional revenue produced by the System Support Rider and allocated to the other classes.

Q: Are there other benefits to adding these large load customers?

A: Yes. Traditional economic development benefits exist for these large load customers. Company witnesses Kevin Gunn and Jeff Martin explain and support the benefits that can be achieved by adding these customers.

VII. CONCLUSION

Q: Please summarize your testimony.

A: The Company has conducted a thorough and diligent process to develop tariffs and rate design approaches that will attract and retain large customers, while protecting non-participants from undue risk. The proposed LLPS Rate Plan starts with the new Schedule LLPS tariff, the core component of the LLPS Rate Plan. Applicable to customers with loads greater than 100 MW, the Schedule LLPS tariff lays out a pricing structure combined with key protections such as minimum bills, exit fees, and collateral requirements. The design also incorporates provisions for interim capacity and contract capacity adjustments,

features that should improve flexibility for customers, facilitate speed-to-market, and avoid potential undue cross-subsidization. The Schedule LLPS design leverages a written Service Agreement to provide further operational clarity and to memorialize customer specific pricing. When linked to the mandatory System Support Rider, Schedule SR, the rate design is reinforced with measures to account for accelerated generation investment and potential cost subsidization.

The various riders and renewable programs that complement Schedule LLPS are a collection of solutions to meet the unique needs of today's large load customers. These programs are responsive the feedback that Evergy received from potential large load customers. They provide key accommodations to help reduce their energy costs and offer a variety of clean and renewable energy options. Specifically, the Customer Capacity Rider and the Demand Response & Local Generation Rider offer a means to control capacity costs and leverage resources owned by the large load customer. The renewable riders, specifically the Renewable Energy Program Rider, Alternative Energy Credit Rider, Green Solution Connections Rider, Direct Renewable Participation Service, and Renewable Energy Rider provide a range of bundled and unbundled solutions to help achieve a given customer's renewable and carbon-free energy goals. The Clean Energy Choice Rider goes beyond these programs and establishes a way for large load customers to actively support electric grid within the areas that large load customers choose to operate.

Finally, the LLPS Rate Plan requires numerous revisions to other tariffs to incorporate the Rate Plan into the Company's current tariffs. These revisions include modifications to the existing EMW Large Power Service and EMM Large Power Service,

Schedule LPS tariffs, additions to the Company's Rules & Regulations, and edits to the EMW and EMM Fuel Adjustment Clause, Rider FAC.

Q: What is your recommendation to the Commission?

A: I recommend the Commission accept and approve the LLPS Rate Plan and its components in full. If approved, this comprehensive solution will allow the Company to address the unique opportunities offered by large load customers and to ensure the maximum benefit for all stakeholders.

Q: Does this conclude your testimony?

A: Yes.

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	)))))	File No. EO-2025-0154

AFFIDAVIT OF BRADLEY D. LUTZ

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

Bradley D. Lutz, being first duly sworn on his oath, states:

1. My name is Bradley D. Lutz. I work in Kansas City, Missouri, and I am employed by Evergy Metro, Inc. as Direct, Regulatory Affairs.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Evergy Missouri Metro and Evergy Missouri West consisting of seventy-two (72) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Bradley D. Lutz

Subscribed and sworn before me this 14th day of February 2025.

Notary Public

My commission expires: 4/26/2025

ANTHONY R. WESTENKIRCHNER
NOTARY PUBLIC - NOTARY SEAL
STATE OF MISSOURI
MY COMMISSION EXPIRES APRIL 26, 2025
PLATTE COUNTY
COMMISSION #17279952

~~KANSAS CITY POWER & LIGHT COMPANY~~EVERGY MISSOURI METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No. 7 ~~First~~2nd Revised Sheet No. 14

Canceling P.S.C. MO. No. 7 1st ~~Original~~Revised Sheet No. 14

For Missouri Retail Service Area

LARGE POWER SERVICE
Schedule LPS

AVAILABILITY

For electric service through one meter to a customer using electric service for purposes other than those included in the availability provisions of the Residential Service Rate Schedule. At the Company's discretion, service may be provided through more than one meter where it is economical for the Company to do so.

Service will not be supplied where the ultimate use is primarily for residential purposes.

Customers whose monthly demand is reasonably expected to reach or exceed one hundred thousand (100,000) kilowatts shall not be allowed to continue receiving service under this schedule and will be required to receive service under Schedule LLPS.

Service is available under this schedule to the following types of customers based on voltage level:

Secondary voltage customer -	Receives service on the low side of the line transformer.
Primary voltage customer -	Receives service at Primary Voltage of 12,000 volts or over but not exceeding 69,000 volts. Customers receiving service at 4160 volts as of May 5, 1986 are also classified as Primary voltage customers. Customer will own all equipment necessary for transformation including the line transformer.
Substation voltage customer -	Service is taken directly out of a distribution substation at primary voltage. The customer will own the feeder circuits out of this substation.

Standby, breakdown, or supplementary service is available under this schedule if the customer seeking such service first enters into a special contract which includes technical and safety requirements similar to those required for qualifying facilities in 4 ~~CSR~~ 20 CSR 4240-20.060(2)(C). These requirements, and the associated interconnection costs, shall be reasonable and assessed on a nondiscriminatory basis with respect to other customers with similar load characteristics. Temporary or seasonal service will not be supplied under this schedule.

TERM OF CONTRACT

Contracts under this schedule shall be for a period of not less than one year from the effective date thereof.

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided ~~the Effective Date of This Tariff Sheet~~January 1, 2023 and

DEFINITIONS

ACCUMULATION PERIODS, FILING DATES AND RECOVERY PERIODS: An accumulation period is the six calendar months during which the actual costs and revenues subject to this rider will be accumulated for the purposes of determining the Fuel Adjustment Rate ("FAR"). The two six-month accumulation periods each year through four years from the effective date of this tariff sheet, the two corresponding twelve-month recovery periods and the filing dates are as shown below. Each filing shall include detailed work papers in electronic format with formulas intact to support the filing.

Accumulation Periods	**Filing Dates**	**Recovery Periods**
January – June	By August 1	October – September
July – December	By February 1	April – March

A recovery period consists of the months during which the FAR is applied to retail customer billings on a per kilowatt-hour (kWh) basis.

COSTS AND REVENUES: Costs eligible for the Fuel and Purchased Power Adjustment ("FPA") will be the Company's allocated jurisdictional costs for the fuel component of the Company's generating units, reservation charges, purchased power energy charges including applicable Southwest Power Pool ("SPP") charges, emission allowance costs and amortizations, cost of transmission of electricity by others associated with purchased power and off-system sales – all as incurred during the accumulation period. These costs will be offset by jurisdictional off-system sales revenues, applicable SPP revenues, ~~and~~ revenue from the sale of Renewable Energy Certificates or Credits ("REC") and Revenues from the Renewable Energy Program Rider, Green Solutions Connections Rider and Alternative Energy Credit Rider. Eligible costs do not include the purchased power demand costs associated with purchased power contracts in excess of one year. Likewise, revenues do not include demand or capacity receipts associated with power contracts in excess of one year.

APPLICABILITY

The price per kWh of electricity sold to retail customers will be adjusted (up or down) in April and October subject to application of the Rider FAC and approval by the Missouri Public Service Commission ("MPSC" or "Commission").

The FAR is the result of dividing the FPA by forecasted Missouri retail net system input ("S_{RP}") for the recovery period, expanded for Voltage Adjustment Factors ("VAF"), rounded to the nearest $0.00001, and aggregating over two accumulation periods. The amount charged on a separate line on retail customers' bills is equal to the current annual FAR multiplied by kWh billed.

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided ~~the Effective Date of This Tariff Sheet~~January 1, 2023 and

FORMULAS AND DEFINITIONS OF COMPONENTS

FPA = 95% * ((ANEC – B) * J) + T + I + P

ANEC = Actual Net Energy Costs = (FC + E + PP + TC – OSSR – R – REV)

FC = Fuel costs, excluding decommissioning and retirement costs, incurred to support sales and revenues associated with the Company's in-service generating plants:
The following costs reflected in Federal Energy Regulatory Commission ("FERC") Account Number 501:
Subaccount 501000: coal commodity and transportation, side release and freeze conditioning agents, dust mitigation agents, applicable taxes, accessorial charges as delineated in railroad accessorial tariffs [additional crew, closing hopper railcar doors, completion of loading of a unit train and its release for movement, completion of unloading of a unit train and its release for movement, delay for removal of frozen coal, destination detention, diversion of empty unit train (including administration fee, holding charges, and out-of-route charges which may include fuel surcharge), diversion of loaded coal trains, diversion of loaded unit train fees (including administration fee, additional mileage fee or out-of-route charges which may include fuel surcharge), fuel surcharge, held in transit, hold charge, locomotive release, miscellaneous handling of coal cars, origin detention, origin re-designation, out-of-route charges (including fuel surcharge), out-of-route movement, pick-up of locomotive power, placement and pick-up of loaded or empty private coal cars on railroad supplied tracks, placement and pick-up of loaded or empty private coal cars on shipper supplied tracks, railcar storage, release of locomotive power, removal, rotation and/or addition of cars, storage charges, switching, trainset positioning, trainset storage, and weighing], unit train maintenance, leases, taxes and depreciation, natural gas costs including reservation charges, fuel quality adjustments, fuel adjustments included in commodity and transportation costs, broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers), oil costs for commodity, transportation, storage, taxes, fees, and fuel losses, coal and oil inventory adjustments, and insurance recoveries, subrogation recoveries and settlement proceeds for increased fuel expenses in the 501 Accounts.
Subaccount 501020: the allocation of the allowed costs in the 501000, 501300, 501400 and 501420 accounts attributed to native load;
Subaccount 501030: the allocation of the allowed costs in the 501000, 501300, 501400 and 501420 accounts attributed to off system sales;
Subaccount 501300: fuel additives and consumable costs for Air Quality Control Systems ("AQCS") operations, such as ammonia, hydrated lime, lime, limestone, limestone inventory adjustments, powder activated carbon, calcium bromide, sulfur, and RESPond, or other consumables which perform similar functions;
Subaccount 501400 and 501420: residuals costs and revenues associated with combustion byproducts, slag and ash disposal costs and revenues including contractors, materials and other miscellaneous expenses.
The following costs reflected in FERC Account Number 518:
Subaccount 518000: nuclear fuel commodity and insurance recoveries, subrogation recoveries and settlement proceeds for increased fuel expenses in the 518 Accounts
Subaccount 518201: nuclear fuel waste disposal expense;
Subaccount 518100: nuclear fuel oil.

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided ~~the Effective Date of This Tariff Sheet~~January 1, 2023 and

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

OSSR = Revenues from Off-System Sales:
The following revenues or costs reflected in FERC Account Number 447:
Subaccount 447020: all revenues from off-system sales. This includes charges and credits related to the SPP IM, or other IMs, including, energy, ancillary services, revenue sufficiency (such as make whole payments and out of merit payments and distributions), revenue neutrality payments and distributions, over collected losses payments and distributions, TCR and ARR settlements, demand reductions, virtual energy costs and revenues and related fees where the virtual energy transaction is a hedge in support of physical operations related to a generating resource or load, generation/export charges, ancillary services including non-performance and distribution payments and SPP uplift revenues or credits, but excluding (1) off-system sales revenues from full and partial requirements sales to municipalities that are served through bilateral contracts in excess of one year, (2) the amounts associated with PPA associated with the Renewable Energy Rider tariff, (3) SPP revenues associated with the CNPPID Hydro PPA and (4) net costs associated with wind PPA entered into after May 2019 whose costs exceed their revenues resulting in a net loss.

Notwithstanding anything to the contrary contained in the tariff sheets for Rider FAC, factors PP and OSSR shall not include costs and revenues for any undersubscribed portion of a permanent Solar Subscription Rider resource allocated to shareholders under the approved stipulation in File No. ER-2022-0129.

Subaccount 447012: capacity charges for capacity sales one year or less in duration;

Subaccount 447030: the allocation of the includable sales in account 447020 not attributed to retail sales.

R = Renewable Energy Credit Revenue:
Revenues reflected in FERC account 509000 and gains or losses to be recorded in FERC accounts 411800 and 411900 from the sale of Renewable Energy Credits (RECs) that are not needed to meet the Missouri Renewable Energy Standards less the cost associated with making the sale.

REV = Revenues from the Renewable Energy Program Rider, Green Solutions Connections Rider and Alternative Energy Credit Rider reflected in retail revenue FERC Account Numbers 440-444

Any cost identified above which is a Missouri-only cost shall be grossed up by the current kWh energy factor, included in the ANEC calculation and allocated as indicated in component J below. Any cost identified above which is a Kansas-only cost shall be excluded from the ANEC calculation.

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided ~~the Effective Date of This Tariff Sheet~~January 1, 2023 and

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

Costs and revenues not specifically detailed in Factors FC, PP, E, TC, OSSR, R or REV shall not be included in the Company's FAR filings; provided however, in the case of Factors PP, TC or OSSR, the market settlement charge types under which SPP or another centrally administered market (e.g., PJM or MISO) bills/credits a cost or revenue need not be detailed in Factors PP or OSSR for the costs or revenues to be considered specifically detailed in Factors PP or OSSR; and provided further, should the SPP or another centrally administered market (e.g. PJM or MISO) implement a new market settlement charge type not listed below or a new schedule not listed in TC:

SPP IM charge/revenue types that are included in the FAC are listed below:

Day-Ahead Ramp Capability Up Amount
Day-Ahead Ramp Capability Down Amount
Day-Ahead Ramp Capability Up Distribution Amount
Day-Ahead Ramp Capability Down Distribution Amount
Day Ahead Regulation Down Service Amount
Day Ahead Regulation Down Service Distribution Amount
Day Ahead Regulation Up Service Amount
Day Ahead Regulation Up Service Distribution Amount
Day Ahead Spinning Reserve Amount
Day Ahead Spinning Reserve Distribution Amount
Day Ahead Supplemental Reserve Amount
Day Ahead Supplemental Reserve Distribution Amount
Real Time Contingency Reserve Deployment Failure Amount
Real Time Contingency Reserve Deployment Failure Distribution Amount
Real Time Ramp Capability Up Amount
Real Time Ramp Capability Down Amount
Real Time Ramp Capability Up Distribution Amount
Real Time Ramp Capability Down Distribution Amount
Real Time Ramp Capability Non-Performance Amount
Real Time Ramp Capability Non-Performance Distribution Amount
Real Time Regulation Service Deployment Adjustment Amount
Real Time Regulation Down Service Amount
Real Time Regulation Down Service Distribution Amount
Real Time Regulation Non-Performance
Real Time Regulation Non-Performance Distribution
Real Time Regulation Up Service Amount
Real Time Regulation Up Service Distribution Amount
Real Time Spinning Reserve Amount
Real Time Spinning Reserve Distribution Amount
Real Time Supplemental Reserve Amount
Real Time Supplemental Reserve Distribution Amount
Day Ahead Asset Energy
Day Ahead Non-Asset Energy
Day Ahead Virtual Energy Amount

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided ~~the Effective Date of This Tariff Sheet~~January 1, 2023 and

Should FERC require any item covered by components FC, E, PP, TC, OSSR, R or REV to be recorded in an account different than the FERC accounts listed in such components, such items shall nevertheless be included in component FC, E, PP, TC, OSSR, R or REV. In the month that the Company begins to record items in a different account, the Company will file with the Commission the previous account number, the new account number and what costs or revenues that flow through the Rider FAC to be recorded in the account.

B = Net base energy costs ordered by the Commission in the last general rate case consistent with the costs and revenues included in the calculation of the FPA. Net Base Energy costs will be calculated as shown below:

S_{AP} x Base Factor ("BF")

S_{AP} = Net system input ("NSI") in kWh for the accumulation period

BF = Company base factor costs per kWh: $0.01829

J = Missouri Retail Energy Ratio = (MO Retail kWh sales + MO Losses) / (MO Retail kWh Sales + MO Losses + KS Retail kWh Sales + KS Losses + Sales for Resale, Municipals kWh Sales [includes border customers] + Sales for Resale, Municipals Losses)
MO Losses = 6.09%; KS Losses = 6.51%; Sales for Resale, Municipals Losses = 6.84%

T = True-up amount as defined below.

I = Interest applicable to (i) the difference between Missouri Retail ANEC and B for all kWh of energy supplied during an AP until those costs have been recovered; (ii) refunds due to prudence reviews ("P"), if any; and (iii) all under- or over-recovery balances created through operation of this FAC, as determined in the true-up filings ("T") provided for herein. Interest shall be calculated monthly at a rate equal to the weighted average interest paid on the Company's short-term debt, applied to the month-end balance of items (i) through (iii) in the preceding sentence.

P = Prudence disallowance amount, if any, as defined in this tariff.

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No. 7 ~~3rd~~4th Revised Sheet No. 50.42

Canceling P.S.C. MO. No. 7 ~~2nd~~3rd Revised Sheet No. 50.42

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided January 9, 2023 and Thereafter)
Effective for the Customer Usage Beginning ~~October 2024~~xxx through ~~March 2025~~xxx

Accumulation Period Ending: **June 2024**			
1	Actual Net Energy Cost (ANEC) = (FC+E+PP+TC-OSSR-R~~-~~REV)		$151,039,699
2	Net Base Energy Cost (B)	-	$138,603,979
	2.1 Base Factor (BF)		$0.01829
	2.2 Accumulation Period NSI (S_{AP})		7,578,128,999
3	(ANEC-B)		$12,435,719
4	Jurisdictional Factor (J)	x	53.7257%
5	(ANEC-B)*J		$6,681,177
6	Customer Responsibility	x	95%
7	95% *((ANEC-B)*J)		$6,347,118
8	True-Up Amount (T)	+	$1,809,350
9	Interest (I)	+	$433,758
10	Prudence Adjustment Amount (P)	+	$0
11	Fuel and Purchased Power Adjustment (FPA)	=	$8,590,226
12	Estimated Recovery Period Retail NSI (S_{RP})	÷	8,868,794,365
13	Current Period Fuel Adjustment Rate (FAR)	=	$0.00097
14			
15	Current Period FAR_{Trans} = FAR x VAF_{Trans}		$0.00100
16	Prior Period FAR_{Trans}	+	($0.00016)
17	Current Annual FAR_{Trans}	=	$0.00084
18			
19	Current Period FAR_{Sub} = FAR x VAF_{Sub}		$0.00101
20	Prior Period FAR_{Sub}	+	($0.00017)
21	Current Annual FAR_{Sub}	=	$0.00084
22			
23	Current Period FAR_{Prim} = FAR x VAF_{Prim}		$0.00102
24	Prior Period FAR_{Prim}	+	($0.00017)
25	Current Annual FAR_{Prim}	=	$0.00085
26			
27	Current Period FAR_{Sec} = FAR x VAF_{Sec}		$0.00104
28	Prior Period FAR_{Sec}	+	($0.00017)
29	Current Annual FAR_{Sec}	=	$0.00087
30	VAF_{Trans} = 1.0300		
31	VAF_{Sub} = 1.0378		
32	VAF_{Prim} = 1.0497		
33	VAF_{Sec} = 1.0690		

9. EXTENSION OF ELECTRIC FACILITIES (continued)

9.11 Summary Of Policy Administration (continued)

(C). Residential Multi-Family or Residential Mobile Home Trailer Parks

All applicants, classified as permanent service, will have a Construction Allowance calculated per the feasibility model (Section 9.02 C. Construction Allowance) for the customized project. The Construction Allowance is subtracted from the Estimated Construction Cost for the Applicant's project in order to determine the Nonrefundable Construction Charge to be paid by Applicant. Applicant will also be responsible for all Estimated Construction Charges related to the cost of connecting to Company's existing and adequate distribution facilities when the length is greater than 100 feet. Applicant will pay these costs to Company as a Nonrefundable Construction Charge.

(D). Commercial or Industrial

All applicants, classified as permanent service, will have a Construction Allowance calculated per the feasibility model (Section 9.02 C. Construction Allowance) for the customized project. The Construction Allowance is subtracted from the Estimated Construction Cost for the Applicant's project in order to determine the Nonrefundable Construction Charge to be paid by Applicant. The cost of the Distribution Extension on public right-of-way is generally included in the Estimated Construction Cost except where the Applicant requires an extension other than a standard overhead extension. Where underground service on public right-of-way is required and agreed to by Company, the Applicant will be required to pay for the required facilities as either a Nonrefundable Construction Charge or as a surcharge on its monthly bill, at Company's discretion.

(E). TRANSMISSION OR SUBSTATION FACILITIES EXTENSIONS

For extensions of transmission or substation facilities, any Customer requesting service with substation or transmission facilities shall pay all costs associated with such extensions. These costs do not include any resulting Network Upgrade costs for facilities classified as transmission under the Southwest Power Pool Open Access Transmission Tariff. Customers requesting service through substation or transmission facilities must complete payment for the extension or make suitable arrangements for installment payments, execute all required agreements associated with the requested extensions, and execute any Service Agreements required by the applicable rate schedule as a condition for any construction to commence.

LARGE POWER SERVICE
Schedule LPS

AVAILABILITY

For electric service through one meter to a customer using electric service for purposes other than those included in the availability provisions of the Residential Service Rate Schedule. At the Company's discretion, service may be provided through more than one meter where it is economical for the Company to do so.

Service will not be supplied where the ultimate use is primarily for residential purposes.

Customers whose monthly demand is reasonably expected to reach or exceed one hundred thousand (100,000) kilowatts shall not be allowed to continue receiving service under this schedule and will be required to receive service under Schedule LLPS.

Service is available under this schedule to the following types of customers based on voltage level:

Secondary voltage customer - Receives service on the low side of the line transformer.

Primary voltage customer - Receives service at Primary Voltage of 12,000 volts or over but not exceeding 69,000 volts. Customers receiving service at 4160 volts as of May 5, 1986 are also classified as Primary voltage customers. Customer will own all equipment necessary for transformation including the line transformer.

Substation voltage customer - Service is taken directly out of a distribution substation at primary voltage. The customer will own the feeder circuits out of this substation.

Standby, breakdown, or supplementary service is available under this schedule if the customer seeking such service first enters into a special contract which includes technical and safety requirements similar to those required for qualifying facilities in 20 CSR 4240-20.060(2)(C). These requirements, and the associated interconnection costs, shall be reasonable and assessed on a nondiscriminatory basis with respect to other customers with similar load characteristics. Temporary or seasonal service will not be supplied under this schedule.

TERM OF CONTRACT

Contracts under this schedule shall be for a period of not less than one year from the effective date thereof.

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided January 1, 2023 and Thereafter)

DEFINITIONS

ACCUMULATION PERIODS, FILING DATES AND RECOVERY PERIODS: An accumulation period is the six calendar months during which the actual costs and revenues subject to this rider will be accumulated for the purposes of determining the Fuel Adjustment Rate ("FAR"). The two six-month accumulation periods each year through four years from the effective date of this tariff sheet, the two corresponding twelve-month recovery periods and the filing dates are as shown below. Each filing shall include detailed work papers in electronic format with formulas intact to support the filing.

