Exhibit No.:	
Issue:	Normalized Retail Revenues; Rate Design; CCOS
Witness:	Graham A. Jaynes
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Evergy Missouri Metro
Case No.:	ER-2026-0143
Date Testimony Prepared:	February 6, 2026

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2026-0143

DIRECT TESTIMONY

OF

GRAHAM A. JAYNES

ON BEHALF OF

EVERGY MISSOURI METRO

Kansas City, Missouri
February 2026

Table of Contents

DIRECT TESTIMONY

OF

GRAHAM A. JAYNES

Case No. ER-2026-0143

I. Introduction

Q. Please state your name and business address.

A. Graham A. Jaynes. 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. and serve as Manager - Regulatory Affairs for Evergy Metro, Inc. d/b/a as Evergy Missouri Metro ("EMM"), Evergy Missouri West, Inc. d/b/a Evergy Missouri West ("EMW" or "Company"), Evergy Metro, Inc. d/b/a Evergy Kansas Metro ("EKM"), and Evergy Kansas Central, Inc. and Evergy South, Inc., collectively d/b/a as Evergy Kansas Central ("EKC") the operating utilities of Evergy, Inc.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of EMM ("Evergy" or the "Company").

Q. What are your responsibilities?

A. My responsibilities are to provide support for the Company's regulatory activities in the Missouri and Kansas Jurisdictions. Specifically, my duties include oversight of class cost of service, tariff management, load analysis, and rate design. Additionally, I manage analytical activities including rate change implementation, billing determinant calculation, and retail revenue calculation.

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

A. I hold a Bachelor of Business Administration in Accounting and Finance from Drury University, with minors in Entrepreneurship in Global Studies. I began my career in 2015 with ONEOK in Tulsa, Oklahoma, serving in Scheduling and Gas Supply for Gathering & Processing. From 2017 to 2024 I held several positions of increasing responsibility in Rates and Regulatory Affairs with Kansas Gas Service in Overland Park, Kansas. I joined Evergy in 2024 as a Lead Regulatory Analyst and assumed my current role as Manager – Regulatory Affairs in 2025.

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 before the State Corporation Commission for the State of Kansas ("KCC").

Q. What is the purpose of your testimony?

A. My testimony (i) explains the Company's development of normalized retail revenues, (ii) presents and supports the Company's rate design proposals—including Commercial and Industrial Demand Thresholds, adoption of a 15-minute demand interval, certain rate eliminations, and reactive demand treatment—(iii) sponsors the electric Class Cost of Service ("CCOS") studies, and (iv) describes the Company's proposed revenue allocation. These proposals are intended to promote administrative clarity, build towards consistency across Missouri jurisdictions, and implement changes in an equitable manner.

My testimony is organized as follows:

- The Company's annualized/normalized revenues

- The Company's Electric Rate Design Proposals
  - Commercial and Industrial Demand Thresholds
  - 15-minute Demand Interval
  - Hours Use Replacement
  - Optional TOU Rate
  - Rate Eliminations
  - Reactive Demand
- The Electric Class Cost of Service Study
- The Company's Revenue Allocation & Proposed Rates
  - Economic Development Rider (EDR)
  - LLPS Premium
  - Net Margin Rates

II. Normalized Revenues

Q. Were the retail revenues included in this filing prepared by you or under your supervision?

A. Yes, they were.

Q. Please describe the method used in developing the revenue for this case.

A. Weather-normalized kWh sales and customer annualization by rate class (Residential, Small General Service, Medium General Service, and Large General Service) were developed by Company witness Albert R. Bass, Jr., as described in his direct testimony. The Company used the 12-month period ending June 30, 2025, as the Test Year.

Under my supervision, monthly bill frequencies were developed for each of the 12 months in the Test Year. These bill frequencies show how many customers and how much usage fell into each billing block under the current rate structures. To create them, we compiled the actual monthly usage and customer counts billed during the test period and applied those values to the existing rate designs. Applying current rates to the usage in each billing block allowed us to reproduce test-year revenues and establish a consistent basis for revenue calculations in this case. Using these bill frequencies, the Company calculated monthly revenues by applying the normalized sales and customer levels for each month of the test period to the corresponding billing frequency data. The total of the monthly revenues was then compared to the actual revenues for the Test Year ending June 30, 2025. The difference between these amounts forms the revenue adjustment shown in the Summary of Adjustments attached to the direct testimony of Company witness Ron Klote.

Q. Were there any changes in the process as compared to the previous EMM rate case?

A. Yes, in an effort to better align with the Commission Staff's process, the Company has adjusted the order of operations of the Current Rates adjustment from the final adjustment to the first adjustment following the recalculation step.

Q. Please describe the Current Rates adjustment and any impact it had on revenues.

A. The Current Rates adjustment would be a recalculation of base rate revenue for the Test Year if there was a change in rates during the Test Year. The change in order of operation had no impact on the revenues because there was no change in rates in the Test Year.

Q. Were all the class revenues developed using the methodology described above?

A. Yes, except for the Large Power Class. The Large Power class revenues generally followed the methodology outlined above but were developed on an individual customer basis. Customer growth was accounted for by the annualization of usage for new customers switching (or starting new service) to the Large Power Class or customers leaving the Large

Power Class (either due to switching to a different rate class or stopping service) through the end of the Test Year. In addition to traditional LPS normalization this case included an adjustment for forecasted Large Load Power Service ("LLPS") activity.

Q. Was the LLPS forecast normalized in the same manner as traditional LPS?

A. No. The LLPS forecast was not normalized in the same manner as traditional LPS.

Q. Why was the LLPS forecast not normalized consistently with traditional LPS treatment?

A. Traditional LPS normalization annualizes any LPS customer lacking 12 months of billing history by projecting a full 12 months of Test Year usage based on available data not based on forecasted data. Because there were no active LLPS customers with billing data during the Test Year, applying traditional normalization would have resulted in zero LLPS revenue being included in the analysis. The Company determined that including LLPS revenue as an adjustment was appropriate and therefore did not apply traditional LPS normalization to the LLPS forecast.