Accumulation Periods	Filing Dates	Recovery Periods
January – June	By August 1	October – September
July – December	By February 1	April – March

A recovery period consists of the months during which the FAR is applied to retail customer billings on a per kilowatt-hour (kWh) basis.

COSTS AND REVENUES: Costs eligible for the Fuel and Purchased Power Adjustment ("FPA") will be the Company's allocated jurisdictional costs for the fuel component of the Company's generating units, reservation charges, purchased power energy charges including applicable Southwest Power Pool ("SPP") charges, emission allowance costs and amortizations, cost of transmission of electricity by others associated with purchased power and off-system sales – all as incurred during the accumulation period. These costs will be offset by jurisdictional off-system sales revenues, applicable SPP revenues, revenue from the sale of Renewable Energy Certificates or Credits ("REC") and Revenues from the Renewable Energy Program Rider, Green Solutions Connections Rider and Alternative Energy Credit Rider. Eligible costs do not include the purchased power demand costs associated with purchased power contracts in excess of one year. Likewise, revenues do not include demand or capacity receipts associated with power contracts in excess of one year.

APPLICABILITY

The price per kWh of electricity sold to retail customers will be adjusted (up or down) in April and October subject to application of the Rider FAC and approval by the Missouri Public Service Commission ("MPSC" or "Commission").

The FAR is the result of dividing the FPA by forecasted Missouri retail net system input ("S_{RP}") for the recovery period, expanded for Voltage Adjustment Factors ("VAF"), rounded to the nearest $0.00001, and aggregating over two accumulation periods. The amount charged on a separate line on retail customers' bills is equal to the current annual FAR multiplied by kWh billed.

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided January 1, 2023 and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS

FPA = 95% * ((ANEC – B) * J) + T + I + P

ANEC = Actual Net Energy Costs = (FC + E + PP + TC – OSSR – R – REV)

FC = Fuel costs, excluding decommissioning and retirement costs, incurred to support sales and revenues associated with the Company's in-service generating plants:
The following costs reflected in Federal Energy Regulatory Commission ("FERC") Account Number 501:
Subaccount 501000: coal commodity and transportation, side release and freeze conditioning agents, dust mitigation agents, applicable taxes, accessorial charges as delineated in railroad accessorial tariffs [additional crew, closing hopper railcar doors, completion of loading of a unit train and its release for movement, completion of unloading of a unit train and its release for movement, delay for removal of frozen coal, destination detention, diversion of empty unit train (including administration fee, holding charges, and out-of-route charges which may include fuel surcharge), diversion of loaded coal trains, diversion of loaded unit train fees (including administration fee, additional mileage fee or out-of-route charges which may include fuel surcharge), fuel surcharge, held in transit, hold charge, locomotive release, miscellaneous handling of coal cars, origin detention, origin re-designation, out-of-route charges (including fuel surcharge), out-of-route movement, pick-up of locomotive power, placement and pick-up of loaded or empty private coal cars on railroad supplied tracks, placement and pick-up of loaded or empty private coal cars on shipper supplied tracks, railcar storage, release of locomotive power, removal, rotation and/or addition of cars, storage charges, switching, trainset positioning, trainset storage, and weighing], unit train maintenance, leases, taxes and depreciation, natural gas costs including reservation charges, fuel quality adjustments, fuel adjustments included in commodity and transportation costs, broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers), oil costs for commodity, transportation, storage, taxes, fees, and fuel losses, coal and oil inventory adjustments, and insurance recoveries, subrogation recoveries and settlement proceeds for increased fuel expenses in the 501 Accounts.
Subaccount 501020: the allocation of the allowed costs in the 501000, 501300, 501400 and 501420 accounts attributed to native load;
Subaccount 501030: the allocation of the allowed costs in the 501000, 501300, 501400 and 501420 accounts attributed to off system sales;
Subaccount 501300: fuel additives and consumable costs for Air Quality Control Systems ("AQCS") operations, such as ammonia, hydrated lime, lime, limestone, limestone inventory adjustments, powder activated carbon, calcium bromide, sulfur, and RESPond, or other consumables which perform similar functions;
Subaccount 501400 and 501420: residuals costs and revenues associated with combustion byproducts, slag and ash disposal costs and revenues including contractors, materials and other miscellaneous expenses.
The following costs reflected in FERC Account Number 518:
Subaccount 518000: nuclear fuel commodity and insurance recoveries, subrogation recoveries and settlement proceeds for increased fuel expenses in the 518 Accounts
Subaccount 518201: nuclear fuel waste disposal expense;
Subaccount 518100: nuclear fuel oil.

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided January 1, 2023 and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

OSSR = Revenues from Off-System Sales:
The following revenues or costs reflected in FERC Account Number 447:
Subaccount 447020: all revenues from off-system sales. This includes charges and credits related to the SPP IM, or other IMs, including, energy, ancillary services, revenue sufficiency (such as make whole payments and out of merit payments and distributions), revenue neutrality payments and distributions, over collected losses payments and distributions, TCR and ARR settlements, demand reductions, virtual energy costs and revenues and related fees where the virtual energy transaction is a hedge in support of physical operations related to a generating resource or load, generation/export charges, ancillary services including non-performance and distribution payments and SPP uplift revenues or credits, but excluding (1) off-system sales revenues from full and partial requirements sales to municipalities that are served through bilateral contracts in excess of one year, (2) the amounts associated with PPA associated with the Renewable Energy Rider tariff, (3) SPP revenues associated with the CNPPID Hydro PPA and (4) net costs associated with wind PPA entered into after May 2019 whose costs exceed their revenues resulting in a net loss.

Notwithstanding anything to the contrary contained in the tariff sheets for Rider FAC, factors PP and OSSR shall not include costs and revenues for any undersubscribed portion of a permanent Solar Subscription Rider resource allocated to shareholders under the approved stipulation in File No. ER-2022-0129.

Subaccount 447012: capacity charges for capacity sales one year or less in duration;

Subaccount 447030: the allocation of the includable sales in account 447020 not attributed to retail sales.

R = Renewable Energy Credit Revenue:
Revenues reflected in FERC account 509000 and gains or losses to be recorded in FERC accounts 411800 and 411900 from the sale of Renewable Energy Credits (RECs) that are not needed to meet the Missouri Renewable Energy Standards less the cost associated with making the sale.

REV = Revenues from the Renewable Energy Program Rider, Green Solutions Connections Rider and Alternative Energy Credit Rider reflected in retail revenue FERC Account Numbers 440-444

Any cost identified above which is a Missouri-only cost shall be grossed up by the current kWh energy factor, included in the ANEC calculation and allocated as indicated in component J below. Any cost identified above which is a Kansas-only cost shall be excluded from the ANEC calculation.

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided January 1, 2023 and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

Costs and revenues not specifically detailed in Factors FC, PP, E, TC, OSSR, R or REV shall not be included in the Company's FAR filings; provided however, in the case of Factors PP, TC or OSSR, the market settlement charge types under which SPP or another centrally administered market (e.g., PJM or MISO) bills/credits a cost or revenue need not be detailed in Factors PP or OSSR for the costs or revenues to be considered specifically detailed in Factors PP or OSSR; and provided further, should the SPP or another centrally administered market (e.g. PJM or MISO) implement a new market settlement charge type not listed below or a new schedule not listed in TC:

SPP IM charge/revenue types that are included in the FAC are listed below:

Day-Ahead Ramp Capability Up Amount
Day-Ahead Ramp Capability Down Amount
Day-Ahead Ramp Capability Up Distribution Amount
Day-Ahead Ramp Capability Down Distribution Amount
Day Ahead Regulation Down Service Amount
Day Ahead Regulation Down Service Distribution Amount
Day Ahead Regulation Up Service Amount
Day Ahead Regulation Up Service Distribution Amount
Day Ahead Spinning Reserve Amount
Day Ahead Spinning Reserve Distribution Amount
Day Ahead Supplemental Reserve Amount
Day Ahead Supplemental Reserve Distribution Amount
Real Time Contingency Reserve Deployment Failure Amount
Real Time Contingency Reserve Deployment Failure Distribution Amount
Real Time Ramp Capability Up Amount
Real Time Ramp Capability Down Amount
Real Time Ramp Capability Up Distribution Amount
Real Time Ramp Capability Down Distribution Amount
Real Time Ramp Capability Non-Performance Amount
Real Time Ramp Capability Non-Performance Distribution Amount
Real Time Regulation Service Deployment Adjustment Amount
Real Time Regulation Down Service Amount
Real Time Regulation Down Service Distribution Amount
Real Time Regulation Non-Performance
Real Time Regulation Non-Performance Distribution
Real Time Regulation Up Service Amount
Real Time Regulation Up Service Distribution Amount
Real Time Spinning Reserve Amount
Real Time Spinning Reserve Distribution Amount
Real Time Supplemental Reserve Amount
Real Time Supplemental Reserve Distribution Amount
Day Ahead Asset Energy
Day Ahead Non-Asset Energy
Day Ahead Virtual Energy Amount

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided January 1, 2023 and Thereafter)

Should FERC require any item covered by components FC, E, PP, TC, OSSR, R or REV to be recorded in an account different than the FERC accounts listed in such components, such items shall nevertheless be included in component FC, E, PP, TC, OSSR, R or REV. In the month that the Company begins to record items in a different account, the Company will file with the Commission the previous account number, the new account number and what costs or revenues that flow through the Rider FAC to be recorded in the account.

B = Net base energy costs ordered by the Commission in the last general rate case consistent with the costs and revenues included in the calculation of the FPA. Net Base Energy costs will be calculated as shown below:

S_{AP} x Base Factor ("BF")

S_{AP} = Net system input ("NSI") in kWh for the accumulation period

BF = Company base factor costs per kWh: $0.01829

J = Missouri Retail Energy Ratio = (MO Retail kWh sales + MO Losses) / (MO Retail kWh Sales + MO Losses + KS Retail kWh Sales + KS Losses + Sales for Resale, Municipals kWh Sales [includes border customers] + Sales for Resale, Municipals Losses)
MO Losses = 6.09%; KS Losses = 6.51%; Sales for Resale, Municipals Losses = 6.84%

T = True-up amount as defined below.

I = Interest applicable to (i) the difference between Missouri Retail ANEC and B for all kWh of energy supplied during an AP until those costs have been recovered; (ii) refunds due to prudence reviews ("P"), if any; and (iii) all under- or over-recovery balances created through operation of this FAC, as determined in the true-up filings ("T") provided for herein. Interest shall be calculated monthly at a rate equal to the weighted average interest paid on the Company's short-term debt, applied to the month-end balance of items (i) through (iii) in the preceding sentence.

P = Prudence disallowance amount, if any, as defined in this tariff.

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided January 9, 2023 and Thereafter)
Effective for the Customer Usage Beginning xxx through xxx

Accumulation Period Ending: **June 2024**			
1	Actual Net Energy Cost (ANEC) = (FC+E+PP+TC-OSSR-R-REV)		$151,039,699
2	Net Base Energy Cost (B)	-	$138,603,979
	2.1 Base Factor (BF)		$0.01829
	2.2 Accumulation Period NSI (S_{AP})		7,578,128,999
3	(ANEC-B)		$12,435,719
4	Jurisdictional Factor (J)	x	53.7257%
5	(ANEC-B)*J		$6,681,177
6	Customer Responsibility	x	95%
7	95% *((ANEC-B)*J)		$6,347,118
8	True-Up Amount (T)	+	$1,809,350
9	Interest (I)	+	$433,758
10	Prudence Adjustment Amount (P)	+	$0
11	Fuel and Purchased Power Adjustment (FPA)	=	$8,590,226
12	Estimated Recovery Period Retail NSI (S_{RP})	÷	8,868,794,365
13	Current Period Fuel Adjustment Rate (FAR)	=	$0.00097
14			
15	Current Period FAR_{Trans} = FAR x VAF_{Trans}		$0.00100
16	Prior Period FAR_{Trans}	+	($0.00016)
17	Current Annual FAR_{Trans}	=	$0.00084
18			
19	Current Period FAR_{Sub} = FAR x VAF_{Sub}		$0.00101
20	Prior Period FAR_{Sub}	+	($0.00017)
21	Current Annual FAR_{Sub}	=	$0.00084
22			
23	Current Period FAR_{Prim} = FAR x VAF_{Prim}		$0.00102
24	Prior Period FAR_{Prim}	+	($0.00017)
25	Current Annual FAR_{Prim}	=	$0.00085
26			
27	Current Period FAR_{Sec} = FAR x VAF_{Sec}		$0.00104
28	Prior Period FAR_{Sec}	+	($0.00017)
29	Current Annual FAR_{Sec}	=	$0.00087
30	VAF_{Trans} = 1.0300		
31	VAF_{Sub} = 1.0378		
32	VAF_{Prim} = 1.0497		
33	VAF_{Sec} = 1.0690		

ALTERNATIVE ENERGY CREDIT RIDER
Schedule AEC

PURPOSE

The purpose of the Alternative Energy Credit Rider program ("Program") is to offer an eligible Customer an opportunity to subscribe to Alternative Energy Credits ("AECs") that are associated with Company-owned nuclear energy resources. The AECs are then included in the Subscriber's energy accounting for a separately agreed to subscription term. The Company shall have the AECs annually certified by a third-party. Under the Program, a Subscriber may agree to receive AEC for a term of one (1), three (3) or five (5) years.

AVAILABILITY

This Program is available on a limited and voluntary basis to non-residential Missouri Metro Customers currently receiving permanent electric service from the Company through Schedules SGS, MGS, LGS, LPS or LLPS who have an annual average monthly peak demand greater than 200 kilowatts (kW). Customers that have an aggregate electric load of at least 2.5 megawatts (MW) based upon peak annual demand and an average of 200 kW per account.

The Company may deem a Subscriber ineligible for this Program if the Subscriber has received a disconnection notice within twelve (12) months preceding its submission of a Participation Agreement, or as set forth in the applicable terms and conditions in the Participation Agreement.

DEFINITIONS

For purposes of this Program, the following definitions apply:

Alternative Energy: Electricity that is generated using Company-owned nuclear energy resources.

Alternative Energy Credits ("AECs"): Attributes from one thousand (1,000) kilowatt hours (kWh) of electricity generated from a Company-owned nuclear energy resource.

Alternative Energy Credit Rate ("AEC Rate"): A dollar per megawatt hour ($/MWh) rate applicable to a Subscriber's monthly amount of Alternative Energy generation. There is a separate Alternative Energy Credit Rate for each agreement term length (1, 3, or 5 years).

Alternative Energy Credit Charge ("AEC Charge"): The AEC Charge shall be calculated monthly as the Subscriber's monthly average subscription (MWh) multiplied by the AEC Rate for specified Participant Agreement term.

Customer's Annual Usage (MWh): Customer's actual metered energy usage over the twelve (12) most recent monthly billing periods for which data is available, or the Subscriber's expected metered energy usage over twelve (12) monthly billing periods as determined by the Company. Customer's Annual Usage shall be established at the time the Participation Agreement is executed by the Customer and memorialized therein.

Participation Agreement: A written contract executed by the Company and a Subscriber setting forth the specific terms of a Subscriber's subscription under this Program including the Subscriber's accounts covered by the subscription. The Participation Agreement shall reflect the Subscription Level, subject to the terms and conditions set forth in this tariff and the Participation Agreement.

Subscriber: An eligible Customer who executes a Participation Agreement with the Company to participate in this Program.

ALTERNATIVE ENERGY CREDIT RIDER
Schedule AEC

DEFINITIONS (continued)

Subscription Level (1-100%): An eligible Customer may subscribe in single percentage increments, up to one-hundred percent (100%) of the Customer's Annual Usage at the time the Participation Agreement is executed by the Customer, subject to the terms of Customer's Participation Agreement.

PRICING

The formula for determining the AEC Charge that shall be billed monthly to a Customer is:

$$\text{AEC Charge} = \frac{\text{Customer's Annual Usage (MWh)} \times \text{Subscription Level (\%)}}{12} \times \text{AEC Rate Price}$$

AEC Rate Pricing			
Designated Resource	**One Year Agreement Term**	**Three Year Agreement Term**	**Five Year Agreement Term**
Wolf Creek	$0.00866 per kWh	$0.00827 per kWh	$0.00788 per kWh

The Customer shall be notified of any pricing updates following Commission approval. Notification will be provided a minimum of thirty (30) days prior to being billed to the Subscriber by the Company. Notifications shall be opt-out communications, and the new rates shall be effective the first billing cycle 60 days after notice is provided.

PROGRAM PROVISIONS AND SPECIAL TERMS

The Customer should carefully consider terms and conditions in the Participation Agreement subject to participation in this Program.

Alternative Energy shall be limited to the generation produced by Company-owned nuclear resources. Service under this rider may be limited, at the sole discretion of the Company, to such available resources.

Certain factors may result in less Alternative Energy being available for this Program than anticipated. If the Alternative Energy generated is not sufficient to meet the sum of the annual Program subscriptions during a calendar year, the Company shall refund each participating Customer 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 Alternative Energy subscribed generation.

Service hereunder is subject to the Company's General Terms and Conditions as approved by the Missouri Public Service Commission and any modification subsequently approved.

All provisions of the rate schedule are subject to changes made by order the regulatory authority having jurisdiction.

REPORTING

The Company shall calculate and provide the Subscriber with its total annual AECs consistent with the Subscriber's subscription, which shall occur in the first quarter of the year following the prior annual year subscription (e.g. in first quarter of 2026 for a 2025 annual subscription).

CUSTOMER CAPACITY RIDER
Schedule CCR

PURPOSE

The Customer Capacity Rider permits an eligible Customer to sell complete rights to capacity contracted from existing resources in the Customer's own supply portfolio to the Company to fulfill some, or all, of the capacity required to serve the Customer. The Customer will receive a bill credit for the supplied capacity, reducing the Customer's demand cost within the applicable monthly billing cycle.

AVAILABILTY

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. Contractual bilateral agreements for accredited capacity shall be for amounts no less than a monthly average of 10,000 kilowatts (kW) per year.

TERM OF SERVICE

The specific term shall be established under the respective bilateral agreement executed between the Customer and Company.

BILLING

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. Details concerning the amount of capacity contracted, and the negotiated price will be memorialized in the Schedule LLPS Service Agreement.

Accreditation and planning reserve margin requirements shall follow SPP protocols and shall be seasonally differentiated, following established SPP processes and revised as needed to reflect any changes. The Company and Customer shall define the accredited capacity amounts and planning reserve margin requirements as part of the bilateral capacity contracting process. Details concerning the amount of capacity contracted, and the negotiated price will be memorialized in the Schedule LLPS Service Agreement. Seasonal periods align with the seasonal periods established by the Customers rate for electric service. Should the SPP seasons and Company billing seasons not align, the Customer and the Company will define the seasonal amounts within the bilateral capacity contract.

Customer capacity contracted under this rider shall be excluded from the Company Energy Cost Adjustment/Fuel Adjustment Charge.

CUSTOMER CAPACITY RIDER
Schedule CCR

PROGRAM PROVISIONS

The contractual bilateral agreement shall transfer all rights to the Company and provide provisions that include, but not limited to, the capacity amount, the capacity accreditation, capacity price, deliverability terms and any other term necessary to define the expected capacity to be received. The accredited capacity amount shall be determined by seasonal capacity accreditation (annually for both summer and winter), as determined by the pertinent SPP methodology.

The Customer's capacity may be Customer-owned, or Customer-contracted, and shall be transferred to the Company via the contractual bilateral agreement. Capacity associated with resources located behind the Customer meter are not acceptable for use under this rider.

The Customer's capacity must be deliverable to the appropriate Company load node. The Customer shall be responsible for the transmission deliverability costs, as determined by SPP.

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.

Annually, the Company shall examine the accredited capacity it receives as compared to the contracted capacity. If the Customer-supplied capacity is less than the contracted amount, the Customer shall be obligated to pay a "make-whole payment" for the difference between the expected contracted capacity amount and seasonal accredited capacity actually received in that year (the "Capacity Shortfall Payment"). The Capacity Shortfall Payment shall be calculated in accordance with the following formula: (Expected Contracted Capacity – Actual Received Accredited Capacity x 1,000 kW/MW) × Applicable Customer Rate Demand Charge. If the actual Customer-supplied capacity is greater than the contracted amount, the Customer will be compensated for each additional kW at the negotiated price in the bilateral contract agreement.

If the Customer terminates service with the Company, the Company and Customer agree that the bilateral contract established under this rider shall be examined and the Company may take steps to terminate or revise the bilateral contract to enable continued delivery of capacity to the Company, as mutually agreed.

REGULATIONS

Service hereunder is subject to the Company's Rules and Regulations as approved by the Missouri Public Service Commission and any modification subsequently approved.

All provisions of the rate schedule are subject to changes made by order the regulatory authority having jurisdiction.

CLEAN ENERGY CHOICE RIDER
Schedule CER

PURPOSE

The Clean Energy Choice Rider provides eligible Customers with a means to influence the Company's generation resource portfolio. Within the Company's Integrated Resource Planning ("IRP") process, the eligible Customer may request clean resource types be deployed in place of or in addition to one or more resources selected in the Company's Preferred Resource Portfolio. If the Customer's requested generation is adopted by the Company as part of a Clean Energy Preferred Resource Plan, the Requesting Customer shall bear the entire cost differential arising from its specific request for clean resources. No energy or capacity will be directly provided to the Requesting Customer from the incremental clean energy resources as a result of participating in this Rider.

AVAILABILTY

This Rider is available to any Customer receiving permanent electric service under the Company's LLPS retail rate schedule or any prospective customer who has executed a Service Agreement with the Company but has not yet received service under the LLPS retail rate schedules.

DEFINITIONS

For purposes of this Rider, the following definitions apply:

Integrated Resource Planning: The Company's IRP (or Integrated Resource Planning process), considers and analyzes demand-side resources, supply-side resources, and renewable energy resources on an equivalent basis, subject to compliance with all legal mandates that may affect the selection of Company electric energy resources. The ultimate goal of an IRP is to develop a Preferred Resource Plan that minimizes the net present value of long-term utility costs while ensuring the Company can provide its Customers with energy services that are safe, reliable, and efficient, at just and reasonable rates, and in a manner that serves the public interest and is consistent with state energy and environmental policies.

Good Utility Practice: The practices, methods, techniques, and standards that would be implemented and followed by a prudent utility operator during the relevant time period or that, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could reasonably have been expected to accomplish the desired result.

Requesting Customer: An eligible Customer who requests that one or more clean energy resources be deployed in place of or in addition to the generation resources selected in the Company's Preferred Resource Plan. There may be multiple Requesting Customers who support the same Clean Energy Preferred Resource Plan.

Preferred Resource Plan: This refers to what the Company has designated as its Preferred Resource Plan in its most recent IRP that has been filed with the Commission by the Company for implementation.

Clean Energy Preferred Resource Plan**:** A Clean Energy Preferred Resource Plan is a separate resource plan the Company may develop. If the Company elects to create a Clean Energy Preferred Resource Plan, the Company will modify its Preferred Resource Plan following an eligible Requesting Customer's request for and evaluation of certain clean resources to be modeled and deployed in place of, or in addition to one or more generation resources selected in the Company's Preferred Resource Plan. The Company retains all discretion in preparing the Clean Energy Preferred Resource Plan to ensure the Clean Energy Preferred Resource Plan meets the Company's requirements to provide safe, reliable, and efficient service. The execution of the Clean Energy Preferred Resource Plan shall be subject to gaining all appropriate regulatory approvals, and in a manner deemed satisfactory to the Company in its sole discretion.

CLEAN ENERGY CHOICE RIDER
Schedule CER

DEFINITIONS (continued)

Cost Differential: The dollar amount difference resulting from the Company's calculated net present value revenue requirement determined for the Company's Preferred Resource Plan, and Company's calculated net present value revenue requirement for the Company's Clean Energy Preferred Resource Plan. The Cost Differential shall be borne by the Requesting Customer(s) and represent a contribution to construction of the resulting clean resource(s). As set forth below, the Cost Differential is subject to adjustment based on actual costs of the Clean Energy Preferred Resource Plan. With the Requesting Customer(s) to be responsible for the differential based on actual costs of the clean energy resource(s), per the terms of the tariff and separate commercial agreement.

PROGRAM PROVISIONS

All aspects of this Rider will occur within the normal timing and execution of the Company's IRP process. Prior to the execution of an IRP cycle, and preferably during the fourth quarter of a given year, a Requesting Customer shall notify the Company through the Requesting Company's Company Customer Solutions representative, its interest in modifying the Company's current Preferred Resource Plan. The Company will engage with the Requesting Customer to understand the Requesting Customer's desired clean resource modifications, will study the alternative resource scenarios, and may then develop a Clean Energy Preferred Resource Plan that attempts to reasonably accommodate the Requesting Customer's clean resource request. Upon doing so, the Company will provide the Requesting Customer with an indicative cost estimate for the associated clean resource modifications, as well as the Cost Differential of such. Should the Requesting Customer request multiple clean resource modifications, the Company may model some or all of them, at its discretion. The Company will ensure any Clean Energy Preferred Resource plan meets the Company's requirements to provide safe, reliable, and efficient service for all customers.

If the Requesting Customer supports the Clean Energy Preferred Resource Plan and wishes to move forward, the Requesting Customer(s) shall execute a separate commercial agreement with the Company committing them to pay the associated Cost Differential of the Clean Energy Preferred Resource Plan, plus all administrative costs, including those associated with obtaining regulatory approvals. The Requesting Customer(s) shall be responsible for all such administrative and approval costs, even if the Clean Energy Preferred Resource Plan is not adopted or otherwise executed.

A Clean Energy Preferred Resource Plan will be submitted to the Commission through the Company's IRP process and is subject to Commission review and order. If found to meet IRP requirements by the Commission, the Company will follow Good Utility Practice to execute the Clean Energy Preferred Resource Plan including obtaining all required Commission approvals associated with resource procurement or construction. If approvals are not granted in a manner satisfactory to the Company in its sole discretion, the Company may not elect to move forward with the Clean Energy Preferred Resource Plan.

The Cost Differential in the earlier executed commercial agreement shall be updated to reflect actual costs of any and all resources included in establishing the Clean Energy Preferred Resource Plan. Unless otherwise agreed to, an installment payment price will be calculated, inclusive of any Contribution in Aide of Construction taxes, and paid by the Requesting Customer(s) over a term that is no greater than the expected life of the clean energy resource(s) selected in the Clean Energy Preferred Resource Plan.

CLEAN ENERGY CHOICE RIDER
Schedule CER

BILLING

A charge representing the Cost Differential to be paid by the Requesting Customer over the specified term shall be included as a specific Levelized Charge added to the Customer's bill.

Should a Clean Energy Preferred Resource Plan include more than one Requesting Customer, the allocation of the Cost Differential shall be determined based on factors such as Requesting Customer load share, cost impacts of requested clean resource technologies, or other factors as determined by the Company.

The Economic Development Rider shall not be applied to the Levelized Charge imputed to the Requesting Customer under this rider.

TERMINATION

Should a Requesting Customer terminate its service at any point after the Company has executed a Clean Energy Preferred Resource Plan specific to the Requesting Customer and before the Cost Differential of the Clean Energy Preferred Resource Plan (or allocated portion) has been fully paid, the Requesting Customer shall be required to pay the outstanding Cost Differential as a single payment, and shall be subject to any additional terms and conditions set forth in a separate commercial agreement..

RENEWABLE ATTRIBUTES

If applicable, the Requesting Customer shall receive the renewable attributes related to the output of the clean resource generation requested and where the Requesting Customer is paying the Cost Differential for the clean resource. The Company shall retire the renewable attributes on behalf of the customer, up to an amount equal to the Requesting Customer's annual energy usage. If the Clean Energy Preferred Resource Plan includes more than one Requesting Customer, the renewable attributes will be allocated to the Requesting Customers on the equivalent basis as the Cost Differential, as applicable.

CLEAN RESOURCE PRODUCTION DATA

A Requesting Customer may request hourly output data from the Company specific to the clean resource(s) included in an adopted and executed Clean Energy Preferred Resource Plan.

REGULATIONS

Service hereunder is subject to the Company's Rules and Regulations as approved by the Missouri Public Service Commission and any modification subsequently approved.

All provisions of the rate schedule are subject to changes made by order the regulatory authority having jurisdiction.

DEMAND RESPONSE & LOCAL GENERATION RIDER
Schedule DRLR

PURPOSE

The Demand Response & Local Generation Rider ("Program" or "DRLR") is designed to reduce Participant load during peak and constrained grid condition periods to improve 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. The Company may, in its discretion, request Participant curtailment for any of these operational or economic reasons.

AVAILABILITY

This rider is available to any Commercial & Industrial Customer receiving permanent electric service under the Company's retail rate Schedule LLPS subject to the terms of that schedule. Customers may participate in Schedule DRLR and other eligible Demand Response ("DR"), and Interruptible Schedules offered by the Company. To participate, the Customer shall complete the required Participation Agreement for the Program.

A Customer is not eligible if the Customer's load reduction capability is registered for demand response participation in a wholesale market directly by the Customer or via a DR Aggregator other than the Company.

DEFINITIONS

For purposes of this Program the following definitions apply:

Participant**:** The Customer, specified as the Participant in the Participation Agreement, is the eligible Customer that has received notification of acceptance into the Program.

Participation Agreement: A non-tariffed commercial contract between the Company and Customer, used for enrollment purposes and to establish the full terms and conditions of the Program. Eligible Customers shall be required to sign the Participation Agreement prior to participating in the Program. This agreement may be provided and executed electronically.

Reduction Amount ("RA"): The reduction of load by the Customer either manually or automated for the duration of the DR event.

Enrolled Load: The total contracted load reduction specified within the Participation Agreement that the Customer may be required to reduce for each curtailment event.

Curtailment Event ("Event"): Period when the Company determines the need for Participants to reduce energy consumption during peak and constrained grid conditions

Calculated Baseline ("CBL"): The calculated estimate of what the Customer most likely would have consumed during the curtailment event period. Baselines are developed for each curtailment event utilizing customer specific data from historic metered usage.

Reduction Credit ("RC"): Credit amount for the curtailment event period during which the event is called and the period(s) of time the Customer has successfully curtailed load.

DEMAND RESPONSE & LOCAL GENERATION RIDER
Schedule DRLR

PROGRAM PROVISIONS

A Participant must show economic and technical feasibility for measurable and verifiable load curtailment during their selected option of availability below:

Option 1 - Constrained: summer curtailment season of June 1 to September 30 and winter curtailment season of December 1 to March 31; 6:00 a.m. to 10:00 p.m., Monday through Friday excluding Holidays.

Option 2 - Unconstrained: All hours: All days; January through December.

The Company shall evaluate the Participant's metered usage data, technical specifications and operational characteristics of the facility's equipment to establish a curtailment plan and estimated associated curtailable load (measured in kW) to determine the Enrolled Load. The Participation Agreement will specify the curtailable load, and commits the Participant to being able to curtail their Enrolled Load during a curtailment event. The Company will issue notice to the Participant in advance of scheduled curtailment events, thus requiring the Participant to curtail their Enrolled Load in accordance with the Participant's chosen method of participation.

The Company shall determine the appropriate timing and length of any curtailment event during each curtailment window, based on the Participant's chosen option above. Notwithstanding the intended curtailment periods identified in Option 1 and Option 2 for the purpose of Schedule DRLR, the Company reserves the right to curtail the Customer year-round as needed for system reliability during circumstantial conditions.

The Company shall communicate with the Participant in advance of a curtailment event to increase the Participant's ability to participate. Participation Agreements shall contain specific information for curtailment event specifications that fall within the following limits.

- Minimum number of events/tests per season (summer) – 1
- Minimum number of events/tests per season (winter) – 1
- Minimum notification prior to an event – 10 minutes

This Program may be executed by manual and/or automated demand response methods. A Participant may utilize on-site back-up or behind the meter generation and/or curtailment methods to meet its RA threshold for the duration of the curtailment event.

- Manual DR
  The Participant may manually execute its facility curtailment plan to curtail at least its Enrolled Load for the duration of the curtailment event.

- Automated Demand Response (ADR) utilizing on-site generation
  The Participant's building/energy management system ("BMS" or "EMS") or facility automation system is utilized in conjunction with the facility's on-site generation or other curtailment methods to execute its curtailment plan. The Participant receives the integrated signal from the utility's event calling system and its BMS/EMS is utilized to execute its curtailment plan by enacting pre-programmed adjustments to respond to DR events.

- On-Site Generation Term
  The Participant has full responsibility for start-up, operation, and maintenance ("O&M"), and regulatory compliance of any on-site generation including any reciprocating internal combustion engine ("RICE") National Emissions Standards for Hazardous Air Pollutants ("NESHAP"), Southwest Power Pool ("SPP"), and/or any other community, governmental or regulatory agency, as applicable. On-site generation operating details, capabilities, and any other criteria negotiated with the Company and the Participant may be documented in the Participation Agreement.

DEMAND RESPONSE & LOCAL GENERATION RIDER
Schedule DRLR

PRICING

All charges, and other terms and conditions of service provided for under the Participant's applicable standard service classification(s) tariff shall continue to apply and shall be based on actual metered energy use during the Participant's normal billing cycle.

Under Schedule DRLR, the Participant will receive an on-bill credit or check payment for its level of reduction achieved and an incentive payment based on its measured curtailment reduction.

Reduction Amount:

The Reduction Amount is a monthly performance amount applied to each billing month in which an event is called. The credit amount is calculated based on the Participant's hourly kWh load compared to the Participant's summer and winter hourly CBL. The Company shall employ a Calculated Baseline methodology to determine the Participant's demand savings associated with a DR curtailment event. A CBL approach applies a model or algorithm to develop a customer-specific baseline for each day from historic metered usage data that is then used to forecast load impacts for each hour of the event absent a curtailment event. This baseline is calibrated to best match recent operational and/or weather patterns. This baseline is then compared to the actual metered average hourly demand during the curtailment event. The difference between the forecasted hourly baseline and the Participant's actual metered hourly usage during the curtailment event equals the hourly kW impact of the curtailment event. All kW shall be calculated as a whole number, and may thus be rounded up or down. The event hourly average kW achieved divided by the kW enrolled is the Participant's percent kW achieved. The Company shall pay the Participant under the terms of Schedule DRLR for the achieved average percent of its enrolled curtailable load within the established baseline and peak curtailment as detailed in the Participation Agreement. The hourly RA formula is:

Hourly RA = CBL kWh for each hour – Actual hourly kWh

Participant Participation Fees:

Participants shall be assessed the following program fees and charges as specified in the Participant Agreement:

1. DR Earnings Opportunity ("EO") Fee – Participant shall compensate the Company for any foregone earnings associated with capacity reduction related to the DRLR enrolled MW capacity for the realized curtailable value during the curtailment period that the reduction occurred.

2. Administration Fee - A fixed charge shall be recovered for all costs associated with Program delivery, implementation/management, and evaluation, which shall be recovered based on a forecasted estimate and trued up annually based on actual Program expenditures for the recovery period.

Reduction Credit:

The Reduction Credit is a variable performance credit for each curtailed kW successfully delivered. Reduction credits are based on a rate of $54.00 per kW-year for "Unconstrained" Participants and $43.20 per kW-year for "Constrained" Participants, and shall be paid in accordance with the credit schedule and incentive rate for the performance month, based on the formula below.

Monthly RC = Monthly Average RA x Monthly Reduction Credit (Constrained or Unconstrained) - DR EO Fee – Administration Fee

DEMAND RESPONSE & LOCAL GENERATION RIDER
Schedule DRLR

CREDIT SCHEDULE:

The credit schedule below outlines the kW/month value and fees for seasonal performance under the Program. Credit values are paid based on measured performance for the month that the curtailment event occurred. Curtailment event credits will not be applied for periods where events are not called, or if the Participant does not perform. Program rates shall be updated annually. The current credit schedule applicable for 2025 is set forth below.

Month	Allocation Percentage	Unconstrained	Constrained $/ kW per Month	Demand Response Earnings Opportunity Fee	Unconstrained Max Hours Per Month	Constrained Max Hours Per Month
		$/kW per Month	$/kW per Month	$/kW per Month	Hours	Hours
January	12.5%	$6.75	$5.38	($1.31)	744	480
February	12.5%	$6.75	$5.38	($1.31)	672	480
March	2.5%	$1.35	$1.08	($0.26)	219	96
April	2.5%	$1.35	$1.08	($0.26)	219	96
May	2.5%	$1.35	$1.08	($0.26)	219	96
June	12.0%	$6.48	$5.16	($1.26)	720	461
July	14.0%	$7.56	$6.02	($1.47)	744	538
August	14.0%	$7.56	$6.02	($1.47)	744	538
September	10.0%	$5.40	$4.30	($1.05)	720	384
October	2.5%	$1.35	$1.08	($0.26)	219	96
November	2.5%	$1.35	$1.08	($0.26)	219	96
December	12.5%	$6.75	$5.38	($1.31)	744	480

DEMAND RESPONSE & LOCAL GENERATION RIDER
Schedule DRLR

PARTICIPATION AGREEMENT TERM

The Participation Agreement shall outline the Participant's Enrolled Load, which can vary by season, dispatch, and duration requirements associated with each DR curtailment event. The Participation Agreement shall last for a term of one year, and automatically renew in one-year increments unless terminated per notification requirements as set forth in the Participation Agreement. The Company reserves the right to terminate Participation Agreements for non-compliance.

REPORTING

The Company shall calculate and provide the Participant with its post event settlement calculations and end of season summary outlining the Participant's performance. Participant's curtailment plans and reduction strategies shall be evaluated annually.

EVALUATION

The Company shall hire a third-party evaluator to perform evaluation, measurement and verification ("EM&V") of the Participant's seasonal performance and calculate impacts, which may be used for SPP accreditation and compliance evaluation.

REGULATIONS

Service hereunder is subject to the Company's Rules and Regulations as approved by the Missouri Public Service Commission and any modification subsequently approved.

All provisions of the rate schedule are subject to changes made by order the regulatory authority having jurisdiction.

GREEN SOLUTION CONNECTIONS
RIDER Schedule GSR

PURPOSE

The purpose of the Green Solution Connections Rider ("Green Solution Connections", "GSR", or "Program") is to offer an eligible Customer the opportunity to subscribe to future year renewable energy attributes within the subscribed term associated with new renewable wind and/or solar generation resources. Under the Program, a Subscriber may elect to receive future renewable energy attributes for a term of ten (10) or fifteen (15) years.

AVAILABILITY

This Program is available on a limited and voluntary basis to non-residential Missouri Customers currently receiving permanent electric service from the Company through Schedules SGS, MGS, LGS, LPS, SGA, MGA, LGA, PGA, LLPS or MKT with an annual average monthly peak demand greater than 200 kilowatts (kW). Customers that have an aggregate electric load of at least 2.5 megawatts (MW) based upon peak annual demand and an average of 200 kW per account and Governmental/Municipal Customers as established by Section 46.040, RSMo, or pursuant to Article VI, Section 15 of the Missouri Constitution and applicable enabling statutes enacted by the General Assembly thereunder may combine separate accounts to participate in this Program.

The Company may deem a Subscriber ineligible for this Program if it has received a disconnection notice within twelve (12) months preceding its submission of a Participation Agreement.

DEFINTIONS

For purposes of this Program, the following definitions apply:

Customer: As defined in the Company's General Rules and Regulations as set forth in the Participation Agreement.

Account: Except as otherwise agreed between the Company and Customer, each premise where electricity is individually metered is an account.

Subscriber: A Customer who executes a Participation Agreement with the Company to participate in the GSR Program.

Program Resource(s): Any commercially operational wind and/or solar generation resources owned by the Company where renewable attributes have been designated for the purpose of this Program. Once commercially operational, renewable generation facilities shall be available to provide forward renewable attributes to Subscribers for a term of ten (10) or fifteen (15) years. Specific Program Resources shall be dedicated to specific phases of the Program.

Program Resource Nameplate Capacity: Total nameplate capacity of the Program Resource(s) in megawatts ("MW") of alternating current power.

Metered Production: Total energy production of the Program Resources that are generating renewable power for the Program at a point in time. Production is measured where the power is injected into the wholesale energy market or by dedicated generation meters at the point of interconnection with the distribution system where resource output offsets power. The value is expressed as the metered production of energy (measured in kilowatt-hours ("kWh"). Each Program Resource shall be separately metered.

GREEN SOLUTION CONNECTIONS
RIDER Schedule GSR

DEFINTIONS (continued)

Renewable Energy ("RE") Allocation Factor (%): This is calculated for each subscription by dividing the RE Level (measured in Megawatts ("MW")) by the total nameplate capacity of the Program Resources (in MW of alternating current power) dedicated to each Program phase. The RE Allocation Factor represents the percentage of the Program Resources for a given phase that produce energy for the Customer. To the extent the Program Resources for a given phase are comprised of multiple resources that begin commercial operation at different times, the Customer's RE Allocation Factor shall be calculated and updated as appropriate to reflect the Customer's share of total nameplate capacity of all Program Resources dedicated to the Program during the time in which the Customer is participating and the Program Resources are generating renewable power.

Renewable Energy Level ("RE Level") (MW): The RE Level shall be determined by the Participation Agreement that is submitted by the Subscriber. Subject to the terms of the Subscriber's Participation Agreement, the RE Level is calculated using the following formula:

$$\text{RE Level (MW)} = \frac{\text{[Customer's Annual Usage (MWh) * Subscription Level (\%)]}}{\text{[8,760 hours/year * Capacity Factor]}}$$

where:

Capacity Factor (1-100%):This is the assumed net capacity factor of the Program Resources dedicated to the applicable Program phase (with the Program phase to be determined by Company when it designates a Program Resource for a given period of time; the assumed net capacity factor shall be weighted when there are multiple Program Resources dedicated to a Program phase); measured as the expected average hourly alternating current output of the Program Resource divided by the nameplate capacity of the Program Resource measured in kW of alternating current power.

Customer's Annual Usage (MWh): This shall reflect the Subscriber's actual metered energy usage over the twelve (12) most recent monthly billing periods for which data is available, or, if such data is not available, the Subscriber's expected metered energy usage over twelve (12) monthly billing periods as determined by the Company. The Customer's Annual Usage shall be established at the time the Participation Agreement is executed by the Subscriber. A Subscriber who experiences an increase in load may amend its Participation Agreement during the term of subscription to increase the RE Level subject to the availability of Program capacity, consistent with the terms of the Participation Agreement. A Subscriber who experiences a decrease in load may amend its Participation Agreement to reflect a new Subscription Level, consistent with the terms of the Participation Agreement.

Subscription Level (1-100%): An enrolled Subscriber may subscribe in single percentage increments, up to one-hundred percent (100%) of the Subscriber's Annual Usage at the time the Participation Agreement is submitted by the Customer, subject to the terms of Subscriber's Participation Agreement.

Subscriber's Allocated Share of Monthly Metered Production: This is calculated as the monthly Metered Production multiplied by RE Allocation Factor.

Green Solution Rate ("GR"): A dollar per MW hour ($/MWh) rate applicable to a participating Customer's allocated share of monthly metered production. There shall be a specific Green Solution Rate for each term length, and specific resource. Subsequent Program phases will be reflected on the applicable Green Solution Rate Schedule for each phase.

Green Solution Charge ("GC"): The GC shall be calculated monthly as the Metered Production multiplied by the Customer's RE Allocation Factor and then multiplied by the GR for the appropriate year of the term.

GREEN SOLUTION CONNECTIONS
RIDER Schedule GSR

DEFINTIONS (continued)

Participation Agreement: A written contract executed by the Company and a Subscriber setting forth the specific terms of a Subscriber's subscription under this Program including the Subscriber's accounts covered by the subscription. The Participation Agreement shall be dedicated to a specific phase of the Program. An eligible Customer may subscribe in percentage increments, up to one hundred percent (100%) of the Customer's Annual Usage, subject to the terms of Customer's Participation Agreement. The Participation Agreement shall reflect the subscription level and Subscriber's RE Level, subject to the terms and conditions in this tariff and the Participation Agreement.

PROGRAM PROVISIONS AND CONDITIONS

1. The Customer should carefully consider terms and conditions in the Participation Agreement subject to participation in this Program.

2. The Renewable Energy Certificates ("REC") associated with the generation output of currently subscribed Program Resources shall be retired on behalf of the Subscriber and shall not be used for any other purposes during the term of subscription. This Program is considered a voluntary program unrelated to compliance with any applicable state or regulatory renewable energy standard requirements or approved commitments. Therefore, the Missouri Public Service Commission ("MPSC") is not actively monitoring the retirement of RECs or allocation amongst Customers.

3. Any Subscriber receiving Renewable Energy Subscription waives all rights to any billing adjustments or other relief arising from a claim that the Subscriber's subscription would be or would have been at a lower cost had the Subscriber not participated in the Program.

4. A Subscriber's subscription for renewable attributes is specific to the Subscriber's specific accounts as specified in the applicable Participation Agreement. A Subscriber's subscription for Renewable Energy Subscription shall be specific to the Program phase specified in the Participation Agreement.

5. If, prior to the end of the term of a given subscription, a Subscriber's premises that constitutes a separate account is relocated to another location within the Company's service territory, the Subscriber shall continue to be enrolled in this Program at the Subscriber's same Subscription Level for the new account established at the new location.