Q. What adjustments have been made to account for LLPS revenue?

A. Two adjustments were made within the total adjustment to retail revenues. First, $16,109,583 revenue was included as a pro forma adjustment. This is the projected amount of revenue from LLPS growth by the true-up period of June 2026. The load associated with this growth represents best-known information at the time and was included in the analysis of Evergy witness Mr. Bass. Further upside potential was recognized from LLPS after the incorporation of this adjustment. The possibility of additional revenue materialized after the incorporation of the first adjustment into all areas of the revenue requirement. This changing LLPS environment supported a late addition after what would normally be a period of locking the revenue requirement model. This meant that an additional, revenue-only adjustment was made of $9,100,000. No determinants were fully incorporated with this associated revenue and will be captured through the update and true-up periods.

Q. Is this pro-forma adjustment directly tied to a specific project?

A. $16.1 million of the LLPS adjustment is associated with a point in time forecast of revenue by true-up. As discussed by Company Witness Mr. Gunn, this LLPS transition is occurring in a changing environment. Company Witness Zac Gladhill explains in his testimony, the Large Load Development Process is inherently iterative, new information becomes available continuously, customer plans evolve, and load expectations adjust as projects progress through different stages. Because of this, the Company must account for the fact that load forecasts are not static and are expected to change as more data is developed.

Consistent with that principle, and as discussed by Company Witness Mr. Gunn, a gross up of $9.1M for LLPS revenue is included, intending to capture growth in a dynamic environment that extends beyond customer-provided forecasts. The additional $9.1 million therefore represents the effect of potential updated load expectations and the variability associated with load development over time, rather than any discrete customer project.

Q. How does this LLPS projected revenue impact the overall revenue requirement?

A. The inclusion of the projected LLPS revenue provides a reduction to the overall revenue requirement.

Q. Do other classes see any other impacts from this projected growth?

A In addition to downward pressure on the revenue requirement, LLPS activity will provide a revenue credit to other classes and allocated cost obligation in the Class Cost of Service discussed later in my testimony. Company witnesses Mr. Gladhill and Mr. Gunn discuss in more detail the LLPS environment.

Q. Is this indicative of treatment in future cases?

A. This case is taking place within a transitionary period as LLPS activity is in the earliest stage of development. LLPS customers represent a rapidly evolving sector with unique characteristics that make forecasting challenging. The newly established LLPS tariff set in File No. EO-2025-0154 does not have active customers in the Test Year and the first enrollment is anticipated in the final months of true-up. For this reason, and the LLPS discussion found in Company witnesses Gunn and Gladhill, the Company believes it is prudent to make pro-forma adjustments that conservatively includes post Test Year activity to reduce revenue requirement.

Customer Count

Q. How are customer counts provided in this case?

A. Customer count metrics are provided in Schedule GAJ-01. They are presented in two forms: (1) the number of customer charges billed and (2) the number of bills issued.

Q. Why are these both relevant data points?

A. In the most recent MO West general rate case (ER-2024-0189) a commitment was made to provide both customer charge count and customer service agreement counts in the next EMW rate case. This commitment originated from a difference of opinion as to which method should be used. The Company proposed to utilize customer charge count as the method for all rate making needs. The Commission Staff utilized both methods.

Q. Was this a MO Metro Commitment?

A. No. The commitment in ER-024-0189 applied specifically to MO West. However the Company believes the underlying considerations are similar in MO Metro and providing both metrics here advances consistency and helps move toward a common understanding across all Evergy Missouri filings.

Q. What are the differences between Bill Count and Customer Charge for the Residential class in each month of the Test Year?

A. The differences for each month of the Test Year are small. The following table, Table 01, details the count methods and the differences. Similar differences were observed in the ER-2024-0189 filing.[1]

Table 01

Normalized Residential Bill Count vs Customer Charge				
Month	Bill Count	Customer Charge	Delta	% Change
July 2024	276,154	274,543	1,611	0.59%
August 2024	276,367	274,741	1,626	0.59%
September 2024	276,669	275,460	1,209	0.44%
October 2024	276,317	275,211	1,107	0.40%
November 2024	276,018	274,920	1,099	0.40%
December 2024	275,941	275,665	276	0.10%
January 2025	275,333	275,247	86	0.03%
February 2025	275,261	275,032	229	0.08%
March 2025	274,768	274,725	44	0.02%
April 2025	275,596	274,327	1,268	0.46%
May 2025	276,214	275,269	945	0.34%
June 2025	275,850	274,781	1,069	0.39%

[1] ER-2024-0189, Rebuttal Testimony of Ms. Marisol Miller, page 6, line 18.

Q. How do these versions of customer charge produce average residential metrics when applied?

A. The Residential Peak Adjustment rate, which has the highest enrollment in the residential class, averages 868.42 monthly kWh when using an average quantity of customer charges Using bill counts to calculate this same metric amounts to 865.22kWh.

Q. What does the company recommend using as a customer count?

A. The Company suggests using the customer charge count for rates that include that billing component and using bill count as the fallback when customer charge is not available. The lack of a customer charge is most prevalent in the Lighting rates.

II. Rate Design

Q. Please list your proposals for rate design?

A. The rate design proposals include the following:

- Demand Thresholds
- 15-minute Demand Interval
- Hours Use Replacement
- Optional TOU Rate
- Rate Eliminations
    - Time Related Pricing
    - All Electric C&I Rates
    - Frozen – Residential TOD Rate (1TE1A) - No Customers
    - Residential Space Heat – No Customers
    - Residential Other Use – No Customers
- Reactive Demand

Q. Have any of these proposals been discussed in prior cases?

A. Yes, Company witness Mr. Lutz describes how the rate design proposals fit within prior case, the Company Rate Design Strategy and other stakeholder interactions. These proposals are mostly a continuation of these efforts.

<u>Demand Thresholds</u>

Q. Please explain the Company's proposal on Demand Thresholds.

A. The Company proposes establishing Demand Thresholds, i.e., class-specific maximum demand levels based upon Non-Coincident Peak (NCP) demand for Commercial and Industrial (C&I) customer classes. When combined with existing minimum billing demand criteria, these thresholds create both lower and upper bounds that more clearly define customer class eligibility and composition based on customer billed demand going forward.

Q. What is the goal of proposing Demand Thresholds?

A. By introducing Demand Thresholds, the Company can correct uneconomic rate selection, mitigate opportunistic rate switching for C&I customers, improve class homogeneity for future jurisdictional alignment, and utilize a simple metric that is easy to understand and review, all while shifting as few customers as possible, minimizing effects to class composition, and maintain revenue neutrality of the proposal.

Q. Describe the analysis of C&I classes that demonstrates a need for Demand Thresholds.

A. In order to affirm the necessity of Demand Thresholds, individual monthly demand data was analyzed to show the distribution of average and maximum customer demand across classes. All C&I customers by class within the Test Year were compiled with their monthly delivered demand, monthly energy consumption, and calculated estimated annual load factor. Customers with twelve months of usage were utilized to prepare scatter plots and box-and-whisker plots of maximum and average demand by load factor for all C&I classes in order to compare intraclass and interclass patterns.

Schedule GAJ-02 Fig. 1.1 through 1.3 shows the box-and-whisker plot for each individual class's customer average monthly peak demand and average non-coincident peak demand. Figure 1.2 highlights material outliers within classes; these outlier customers are well outside the normal range for their class. This same pattern is evident in the summary statistics in table 02 below with all values below expressed in kilowatts (kW).

Table 02

Class	**Class Average Monthly Peak Demand**	**Class Median Monthly Peak Demand**	**95th Percentile of Customer Avg Peak Demand**	**Customer Average Non-Coincident Peak**	**Customer Non-Coincident Peak Range**
SGS	*8.73*	*4.10*	*25.01*	*12.92*	*1,537.20*
MGS	*58.75*	*35.13*	*157.25*	*81.74*	*3,115.14*
LGS	*496.74*	*280.49*	*1,578.61*	*693.75*	*24,540.65*
LPS	*4,927.11*	*2,874.46*	*17,181.71*	*5,686.95*	*37,473.84*

The data portrays classes that are strongly right skewed, skewed toward higher kW values, signaling outlier customers well above what could be considered a typical customer for the class. A class average that materially exceeds the median points to outsized influence from upper-tail customers. For example, in SGS, the 95th percentile of average peak is more than six times the class median. The customer non-coincident peak range shows how far out these outliers go. Schedule GAJ-02 Figures 2.1-3.2 further illustrates the spread of customers NCP and average monthly peak demands by load factor across classes.

This again helps visualize the need for Maximum Demand Thresholds to better homogenize customers across classes by migrating customers towards classes more aligned with their service requirements and costs.

Q. What justification can you provide that these issues need to be corrected?

A. Foundational ratemaking principles and Missouri law require similarly situated customers to be classified and charged in a similar manner.

RSMo § 393.130 states:

> All charges made or demanded by any such gas corporation, electrical corporation, water corporation or sewer corporation for gas, electricity, water, sewer or any service rendered or to be rendered shall be just and reasonable and not more than allowed by law or by order or decision of the commission. 2. No gas corporation, electrical corporation, water corporation or sewer corporation shall directly or indirectly by any special rate, rebate, drawback or other device or method, charge, demand, collect or receive from any person or corporation a greater or less compensation for gas, electricity, water, sewer or for any service rendered or to be rendered or in connection therewith, except as authorized in this chapter, than it charges, demands, collects or receives from any other person or corporation for doing a **like and contemporaneous service with respect thereto under the same or substantially similar circumstances or conditions**.

This Missouri statute section states that homogenous customers shall be classified and charged in a similar manner to each other, based on similar services being rendered. Under current C&I rate design, nothing prevents a large capacity customer from dropping from an LGS rate to an SGS rate if doing so would reduce their bills, even though the costs they incur on the system are similar to those customers who maintain a service agreement on an LGS rate. While some of these customers may not connect at the same voltage, a driver of their costs would be similarly based on the expenses required to meet their peak demand. The only obstacles to this behavior is administrative and potential price signals.

For an example observed in preparation of this proposal, a 24-hour, large square footage casino and hotel is currently served under MGS, even though the MGS class is designed to service customers under 200 kW of demand, commonly customers such as retail stores and a small convenience store. Likewise, our review identified a large commercial distribution center served under SGS. The SGS class is designed to service customers under 25 kW of demand, commonly customers such as hair salons and small professional offices. These outlier examples, alongside the analysis above, demonstrate a need to apply additional demand-based metrics to ensure customers are assigned to appropriate classes.

Q. Explain how this proposal establishes Demand Thresholds.

A. Previous Demand Thresholds analysis from EKC and EKM was leveraged as starting points for application and analysis of the impacts of proposing Demand Thresholds. Schedule GAJ-02 Fig. 4.1 and 4.2 show the results of applying EKC and EKM thresholds to the EMM C&I customer classes. Applying either set of thresholds significantly altered the current composition of C&I classes. The column labeled "Class Size Δ" in Table 1 (GAJ-02) labeled "Net Impact to Class Sizes" provides a metric of total class shifting by calculating the absolute value of customers shifted between classes. By minimizing this metric, class composition would be maintained as close to pre-Demand Threshold levels as possible. By leaning on the class analysis related to Customer Average NCP, the Company arrived at the following Demand Thresholds that minimally affect class composition while minimizing individual customers being moved:

- Small General: ≤31kW;
- Medium General: ≤250kW;
- Large General: ≤3,000kW.

Thresholds were then applied to the customers in the dataset to migrate them to their appropriate class. The resulting change to class statistics is shown below. Please note all values below are in kW units.

Table 03

Class	Class Average Monthly Peak Demand	Class Median Monthly Peak Demand	95th Percentile of Customer Avg Peak Demand	Customer Average Non-Coincident Peak	Customer Non-Coincident Peak Range
SGS	*5.81*	*4.01*	*17.71*	*8.43*	*31.00*
MGS	*57.46*	*42.32*	*143.97*	*80.75*	*218.47*
LGS	*460.23*	*314.07*	*1,318.49*	*626.66*	*2,746.27*
LPS	*6,258.08*	*3,866.33*	*17,181.71*	*7,837.23*	*34,455.84*

Comparing this new table with the previous table shows class average monthly peak demands moved closer to the median for SGS, MGS, and LGS classes. 95th percentile of customer average peak demand also reduces as well, signaling large outliers were migrated out. For the LPS class, we see customer average and median shift upwards signaling low demand customers have been migrated downwards.