6. If, prior to the end of the term of a subscription, a Subscriber provides written notice to terminate its Renewable Energy Subscription for an account covered by a Participation Agreement:

    a. The Subscriber may, without penalty, transfer the Renewable Energy Subscription, as set forth in and as permitted by the terms of the Participation Agreement, to another Customer account(s) if the account is within the Company's service territory and is either (i) currently not covered by a Participation Agreement, or (ii) covered by a Participation Agreement for only a part of its RE Level. In either case the consumption at the new account may be transferred if: (i) the eligible unsubscribed usage at an account that had already been receiving Renewable Energy Subscription under; and (ii) is sufficient to meet the full Renewable Energy Subscription Level under the Agreement; or

    b. At the Subscriber's written request, at least sixty (60) days prior to the desired termination date, the Company shall attempt to find another interested customer that satisfies the Company's eligibility requirements, executes and delivers a Participation Agreement, and is willing to accept transfer of the Renewable Energy Subscription (or that part which cannot be transferred to another Customer account) for the remainder of the term of the subscription at issue; or

GREEN SOLUTION CONNECTIONS
RIDER Schedule GSR

PROGRAM PROVISIONS AND CONDITIONS (continued)

c. If option a) or b) are not satisfied, the Subscriber shall continue to be obligated to pay for the Green Solution Charge as to that part of the Renewable Energy Subscription that was not transferred for the remainder of the Customer's subscription term; or

d. If option a) or b) are not satisfied, in lieu of option c), the Customer may terminate the Renewable Energy Subscription or the account at issue upon payment of the Termination Fee, which shall be: the sum of the Green Solution Charge for the remainder of the term of the Participation Agreement based on the Customer's Renewable Energy Subscription Level and the applicable Green Solution Rate.

7. The availability of Renewable Energy Subscriptions shall be limited to the unsubscribed RECs available, and the remaining life of Program Resource(s) dedicated to a given Program phase. Subscriptions that exceed the available attributes and remaining life of available Program Resources shall no longer be offered.

8. A Customer's Renewable Energy Subscription is not a security and does not represent an ownership interest in any of the Program Resources. There is no guarantee that the Subscriber shall realize any savings from participation in the Program, as the Subscriber acknowledges that its total charges for electric service may exceed the charges it would have incurred if it did not subscribe to the Program.

9. Upon the occurrence of any act or event not within the reasonable control of Company (i.e., force majeure event or change in law) that affects a Program Resource, the Company shall be excused from performance under the Participation Agreement for any Subscriber(s) in the Program phase to which such Program Resource is dedicated; to the extent such performance is delayed or prevented by such act or event. In the event a Program Resource is damaged, or production and/or transmittal of energy produced by a Program Resource is prevented from normal operations for more than six (6) months, the Company may remove the affected Program Resource from the Program by providing notice to any Subscribers in the applicable Program phase. In such event, the Subscriber's Renewable Energy Subscription Levels shall be reduced pro-rata to the degree necessary to account for the available Program Resource capacity, subject to the Company's right to add additional Program Resources dedicated to the affected Program phase and to increase the Subscriber's Subscription Levels pro-rata up to the Subscription Level(s) prior to such pro- ration as additional Program Resource attributes for the applicable Program phase become available. If a Program Resource is removed from the Program under this paragraph and the remaining available attributes results in a Subscriber's Subscription Level being reduced to less than fifty percent (50%) of their Subscription Level, the Customer may cancel its Program enrollment by providing written notice within ninety (90) days after their Renewable Energy Subscription Level is reduced due to the removal of a Program Resource from the Program. In such case, the term of a Subscriber's subscription shall be deemed unaffected by any such force majeure event, removal of a Program Resource from the Program, or a change in the Subscription Level.

REGULATIONS

In addition to the above rules and regulations, all of Company's Rules and Regulations shall apply to the subscription supplied under this Program, except as specifically modified herein.

GREEN SOLUTION CONNECTIONS
RIDER Schedule GSR

EXPANSION

The Company may add Program phases if there are sufficient subscriptions to support and the MPSC approves any required Certificate of Convenience and Necessity ("CCN") for additional resources needed to serve the added Program phase, or if a CCN is not required, upon the commencement of commercial operation of such a resource.

PRICING

GREEN SOLUTIONS RATE SCHEDULE – PROGRAM RESOURCE NO. 1

This rider applies to renewable energy service for a Customer enrolled in Program Phase No. 1. Subsequent Program phases, if any, shall have a separate rate schedule.

Year	Green Solution Rate ($/MWh) Resource 1A XX MW 15 Year Agreement Term	Green Solution Rate ($/MWh) Resource 1B XX MW 10 Year Agreement Term
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		

LARGE LOAD POWER SERVICE
Schedule LLPS

PURPOSE

Service under this schedule is required for a new or expanded facility beginning service after [effective date] with a Peak Load forecast reasonably expected to be equal to or in excess of a Monthly Maximum Demand of one hundred thousand (100,000) kilowatts any time during the Term. Existing Customers, as of [effective date], whose Monthly Maximum Demand is reasonably expected to reach or exceed one hundred thousand (100,000) kilowatts in a given calendar year shall be required to take electric service under this schedule. Customers locating in the state as a result of a state program established for attracting large capital investments in new facilities and operations by businesses engaged in advanced manufacturing, aerospace, distribution, logistics, and transportation, food and agriculture; or professional and technical services have the option to choose to receive service under this schedule or, upon reaching an agreement with Evergy Missouri Metro, to enter into a special contract with Evergy Missouri Metro for the provision of electric service that is approved by the Commission under its applicable standards or Company tariff.

AVAILABILITY

For electric service through one meter to a customer using electric service for purposes other than those included in the availability provisions of the Residential Service Rate Schedule. At the Company's discretion, service may be provided through more than one meter where it is economical or preferred for the Company to do so.

Service is available under this schedule to the following types of customers based on voltage level:

Substation voltage customer - Service is taken directly out of a distribution substation at primary voltage. The customer will own the feeder circuits out of this substation.

Transmission voltage customer - The customer owns, leases, or otherwise bears financial responsibility for the distribution substation. Normally, service is taken off the Company's transmission system.

TERM

Service Agreements under this schedule shall be for a period of fifteen (15) years, commencing on the date when permanent service is received. This term may include a transitional load period (ramp period) of no more than five (5) years.

The Service Agreement term shall remain in effect thereafter unless cancelled, modified pursuant to the terms hereunder, or the customer selects and is qualified to receive service under another applicable Company rate schedule.

LARGE LOAD POWER SERVICE
Schedule LLPS

RATE

A.	CUSTOMER CHARGE (per month):	$1,181.28	
B.	GRID CHARGE		
	Per kW of Grid Demand per month-Substation	$3.003	
	Per kW of Grid Demand per month-Trans.	$2.200	
C.	DEMAND CHARGE:		
	Per kW of Billing Demand per month	Summer Season	Winter Season
	All kW	$14.000	$12.000
D.	ENERGY CHARGE:	Summer Season	Winter Season
	All kWh:	$0.02988	$0.02988

DETERMINATION OF DEMANDS

Demand shall be determined by demand instruments or, at the Company's option, by demand tests.

Monthly Maximum Demand: The Monthly Maximum Demand is defined as the highest demand indicated in any 15-minute interval during the month on all meters.

Grid Demand: Grid Demand shall be equal to the highest Monthly Maximum Demand occurring in the last twelve (12) months including the current month.

Minimum Demand: Minimum Demand shall be 80% of the annual Contract Capacity.

Billing Demand: Billing Demand shall be the higher of: (a) the Monthly Maximum Demand in the current month or (b) the Minimum Demand.

INTERIM CAPACITY

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

REACTIVE DEMAND ADJUSTMENT

Company may determine the customer's monthly maximum 15-minute reactive demand in kilovars. In each month a charge of $0.99294 per month shall be made for each kilovar by which such maximum reactive demand is greater than fifty percent (50%) of the customer's Monthly Maximum Demand (kW) in that month. The maximum reactive demand in kilovars shall be computed similarly to the Monthly Maximum Demand as defined in the Determination of Demands section.

LARGE LOAD POWER SERVICE
Schedule LLPS

COLLATERAL REQUIREMENTS:

In addition to the Credit Regulations tariff found in section 2.07 of the Company's General Rules and Regulations, the Customer shall provide collateral to the Company ("Collateral Requirement") based upon the creditworthiness of the Customer and as outlined below.

The amount of collateral to be provided is equal to thirty-six (36) months multiplied by the maximum expected monthly bill under the Contract Capacity established for the upcoming year. The amount of collateral under the foregoing calculation will be recomputed annually, and the Customer shall provide the recomputed amount if it is 10% or more, greater than the current amount held.

A Customer with a credit rating of at least A- from S&P and A3 from Moody's and liquidity greater than ten times the Collateral Requirement shall be exempt from the Collateral Requirements. A Customer that does not have a credit rating from S&P and Moody's but maintains liquidity greater than ten times the Collateral Requirement (evidenced by providing quarterly financial statements and certification that on the date financial statements are provided that the Customer's liquidity meets the ten times threshold) shall be exempt from 50 percent of the Collateral Requirements not to exceed an exemption of more than $250 million.
The Collateral Requirement must be provided in one or more of the following forms:

a. A guarantee from the ultimate parent or a corporate affiliate of the Customer for the full Collateral Requirement, so long as the guarantor has both (a) a credit rating of at least A- from S&P and A3 from Moody's and (b) liquidity greater than ten times the Collateral Requirement; or

b. A standby irrevocable Letter of Credit ("Letter of Credit") for the full Collateral Requirement. The Letter of Credit must be issued by a U.S. bank or the U.S. branch of a foreign bank, which is not affiliated with the Large Load Customer or its guarantor, with a credit rating of at least A- from S&P and A3 from Moody's. Such security must be issued for a minimum term of 360 days. The Customer must cause the renewal or extension of the security for additional consecutive terms of 360 days or more no later than 30 days prior to each expiration date of the security. If the security is not renewed or extended as required herein, the Company will have the right to draw immediately upon the Letter of Credit and be entitled to hold the amounts so drawn as security. The Letter of Credit must be in a format acceptable to and approved by the Company; or

c. Cash for the full Collateral Requirement.

SPECIAL TERMS

Customers receiving service under this schedule are required to enter in a written Service Agreement that specifies certain provisions of their electric service, including, but not limited to, load characteristics, customer-specific terms, applicable construction cost recovery terms, and other service details, including definition of operating procedures.

The terms and conditions of service under this this schedule shall apply upon a request for service by an eligible customer but service to Customers under this schedule shall not commence until the Company has sufficient capacity to meet the Customer's Contract Capacity requirements.

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

LARGE LOAD POWER SERVICE
Schedule LLPS

ADJUSTMENTS AND SURCHARGES

The rates hereunder are subject to adjustment as provided in the following schedules:

- Fuel Adjustment Clause (FAC)
- Demand Side Investment Mechanism Rider (DSIM)
- Tax Adjustment (TA)
- System Support Rider (SR)

REGULATIONS

In addition to the above rules and regulations, all of Company's General Rules and Regulations shall apply to the subscription supplied under this Program, except as specifically modified herein.

All provisions of the rate schedule are subject to changes made by order the regulatory authority having jurisdiction.

RENEWABLE ENERGY PROGRAM RIDER
Schedule RENEW

PURPOSE

Applicable to any customer using electric service supplied at one point of delivery. Backup, breakdown, standby, supplemental, short term, resale, or shared electric services are not available under this rate schedule.

AVAILABILITY

Renewable energy is available to customers participating in a voluntary renewable energy program offered by the Company.

CHARACTER OF SERVICE

The Company agrees to generate or purchase energy from renewable sources and/or purchase Renewable Energy Credits (RECs) in an amount at least equal to the level of service purchased by participants in the Renewable Energy Program. Energy output from renewable sources will vary from month to month due to weather and other factors.

REC PURCHASE OPTION AND PARTICIPATION LEVELS

Participants may subscribe up to 100 percent of their annual energy usage. During initial sign up, the Customer will designate their desired subscription percentage in increments of 10 percent. The formula for determining the amount that will be billed to a Customer is:

$$Billed\ Amount = \begin{pmatrix} Monthly\ kWh\ Consumption \times \\ Subscription\ Percentage\ (10-100\%) \end{pmatrix} \times Renewable\ Energy\ Charge$$

The amount of renewable energy kWh available to participating Customers shall be determined by the Company based on the amount of renewable energy sources and RECs anticipated to be available to the Company for any Program year. If customer 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

RENEWABLE ENERGY PROGRAM RIDER
Schedule RENEW

MONTHLY RATE

Renewable energy is available to customers participating in a voluntary renewable energy program offered by the Company.

Renewable Energy Charge:	$0.00265 per kWh
Consisting of:	
REC Charge:	$0.00255 per kWh
Administrative Charge:	$0.00010 per kWh

Renewable Energy Charges are in addition to the charges of the applicable Rate Schedule under which customer takes electric service.

MONTHLY BILLING

The entire bill amount, inclusive of all standard rate charges and Program charges, must be paid according to the payment terms set forth in the Company Rules and Regulations.

SUBSCRIPTION TERM

The Program is voluntary, month-to-month, with no upfront costs or contract required. Participants can change their level of support or cancel at any time with no penalties or cancellation fees by notifying the Company.

ANNUAL UPDATE AND NOTIFICATION PROCESS

Enrolled Customers will be notified in November or December of pricing updates by the Company for the upcoming year. Notifications will be opt-out communications with the new rates that will be effective the first billing cycle in January of the next calendar year.

RENEWABLE ENERGY PROGRAM RIDER
Schedule RENEW

DEFINITIONS AND CONDITIONS

1. Renewable Energy, as used in this rate schedule, shall mean electricity that is generated using renewable energy resources as defined in RSMo 393.1025(5). A commitment to sustainable energy initiatives means implementation by individual large commercial and industrial customers of programs that are recognized by the utility industry and government as having an elevated level of commitment to our environment, energy efficiency and renewable energy programs.

2. Renewable Energy and Renewable Energy Credits utilized under the Renewable Energy Program Rider cannot be used by the Company to comply with the State's Renewable Energy Standard, RSMo 393.1030, and amendments thereto, as well as the resulting Missouri Administrative Regulations.

3. Customer may subscribe for an amount of Renewable Energy up to its maximum monthly usage.

4. Renewable Energy shall be limited to the sum of (a) generation produced by Company-owned renewable sources, (b) 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.

5. Changes in the weather and other factors may result in less Renewable Energy being available to the Company than anticipated. If the Renewable Energy resources obtained by the Company for a program year are not sufficient to meet commitment levels, the Company will refund to each participating Customer at the end of each program year an amount equal to the Renewable Energy Charge (or discounted Renewable Energy Charge, if applicable), multiplied by the difference between the Customer's pro rata share of Renewable Energy resources obtained by the Company for such program year and the Renewable Energy the Customer committed to purchase.

SYSTEM SUPPORT RIDER
Schedule SR

PURPOSE

The System Support Rider requires an additional charge paid by Customers receiving service under Schedule LLPS to ensure appropriate recovery of costs incurred to serve Schedule LLPS customers, and to reflect the acceleration of resource investment required to serve large loads that join the Company's system under Schedule LLPS, as well as other acceleration-related impacts associated with operations of these resources.

AVAILABILITY

This rider is applicable to all Customers receiving service under Schedule LLPS.

TERM

Charges under this schedule shall be applied during the Customer's term of service under Schedule LLPS.

PROGRAM PROVISIONS

The System Support Charge will consist of two components, (1) a Cost Recovery Component and (2) an Acceleration Component.

The Cost Recovery Component shall be calculated based on comparing the Schedule LLPS Customer's estimated rate revenue and estimated revenue prior to applying Schedule CCR, Schedule DRLR, or Schedule CEC. Should the Schedule LLPS Customer's estimated revenue fall below the Customer's estimated rate revenue, an amount, expressed in a dollar per kW ($/kw) charge, will be added to the customer billing through this Rider charge. The Cost Recovery Component shall be customer-specific and memorialized in Exhibit D of the Customer Service Agreement. This comparison shall be completed annually.

The Acceleration Component shall reflect the difference in the net present value revenue requirements tied to a representative combined-cycle natural gas fired turbine generation ("CCGT") as a result of constructing the CCGT ten years sooner than otherwise would have occurred under normal planned growth, recovered over a 30-year period, as determined by the Company. The difference in revenue requirements shall be multiplied by the ratio of non-Schedule LLPS peak load to total system load to isolate the non-Schedule LLPS acceleration cost to be recovered. The System Support Charge shall be expressed in the form of dollars per kW ($/kW). The Acceleration Component shall be calculated and updated as part of each Company rate proceeding.

The System Support Rider charge shall be the combination of both of these components and be applied to the Customer's monthly billing, identified as a separate line item.

ACCELERATION COMPONENT

The Acceleration Component shall be $9.59 per kW.

BILLING

The charge for the System Support Rider will be determined as follows:

SR charge = Cost Recovery Component + Acceleration Component

The charges associated with this System Support Rider will be determined by multiplying the SR Charge by the Grid Demand as defined in Schedule LLPS and shown as a separate line on the customer's bill.

SYSTEM SUPPORT RIDER
Schedule SR

CHARGE PROVISIONS

After the initial fifteen (15)-year term of service under Schedule LLPS, Customers whose annual peak demand has not increased by more than five (5) percent in the five (5) prior years may request to terminate the Acceleration Component of this charge. If, after removal of the Acceleration Component, the Customer subsequently modifies the Customer Capacity defined under Schedule LLPS by twenty (20) percent or twenty (20) megawatts (MW), whichever is lower, the Acceleration Component will be applied for the remainder of the Schedule LLPS term beginning in the year when this threshold is met.

Should a Customer participate in the Customer Capacity Rider (Schedule CCR), and supply in excess of eighty percent (80%) of the capacity required to serve its load under Schedule CCR, such Customer may request to terminate the Acceleration Component of this charge for the term of the Schedule CCR participation, which the Company shall reasonably grant if it does not identify other rate design concerns with doing so.

The SR Charge shall not be subject to any related Economic Development Rider discount.

To achieve the needed support to non-Schedule LLPS customers, these revenues will be allocated to other non-LPS class customers within the Company Class Cost of Service study performed during a general rate proceeding to offset system costs created by Schedule LLPS customers.

REGULATIONS

Service hereunder is subject to the Company's Rules and Regulations as approved by the Missouri Public Service Commission and any modification subsequently approved.

All provisions of the rate schedule are subject to changes made by order the regulatory authority having jurisdiction.

SERVICE AGREEMENTS (continued)

2.12 SERVICE TO LOADS GREATER THAN 25MW

A. Customers, or prospective Customers seeking service for loads expected to be greater than 25 megawatts (MW) shall be subject to an initial evaluation and study by the Company prior to receiving service. Such Customers shall notify the Company, in advance, concerning the expected load, project location, and project schedule. The Company will respond with an initial evaluation detailing its conditions of service.

B. Customers choosing to move forward and seek service for a project shall complete and comply with terms set forth in a Letter of Agreement and submit a refundable deposit of $200,000 that will be used to offset costs associated with project planning. Should costs exceed this deposit an additional refundable deposit of $200,000 shall be required. Additional refundable deposits will be required such that the Customer pays all project planning costs associated with their project. Initial deposit funds not used during planning shall be refunded to the customer without interest. These Customers shall be placed in a queue based on the date on which they provided the required information and deposit.

    1. Service related to projects the Company designates as serving the community interest may be given priority in the queue and may not be required to submit a deposit. Community interest projects are those that are part of a competitive search in which the Company is competing against at least one other location for the project, the Customer reasonably demonstrates that the project will employ at least 250 permanent, full-time 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.

    2. The Company shall have sole discretion on the deposit applicability and managing projects in the queue.

C. The Company will work on advanced study and scoping for up to four (4) projects at a time. Customers with projects being studied shall be notified of the study results and plans to receive service. Once an Initial Projects Agreement is complete, the Company will send necessary details to the Southwest Power Pool (“SPP”) for its review. Completed plans shall be valid for six months.

D. Customers choosing to receive service according to these plans shall complete the required agreements to facilitate construction and all required Service Agreements to receive service. The Schedule LLPS tariff and associated Service Agreement contain additional requirements for qualifying projects that must be met to receive service. Customers failing to complete these agreements within the timeframe allowed may be returned to the queue.

E. Additional details regarding the queue process and submission shall be posted to and updated from time to time on the Company’s website.

9. EXTENSION OF ELECTRIC FACILITIES (continued)

9.11 Summary Of Policy Administration (continued)

(C). Residential Multi-Family or Residential Mobile Home Trailer Parks

All applicants, classified as permanent service, will have a Construction Allowance calculated per the feasibility model (Section 9.02 C. Construction Allowance) for the customized project. The Construction Allowance is subtracted from the Estimated Construction Cost for the Applicant's project in order to determine the Nonrefundable Construction Charge to be paid by Applicant. Applicant will also be responsible for all Estimated Construction Charges related to the cost of connecting to Company's existing and adequate distribution facilities when the length is greater than 100 feet. Applicant will pay these costs to Company as a Nonrefundable Construction Charge.

(D). Commercial or Industrial

All applicants, classified as permanent service, will have a Construction Allowance calculated per the feasibility model (Section 9.02 C. Construction Allowance) for the customized project. The Construction Allowance is subtracted from the Estimated Construction Cost for the Applicant's project in order to determine the Nonrefundable Construction Charge to be paid by Applicant. The cost of the Distribution Extension on public right-of-way is generally included in the Estimated Construction Cost except where the Applicant requires an extension other than a standard overhead extension. Where underground service on public right-of-way is required and agreed to by Company, the Applicant will be required to pay for the required facilities as either a Nonrefundable Construction Charge or as a surcharge on its monthly bill, at Company's discretion.

(E). TRANSMISSION OR SUBSTATION FACILITIES EXTENSIONS

For extensions of transmission or substation facilities, any Customer requesting service with substation or transmission facilities shall pay all costs associated with such extensions. These costs do not include any resulting Network Upgrade costs for facilities classified as transmission under the Southwest Power Pool Open Access Transmission Tariff. Customers requesting service through substation or transmission facilities must complete payment for the extension or make suitable arrangements for installment payments, execute all required agreements associated with the requested extensions, and execute any Service Agreements required by the applicable rate schedule as a condition for any construction to commence.

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE
(Applicable to Service Provided ~~the Effective Date of This Tariff Sheet~~January 1, 2025 and Thereafter)

DEFINITIONS:

ACCUMULATION PERIODS, FILING DATES AND RECOVERY PERIODS:

An accumulation period is the six calendar months during which the actual costs and revenues subject to this rider will be accumulated for the purposes of determining the Fuel Adjustment Rate ("FAR"). The two six-month accumulation periods each year through four years from the effective date of this tariff sheet, the two corresponding twelve-month recovery periods and the filing dates will be as shown below. Each filing shall include detailed work papers in electronic format to support the filing.

Accumulation Periods	Filing Dates	Recovery Periods
June – November	By January 1	March – February
December – May	By July 1	September – August

A recovery period consists of the months during which the FAR is applied to customer billings on a per kilowatt-hour (kWh) basis.