Q. Does this proposal impact CCOS?

A. Yes, the impact on class cost of service is discussed below in the CCOS study portion of testimony.

Q. Were estimated individual customer bill impacts calculated?

A. Yes. Estimated 12-month bill impacts for customers likely to migrate under the proposed thresholds were calculated. Bills were estimated utilizing customer's Test Year actual usage; those customers with less than 12 months of usage had minimum bills calculated for months with no usage. Additionally, the facilities charge was estimated based on the customer's NCP regardless of what month in the Test Year it occurred. In total, 4,224 customers (11.5% of C&I customers) were estimated to be migrated. The estimated average annual bill difference for these 4,224 customers is $88.10, with 95% of migrating customers falling between $(13,285.71) and $6,958.50. An estimated 663 customers could see an impact of greater than 10% of their annual bill at current rate, with 406 of these customers having 12 full months of usage.

Q. Does this proposal fully align rate classes across Missouri jurisdictions?

A. No. This standalone proposal does not fully align rate classes across Missouri jurisdictions. It does, however, improve homogeneity within Missouri Metro, facilitating apples-to-apples analysis of classes across the jurisdictions in the future. It is Evergy's intention to propose similar Demand Thresholds in a future Missouri West rate case. If the customer alignment of both jurisdictions are improved, a future proposal to consolidate the customer classes will be completed more cleanly. Without a move towards class homogeneity, future rate structure alignment with Missouri West will be complicated or impacts will be too large for alignment in a given rate case.

Q. Does this proposal include any adjustments to existing billing demand minimums established in existing tariffs?

A. No. Although establishing maximum kW Demand Thresholds could warrant revisiting class minimums, the Company proposes, as a mitigation effort, to maintain current minimums at this time. While this does not eliminate all impacts, it reduces the burden on customers who migrate upward due to short-term activity.

Q. What effect does this proposal have on customer charge blocking?

A. Under the current class structure, customer charge is blocked by tiers of kW levels. The function of this tiering is largely made redundant by the implementation of maximum Demand Thresholds. After implementing Demand Thresholds, the customer charges for each class were replaced with the average customer charge and set to a single fixed charge. In addition to the nullification by the new thresholds, a single customer charge for each class has the added benefit of clear understandability for customers.

<u>15-minute Demand Interval</u>

Q. How is monthly max demand measured currently?

A. The monthly maximum demand is currently defined as the sum of the highest demand recorded in any 30-minute interval during the month on all non-space heat and non-water heat meters, plus the highest demand recorded in any 30-minute interval during the month on the space heat meter, if applicable, and the highest demand recorded in any 30-minute interval during the month on the water heat meter, if applicable. Said plainly, customer billing demands are measured by readings taken every 30 minutes by the customer's electric meter. Fluctuations of demand, higher or lower, in between these readings are not captured by the meter.

Q. Is this consistent with other jurisdictions?

A. No. In the EMW jurisdiction, monthly maximum demand is defined as the customer's highest 15-minute integrated demand, measured in kW, during the current billing period. In addition, Empire District Electric Company and Ameren Missouri, use 15-minute demands for commercial and industrial customer billing purposes.

Q. What change is the Company proposing?

A The Company is proposing moving from a 30-minute interval to relying on a 15-minute interval for measuring demand.

Q. What is the benefit of moving to a 15-minute interval over a 30-minute interval?

A. Transitioning from a 30-minute interval to a 15-minute interval will provide a more accurate representation of a customer's peak usage. A shorter interval captures brief fluctuations in demand that a longer interval may not give visibility to. This change also supports the Company's objective to align practices across the EMM and EMW jurisdictions.

Q. How did you convert determinants for this filing?

A. Determinants were converted by applying a conversion factor to the demand and facilities billing components. A factor of 1.03042 was applied to all determinants across all rate codes consistently.

Q. How was that conversion factor developed?

A. Using customer-level 15-minute interval data paired with billed 30-minute demand, we developed rate-level monthly factors, screened outliers, and computed a weighted annual factor to restate determinants. This approach allows future updates without re-rerunning the full study and is applied to maintain revenue neutrality for the affected components at implementation.

Table 04

	Simple Average	Weighted Average
Including Outliers	1.02319	1.02086
Excluding Outliers	1.03533	1.03042

Q. What is the nature of these outliers and why did the Company choose to exclude them from development of this factor?

A. The outliers reflected extreme values driven primarily by timing differences between the Meter Data Management ("MDM") system and billing data, especially for small rate codes.

Because MDM captures usage changes in real time while billing data is synchronized to the billing cycle, usage shut offs or adjustments within a month could appear as large increases or decreases when the two systems were compared. The Company excluded these values to ensure the factor reflected normal customer behavior.

Q. Will the conversion factor play a role in customer billing going forward?

A. No. The conversion factor is only needed for this rate case. Going forward, customer billing will be based on demand measured by the customer's meter.

Hours Use Replacement

Q. How was the replacement of hours use design evaluated?

A. Evergy engaged The Brattle Group to develop, evaluate, and recommend rate design options to replace the existing Hours Use rate that is currently applicable to commercial and industrial customers.

The existing Hours Use rate was designed to promote efficient utilization of Evergy's energy infrastructure, but its complexity limits customer understanding and engagement. More transparent and actionable price signals can help customers align their consumption patterns with their preferences while providing the Company with an additional tool to manage an increasingly dynamic power system. Importantly, well-structured rate designs also advance cost causation principles by aligning more closely what customers pay with the costs that they impose on the system.

Schedule GAJ-04 contains the full report produced by The Brattle Group detailing the process and recommendations.

Q. What options were advanced after The Brattle Group's evaluation?

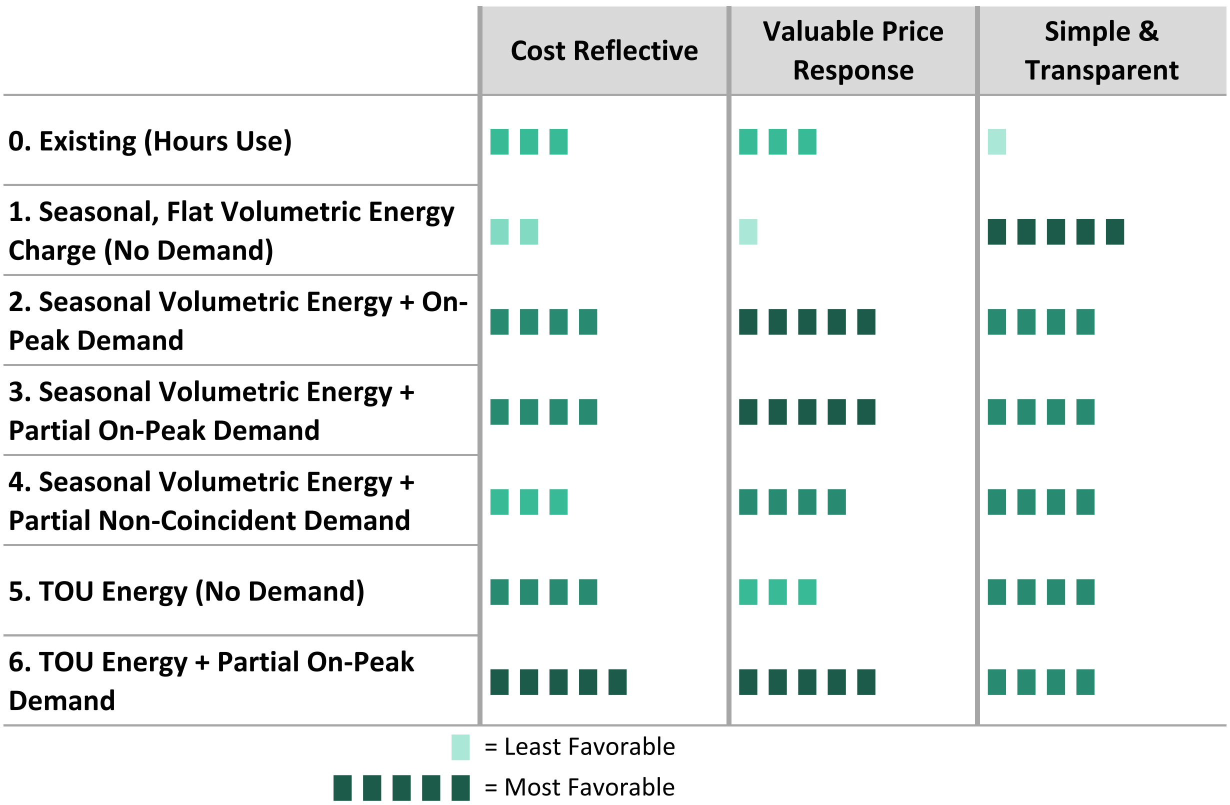
A. After a screening process to narrow down suitable alternatives, six options were modeled for further analysis. These include:

1. A rate with a seasonal, flat volumetric energy charge;
2. A rate with a seasonal, flat volumetric energy charge + a full on-peak demand charge;
3. A rate with a seasonal, flat volumetric energy charge + a partial on-peak demand charge;
4. A rate with a seasonal, flat volumetric energy charge + a partial non-coincident demand charge;
5. A rate with a time-of-use (TOU) energy charge and no demand charge; and
6. A rate with a TOU energy charge and an on-peak demand charge.

Q. What is the Company proposing as the replacement for Hours Use?

A. The Company is proposing option 3 from the list above for SGS, MGS, LGS, and LPS. Figure 1 shows that option 3 is a favorable replacement and that option 6 is a viable option for some scenarios. The Company proposes offering option 6 as an opt-in rate in addition to the Seasonal Volumetric + Partial On-Peak Demand further in my testimony.

Figure 1



Q. Why does the Company propose replacing hours use with the same structure for all classes?

A. Given the rate design changes such as Demand Thresholds within C&I classes, maintaining a similar structure across classes prioritizes customer understandability and transparency. Further, this proposed change increases the likelihood that customers can clearly plan and incorporate price signals as intended.

Q. What is The Brattle Group's recommendation?

A. The report's final recommendation is in line with the company's approach, reiterating the following support:

> The recommended [Option 3] balances cost reflectivity and simplicity. It recovers demand-related costs associated with system peak hours through an on-peak demand charge, while recovering remaining costs through a seasonal flat volumetric energy charge.

> The structure provides clear, actionable price signals that encourage customers to reduce consumption during system peak periods, without requiring them to monitor load factors in real time or perform additional calculations to manage their bills. Some small C&I customers may lack the tools or operational flexibility to actively manage energy usage, but the bill impacts observed for small C&I customers under this rate option are relatively modest. For customers who are able to respond to price signals, they can also expect to save on their electricity bills. Relative to the current Hours Use rate, this option also results in more stable and favorable bill outcomes, with fewer customers experiencing extreme bill changes during the transition. Further, rates featuring on-peak demand charges are increasingly common for C&I customers across the US.
>
> In addition, we recommend that Evergy apply a seasonal peak adjustment charge or credit to the energy charge. By reflecting the time-varying nature of energy costs, this mechanism would help familiarize customers with the concept of intraday price variability, and the relatively low pricing levels would minimize customer bill impacts.
>
> Finally, we recommend that Evergy introduce, as an optional offering, a rate structure featuring a time-of-use (TOU) energy charge combined with an on-peak demand charge (Option 6). This optional rate would provide more dynamic energy and demand price signals, creating stronger incentives for customers to actively manage usage and reduce electricity costs.

Q. What are the proposed replacement rates?

A. Table 5 below includes the pricing of the replacement rates prior to increases for the rate case revenue requirement.

Table 5

Proposed Rates		SGS	MGS	LGS	LPS
Customer Charge: amount customer pays per month		$21.415	$60.084	$228.288	$1,170.787
Facilities Charge: per kW of Facilities Demand		$2.981*	$3.189	$3.440	3.921
Demand Charge: per kW of Billing Demand	Summer	$15.044	$14.640	$15.277	$13.925
	Winter	$6.607	$6.336	$6.705	$7.250
Energy Charge: per kWh of monthly usage	Summer Energy Charge	$0.07519	$0.06301	$0.05762	$0.05966
	Summer Peak Adder	$0.01000	$0.01000	$0.01000	$0.01000
	Summer Super Off-Peak Credit	-$0.01000	-$0.01000	-$0.01000	-$0.01000
	Winter Energy Charge	$0.07624	$0.06421	$0.05991	$0.06033
	Winter Super Off-Peak Credit	-$0.01000	-$0.01000	-$0.01000	-$0.01000

Note: The prices shown in the table are for secondary voltage and do not include riders, taxes, and other applicable fees. Please refer to the Appendix for prices for other voltage levels. Rates shown are indicative and calculated based on proposed Hours Use charges for SGSE, MGSE, LGSE and PGSE in this rate case. The final rates will be based on the Commission's approved revenue requirement and corresponding billing determinants for the rate class.
* SGS facilities charge is only assessed for demand beyond 25 kW.