COSTS AND REVENUES:

Costs eligible for the Fuel and Purchased Power Adjustment ("FPA") will be the Company's allocated Jurisdictional costs for the fuel component of the Company's generating units, reservation charges, purchased power energy charges including applicable Southwest Power Pool ("SPP") charges, emission allowance costs and amortizations, cost of transmission of electricity by others associated with purchased power and off-system sales, and the cost described below associated with the company's hedging program all as incurred during the accumulation period. These costs will be offset by jurisdictional off-system sales revenues, applicable SPP revenues, revenue from the sale of Renewable Energy Certificates or Credits ("REC") and Revenues from the Renewable Energy Program Rider, Green Solutions Connections Rider and Alternative Energy Credit Rider. Eligible costs do not include the purchased power demand costs associated with purchased power contracts in excess of one year or costs associated with service provided to customers taking energy through Schedule MKT. Likewise, revenues do not include demand or capacity receipts associated with power contracts in excess of one year.

APPLICABILITY:

The price per kWh of electricity sold to retail customers not served under Schedule MKT will be adjusted (up or down) in March and September subject to application of the Rider FAC and approval by the Missouri Public Service Commission ("MPSC" or "Commission").

The FAR is the result of dividing the FPA by forecasted Missouri retail net system input ("S_{RP}") for the recovery period, expanded for Voltage Adjustment Factors ("VAF"), rounded to the nearest $0.00001, and aggregated over two accumulation periods. The amount charged on a separate line on retail customers' bills is equal to the current annual FAR multiplied by kWh billed.

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE
(Applicable to Service Provided ~~the Effective Date of This Tariff Sheet~~January 1, 2025 and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS

FPA = 95% * ((ANEC – B) * J) + T + I + P

ANEC = Actual Net Energy Costs = (FC + E + PP + TC – OSSR – R – REV)

FC = Fuel costs, excluding decommissioning and retirement costs, Incurred to support sales and revenues associated with the Company's in-service generating plants:
The following costs reflected in Federal Energy Regulatory Commission ("FERC") Account Number 501:
Subaccount 501000: coal commodity and transportation, side release and freeze conditioning agents, dust mitigation agents, accessorial charges as delineated in railroad accessorial tariffs [additional crew, closing hopper railcar doors, completion of loading of a unit train and its release for movement, completion of unloading of a unit train and its release for movement, delay for removal of frozen coal, destination detention, diversion of empty unit train (including administration fee, holding charges, and out-of-route charges which may include fuel surcharge), diversion of loaded coal trains, diversion of loaded unit train fees (including administration fee, additional mileage fee or out-of-route charges which may include fuel surcharge), fuel surcharge, held in transit, hold charge, locomotive release, miscellaneous handling of coal cars, origin detention, origin re-designation, out-of-route charges (including fuel surcharge), out-of-route movement, pick-up of locomotive power, placement and pick-up of loaded or empty private coal cars on railroad supplied tracks, placement and pick-up of loaded or empty private coal cars on shipper supplied tracks, railcar storage, release of locomotive power, removal, rotation and/or addition of cars, storage charges, switching, trainset positioning, trainset storage, and weighing], unit train maintenance, leases, depreciation and applicable taxes, natural gas costs including reservation charges, fuel quality adjustments, natural gas hedging costs, fuel adjustments included in commodity and transportation costs, broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers), and margins (cash or collateral used to secure or maintain the Company's hedge position with a brokerage or exchange), oil costs for commodity, propane costs, storage, taxes, fees, and fuel losses, coal and oil inventory adjustments, and insurance recoveries, subrogation recoveries and settlement proceeds for fuel expenses in the 501 Accounts.
Subaccount 501020: the allocation of the allowed costs in the 501000, 501300 and 501400 accounts attributed to native load;
Subaccount 501030: the allocation of the allowed costs in the 501000, 501300 and 501400 accounts attributed to off-system sales;
Subaccount 501300: fuel additives and consumable costs for Air Quality Control Systems ("AQCS") operations, such as ammonia, hydrated lime, lime, limestone, limestone inventory adjustment, powder activated carbon, urea, propane, sodium bicarbonate, calcium bromide, sulfur, and RESPond, or other consumables which perform similar functions;
Subaccount 501400 : residual costs and revenues associated with combustion byproducts, slag and ash disposal costs and revenues including contractors, materials and other miscellaneous expenses.

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE
(Applicable to Service Provided ~~the Effective Date of This Tariff Sheet~~January 1, 2025 and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued):

OSSR = Revenues from Off-System Sales:

The following revenues or costs reflected in FERC Account Number 447:

Subaccount 447020: all revenues from off-system sales. This includes charges and credits related to the SPP IM, or other IMs, including, energy, ancillary services, revenue sufficiency (such as make whole payments and out of merit payments and distributions), revenue neutrality payments and distributions, over collected losses payments and distributions, , demand reductions, virtual energy costs and revenues and related fees where the virtual energy transaction is a hedge in support of physical operations related to a generating resource or load, generation/export charges, ancillary services including non-performance and distribution payments and SPP uplift revenues or credits, excluding (1) off-system sales revenues from full and partial requirements sales to municipalities that are served through bilateral contracts in excess of one year, and (2) the amounts associated with purchased power agreements associated with the Renewable Energy Rider tariff and (3) net costs associated with wind PPA entered into after May 2019 whose costs exceed their revenues resulting in a net loss.

Notwithstanding anything to the contrary contained in the tariff sheets for Rider FAC, factors PP and OSSR shall not include costs and revenues for any undersubscribed portion of a permanent Solar Subscription Rider resource allocated to shareholders under the approved stipulation in File No. ER-2022-0130.

Subaccount 447012: capacity charges for capacity sales one year or less in duration;

Subaccount 447030: the allocation of the includable sales in account 447020 not attributed to retail sales.

R = Emissions and Environmental Credits (this will only include Renewable Energy Credits) Gains or losses:

Subaccounts 411.8 and 411.9: gains and losses of the sale of emission allowances in the current FAC accumulation period.

Subaccounts 411.11 and 411.12: for gains and losses on the sale of environmental credits (this will only include Renewable Energy Credits) in the current FAC accumulation period

REV = Revenues from the Renewable Energy Program Rider, Green Solutions Connections Rider and Alternative Energy Credit Rider reflected in retail revenue FERC Account Numbers 440-444

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE
(Applicable to Service Provided ~~the Effective Date of This Tariff Sheet~~January 1, 2025 and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued):

Hedging costs are defined as realized losses and costs (including broker commissions, fees, and margins) minus realized gains associated with mitigating volatility in the Company's cost of natural gas limited to the Company's use of derivatives in the form of forward contracts.

Costs and revenues not specifically detailed in Factors FC, PP, E, TC, OSSR, R or REV shall not be included in the Company's FAR filings; provided however, in the case of Factors PP, TC or OSSR, the market settlement charge types under which SPP or another centrally administered market (e.g., PJM or MISO) bills/credits a cost or revenue need not be detailed in Factors PP or OSSR for the costs or revenues to be considered specifically detailed in Factors PP or OSSR; and provided further, should the SPP or another centrally administered market (e.g. PJM or MISO) implement a new market settlement charge type not listed below or a new schedule not listed in TC.

SPP IM charge/revenue types that are included in the FAC are listed below:

Day Ahead Ramp Capability Up Amount
Day Ahead Ramp Capability Down Amount
Day Ahead Ramp Capability Up Distribution Amount
Day Ahead Ramp Capability Down Distribution Amount
Day Ahead Regulation Down Service Amount
Day Ahead Regulation Down Service Distribution Amount
Day Ahead Regulation Up Service Amount
Day Ahead Regulation Up Service Distribution Amount
Day Ahead Spinning Reserve Amount
Day Ahead Spinning Reserve Distribution Amount
Day Ahead Supplemental Reserve Amount
Day Ahead Supplemental Reserve Distribution Amount
Real Time Contingency Reserve Deployment Failure Amount
Real Time Contingency Reserve Deployment Failure Distribution Amount
Real Time Ramp Capability Up Amount
Real Time Ramp Capablity Down Amount
Real Time Ramp Capability Up Distribution Amount
Day Ahead Uncertainty Reserve Amount
Day Ahead Uncertainty Reserve Distribution Amount
Real Time Uncertainty Reserve Amount
Real Time Uncertainty Reserve Distribution Amount
Real Time Uncertainty Reserve Non-Performance Amount
Real Time Uncertainty Reserve Non-Performance Distribution Amount

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE
(Applicable to Service Provided ~~the Effective Date of This Tariff Sheet~~January 1, 2025 and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued):

SPP IM charge/revenue types that are included in the FAC (continued)

Miscellaneous Amount
Reliability Unit Commitment Make Whole Payment Amount
Real Time Out of Merit Amount
Reliability Unit Commitment Make Whole Payment Distribution Amount
Over Collected Losses Distribution Amount
Real Time Joint Operating Agreement Amount
Real Time Reserve Sharing Group Amount
Real Time Reserve Sharing Group Distribution Amount
Real Time Demand Reduction Amount
Real Time Demand Reduction Distribution Amount
Real Time Pseudo Tie Congestion Amount
Real Time Pseudo Tie Losses Amount
Unused Regulation Up Mileage Make Whole Payment Amount
Unused Regulation Down Mileage Make Whole Payment Amount
Revenue Neutrality Uplift Distribution Amount

Should FERC require any item covered by components FC, E, PP, TC, OSSR R or REV to be recorded in an account different than the FERC accounts listed in such components, such items shall nevertheless be included in component FC, E, PP, TC, OSSR R or REV. In the month that the Company begins to record items in a different account, the Company will file with the Commission the previous account number, the new account number and what costs or revenues that flow through the Rider FAC to be recorded in the account.

B = Net base energy costs ordered by the Commission in the last general rate case consistent with the costs and revenues included in the calculation of the FPA. N e t Base Energy costs will be calculated as shown below:

S_{AP} x Base Factor (“BF”)

S_{AP} = Net system input (“NSI”) in kWh for the accumulation period, at the generation level, excluding the energy used by customers served under the MKT Schedule.

BF = Company base factor costs per kWh: $0.02309

J = Missouri Retail Energy Ratio = Retail kWh sales/total system kWh
Where: total system kWh equals retail and full and partial requirement sales associated with MO West.

T = True-up amount as defined below.

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE
(Applicable to Service Provided ~~the Effective Date of This Tariff Sheet~~January 1, 2025 and Thereafter)

Accumulation Period Ending:			
1	Actual Net Energy Cost (ANEC) = (FC+E+PP+TC-OSSR-R-REV)		
2	Net Base Energy Cost (B)	-	
	2.1 Base Factor (BF)		$0.02309
	2.2 Accumulation Period NSI (S_{AP})		
3	(ANEC-B)		
4	Jurisdictional Factor (J)	x	
5	(ANEC-B)*J		
6	Customer Responsibility	x	
7	95% *((ANEC-B)*J)		
8	True-Up Amount (T)	+	
9	Interest (I)	+	
10	Prudence Adjustment Amount (P)	+	
11	Fuel and Purchased Power Adjustment (FPA)	=	
	~~11.1 PISA Deferral (Sec. 393.1400)~~		
	~~11.2 FPA Subject to Recover in True-Up~~		
12	Estimated Recovery Period Retail NSI (S_{RP})	÷	
13	**Current Period Fuel Adjustment Rate (FAR)**	=	
14	Current Period FAR_{Sec} = FAR x VAF_{Sec}		
15	Prior Period FAR_{Sec}	+	
16	Current Annual FAR_{Sec}	=	
17	Current Period FAR_{Prim} = FAR x VAF_{Prim}		
18	Prior Period FAR_{Prim}	+	
19	Current Annual FAR_{Prim}	=	
20	Current Period FAR_{Sub} = FAR x VAF_{Sub}		
21	Prior Period FAR_{Sub}	+	
22	Current Annual FAR_{Sub}	=	
23	Current Period FAR_{Trans} = FAR x VAF_{Trans}		
24	Prior Period FAR_{Trans}	+	
25	Current Annual FAR_{Trans}	=	
26	VAF_{Sec} = 1.0766		
27	VAF_{Prim} = 1.0503		
28	VAF_{Sub} = 1.0388		
29	VAF_{Trans} = 1.0300		

LARGE POWER SERVICE
ELECTRIC

AVAILABILITY

This schedule is available for all general service use, such as combined lighting and power service to any customer who shall contract for a minimum capacity of five-hundred (500) kilowatts (kW) for a period of twelve consecutive months. Customers whose monthly demand is reasonably expected to reach or exceed one hundred thousand (100,000) kilowatts shall not be allowed to continue receiving service under this schedule and will be required to receive service under Schedule LLPS.

Service is available under this schedule to the following types of customers based on voltage level:

Secondary voltage customer - Receives service on the low side of the line transformer.

Primary voltage customer - Receives service at Primary Voltage of 2,400 volts or over but not exceeding 69,000 volts. Normally, the customer will own all equipment necessary for transformation including the line transformer.

Substation voltage customer - Service is taken directly out of a distribution substation at primary voltage. Normally, the customer will own the feeder circuits out of this substation.

Transmission voltage customer - The customer owns, leases, or otherwise bears financial responsibility for the distribution substation. Normally, service is taken off of the Company's transmission system.

This rate is not available for standby, breakdown, supplementary, maintenance or resale service except as noted below.

The restriction against "submetering" and reselling" found in the Company's Rules and Regulations 3.02 (A) and (B) shall not apply where a vacated single tenant premise to which the Company provided service through a single meter for a minimum of five contiguous years has been repurposed as a multi-tenant premise that provides an economic benefit to the immediate area by creating or retaining jobs and avoiding or alleviating economic blight in the immediate area.

Charges to the tenants for electric utility service with respect to any given period shall not exceed the amount of the Company's billing to the customer for that period.

Tenants of such repurposed premise are not customers of the Company and as such are not subject to the Company's tariff. The landlord/property manager shall retain a copy of all individual tenant billings for a period of five years and provide such billing information within ten (10) days to the Company and/or the Missouri Public Service Commission upon request.

CHARACTER OF SERVICE

Single-phase, 60 Hertz, nominally 120/240 volt firm electric service, provided from the Company's secondary distribution system. Three-phase secondary service shall be available where three-phase facilities are available without additional construction or may be made available at additional charge at voltages not exceeding 480 volts. Three-phase primary distribution service shall be available where primary distribution facilities are available without additional construction or may be made available at additional charge at 2,400, 12,470, or 24,900 nominal volts. Primary service may be served from Company's 69,000 volt or 34,500 volt systems, at Company's option, through Company owned transformation. The customer may request contractual service from the 69,000 volt or 34,500 volt systems, if such systems are available at the customer's point of delivery without additional construction, and the customer provides transformer.

Special Rate for Incremental Load Service (FROZEN)
Schedule SIL

PURPOSE:

This rate schedule is designed to provide certain Customers with new or incremental increases in load, access to a special rate that is not based on the Company's cost of service like generally available tariff rates, but is designed to recover no less than the incremental costs of serving the new load. The Customer load will be served primarily by renewable energy resources separate from energy resources used to serve general customers of the Company.

AVAILABILITY:

This schedule is not available to new customers after xxx (date).

This special rate is available to customers with new, incremental load who:

- Have a facility whose primary industry is the smelting of aluminum and primary metals, (Standard Industrial Classification Code 3334) or
- Have a facility whose primary industry is the production or fabrication of steel (North American Industrial Classification System 331110) or
- Operate a facility with an increase in load equal to or in excess of a monthly demand of fifty megawatts

Each customer must demonstrate the new, incremental load can:

- Show a competitive need, documenting the facility would not commence operations absent the special rate,
- Show the special rate is in the interest of the state of Missouri when considering the interests of the customers of the Company, considering the incremental cost of serving the facility to receive the special rate, and the interests of the citizens of the state generally in promoting economic development, improving the tax base, providing employment opportunities in the state, and promoting such other benefits to the state as the commission may determine are created by approval of the special rate

This rate is not available for standby, breakdown, supplementary, maintenance or resale service except as noted below. Sub-metering or the reselling of electricity is prohibited.

Availability of service under this tariff may be limited by the Company due to constraints with, or protection for, Company generation resources or the transmission grid.

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.

~~Service under this tariff shall be excluded from projected energy calculations used to establish charges under Riders FAC and RESRAM, and programs offered pursuant to the Missouri Energy Efficiency Investment Act, unless otherwise ordered by the Commission when approving a contract for service under this tariff.~~

Special Rate for Incremental Load Service (FROZEN)
Schedule SIL

AVAILABILITY: (cont.)

Service under this tariff shall be excluded from projected energy calculations used to establish charges under Riders FAC and RESRAM, and programs offered pursuant to the Missouri Energy Efficiency Investment Act, unless otherwise ordered by the Commission when approving a contract for service under this tariff.

TERMS & CONDITIONS:

Service under this rate schedule requires a written contract between the Company and the Customer. Each Special Incremental Load Rate Contract shall collect at least the incremental cost incurred by the Company to serve the Customer. Incremental costs shall be calculated, and profitability must be demonstrated at the time the contract is approved to confirm that revenues to be received from Customers under this Schedule are expected to be sufficient to cover the Company's increased costs to offer service pursuant to each Special Incremental Load Rate Contract. All charges for service under this rate schedule shall be limited to the charges contained in the contract between the Company and the Customer.

CONTRACT DOCUMENTATION:

At least 60 days prior to the effective date of the Special Incremental Load Rate Contract, the Company will file the individual Special Incremental Load Rate Contract and supporting documentation with the Commission for approval. The supporting documentation will include the following items:

1. Customer Needs: Company shall provide a narrative description of the reasons why the Special Incremental Load Rate is necessary for this Customer.

2. Customer Alternatives: Company shall describe competitive alternatives available to the Customer.

3. Incremental Costs: Company shall quantify the expected incremental cost associated with the Special Incremental Load Rate Contract Customer.

4. Profitability: Company shall quantify the expected profitability of the Special Incremental Load Rate Contract as the difference between the revenues expected to be generated from the pricing provisions in the Special Incremental Load Rate Contract compared to Company's expected incremental costs. All significant assumptions shall be identified that affect this quantification.

5. Other Ratepayer Benefits: Company shall quantify the benefits that it believes will accrue to other ratepayers from the Special Incremental Load Rate Contract. All significant assumptions shall be identified that affect this quantification.

6. Other Economic Benefits to the Area: the Company and/or local economic development agency shall quantify the economic benefits to the state, metropolitan area, and/or local area that Company projects to be realized as a result of the Special Incremental Load Rate Contract. The Company will also file an affidavit from the state, metropolitan area and/or local area economic development agency that is also providing benefits to the customer.

Special Rate for Incremental Load Service (FROZEN)
Schedule SIL

TERM:

The initial term may vary for each customer served under this rate schedule but in no instance, should the term be greater than ten (10) years. Prior to the end of the term, the Company and Customer will work together to evaluate an extension of the term and if mutually appropriate, work together to secure any required approvals for an extension of the term. Each subsequent extension shall not exceed an additional ten (10) years.

SPECIAL RATE, PROVISIONS, AND TERMS:

1. The Special Incremental Load Rate will be determined for each Customer based on expected loads and the renewable energy resource planned to serve the Customer. Details about the rate including all terms and conditions related to the Special Incremental Load Rate will be documented through a Special Incremental Load Rate Contract.

2. The Special Incremental Load Rate will be designed to recover no less than the incremental cost to serve the Customer over the term of the Special Incremental Load Rate Contract. Non-participating customers shall be held harmless from any deficit in revenues provided by any customer served under this tariff.

3. All Special Incremental Load Rate Contracts executed under this tariff will include the following provisions:
   a. Special Rate – details about the structure and rate to be paid by the Customer.
   b. Agreement Term – clear identification of the dates associated with the Special Rate, particularly the start date for contract term.
   c. Confidentiality – terms to establish protections needed to protect data under competitive conditions.
   d. Operational Parameters – details about the expected operation of the facility to be served.

4. The Company will make provisions to uniquely identify the costs and revenues for each respective Special Incremental Load Rate Contract within its books and records. This information will be available to support periodic reporting as ordered by the Commission. At the time of a general rate proceeding the portion of the Company's revenue requirement associated with the incremental costs net of PPA net revenues to serve the Customer shall be assigned to the Customer. The Customer's rate revenues shall be reflected in Company's net revenue requirement. If the Customer's rate revenues do not exceed the incremental cost to serve the Customer as reflected in the revenue requirement calculation, the Company shall make an additional revenue adjustment covering the shortfall to the revenue requirement calculation through the true-up period, to ensure that non-Schedule SIL customers will be held harmless from such effects from the service under Schedule SIL. In no event shall any revenue deficiency (that is, a greater amount of the Customer's incremental costs compared to the Customer's revenues) be reflected in the Company's cost of service in each general rate proceeding for the duration of service to the Customer(s) during the terms of the contract between Company and Customer served under this tariff.

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

Special Rate for Incremental Load Service (FROZEN)
Schedule SIL

SPECIAL INCREMENTAL LOAD RATE CONTRACTS:

Start Date of Special Incremental Load Rate Contract	Name of Customer	Address	Term of Special Incremental Rate
January 1, 2020	Nucor Steel Sedalia, LLC	500 Rebar Rd, Sedalia, MO	10 years

~~2.09~~ Returned Payment

If a customer tenders to Company a check, draft, or a payment order in payment for service billed which is ultimately dishonored for reasons other than bank error, the customer shall be assessed a Returned Payment Charge per Section 12 of these Rules.

2.10 Service to loads greater than 25MW

A. Customers, or prospective Customers seeking service for loads expected to be greater than 25 megawatts (MW) shall be subject to an initial evaluation and study by the Company prior to receiving service. Such Customers shall notify the Company, in advance, concerning the expected load, project location, and project schedule. The Company will respond with an initial evaluation detailing its conditions of service.
B. Customers choosing to move forward and seek service for a project shall complete and comply with terms set forth in a Letter of Agreement and submit a refundable deposit of $200,000 that will be used to offset costs associated with project planning. Should costs exceed this deposit an additional refundable deposit of $200,000 shall be required. Additional refundable deposits will be required such that the Customer pays all project planning costs associated with their project. Initial deposit funds not used during planning shall be refunded to the customer without interest. These Customers shall be placed in a queue based on the date on which they provided the required information and deposit.
    a. Service related to projects the Company designates as serving the community interest may be given priority in the queue and may not be required to submit a deposit. Community interest projects are those that are part of a competitive search in which the Company is competing against at least one other location for the project, the Customer reasonably demonstrates that the project will employ at least 250 permanent, full-time 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.
    b. The Company shall have sole discretion on the deposit applicability and managing projects in the queue.
C. The Company will work on advanced study and scoping for up to four (4) projects at a time. Customers with projects being studied shall be notified of the study results and plans to receive service. Once an Initial Projects Agreement is complete, the Company will send necessary details to the Southwest Power Pool ("SPP") for its review. Completed plans shall be valid for six months.
D. Customers choosing to receive service according to these plans shall complete the required agreements to facilitate construction and all required Service Agreements to receive service. The Schedule LLPS tariff and associated Service Agreement contain additional requirements for qualifying projects that must be met to receive service. Customers failing to complete these agreements within the timeframe allowed may be returned to the queue.
~~A.~~E. Additional details regarding the queue process and submission shall be posted to and updated from time to time on the Company's website.

7.11 Summary of Policy Administration (Continued):

C. Residential Multi-Family or Residential Mobile Home Trailer Parks

All applicants, classified as permanent service, will have a Construction Allowance calculated per the feasibility model (Section 7.02 C. Construction Allowance) for the customized project. The Construction Allowance is subtracted from the Estimated Construction Cost for the Applicant's project in order to determine the Nonrefundable Construction Charge to be paid by Applicant. Applicant will also be responsible for all Estimated Construction Charges related to the cost of connecting to Company's existing and adequate distribution facilities when the length is greater than 100 feet. Applicant will pay these costs to Company as a Nonrefundable Construction Charge.

D. Commercial or Industrial

All applicants, classified as permanent service, will have a Construction Allowance calculated per the feasibility model (Section 7.02 C. Construction Allowance) for the customized project. The Construction Allowance is subtracted from the Estimated Construction Cost for the Applicant's project in order to determine the Nonrefundable Construction Charge to be paid by Applicant. The cost of the Distribution Extension on public right-of-way is generally included in the Estimated Construction Cost except where the Applicant requires an extension other than a standard overhead extension. Where underground service on public right-of-way is required and agreed to by Company, the Applicant will be required to pay for the required facilities as either a Nonrefundable Construction Charge or as a surcharge on its monthly bill, at Company's discretion.

E. Transmission or Facilities Extensions

For extensions of transmission or substation facilities, any Customer requesting service with substation or transmission facilities shall pay all costs associated with such extensions. These costs do not include any resulting Network Upgrade costs for facilities classified as transmission under the Southwest Power Pool Open Access Transmission Tariff. Customers requesting service through substation or transmission facilities must complete payment for the extension or make suitable arrangements for installment payments, execute all required agreements associated with the requested extensions, and execute any Service Agreements required by the applicable rate schedule as a condition for any construction to commence.

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE
(Applicable to Service Provided January 1, 2025 and Thereafter)

DEFINITIONS:

ACCUMULATION PERIODS, FILING DATES AND RECOVERY PERIODS:

An accumulation period is the six calendar months during which the actual costs and revenues subject to this rider will be accumulated for the purposes of determining the Fuel Adjustment Rate ("FAR"). The two six-month accumulation periods each year through four years from the effective date of this tariff sheet, the two corresponding twelve-month recovery periods and the filing dates will be as shown below. Each filing shall include detailed work papers in electronic format to support the filing.

Accumulation Periods	Filing Dates	Recovery Periods
June – November	By January 1	March – February
December – May	By July 1	September – August

A recovery period consists of the months during which the FAR is applied to customer billings on a per kilowatt-hour (kWh) basis.

COSTS AND REVENUES:

Costs eligible for the Fuel and Purchased Power Adjustment ("FPA") will be the Company's allocated Jurisdictional costs for the fuel component of the Company's generating units, reservation charges, purchased power energy charges including applicable Southwest Power Pool ("SPP") charges, emission allowance costs and amortizations, cost of transmission of electricity by others associated with purchased power and off-system sales, and the cost described below associated with the company's hedging program all as incurred during the accumulation period. These costs will be offset by jurisdictional off-system sales revenues, applicable SPP revenues, revenue from the sale of Renewable Energy Certificates or Credits ("REC") and Revenues from the Renewable Energy Program Rider, Green Solutions Connections Rider and Alternative Energy Credit Rider. Eligible costs do not include the purchased power demand costs associated with purchased power contracts in excess of one year or costs associated with service provided to customers taking energy through Schedule MKT. Likewise, revenues do not include demand or capacity receipts associated with power contracts in excess of one year.

APPLICABILITY:

The price per kWh of electricity sold to retail customers not served under Schedule MKT will be adjusted (up or down) in March and September subject to application of the Rider FAC and approval by the Missouri Public Service Commission ("MPSC" or "Commission").

The FAR is the result of dividing the FPA by forecasted Missouri retail net system input ("S_{RP}") for the recovery period, expanded for Voltage Adjustment Factors ("VAF"), rounded to the nearest $0.00001, and aggregated over two accumulation periods. The amount charged on a separate line on retail customers' bills is equal to the current annual FAR multiplied by kWh billed.

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE
(Applicable to Service Provided January 1, 2025 and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS

FPA = 95% * ((ANEC – B) * J) + T + I + P

ANEC = Actual Net Energy Costs = (FC + E + PP + TC – OSSR – R – REV)

FC = Fuel costs, excluding decommissioning and retirement costs, Incurred to support sales and revenues associated with the Company's in-service generating plants:
The following costs reflected in Federal Energy Regulatory Commission ("FERC") Account Number 501:
Subaccount 501000: coal commodity and transportation, side release and freeze conditioning agents, dust mitigation agents, accessorial charges as delineated in railroad accessorial tariffs [additional crew, closing hopper railcar doors, completion of loading of a unit train and its release for movement, completion of unloading of a unit train and its release for movement, delay for removal of frozen coal, destination detention, diversion of empty unit train (including administration fee, holding charges, and out-of-route charges which may include fuel surcharge), diversion of loaded coal trains, diversion of loaded unit train fees (including administration fee, additional mileage fee or out-of-route charges which may include fuel surcharge), fuel surcharge, held in transit, hold charge, locomotive release, miscellaneous handling of coal cars, origin detention, origin re-designation, out-of-route charges (including fuel surcharge), out-of-route movement, pick-up of locomotive power, placement and pick-up of loaded or empty private coal cars on railroad supplied tracks, placement and pick-up of loaded or empty private coal cars on shipper supplied tracks, railcar storage, release of locomotive power, removal, rotation and/or addition of cars, storage charges, switching, trainset positioning, trainset storage, and weighing], unit train maintenance, leases, depreciation and applicable taxes, natural gas costs including reservation charges, fuel quality adjustments, natural gas hedging costs, fuel adjustments included in commodity and transportation costs, broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers), and margins (cash or collateral used to secure or maintain the Company's hedge position with a brokerage or exchange), oil costs for commodity, propane costs, storage, taxes, fees, and fuel losses, coal and oil inventory adjustments, and insurance recoveries, subrogation recoveries and settlement proceeds for fuel expenses in the 501 Accounts.
Subaccount 501020: the allocation of the allowed costs in the 501000, 501300 and 501400 accounts attributed to native load;
Subaccount 501030: the allocation of the allowed costs in the 501000, 501300 and 501400 accounts attributed to off-system sales;
Subaccount 501300: fuel additives and consumable costs for Air Quality Control Systems ("AQCS") operations, such as ammonia, hydrated lime, lime, limestone, limestone inventory adjustment, powder activated carbon, urea, propane, sodium bicarbonate, calcium bromide, sulfur, and RESPond, or other consumables which perform similar functions;
Subaccount 501400 : residual costs and revenues associated with combustion byproducts, slag and ash disposal costs and revenues including contractors, materials and other miscellaneous expenses.

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE
(Applicable to Service Provided January 1, 2025 and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued):

OSSR = Revenues from Off-System Sales:

The following revenues or costs reflected in FERC Account Number 447:

Subaccount 447020: all revenues from off-system sales. This includes charges and credits related to the SPP IM, or other IMs, including, energy, ancillary services, revenue sufficiency (such as make whole payments and out of merit payments and distributions), revenue neutrality payments and distributions, over collected losses payments and distributions, , demand reductions, virtual energy costs and revenues and related fees where the virtual energy transaction is a hedge in support of physical operations related to a generating resource or load, generation/export charges, ancillary services including non-performance and distribution payments and SPP uplift revenues or credits, excluding (1) off-system sales revenues from full and partial requirements sales to municipalities that are served through bilateral contracts in excess of one year, and (2) the amounts associated with purchased power agreements associated with the Renewable Energy Rider tariff and (3) net costs associated with wind PPA entered into after May 2019 whose costs exceed their revenues resulting in a net loss.

Notwithstanding anything to the contrary contained in the tariff sheets for Rider FAC, factors PP and OSSR shall not include costs and revenues for any undersubscribed portion of a permanent Solar Subscription Rider resource allocated to shareholders under the approved stipulation in File No. ER-2022-0130.

Subaccount 447012: capacity charges for capacity sales one year or less in duration;

Subaccount 447030: the allocation of the includable sales in account 447020 not attributed to retail sales.

R = Emissions and Environmental Credits (this will only include Renewable Energy Credits) Gains or losses:

Subaccounts 411.8 and 411.9: gains and losses of the sale of emission allowances in the current FAC accumulation period.

Subaccounts 411.11 and 411.12: for gains and losses on the sale of environmental credits (this will only include Renewable Energy Credits) in the current FAC accumulation period

REV = Revenues from the Renewable Energy Program Rider, Green Solutions Connections Rider and Alternative Energy Credit Rider reflected in retail revenue FERC Account Numbers 440-444

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE
(Applicable to Service Provided January 1, 2025 and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued):

Hedging costs are defined as realized losses and costs (including broker commissions, fees, and margins) minus realized gains associated with mitigating volatility in the Company's cost of natural gas limited to the Company's use of derivatives in the form of forward contracts.

Costs and revenues not specifically detailed in Factors FC, PP, E, TC, OSSR, R or REV shall not be included in the Company's FAR filings; provided however, in the case of Factors PP, TC or OSSR, the market settlement charge types under which SPP or another centrally administered market (e.g., PJM or MISO) bills/credits a cost or revenue need not be detailed in Factors PP or OSSR for the costs or revenues to be considered specifically detailed in Factors PP or OSSR; and provided further, should the SPP or another centrally administered market (e.g. PJM or MISO) implement a new market settlement charge type not listed below or a new schedule not listed in TC.

SPP IM charge/revenue types that are included in the FAC are listed below:

Day Ahead Ramp Capability Up Amount
Day Ahead Ramp Capability Down Amount
Day Ahead Ramp Capability Up Distribution Amount
Day Ahead Ramp Capability Down Distribution Amount
Day Ahead Regulation Down Service Amount
Day Ahead Regulation Down Service Distribution Amount
Day Ahead Regulation Up Service Amount
Day Ahead Regulation Up Service Distribution Amount
Day Ahead Spinning Reserve Amount
Day Ahead Spinning Reserve Distribution Amount
Day Ahead Supplemental Reserve Amount
Day Ahead Supplemental Reserve Distribution Amount
Real Time Contingency Reserve Deployment Failure Amount
Real Time Contingency Reserve Deployment Failure Distribution Amount
Real Time Ramp Capability Up Amount
Real Time Ramp Capablity Down Amount
Real Time Ramp Capability Up Distribution Amount
Day Ahead Uncertainty Reserve Amount
Day Ahead Uncertainty Reserve Distribution Amount
Real Time Uncertainty Reserve Amount
Real Time Uncertainty Reserve Distribution Amount
Real Time Uncertainty Reserve Non-Performance Amount
Real Time Uncertainty Reserve Non-Performance Distribution Amount

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE
(Applicable to Service Provided January 1, 2025 and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued):

SPP IM charge/revenue types that are included in the FAC (continued)

Miscellaneous Amount
Reliability Unit Commitment Make Whole Payment Amount
Real Time Out of Merit Amount
Reliability Unit Commitment Make Whole Payment Distribution Amount
Over Collected Losses Distribution Amount
Real Time Joint Operating Agreement Amount
Real Time Reserve Sharing Group Amount
Real Time Reserve Sharing Group Distribution Amount
Real Time Demand Reduction Amount
Real Time Demand Reduction Distribution Amount
Real Time Pseudo Tie Congestion Amount
Real Time Pseudo Tie Losses Amount
Unused Regulation Up Mileage Make Whole Payment Amount
Unused Regulation Down Mileage Make Whole Payment Amount
Revenue Neutrality Uplift Distribution Amount

Should FERC require any item covered by components FC, E, PP, TC, OSSR R or REV to be recorded in an account different than the FERC accounts listed in such components, such items shall nevertheless be included in component FC, E, PP, TC, OSSR R or REV. In the month that the Company begins to record items in a different account, the Company will file with the Commission the previous account number, the new account number and what costs or revenues that flow through the Rider FAC to be recorded in the account.

B = Net base energy costs ordered by the Commission in the last general rate case consistent with the costs and revenues included in the calculation of the FPA. N e t Base Energy costs will be calculated as shown below:

S_{AP} x Base Factor (“BF”)

S_{AP} = Net system input (“NSI”) in kWh for the accumulation period, at the generation level, excluding the energy used by customers served under the MKT Schedule.

BF = Company base factor costs per kWh: $0.02309

J = Missouri Retail Energy Ratio = Retail kWh sales/total system kWh
Where: total system kWh equals retail and full and partial requirement sales associated with MO West.

T = True-up amount as defined below.

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE
(Applicable to Service Provided January 1, 2025 and Thereafter)

Accumulation Period Ending:			
1	Actual Net Energy Cost (ANEC) = (FC+E+PP+TC-OSSR-R-REV)		
2	Net Base Energy Cost (B)	-	
	2.1 Base Factor (BF)		$0.02309
	2.2 Accumulation Period NSI (S_{AP})		
3	(ANEC-B)		
4	Jurisdictional Factor (J)	x	
5	(ANEC-B)*J		
6	Customer Responsibility	x	
7	95% *((ANEC-B)*J)		
8	True-Up Amount (T)	+	
9	Interest (I)	+	
10	Prudence Adjustment Amount (P)	+	
11	Fuel and Purchased Power Adjustment (FPA)	=	
12	Estimated Recovery Period Retail NSI (S_{RP})	÷	
13	**Current Period Fuel Adjustment Rate (FAR)**	**=**	
14	Current Period FAR_{Sec} = FAR x VAF_{Sec}		
15	Prior Period FAR_{Sec}	+	
16	Current Annual FAR_{Sec}	=	
17	Current Period FAR_{Prim} = FAR x VAF_{Prim}		
18	Prior Period FAR_{Prim}	+	
19	Current Annual FAR_{Prim}	=	
20	Current Period FAR_{Sub} = FAR x VAF_{Sub}		
21	Prior Period FAR_{Sub}	+	
22	Current Annual FAR_{Sub}	=	
23	Current Period FAR_{Trans} = FAR x VAF_{Trans}		
24	Prior Period FAR_{Trans}	+	
25	Current Annual FAR_{Trans}	=	
26	VAF_{Sec} = 1.0766		
27	VAF_{Prim} = 1.0503		
28	VAF_{Sub} = 1.0388		
29	VAF_{Trans} = 1.0300		

LARGE POWER SERVICE
ELECTRIC

AVAILABILITY

This schedule is available for all general service use, such as combined lighting and power service to any customer who shall contract for a minimum capacity of five-hundred (500) kilowatts (kW) for a period of twelve consecutive months. Customers whose monthly demand is reasonably expected to reach or exceed one hundred thousand (100,000) kilowatts shall not be allowed to continue receiving service under this schedule and will be required to receive service under Schedule LLPS.

Service is available under this schedule to the following types of customers based on voltage level:

Secondary voltage customer - Receives service on the low side of the line transformer.

Primary voltage customer - Receives service at Primary Voltage of 2,400 volts or over but not exceeding 69,000 volts. Normally, the customer will own all equipment necessary for transformation including the line transformer.

Substation voltage customer - Service is taken directly out of a distribution substation at primary voltage. Normally, the customer will own the feeder circuits out of this substation.

Transmission voltage customer - The customer owns, leases, or otherwise bears financial responsibility for the distribution substation. Normally, service is taken off of the Company's transmission system.

This rate is not available for standby, breakdown, supplementary, maintenance or resale service except as noted below.

The restriction against "submetering" and reselling" found in the Company's Rules and Regulations 3.02 (A) and (B) shall not apply where a vacated single tenant premise to which the Company provided service through a single meter for a minimum of five contiguous years has been repurposed as a multi-tenant premise that provides an economic benefit to the immediate area by creating or retaining jobs and avoiding or alleviating economic blight in the immediate area.

Charges to the tenants for electric utility service with respect to any given period shall not exceed the amount of the Company's billing to the customer for that period.

Tenants of such repurposed premise are not customers of the Company and as such are not subject to the Company's tariff. The landlord/property manager shall retain a copy of all individual tenant billings for a period of five years and provide such billing information within ten (10) days to the Company and/or the Missouri Public Service Commission upon request.

CHARACTER OF SERVICE

Single-phase, 60 Hertz, nominally 120/240 volt firm electric service, provided from the Company's secondary distribution system. Three-phase secondary service shall be available where three-phase facilities are available without additional construction or may be made available at additional charge at voltages not exceeding 480 volts. Three-phase primary distribution service shall be available where primary distribution facilities are available without additional construction or may be made available at additional charge at 2,400, 12,470, or 24,900 nominal volts. Primary service may be served from Company's 69,000 volt or 34,500 volt systems, at Company's option, through Company owned transformation. The customer may request contractual service from the 69,000 volt or 34,500 volt systems, if such systems are available at the customer's point of delivery without additional construction, and the customer provides transformer.

Special Rate for Incremental Load Service (FROZEN)
Schedule SIL

PURPOSE:

This rate schedule is designed to provide certain Customers with new or incremental increases in load, access to a special rate that is not based on the Company's cost of service like generally available tariff rates, but is designed to recover no less than the incremental costs of serving the new load. The Customer load will be served primarily by renewable energy resources separate from energy resources used to serve general customers of the Company.

AVAILABILITY:

This schedule is not available to new customers after xxx (date).

This special rate is available to customers with new, incremental load who:

- Have a facility whose primary industry is the smelting of aluminum and primary metals, (Standard Industrial Classification Code 3334) or
- Have a facility whose primary industry is the production or fabrication of steel (North American Industrial Classification System 331110) or
- Operate a facility with an increase in load equal to or in excess of a monthly demand of fifty megawatts

Each customer must demonstrate the new, incremental load can:

- Show a competitive need, documenting the facility would not commence operations absent the special rate,
- Show the special rate is in the interest of the state of Missouri when considering the interests of the customers of the Company, considering the incremental cost of serving the facility to receive the special rate, and the interests of the citizens of the state generally in promoting economic development, improving the tax base, providing employment opportunities in the state, and promoting such other benefits to the state as the commission may determine are created by approval of the special rate

This rate is not available for standby, breakdown, supplementary, maintenance or resale service except as noted below. Sub-metering or the reselling of electricity is prohibited.

Availability of service under this tariff may be limited by the Company due to constraints with, or protection for, Company generation resources or the transmission grid.

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.

Special Rate for Incremental Load Service (FROZEN)
Schedule SIL

AVAILABILITY: (cont.)

Service under this tariff shall be excluded from projected energy calculations used to establish charges under Riders FAC and RESRAM, and programs offered pursuant to the Missouri Energy Efficiency Investment Act, unless otherwise ordered by the Commission when approving a contract for service under this tariff.

TERMS & CONDITIONS:

Service under this rate schedule requires a written contract between the Company and the Customer. Each Special Incremental Load Rate Contract shall collect at least the incremental cost incurred by the Company to serve the Customer. Incremental costs shall be calculated, and profitability must be demonstrated at the time the contract is approved to confirm that revenues to be received from Customers under this Schedule are expected to be sufficient to cover the Company's increased costs to offer service pursuant to each Special Incremental Load Rate Contract. All charges for service under this rate schedule shall be limited to the charges contained in the contract between the Company and the Customer.

CONTRACT DOCUMENTATION:

At least 60 days prior to the effective date of the Special Incremental Load Rate Contract, the Company will file the individual Special Incremental Load Rate Contract and supporting documentation with the Commission for approval. The supporting documentation will include the following items:

1. Customer Needs: Company shall provide a narrative description of the reasons why the Special Incremental Load Rate is necessary for this Customer.

2. Customer Alternatives: Company shall describe competitive alternatives available to the Customer.

3. Incremental Costs: Company shall quantify the expected incremental cost associated with the Special Incremental Load Rate Contract Customer.

4. Profitability: Company shall quantify the expected profitability of the Special Incremental Load Rate Contract as the difference between the revenues expected to be generated from the pricing provisions in the Special Incremental Load Rate Contract compared to Company's expected incremental costs. All significant assumptions shall be identified that affect this quantification.

5. Other Ratepayer Benefits: Company shall quantify the benefits that it believes will accrue to other ratepayers from the Special Incremental Load Rate Contract. All significant assumptions shall be identified that affect this quantification.

6. Other Economic Benefits to the Area: the Company and/or local economic development agency shall quantify the economic benefits to the state, metropolitan area, and/or local area that Company projects to be realized as a result of the Special Incremental Load Rate Contract. The Company will also file an affidavit from the state, metropolitan area and/or local area economic development agency that is also providing benefits to the customer.

Special Rate for Incremental Load Service (FROZEN)
Schedule SIL

TERM:

The initial term may vary for each customer served under this rate schedule but in no instance, should the term be greater than ten (10) years. Prior to the end of the term, the Company and Customer will work together to evaluate an extension of the term and if mutually appropriate, work together to secure any required approvals for an extension of the term. Each subsequent extension shall not exceed an additional ten (10) years.

SPECIAL RATE, PROVISIONS, AND TERMS:

1. The Special Incremental Load Rate will be determined for each Customer based on expected loads and the renewable energy resource planned to serve the Customer. Details about the rate including all terms and conditions related to the Special Incremental Load Rate will be documented through a Special Incremental Load Rate Contract.

2. The Special Incremental Load Rate will be designed to recover no less than the incremental cost to serve the Customer over the term of the Special Incremental Load Rate Contract. Non-participating customers shall be held harmless from any deficit in revenues provided by any customer served under this tariff.

3. All Special Incremental Load Rate Contracts executed under this tariff will include the following provisions:
   a. Special Rate – details about the structure and rate to be paid by the Customer.
   b. Agreement Term – clear identification of the dates associated with the Special Rate, particularly the start date for contract term.
   c. Confidentiality – terms to establish protections needed to protect data under competitive conditions.
   d. Operational Parameters – details about the expected operation of the facility to be served.

4. The Company will make provisions to uniquely identify the costs and revenues for each respective Special Incremental Load Rate Contract within its books and records. This information will be available to support periodic reporting as ordered by the Commission. At the time of a general rate proceeding the portion of the Company's revenue requirement associated with the incremental costs net of PPA net revenues to serve the Customer shall be assigned to the Customer. The Customer's rate revenues shall be reflected in Company's net revenue requirement. If the Customer's rate revenues do not exceed the incremental cost to serve the Customer as reflected in the revenue requirement calculation, the Company shall make an additional revenue adjustment covering the shortfall to the revenue requirement calculation through the true-up period, to ensure that non-Schedule SIL customers will be held harmless from such effects from the service under Schedule SIL. In no event shall any revenue deficiency (that is, a greater amount of the Customer's incremental costs compared to the Customer's revenues) be reflected in the Company's cost of service in each general rate proceeding for the duration of service to the Customer(s) during the terms of the contract between Company and Customer served under this tariff.

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

Special Rate for Incremental Load Service (FROZEN)
Schedule SIL

SPECIAL INCREMENTAL LOAD RATE CONTRACTS:

Start Date of Special Incremental Load Rate Contract	Name of Customer	Address	Term of Special Incremental Rate
January 1, 2020	Nucor Steel Sedalia, LLC	500 Rebar Rd, Sedalia, MO	10 years

ALTERNATIVE ENERGY CREDIT RIDER
Schedule AEC

PURPOSE

The purpose of the Alternative Energy Credit Rider program ("Program") is to offer an eligible Customer an opportunity to subscribe to Alternative Energy Credits ("AECs") that are associated with Company-owned nuclear energy resources. The AECs are then included in the Subscriber's energy accounting for a separately agreed to subscription term. The Company shall have the AECs annually certified by a third-party. Under the Program, a Subscriber may agree to receive AEC for a term of one (1), three (3) or five (5) years.