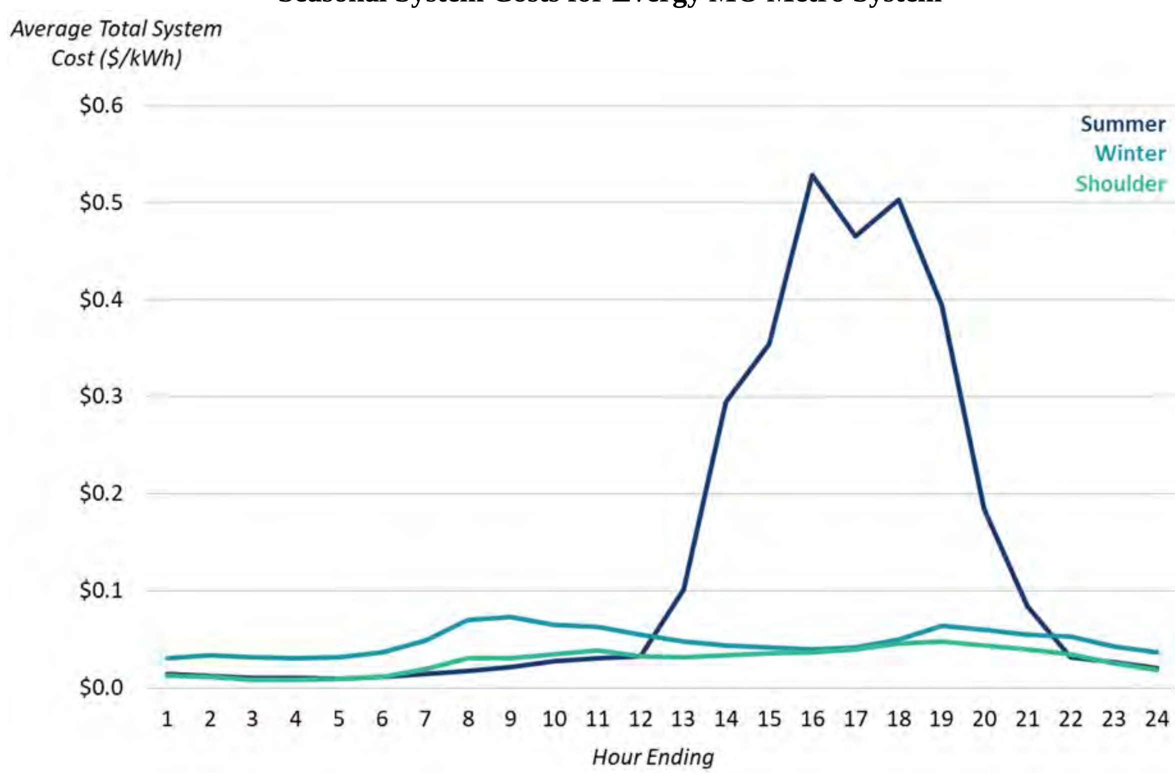
Q. Did the Company perform any analysis of the possible impacts?

A. Yes. Customer bill impacts by voltage level were computed by Brattle and are included as GAJ-04 Figures 16:21. The range of average percent bill increase among non-benefiters for the replacement rate was from 5%-14% depending on the class and voltage. Customers with bill savings ranged from 22-82% depending on the class and voltage.

Q. Would you please summarize how the structures and pricing were developed?

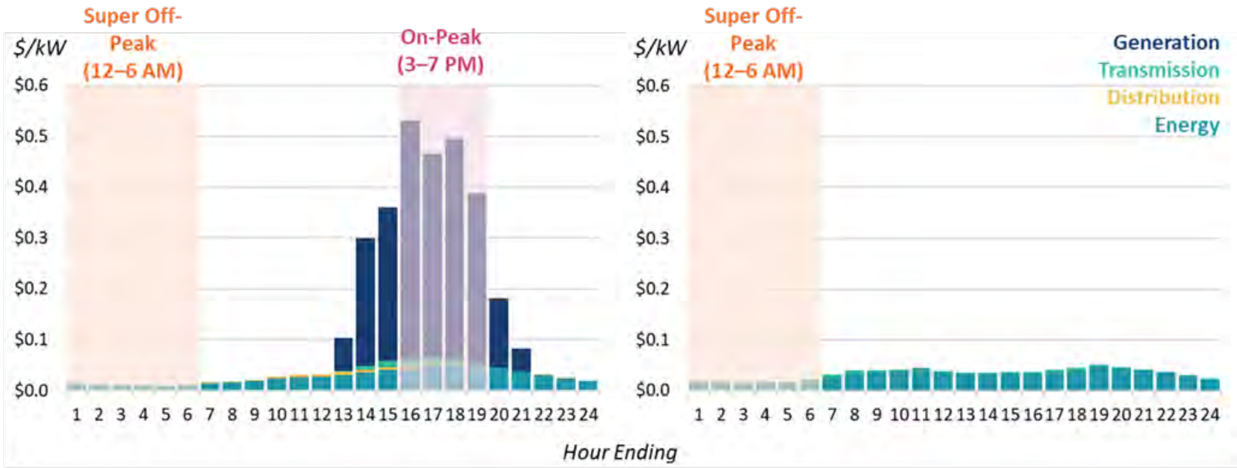
A. The design process began with establishing the TOU periods using the summer and winter periods common to our other rates. We assigned costs for generation, transmission, distribution, and energy we assigned to each hour of the year. Consideration was made to assign costs according to the driver of these costs. Distribution costs for example, are thought to better align with class load and were assigned accordingly. The following figures, Figure 2 and Figure 3, summarize the hourly cost totals and the resulting periods are identified. It is this result that led us to propose three TOU periods in the summer months and two TOU periods in the winter months.