AVAILABILITY

This Program is available on a limited and voluntary basis to non-residential Missouri West Customers currently receiving permanent electric service from the Company through Schedules SGS, MGS, LGS, LPS or LLPS who have an annual average monthly peak demand greater than 200 kilowatts (kW). Customers that have an aggregate electric load of at least 2.5 megawatts (MW) based upon peak annual demand and an average of 200 kW per account.

The Company may deem a Subscriber ineligible for this Program if the Subscriber has received a disconnection notice within twelve (12) months preceding its submission of a Participation Agreement, or as set forth in the applicable terms and conditions in the Participation Agreement.

DEFINITIONS

For purposes of this Program, the following definitions apply:

Alternative Energy: Electricity that is generated using Company-owned nuclear energy resources.

Alternative Energy Credits ("AECs"): Attributes from one thousand (1,000) kilowatt hours (kWh) of electricity generated from a Company-owned nuclear energy resource.

Alternative Energy Credit Rate ("AEC Rate"): A dollar per megawatt hour ($/MWh) rate applicable to a Subscriber's monthly amount of Alternative Energy generation. There is a separate Alternative Energy Credit Rate for each agreement term length (1, 3, or 5 years).

Alternative Energy Credit Charge ("AEC Charge"): The AEC Charge shall be calculated monthly as the Subscriber's monthly average subscription (MWh) multiplied by the AEC Rate for specified Participant Agreement term.

Customer's Annual Usage (MWh): Customer's actual metered energy usage over the twelve (12) most recent monthly billing periods for which data is available, or the Subscriber's expected metered energy usage over twelve (12) monthly billing periods as determined by the Company. Customer's Annual Usage shall be established at the time the Participation Agreement is executed by the Customer and memorialized therein.

Participation Agreement: A written contract executed by the Company and a Subscriber setting forth the specific terms of a Subscriber's subscription under this Program including the Subscriber's accounts covered by the subscription. The Participation Agreement shall reflect the Subscription Level, subject to the terms and conditions set forth in this tariff and the Participation Agreement.

Subscriber: An eligible Customer who executes a Participation Agreement with the Company to participate in this Program.

ALTERNATIVE ENERGY CREDIT RIDER
Schedule AEC

DEFINITIONS (continued)

Subscription Level (1-100%): An eligible Customer may subscribe in single percentage increments, up to one-hundred percent (100%) of the Customer's Annual Usage at the time the Participation Agreement is executed by the Customer, subject to the terms of Customer's Participation Agreement.

PRICING

The formula for determining the AEC Charge that shall be billed monthly to a Customer is:

$$\text{AEC Charge} = \frac{\text{Customer's Annual Usage (MWh)} \times \text{Subscription Level (\%)}}{12} \times \text{AEC Rate Price}$$

AEC Rate Pricing			
Designated Resource	**One Year Agreement Term**	**Three Year Agreement Term**	**Five Year Agreement Term**
Wolf Creek	$0.00866 per kWh	$0.00827 per kWh	$0.00788 per kWh

The Customer shall be notified of any pricing updates following Commission approval. Notification will be provided a minimum of thirty (30) days prior to being billed to the Subscriber by the Company. Notifications shall be opt-out communications, and the new rates shall be effective the first billing cycle 60 days after notice is provided.

PROGRAM PROVISIONS

The Customer should carefully consider terms and conditions in the Participation Agreement subject to participation in this Program.

Alternative Energy shall be limited to the generation produced by Company-owned nuclear resources. Service under this rider may be limited, at the sole discretion of the Company, to such available resources.

Certain factors may result in less Alternative Energy being available for this Program than anticipated. If the Alternative Energy generated is not sufficient to meet the sum of the annual Program subscriptions during a calendar year, the Company shall refund each participating Customer 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 Alternative Energy subscribed generation.

Service hereunder is subject to the Company's General Terms and Conditions as approved by the Missouri Public Service Commission and any modification subsequently approved.

All provisions of the rate schedule are subject to changes made by order the regulatory authority having jurisdiction.

REPORTING

The Company shall calculate and provide the Subscriber with its total annual AECs consistent with the Subscriber's subscription, which shall occur in the first quarter of the year following the prior annual year subscription (e.g. in first quarter of 2026 for a 2025 annual subscription).

CUSTOMER CAPACITY RIDER
Schedule CCR

PURPOSE

The Customer Capacity Rider permits an eligible Customer to sell complete rights to capacity contracted from existing resources in the Customer's own supply portfolio to the Company to fulfill some, or all, of the capacity required to serve the Customer. The Customer will receive a bill credit for the supplied capacity, reducing the Customer's demand cost within the applicable monthly billing cycle.

AVAILABILTY

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. Contractual bilateral agreements for accredited capacity shall be for amounts no less than a monthly average of 10,000 kilowatts (kW) per year.

TERM OF SERVICE

The specific term shall be established under the respective bilateral agreement executed between the Customer and Company.

BILLING

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. Details concerning the amount of capacity contracted, and the negotiated price will be memorialized in the Schedule LLPS Service Agreement.

Accreditation and planning reserve margin requirements shall follow SPP protocols and shall be seasonally differentiated, following established SPP processes and revised as needed to reflect any changes. The Company and Customer shall define the accredited capacity amounts and planning reserve margin requirements as part of the bilateral capacity contracting process. Details concerning the amount of capacity contracted, and the negotiated price will be memorialized in the Schedule LLPS Service Agreement. Seasonal periods align with the seasonal periods established by the Customers rate for electric service. Should the SPP seasons and Company billing seasons not align, the Customer and the Company will define the seasonal amounts within the bilateral capacity contract.

Customer capacity contracted under this rider shall be excluded from the Company Energy Cost Adjustment/Fuel Adjustment Charge.

CUSTOMER CAPACITY RIDER
Schedule CCR

PROGRAM PROVISIONS

The contractual bilateral agreement shall transfer all rights to the Company and provide provisions that include, but not limited to, the capacity amount, the capacity accreditation, capacity price, deliverability terms and any other term necessary to define the expected capacity to be received. The accredited capacity amount shall be determined by seasonal capacity accreditation (annually for both summer and winter), as determined by the pertinent SPP methodology.

The Customer's capacity may be Customer-owned, or Customer-contracted, and shall be transferred to the Company via the contractual bilateral agreement. Capacity associated with resources located behind the Customer meter are not acceptable for use under this rider.

The Customer's capacity must be deliverable to the appropriate Company load node. The Customer shall be responsible for the transmission deliverability costs, as determined by SPP.

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.

Annually, the Company shall examine the accredited capacity it receives as compared to the contracted capacity. If the Customer-supplied capacity is less than the contracted amount, the Customer shall be obligated to pay a "make-whole payment" for the difference between the expected contracted capacity amount and seasonal accredited capacity actually received in that year (the "Capacity Shortfall Payment"). The Capacity Shortfall Payment shall be calculated in accordance with the following formula: (Expected Contracted Capacity – Actual Received Accredited Capacity x 1,000 kW/MW) × Applicable Customer Rate Demand Charge. If the actual Customer-supplied capacity is greater than the contracted amount, the Customer will be compensated for each additional kW at the negotiated price in the bilateral contract agreement.

If the Customer terminates service with the Company, the Company and Customer agree that the bilateral contract established under this rider shall be examined and the Company may take steps to terminate or revise the bilateral contract to enable continued delivery of capacity to the Company, as mutually agreed.

REGULATIONS

Service hereunder is subject to the Company's Rules and Regulations as approved by the Missouri Public Service Commission and any modification subsequently approved.

All provisions of the rate schedule are subject to changes made by order the regulatory authority having jurisdiction.

CLEAN ENERGY CHOICE RIDER
Schedule CER

PURPOSE

The Clean Energy Choice Rider provides eligible Customers with a means to influence the Company's generation resource portfolio. Within the Company's Integrated Resource Planning ("IRP") process, the eligible Customer may request clean resource types be deployed in place of or in addition to one or more resources selected in the Company's Preferred Resource Portfolio. If the Customer's requested generation is adopted by the Company as part of a Clean Energy Preferred Resource Plan, the Requesting Customer shall bear the entire cost differential arising from its specific request for clean resources. No energy or capacity will be directly provided to the Requesting Customer from the incremental clean energy resources as a result of participating in this Rider.

AVAILABILITY

This Rider is available to any Customer receiving permanent electric service under the Company's LLPS retail rate schedule or any prospective customer who has executed a Service Agreement with the Company but has not yet received service under the LLPS retail rate schedules.

DEFINITIONS

For purposes of this Rider, the following definitions apply:

Integrated Resource Planning: The Company's IRP (or Integrated Resource Planning process), considers and analyzes demand-side resources, supply-side resources, and renewable energy resources on an equivalent basis, subject to compliance with all legal mandates that may affect the selection of Company electric energy resources. The ultimate goal of an IRP is to develop a Preferred Resource Plan that minimizes the net present value of long-term utility costs while ensuring the Company can provide its Customers with energy services that are safe, reliable, and efficient, at just and reasonable rates, and in a manner that serves the public interest and is consistent with state energy and environmental policies.

Good Utility Practice: The practices, methods, techniques, and standards that would be implemented and followed by a prudent utility operator during the relevant time period or that, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could reasonably have been expected to accomplish the desired result.

Requesting Customer: An eligible Customer who requests that one or more clean energy resources be deployed in place of or in addition to the generation resources selected in the Company's Preferred Resource Plan. There may be multiple Requesting Customers who support the same Clean Energy Preferred Resource Plan.

Preferred Resource Plan: This refers to what the Company has designated as its Preferred Resource Plan in its most recent IRP that has been filed with the Commission by the Company for implementation.

Clean Energy Preferred Resource Plan: A Clean Energy Preferred Resource Plan is a separate resource plan the Company may develop. If the Company elects to create a Clean Energy Preferred Resource Plan, the Company will modify its Preferred Resource Plan following an eligible Requesting Customer's request for and evaluation of certain clean resources to be modeled and deployed in place of, or in addition to one or more generation resources selected in the Company's Preferred Resource Plan. The Company retains all discretion in preparing the Clean Energy Preferred Resource Plan to ensure the Clean Energy Preferred Resource Plan meets the Company's requirements to provide safe, reliable, and efficient service. The execution of the Clean Energy Preferred Resource Plan shall be subject to gaining all appropriate regulatory approvals, and in a manner deemed satisfactory to the Company in its sole discretion.

CLEAN ENERGY CHOICE RIDER
Schedule CER

DEFINITIONS (continued)

Cost Differential The dollar amount difference resulting from the Company's calculated net present value revenue requirement determined for the Company's Preferred Resource Plan, and Company's calculated net present value revenue requirement for the Company's Clean Energy Preferred Resource Plan. The Cost Differential shall be borne by the Requesting Customer(s) and represent a contribution to construction of the resulting clean resource(s). As set forth below, the Cost Differential is subject to adjustment based on actual costs of the Clean Energy Preferred Resource Plan. With the Requesting Customer(s) to be responsible for the differential based on actual costs of the clean energy resource(s), per the terms of the tariff and separate commercial agreement.

PROGRAM PROVISIONS

All aspects of this Rider will occur within the normal timing and execution of the Company's IRP process. Prior to the execution of an IRP cycle, and preferably during the fourth quarter of a given year, a Requesting Customer shall notify the Company through the Requesting Company's Company Customer Solutions representative, its interest in modifying the Company's current Preferred Resource Plan. The Company will engage with the Requesting Customer to understand the Requesting Customer's desired clean resource modifications, will study the alternative resource scenarios, and may then develop a Clean Energy Preferred Resource Plan that attempts to reasonably accommodate the Requesting Customer's clean resource request. Upon doing so, the Company will provide the Requesting Customer with an indicative cost estimate for the associated clean resource modifications, as well as the Cost Differential of such. Should the Requesting Customer request multiple clean resource modifications, the Company may model some or all of them, at its discretion. The Company will ensure any Clean Energy Preferred Resource plan meets the Company's requirements to provide safe, reliable, and efficient service for all customers.

If the Requesting Customer supports the Clean Energy Preferred Resource Plan and wishes to move forward, the Requesting Customer(s) shall execute a separate commercial agreement with the Company committing them to pay the associated Cost Differential of the Clean Energy Preferred Resource Plan, plus all administrative costs, including those associated with obtaining regulatory approvals. The Requesting Customer(s) shall be responsible for all such administrative and approval costs, even if the Clean Energy Preferred Resource Plan is not adopted or otherwise executed.

A Clean Energy Preferred Resource Plan will be submitted to the Commission through the Company's IRP process and is subject to Commission review and order. If found to meet IRP requirements by the Commission, the Company will follow Good Utility Practice to execute the Clean Energy Preferred Resource Plan including obtaining all required Commission approvals associated with resource procurement or construction. If approvals are not granted in a manner satisfactory to the Company in its sole discretion, the Company may not elect to move forward with the Clean Energy Preferred Resource Plan.

The Cost Differential in the earlier executed commercial agreement shall be updated to reflect actual costs of any and all resources included in establishing the Clean Energy Preferred Resource Plan. Unless otherwise agreed to, an installment payment price will be calculated, inclusive of any Contribution in Aide of Construction taxes, and paid by the Requesting Customer(s) over a term that is no greater than the expected life of the clean energy resource(s) selected in the Clean Energy Preferred Resource Plan.

CLEAN ENERGY CHOICE RIDER
Schedule CER

BILLING

A charge representing the Cost Differential to be paid by the Requesting Customer over the specified term shall be included as a specific Levelized Charge added to the Customer's bill.

Should a Clean Energy Preferred Resource Plan include more than one Requesting Customer, the allocation of the Cost Differential shall be determined based on factors such as Requesting Customer load share, cost impacts of requested clean resource technologies, or other factors as determined by the Company.

The Economic Development Rider shall not be applied to the Levelized Charge imputed to the Requesting Customer under this rider.

TERMINATION

Should a Requesting Customer terminate its service at any point after the Company has executed a Clean Energy Preferred Resource Plan specific to the Requesting Customer and before the Cost Differential of the Clean Energy Preferred Resource Plan (or allocated portion) has been fully paid, the Requesting Customer shall be required to pay the outstanding Cost Differential as a single payment, and shall be subject to any additional terms and conditions set forth in a separate commercial agreement..

RENEWABLE ATTRIBUTES

If applicable, the Requesting Customer shall receive the renewable attributes related to the output of the clean resource generation requested and where the Requesting Customer is paying the Cost Differential for the clean resource. The Company shall retire the renewable attributes on behalf of the customer, up to an amount equal to the Requesting Customer's annual energy usage. If the Clean Energy Preferred Resource Plan includes more than one Requesting Customer, the renewable attributes will be allocated to the Requesting Customers on the equivalent basis as the Cost Differential, as applicable.

CLEAN RESOURCE PRODUCTION DATA

A Requesting Customer may request hourly output data from the Company specific to the clean resource(s) included in an adopted and executed Clean Energy Preferred Resource Plan.

REGULATIONS

Service hereunder is subject to the Company's Rules and Regulations as approved by the Missouri Public Service Commission and any modification subsequently approved.

All provisions of the rate schedule are subject to changes made by order the regulatory authority having jurisdiction.

DEMAND RESPONSE & LOCAL GENERATION RIDER
Schedule DRLR

PURPOSE

The Demand Response & Local Generation Rider ("Program" or "DRLR") is designed to reduce Participant load during peak and constrained grid condition periods to improve 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. The Company may, in its discretion, request Participant curtailment for any of these operational or economic reasons.

AVAILABILITY

This rider is available to any Commercial & Industrial Customer receiving permanent electric service under the Company's retail rate Schedule LLPS subject to the terms of that schedule. Customers may participate in Schedule DRLR and other eligible Demand Response ("DR"), and Interruptible Schedules offered by the Company. To participate, the Customer shall complete the required Participation Agreement for the Program.

A Customer is not eligible if the Customer's load reduction capability is registered for demand response participation in a wholesale market directly by the Customer or via a DR Aggregator other than the Company.

DEFINITIONS

For purposes of this Program the following definitions apply:

Participant: The Customer, specified as the Participant in the Participation Agreement, is the eligible Customer that has received notification of acceptance into the Program.

Participation Agreement: A non-tariffed commercial contract between the Company and Customer, used for enrollment purposes and to establish the full terms and conditions of the Program. Eligible Customers shall be required to sign the Participation Agreement prior to participating in the Program. This agreement may be provided and executed electronically.

Reduction Amount ("RA"): The reduction of load by the Customer either manually or automated for the duration of the DR event.

Enrolled Load: The total contracted load reduction specified within the Participation Agreement that the Customer may be required to reduce for each curtailment event.

Curtailment Event ("Event"): Period when the Company determines the need for Participants to reduce energy consumption during peak and constrained grid conditions

Calculated Baseline ("CBL"): The calculated estimate of what the Customer most likely would have consumed during the curtailment event period. Baselines are developed for each curtailment event utilizing customer specific data from historic metered usage.

Reduction Credit ("RC"): Credit amount for the curtailment event period during which the event is called and the period(s) of time the Customer has successfully curtailed load.

DEMAND RESPONSE & LOCAL GENERATION RIDER
Schedule DRLR

PROGRAM PROVISIONS

A Participant must show economic and technical feasibility for measurable and verifiable load curtailment during their selected option of availability below:

Option 1 - Constrained: summer curtailment season of June 1 to September 30 and winter curtailment season of December 1 to March 31; 6:00 a.m. to 10:00 p.m., Monday through Friday excluding Holidays.

Option 2 - Unconstrained: All hours: All days; January through December.

The Company shall evaluate the Participant's metered usage data, technical specifications and operational characteristics of the facility's equipment to establish a curtailment plan and estimated associated curtailable load (measured in kW) to determine the Enrolled Load. The Participation Agreement will specify the curtailable load, and commits the Participant to being able to curtail their Enrolled Load during a curtailment event. The Company will issue notice to the Participant in advance of scheduled curtailment events, thus requiring the Participant to curtail their Enrolled Load in accordance with the Participant's chosen method of participation.

The Company shall determine the appropriate timing and length of any curtailment event during each curtailment window, based on the Participant's chosen option above. Notwithstanding the intended curtailment periods identified in Option 1 and Option 2 for the purpose of Schedule DRLR, the Company reserves the right to curtail the Customer year-round as needed for system reliability during circumstantial conditions.

The Company shall communicate with the Participant in advance of a curtailment event to increase the Participant's ability to participate. Participation Agreements shall contain specific information for curtailment event specifications that fall within the following limits.

- Minimum number of events/tests per season (summer) – 1
- Minimum number of events/tests per season (winter) – 1
- Minimum notification prior to an event – 10 minutes

This Program may be executed by manual and/or automated demand response methods. A Participant may utilize on-site back-up or behind the meter generation and/or curtailment methods to meet its RA threshold for the duration of the curtailment event.

- Manual DR
  The Participant may manually execute its facility curtailment plan to curtail at least its Enrolled Load for the duration of the curtailment event.

- Automated Demand Response (ADR) utilizing on-site generation
  The Participant's building/energy management system ("BMS" or "EMS") or facility automation system is utilized in conjunction with the facility's on-site generation or other curtailment methods to execute its curtailment plan. The Participant receives the integrated signal from the utility's event calling system and its BMS/EMS is utilized to execute its curtailment plan by enacting pre-programmed adjustments to respond to DR events.

- On-Site Generation Term
  The Participant has full responsibility for start-up, operation, and maintenance ("O&M"), and regulatory compliance of any on-site generation including any reciprocating internal combustion engine ("RICE") National Emissions Standards for Hazardous Air Pollutants ("NESHAP"), Southwest Power Pool ("SPP"), and/or any other community, governmental or regulatory agency, as applicable. On-site generation operating details, capabilities, and any other criteria negotiated with the Company and the Participant may be documented in the Participation Agreement.

DEMAND RESPONSE & LOCAL GENERATION RIDER
Schedule DRLR

PRICING

All charges, and other terms and conditions of service provided for under the Participant's applicable standard service classification(s) tariff shall continue to apply and shall be based on actual metered energy use during the Participant's normal billing cycle.

Under Schedule DRLR, the Participant will receive an on-bill credit or check payment for its level of reduction achieved and an incentive payment based on its measured curtailment reduction.

Reduction Amount:

The Reduction Amount is a monthly performance amount applied to each billing month in which an event is called. The credit amount is calculated based on the Participant's hourly kWh load compared to the Participant's summer and winter hourly CBL. The Company shall employ a Calculated Baseline methodology to determine the Participant's demand savings associated with a DR curtailment event. A CBL approach applies a model or algorithm to develop a customer-specific baseline for each day from historic metered usage data that is then used to forecast load impacts for each hour of the event absent a curtailment event. This baseline is calibrated to best match recent operational and/or weather patterns. This baseline is then compared to the actual metered average hourly demand during the curtailment event. The difference between the forecasted hourly baseline and the Participant's actual metered hourly usage during the curtailment event equals the hourly kW impact of the curtailment event. All kW shall be calculated as a whole number, and may thus be rounded up or down. The event hourly average kW achieved divided by the kW enrolled is the Participant's percent kW achieved. The Company shall pay the Participant under the terms of Schedule DRLR for the achieved average percent of its enrolled curtailable load within the established baseline and peak curtailment as detailed in the Participation Agreement. The hourly RA formula is:

Hourly RA = CBL kWh for each hour – Actual hourly kWh

Participant Participation Fees:

Participants shall be assessed the following program fees and charges as specified in the Participant Agreement:

1. DR Earnings Opportunity ("EO") Fee – Participant shall compensate the Company for any foregone earnings associated with capacity reduction related to the DRLR enrolled MW capacity for the realized curtailable value during the curtailment period that the reduction occurred.

2. Administration Fee - A fixed charge shall be recovered for all costs associated with Program delivery, implementation/management, and evaluation, which shall be recovered based on a forecasted estimate and trued up annually based on actual Program expenditures for the recovery period.

Reduction Credit:

The Reduction Credit is a variable performance credit for each curtailed kW successfully delivered. Reduction credits are based on a rate of $54.00 per kW-year for "Unconstrained" Participants and $43.20 per kW-year for "Constrained" Participants, and shall be paid in accordance with the credit schedule and incentive rate for the performance month, based on the formula below.

Monthly RC = Monthly Average RA x Monthly Reduction Credit (Constrained or Unconstrained) - DR EO Fee – Administration Fee

DEMAND RESPONSE & LOCAL GENERATION RIDER
Schedule DRLR

CREDIT SCHEDULE

The credit schedule below outlines the kW/month value and fees for seasonal performance under the Program. Credit values are paid based on measured performance for the month that the curtailment event occurred. Curtailment event credits will not be applied for periods where events are not called, or if the Participant does not perform. Program rates shall be updated annually. The current credit schedule applicable for 2025 is set forth below.