<u>Figure 2</u>
Seasonal System Costs for Evergy MO Metro System



Note: Summer = June-Sept, Winter = Dec-Feb, Shoulder = March-May, Oct-Nov

<u>Figure 3</u>
Hourly Summer (left) and Non-Summer System Costs for C&I Customers



Next, we calculated the rate components based on the underlying cost drivers. In this design the components are customer, facilities demand, demand, and energy charges. The rates are designed to be revenue neutral at the customer class level. Further details concerning the cost assignment are offered in section III of Schedule GAJ-04, starting on page 14.

Q. What led the Company to propose a three-period design for summer months but a two-period design for winter months?

A. As observed in Figure 2 and Figure 3, using the periods in this way best aligns with the costs. As EMM is a summer-peaking utility, it is reasonable to expect the higher costs in those hours for the summer months. Establishing the on-peak period from 3pm to 7pm also aligns closely with on-peak periods used for other TOU rates in EMM, EMW, and rates in the Kansas jurisdiction providing administrative benefits. Turning to the winter months, less price variability is observed. Instead of forcing the winter design to three periods and having period pricing with little to no difference, we chose to only provide for two TOU periods in the winter months.

Optional Time of Use rate for Commercial and Industrial Customers

Q. Please describe the proposed optional Time of Use rate for non-residential customers.

A. EMM is proposing an optional three-period, four-part Time of Use rate that will be available to the Small General Service, Medium General Service, Large General Service, and Large Power[2] customer classes. Demand Thresholds proposed in the case will also apply to these new optional rates. The four-part design consists of a customer charge, facilities charge, demand charge and energy charge. The energy charge is in the form of a three-period design with an "on-peak" period from 3 pm to 7 pm on non-holiday weekdays in summer months, a "super-off-peak" period from midnight to 6 am every day throughout the year, and an "off-peak" period for all other hours of the year. Holidays are New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. The Company retained The Brattle Group to determine the rate design and pricing for the Company based on design details formulated through the Customer Group meetings. A report supporting the rate design is attached to my testimony as Schedule GAJ-04.

Q. How was this rate originally developed?

A. This rate design was originally proposed and approved in the Evergy Kansas Central jurisdiction[3] and was the result of an extensive collaboration with representatives of 18 individual companies[4] in that jurisdiction ("Customer Group"). The direct input and

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[2] The proposed rate will not be available to customers required to receive service under the Large Load Power Service rate, Schedule LLPS.

[3] Docket No. 25-EKCE-294-RTS

[4] The Customer Group included representative from the Kansas Chamber of Commerce and Industry, Inc.; Wichita Regional Chamber of Commerce; the United States Department of Defense; Kansas Industrial Consumer Group; Lawrence Paper Company; Spirit AeroSystems, Inc.; Occidental Chemical Corporation; Goodyear Tire & Rubber Company; Associated Purchasing Services Corporation; United School District #259 Sedgwick County, Kansas; Johnson County Community College; USD 223 Olathe School District; USD 512 Shawnee Mission School District; USD 232 DeSoto School District; USD 229, the Blue Valley School District; CVR Refining CVL, LLC; HF Sinclair El Dorado Refining LLC; and Walmart, Inc.

feedback received from the Customer Group concerning the rate design was critical in defining the final design.

Q. Do you believe the rate design is equally applicable to Missouri non-residential customers?

A. Yes. Missouri and Kansas non-residential customers share many perspectives on rate design and would benefit similarly from this optional rate. It is notable that Walmart Inc., who has intervened in past Evergy Missouri rate cases, was a Party in the Kansas Central proceeding and participant in this rate design development.

Q. What pricing has been established for the rate?

A. GAJ-04 “VI. Appendix” details the proposed pricing for the optional TOU schedules at current rates. See Figure 12-14 option 6 for the pricing details.

Q. Why did the Company decide to include a demand charge within a TOU design?

A. We made a decision to include a demand charge within this optional rate offering based on our review of C&I TOU rate examples from other jurisdictions and discussions with the Customer Group. Results from the jurisdictional scan show that it is common for C&I rates to feature a demand charge, especially among the optional rates. The Customer Group also indicated preference for the four-part design, with a separate charge for facilities demand to address distribution costs and for demand associated with generation costs.

Q. How do you expect customers will use this rate design?

A. Based on comments made by the Customer Group, it is believed that there are customers who may be flexible with their energy consumption and will select this rate option which allows them to shift usage to the off-peak and super-off-peak periods reducing their energy costs.

Q. Will this reduction be impactful to the Company and its revenues?

A. Yes, we would expect some impact. While the proposed rates are designed to be revenue neutral at the class level, it is expected that the optional schedule will mainly attract customers that stand to benefit from the proposed rate. It is difficult at this time to estimate how many customers plan on taking service under the TOU schedule and how aggressive the customers will be in changing their behavior to take advantage of the off-peak and super off-peak pricing. Extreme adoption of the optional TOU schedule could reduce the revenue recovered by the Company. It is expected that the Company may be able to lower costs in conjunction with these shifts in energy usage as the Company will procure less energy during these higher-cost hours. In addition to these immediate benefits, a reduction in peak load means that the Company will procure less generation capacity to meet peak load in the long run, resulting in additional savings for customers. If that occurs, the revenue loss would be offset by the cost savings.

Q. Going forward, do you expect the optional TOU rate design to change?

A. Yes. We expect customer loads and system costs to change. This could lead to adjustment of the TOU periods. The Company or Customers could bring forward proposals to refine the classification of costs between demand and energy. It is reasonable to expect that this rate design will change over time to adjust to the conditions observed at that time.

Rate Eliminations

Q. Please describe the rate eliminations.

A. The proposed rate eliminations fall into two categories. Rates without active customers and those with active customers. For those without active customers, there is no bill impact calculated, and this serves as tariff cleanup. For those with active customers bill impacts were computed for each elimination.

Q. Please describe the rates without customers.

A. The rates without active customers include Residential Space Heat, Residential Time-of-Day, and Residential Other use.

Q. Why are you proposing elimination of the All Electrics?

A. As described by Company witness Brad Lutz, the Company is taking steps withing the rate modernization framework towards jurisdictional alignment. Removing legacy rate options such as all-electric rates simplifies offerings and reduces barriers towards consolidation.