Month	Allocation Percentage	Unconstrained	Constrained $/ kW per Month	Demand Response Earnings Opportunity Fee	Unconstrained Max Hours Per Month	Constrained Max Hours Per Month
		$/kW per Month	$/kW per Month	$/kW per Month	Hours	Hours
January	12.5%	$6.75	$5.38	($1.31)	744	480
February	12.5%	$6.75	$5.38	($1.31)	672	480
March	2.5%	$1.35	$1.08	($0.26)	219	96
April	2.5%	$1.35	$1.08	($0.26)	219	96
May	2.5%	$1.35	$1.08	($0.26)	219	96
June	12.0%	$6.48	$5.16	($1.26)	720	461
July	14.0%	$7.56	$6.02	($1.47)	744	538
August	14.0%	$7.56	$6.02	($1.47)	744	538
September	10.0%	$5.40	$4.30	($1.05)	720	384
October	2.5%	$1.35	$1.08	($0.26)	219	96
November	2.5%	$1.35	$1.08	($0.26)	219	96
December	12.5%	$6.75	$5.38	($1.31)	744	480

DEMAND RESPONSE & LOCAL GENERATION RIDER
Schedule DRLR

PARTICIPATION AGREEMENT TERM

The Participation Agreement shall outline the Participant's Enrolled Load, which can vary by season, dispatch, and duration requirements associated with each DR curtailment event. The Participation Agreement shall last for a term of one year, and automatically renew in one-year increments unless terminated per notification requirements as set forth in the Participation Agreement. The Company reserves the right to terminate Participation Agreements for non-compliance.

REPORTING

The Company shall calculate and provide the Participant with its post event settlement calculations and end of season summary outlining the Participant's performance. Participant's curtailment plans and reduction strategies shall be evaluated annually.

EVALUATION

The Company shall hire a third-party evaluator to perform evaluation, measurement and verification ("EM&V") of the Participant's seasonal performance and calculate impacts, which may be used for SPP accreditation and compliance evaluation.

REGULATIONS

Service hereunder is subject to the Company's Rules and Regulations as approved by the Missouri Public Service Commission and any modification subsequently approved.

All provisions of the rate schedule are subject to changes made by order the regulatory authority having jurisdiction.

LARGE LOAD POWER SERVICE
Schedule LLPS

PURPOSE

Service under this schedule is required for a new or expanded facility beginning service after [effective date] with a Peak Load forecast reasonably expected to be equal to or in excess of a Monthly Maximum Demand of one hundred thousand (100,000) kilowatts any time during the Term. Existing Customers, as of [effective date], whose Monthly Maximum Demand is reasonably expected to reach or exceed one hundred thousand (100,000) kilowatts in a given calendar year shall be required to take electric service under this schedule. Customers locating in the state as a result of a state program established for attracting large capital investments in new facilities and operations by businesses engaged in advanced manufacturing, aerospace, distribution, logistics, and transportation, food and agriculture; or professional and technical services have the option to choose to receive service under this schedule or, upon reaching an agreement with Evergy Missouri West, to enter into a special contract with Evergy Missouri West for the provision of electric service that is approved by the Commission under its applicable standards of Company tariff.

AVAILABILITY

For electric service through one meter to a customer using electric service for purposes other than those included in the availability provisions of the Residential Service Rate Schedule. At the Company's discretion, service may be provided through more than one meter where it is economical or preferred for the Company to do so.

Service is available under this schedule to the following types of customers based on voltage level:

Substation voltage customer - Service is taken directly out of a distribution substation at primary voltage. The customer will own the feeder circuits out of this substation.

Transmission voltage customer - The customer owns, leases, or otherwise bears financial responsibility for the distribution substation. Normally, service is taken off the Company's transmission system.

TERM

Service Agreements under this schedule shall be for a period of fifteen (15) years, commencing on the date when permanent service is received. This term may include a transitional load period (ramp period) of no more than five (5) years.

The Service Agreement term shall remain in effect thereafter unless cancelled, modified pursuant to the terms hereunder, or the customer selects and is qualified to receive service under another applicable Company rate schedule.

LARGE LOAD POWER SERVICE
Schedule LLPS

RATE

A. CUSTOMER CHARGE (per month): $675.00

B. GRID CHARGE
Per kW of Grid Demand per month-Substation $4.811
Per kW of Grid Demand per month-Trans. $4.750

C. DEMAND CHARGE:

Per kW of Billing Demand per month	Summer Season	Winter Season
All kW	$10.000	$8.000

D. ENERGY CHARGE:

	Summer Season	Winter Season
All kWh:	$0.02881	$0.02881

E. REACTIVE DEMAND ADJUSTMENT: $0.46 per kVar

DETERMINATION OF DEMANDS

Demand shall be determined by demand instruments or, at the Company's option, by demand tests.

Monthly Maximum Demand: The Monthly Maximum Demand is defined as the highest demand indicated in any 15-minute interval during the month on all meters.

Grid Demand: Grid Demand shall be equal to the highest Monthly Maximum Demand occurring in the last twelve (12) months including the current month.

Minimum Demand: Minimum Demand shall be 80% of the annual Contract Capacity.

Billing Demand: Billing Demand shall be the higher of: (a) the Monthly Maximum Demand in the current month or (b) the Minimum Demand.

INTERIM CAPACITY:

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

REACTIVE DEMAND ADJUSTMENT:

Company shall determine customer's maximum reactive demand in kVar. Each month a charge shall be made for each kVar by which the maximum reactive demand is greater than fifty-percent (50%) of customer's maximum kW demand for that month. The reactive demand adjustment will be based on the ratio of the customer's maximum monthly fifteen (15) minute reactive demand in kVar to the customer's maximum kW demand for the billing period.

LARGE LOAD POWER SERVICE
Schedule LLPS

CONTRACT CAPACITY

The Service Agreement shall include provisions for the Customer's Contract Capacity requirement. The Contract Capacity shall be the annual peak load requirement, specified by the Customer, for the term of the Service Agreement. The Contract Capacity shall include any ramp load preceding the steady-state Contract Capacity.

Prior to expiration of the Service Agreement, the Customer must provide, and the Company agree to a Contract Capacity for the subsequent Service Agreement term.

The Customer may request to reduce the Contract Capacity during the term, at any time after the first five (5) years of the term by up to 20%, in total, by giving the Company at least 36 months written notice prior to the beginning of the year for which the reduction is sought. The Customer may reduce its contract capacity beyond 20% at any time after the first five years of the term by giving the Company at least 36 months written notice prior to the beginning of the year for which the reduction is sought, subject to payment of a capacity reduction fee. The capacity reduction fee shall be calculated as the nominal value of the remaining Minimum Charge for the terminated/reduced capacity in excess of the 20% allowed reduction. The capacity reduction fee shall be due and payable to the Company upon the effective date of the capacity reduction.

Following receipt of proper notice, the Company will use reasonable efforts, consistent with its obligations as a public utility, to mitigate the capacity reduction fee amount owed by the Customer by evaluating the opportunity to assign the reduced capacity to serve other new Customers, to expand service to existing Customers, or otherwise secure offsetting expected revenues.

MINIMUM MONTHLY BILL

The Minimum Monthly Bill shall be equal to the sum of the Customer Charge, Grid Charge, Demand Charge, and Reactive Demand Adjustment.

SUMMER AND WINTER SEASONS

For determination of seasonal periods, the four (4) summer months shall be defined as the four (4) calendar months of June through September. The eight (8) winter months shall be defined as the eight (8) calendar months of October through May. Customer billing periods shall align with calendar months. In the event that a rate or rider rate changes within a calendar month, customer charges and demand-based rates will be prorated based on the number of days of the month subject to each rate, and energy rates will be calculated based on actual usage under each applicable rates.

TERMINATION OR CHANGE OF SCHEDULE

The Customer may terminate service under this schedule, and no longer be a customer of the Company or seek service under another applicable schedule, after written notice to the Company. The Customer shall provide written notice to the Company, no later than thirty-six (36) months prior to the requested date of termination or schedule change.

Upon termination of service under this schedule, the Customer is required to pay an exit fee equal to the minimum charges for the remaining period of the term or for twelve (12) months of service, whichever is greater. If a Customer selects to receive service under another applicable Company rate schedule, no exit fee shall be applied.

If the Customer is receiving any Interim Capacity at the time of written notice, the Company and Customer shall take steps to repurpose the related capacity contract(s) prior to termination of service under this schedule. If the Interim Capacity cannot be repurposed, the Customer will be responsible for all costs associated with termination of the capacity contract(s).

LARGE LOAD POWER SERVICE
Schedule LLPS

COLLATERAL REQUIREMENTS

In addition to the Deposits and Guarantees of Payment tariff found in section 2.04 of the Company's General Rules and Regulations, the Customer shall provide collateral to the Company ("Collateral Requirement") based upon the creditworthiness of the Customer and as outlined below.

The amount of collateral to be provided is equal to thirty-six (36) months multiplied by the maximum expected monthly bill under the Contract Capacity established for the upcoming year. The amount of collateral under the foregoing calculation will be recomputed annually, and the Customer shall provide the recomputed amount if it is 10% or more, greater than the current amount held.

A Customer with a credit rating of at least A- from S&P and A3 from Moody's and liquidity greater than ten times the Collateral Requirement shall be exempt from the Collateral Requirements. A Customer that does not have a credit rating from S&P and Moody's but maintains liquidity greater than ten times the Collateral Requirement (evidenced by providing quarterly financial statements and certification that on the date financial statements are provided that the Customer's liquidity meets the ten times threshold) shall be exempt from 50 percent of the Collateral Requirements not to exceed an exemption of more than $250 million.
The Collateral Requirement must be provided in one or more of the following forms:

a. A guarantee from the ultimate parent or a corporate affiliate of the Customer for the full Collateral Requirement, so long as the guarantor has both (a) a credit rating of at least A- from S&P and A3 from Moody's and (b) liquidity greater than ten times the Collateral Requirement; or

b. A standby irrevocable Letter of Credit ("Letter of Credit") for the full Collateral Requirement. The Letter of Credit must be issued by a U.S. bank or the U.S. branch of a foreign bank, which is not affiliated with the Large Load Customer or its guarantor, with a credit rating of at least A- from S&P and A3 from Moody's. Such security must be issued for a minimum term of 360 days. The Customer must cause the renewal or extension of the security for additional consecutive terms of 360 days or more no later than 30 days prior to each expiration date of the security. If the security is not renewed or extended as required herein, the Company will have the right to draw immediately upon the Letter of Credit and be entitled to hold the amounts so drawn as security. The Letter of Credit must be in a format acceptable to and approved by the Company; or

c. Cash for the full Collateral Requirement.

LARGE LOAD POWER SERVICE
Schedule LLPS

SPECIAL TERMS

Customers receiving service under this schedule are required to enter in a written Service Agreement that specifies certain provisions of their electric service, including, but not limited to, load characteristics, customer-specific terms, applicable construction cost recovery terms, and other service details, including definition of operating procedures.

The terms and conditions of service under this this schedule shall apply upon a request for service by an eligible customer but service to Customers under this schedule shall not commence until the Company has sufficient capacity to meet the Customer's Contract Capacity requirements.

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

ADJUSTMENTS AND SURCHARGES

The rates hereunder are subject to adjustment as provided in the following schedules:

- Fuel Adjustment Clause (FAC)
- Demand Side Investment Mechanism Rider (DSIM)
- Renewable Energy Standard Rate Adjustment Mechanism Rider (RESRAM)
- Tax Adjustment (TA)
- Securitized Utility Tariff Rider (SUR)
- System Support Rider (SR)

REGULATIONS

In addition to the above rules and regulations, all of Company's General Rules and Regulations shall apply to the subscription supplied under this Program, except as specifically modified herein.

All provisions of the rate schedule are subject to changes made by order the regulatory authority having jurisdiction.

RENEWABLE ENERGY PROGRAM RIDER
Schedule RENEW

PURPOSE

Applicable to any customer using electric service supplied at one point of delivery. Backup, breakdown, standby, supplemental, short term, resale, or shared electric services are not available under this rate schedule.

AVAILABILITY

Renewable energy is available to customers participating in a voluntary renewable energy program offered by the Company.

CHARACTER OF SERVICE

The Company agrees to generate or purchase energy from renewable sources and/or purchase Renewable Energy Credits (RECs) in an amount at least equal to the level of service purchased by participants in the Renewable Energy Program. Energy output from renewable sources will vary from month to month due to weather and other factors.

REC PURCHASE OPTION AND PARTICIPATION LEVELS

Participants may subscribe up to 100 percent of their annual energy usage. During initial sign up, the Customer will designate their desired subscription percentage in increments of 10 percent. The formula for determining the amount that will be billed to a Customer is:

$$Billed\ Amount = \begin{pmatrix} Monthly\ kWh\ Consumption \times \\ Subscription\ Percentage\ (10-100\%) \end{pmatrix} \times Renewable\ Energy\ Charge$$

The amount of renewable energy kWh available to participating Customers shall be determined by the Company based on the amount of renewable energy sources and RECs anticipated to be available to the Company for any Program year. If customer 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

RENEWABLE ENERGY PROGRAM RIDER
Schedule RENEW

MONTHLY RATE

Renewable energy is available to customers participating in a voluntary renewable energy program offered by the Company.

Renewable Energy Charge:	$0.00265 per kWh
Consisting of:	
REC Charge:	$0.00255 per kWh
Administrative Charge:	$0.00010 per kWh

Renewable Energy Charges are in addition to the charges of the applicable Rate Schedule under which customer takes electric service.

MONTHLY BILLING

The entire bill amount, inclusive of all standard rate charges and Program charges, must be paid according to the payment terms set forth in the Company Rules and Regulations.

SUBSCRIPTION TERM

The Program is voluntary, month-to-month, with no upfront costs or contract required. Participants can change their level of support or cancel at any time with no penalties or cancellation fees by notifying the Company.

ANNUAL UPDATE AND NOTIFICATION PROCESS

Enrolled Customers will be notified in November or December of pricing updates by the Company for the upcoming year. Notifications will be opt-out communications with the new rates that will be effective the first billing cycle in January of the next calendar year.

RENEWABLE ENERGY PROGRAM RIDER
Schedule RENEW

DEFINITIONS AND CONDITIONS

1. Renewable Energy, as used in this rate schedule, shall mean electricity that is generated using renewable energy resources as defined in RSMo 393.1025(5). A commitment to sustainable energy initiatives means implementation by individual large commercial and industrial customers of programs that are recognized by the utility industry and government as having an elevated level of commitment to our environment, energy efficiency and renewable energy programs.

2. Renewable Energy and Renewable Energy Credits utilized under the Renewable Energy Program Rider cannot be used by the Company to comply with the State's Renewable Energy Standard, RSMo 393.1030, and amendments thereto, as well as the resulting Missouri Administrative Regulations.

3. Customer may subscribe for an amount of Renewable Energy up to its maximum monthly usage.

4. Renewable Energy shall be limited to the sum of (a) generation produced by Company-owned renewable sources, (b) 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.

5. Changes in the weather and other factors may result in less Renewable Energy being available to the Company than anticipated. If the Renewable Energy resources obtained by the Company for a program year are not sufficient to meet commitment levels, the Company will refund to each participating Customer at the end of each program year an amount equal to the Renewable Energy Charge (or discounted Renewable Energy Charge, if applicable), multiplied by the difference between the Customer's pro rata share of Renewable Energy resources obtained by the Company for such program year and the Renewable Energy the Customer committed to purchase.

SYSTEM SUPPORT RIDER
Schedule SR

PURPOSE

The System Support Rider requires an additional charge paid by Customers receiving service under Schedule LLPS to ensure appropriate recovery of costs incurred to serve Schedule LLPS customers, and to reflect the acceleration of resource investment required to serve large loads that join the Company's system under Schedule LLPS, as well as other acceleration-related impacts associated with operations of these resources.

AVAILABILITY

This rider is applicable to all Customers receiving service under Schedule LLPS.

TERM

Charges under this schedule shall be applied during the Customer's term of service under Schedule LLPS.

PROGRAM PROVISIONS

The System Support Charge will consist of two components, (1) a Cost Recovery Component and (2) an Acceleration Component.

The Cost Recovery Component shall be calculated based on comparing the Schedule LLPS Customer's estimated rate revenue and estimated revenue prior to applying Schedule CCR, Schedule DRLR, or Schedule CEC. Should the Schedule LLPS Customer's estimated revenue fall below the Customer's estimated rate revenue, an amount, expressed in a dollar per kW ($/kw) charge, will be added to the customer billing through this Rider charge. The Cost Recovery Component shall be customer-specific and memorialized in Exhibit D of the Customer Service Agreement. This comparison shall be completed annually.

The Acceleration Component shall reflect the difference in the net present value revenue requirements tied to a representative combined-cycle natural gas fired turbine generation ("CCGT") as a result of constructing the CCGT ten years sooner than otherwise would have occurred under normal planned growth, recovered over a 30-year period, as determined by the Company. The difference in revenue requirements shall be multiplied by the ratio of non-Schedule LLPS peak load to total system load to isolate the non-Schedule LLPS acceleration cost to be recovered. The System Support Charge shall be expressed in the form of dollars per kW ($/kW). The Acceleration Component shall be calculated and updated as part of each Company rate proceeding.

The System Support Rider charge shall be the combination of both of these components and be applied to the Customer's monthly billing, identified as a separate line item.

ACCELERATION COMPONENT

The Acceleration Component shall be $9.64 per kW.

BILLING

The charge for the System Support Rider will be determined as follows:

SR charge = Cost Recovery Component + Acceleration Component

The charges associated with this System Support Rider will be determined by multiplying the SR Charge by the Grid Demand as defined in Schedule LLPS and shown as a separate line on the customer's bill.

SYSTEM SUPPORT RIDER
Schedule SR

CHARGE PROVISIONS

After the initial fifteen (15)-year term of service under Schedule LLPS, Customers whose annual peak demand has not increased by more than five (5) percent in the five (5) prior years may request to terminate the Acceleration Component of this charge. If, after removal of the Acceleration Component, the Customer subsequently modifies the Customer Capacity defined under Schedule LLPS by twenty (20) percent or twenty (20) megawatts (MW), whichever is lower, the Acceleration Component will be applied for the remainder of the Schedule LLPS term beginning in the year when this threshold is met.

Should a Customer participate in the Customer Capacity Rider (Schedule CCR), and supply in excess of eighty percent (80%) of the capacity required to serve its load under Schedule CCR, such Customer may request to terminate the Acceleration Component of this charge for the term of the Schedule CCR participation, which the Company shall reasonably grant if it does not identify other rate design concerns with doing so.

The SR Charge shall not be subject to any related Economic Development Rider discount.

To achieve the needed support to non-Schedule LLPS customers, these revenues will be allocated to other non-LPS class customers within the Company Class Cost of Service study performed during a general rate proceeding to offset system costs created by Schedule LLPS customers.

REGULATIONS

Service hereunder is subject to the Company's Rules and Regulations as approved by the Missouri Public Service Commission and any modification subsequently approved.

All provisions of the rate schedule are subject to changes made by order the regulatory authority having jurisdiction.

2.09 Returned Payment

If a customer tenders to Company a check, draft, or a payment order in payment for service billed which is ultimately dishonored for reasons other than bank error, the customer shall be assessed a Returned Payment Charge per Section 12 of these Rules.

2.10 Service to loads greater than 25MW

A. Customers, or prospective Customers seeking service for loads expected to be greater than 25 megawatts (MW) shall be subject to an initial evaluation and study by the Company prior to receiving service. Such Customers shall notify the Company, in advance, concerning the expected load, project location, and project schedule. The Company will respond with an initial evaluation detailing its conditions of service.
B. Customers choosing to move forward and seek service for a project shall complete and comply with terms set forth in a Letter of Agreement and submit a refundable deposit of $200,000 that will be used to offset costs associated with project planning. Should costs exceed this deposit an additional refundable deposit of $200,000 shall be required. Additional refundable deposits will be required such that the Customer pays all project planning costs associated with their project. Initial deposit funds not used during planning shall be refunded to the customer without interest. These Customers shall be placed in a queue based on the date on which they provided the required information and deposit.
    a. Service related to projects the Company designates as serving the community interest may be given priority in the queue and may not be required to submit a deposit. Community interest projects are those that are part of a competitive search in which the Company is competing against at least one other location for the project, the Customer reasonably demonstrates that the project will employ at least 250 permanent, full-time 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.
    b. The Company shall have sole discretion on the deposit applicability and managing projects in the queue.
C. The Company will work on advanced study and scoping for up to four (4) projects at a time. Customers with projects being studied shall be notified of the study results and plans to receive service. Once an Initial Projects Agreement is complete, the Company will send necessary details to the Southwest Power Pool (“SPP”) for its review. Completed plans shall be valid for six months.
D. Customers choosing to receive service according to these plans shall complete the required agreements to facilitate construction and all required Service Agreements to receive service. The Schedule LLPS tariff and associated Service Agreement contain additional requirements for qualifying projects that must be met to receive service. Customers failing to complete these agreements within the timeframe allowed may be returned to the queue.
E. Additional details regarding the queue process and submission shall be posted to and updated from time to time on the Company’s website.

7.11 Summary of Policy Administration (Continued)

C. Residential Multi-Family or Residential Mobile Home Trailer Parks

All applicants, classified as permanent service, will have a Construction Allowance calculated per the feasibility model (Section 7.02 C. Construction Allowance) for the customized project. The Construction Allowance is subtracted from the Estimated Construction Cost for the Applicant's project in order to determine the Nonrefundable Construction Charge to be paid by Applicant. Applicant will also be responsible for all Estimated Construction Charges related to the cost of connecting to Company's existing and adequate distribution facilities when the length is greater than 100 feet. Applicant will pay these costs to Company as a Nonrefundable Construction Charge.

D. Commercial or Industrial

All applicants, classified as permanent service, will have a Construction Allowance calculated per the feasibility model (Section 7.02 C. Construction Allowance) for the customized project. The Construction Allowance is subtracted from the Estimated Construction Cost for the Applicant's project in order to determine the Nonrefundable Construction Charge to be paid by Applicant. The cost of the Distribution Extension on public right-of-way is generally included in the Estimated Construction Cost except where the Applicant requires an extension other than a standard overhead extension. Where underground service on public right-of-way is required and agreed to by Company, the Applicant will be required to pay for the required facilities as either a Nonrefundable Construction Charge or as a surcharge on its monthly bill, at Company's discretion.

E. Transmission or Facilities Extensions

For extensions of transmission or substation facilities, any Customer requesting service with substation or transmission facilities shall pay all costs associated with such extensions. These costs do not include any resulting Network Upgrade costs for facilities classified as transmission under the Southwest Power Pool Open Access Transmission Tariff. Customers requesting service through substation or transmission facilities must complete payment for the extension or make suitable arrangements for installment payments, execute all required agreements associated with the requested extensions, and execute any Service Agreements required by the applicable rate schedule as a condition for any construction to commence.