Q. What are the bill impacts of removing the All-Electric C&I Rates?

A. Estimated 12-month bill impacts were calculated for customers leaving the All-electric C&I rates. Bills were estimated utilizing customer's Test Year actual usage; those customers with fewer than 12 months of usage had minimum bills calculated for months with no usage. Additionally, the facilities charge was estimated based on the customer's NCP regardless of what month in the Test Year it occurred. All customers were migrated, if necessary, in accordance with the Demand Threshold proposal and had the weighted conversion rate applied to convert billing demand to 15-minute interval demand. Customers receiving service under the Small General class of all-electric rates could likely see an average difference of $102.28 annually. Customers receiving service under the Medium General and Large General all electric rates could likely see an average difference of $1,751.71 and $4,201.20, respectively. In total, 95% of customers leaving the all-electric rates could see an impact between $33.39 and $6,673.79.

Q. Why are you proposing elimination of the Time Related Pricing rate?

A. Consistent with the All-Electric proposal, this is in line with rate modernization efforts as described by Company witness Brad Lutz. The Time Related Price rate has had low participation and a need for a simplified replacement. In EMM, the Time Related Pricing rates have 3 active Service Agreements, two of which are under the same account.

Q. Does the Company plan on offering a time-based rate as a replacement?

A. Yes, the Company is proposing an Optional TOU rate for MGS, LGS, and LPS customers. The previous TRP rate was limited to just LGS and LPS customers. The Company believes that a simplified rate with a more traditional TOU structure will offer greater customer understandability with clearer price signals due to not have as many Energy Charge “periods”.

Q. What are the bill impacts of removing Time Related Pricing?

A. Estimated 12-month bill impacts were calculated for customers leaving the Time Related Pricing rates. Bills were estimated utilizing customer's test year actual usage. All customers were migrated, if necessary, in accordance with the Demand Threshold proposal and had the weighted conversion rate applied to convert facilities demand and billing demand to 15-minute interval demand. Pricing was applied from the neutralized standard rates. The median customer impact was 15.74%.

Q. Would TRP customers be required to remain on the standard rate?

A. No. The Company will work with these customers to determine the best fit rate inclusive of the new Optional TOU rate. The optional TOU is the presumed replacement for TRP customers.

Reactive Demand

Q. What is the Company proposing in regard to the Reactive Demand Adjustment?

A. The Company proposes to eliminate the Reactive Demand Adjustment for the MGS and LGS classes, aligning with EMW tariff structure, under which only the LPS class retains a Reactive Demand Adjustment. Company witness Mr. Lutz discusses the research supporting this proposed change to the Reactive Demand adjustment in his Direct Testimony.

Q. What is the impact to customers from removing Reactive Demand?

A. Eliminating the Reactive Demand Adjustment is revenue-neutral within each affected rate class. The revenues currently collected through the specific reactive demand charge will instead be recovered through the pricing of the other billing determinants within the class. Because the amount of revenue shifted is small relative to total class revenue, the resulting price adjustments to other bill elements is minimal and absorbed by the other revenue neutralization efforts. Reactive demand revenues represent only 0.142% of total MGS revenue and 0.136% of total LGS revenue. Eliminating low-materiality charges brings the added benefit of improving tariff simplicity and transparency.

Revenue Neutralization

Q. Will the previously described rate design proposals have an impact on revenues?

A. Yes. All else equal, the proposals would affect revenues.

Q. How did the Company handle the revenue impact?

A. To ensure that the rate design proposals had no net impact on overall revenues, the Company took steps to ensure that total C&I revenues after all rate design proposals were implemented, recovered the same amount of revenues without any of the rate design proposals implemented. The adjustment to retail revenues and the subsequent revenue requirement was established prior to any rate design proposals and any change after implementing changes was neutralized back to the original revenue requirement.

After Demand Threshold migration, the change in retail revenue was a reduction of $216,980. Next, we calculated the proportion of revenue each C&I class had Post-Migration and applied that share to the $216,980. The resulting impact was a 0.04% increase to each class's revenue. The next step was to neutralize the impact of moving from 30 to 15-minute demand intervals. Following the same process, each class had a reduction of -0.93% to their revenue, ensuring that after each rate design step, total C&I revenue collection was $519,038,980.

Table 6

Demand Threshold Revenue Neutralization				*$ 216,980*		
	Pre-Migration	Post-Migration Revenue	% of Rev	Share of Neutralization	Rate % increase	Adjusted Revenue
SGS	$ 87,203,704	$ 56,411,134	10.87%	$ 23,592	0.04%	$ 56,434,726
MGS	$ 125,514,616	$ 126,016,296	24.29%	$ 52,702	0.04%	$ 126,068,998
LGS	$ 185,882,652	$ 186,576,367	35.96%	$ 78,029	0.04%	$ 186,654,396
LPS	$ 120,438,008	$ 149,818,203	28.88%	$ 62,656	0.04%	$ 149,880,860
Total	$ 519,038,980	$ 518,822,000	100.00%	$ 216,980		$ 519,038,980

Table 7

Demand Threshold Revenue Neutralization				*$ 216,980*		
Demand Interval Revenue Neutralization				*$ (4,868,883)*	-0.93%	
Total Revenue Neutralization				*$ (4,651,903)*	-0.89%	
	Demand Interval Revenue	Demand Interval Revenue w/Demand Threshold Adjustment	% of Rev	Share of Demand Interval Neutralization	Demand Interval % Change	Demand Interval Adjusted Revenue
SGS	$ 56,420,933	$ 56,444,525	10.77%	$ (524,561)	-0.93%	$ 55,919,964
MGS	$ 126,842,397	$ 126,895,099	24.22%	$ (1,179,286)	-0.93%	$ 125,715,813
LGS	$ 187,977,620	$ 188,055,649	35.89%	$ (1,747,676)	-0.93%	$ 186,307,973
LPS	$ 152,449,933	$ 152,512,590	29.11%	$ (1,417,360)	-0.93%	$ 151,095,230
Total	$ 523,690,883	$ 523,907,863	100.00%	$ (4,868,883)		$ 519,038,980

Q. Does the calculated revenue neutralization include rate eliminations?

A. Yes. Rate eliminations were included in Table 7 amounts and therefore neutralized collectively with demand interval conversion.

III. Electric Class Cost of Service

Q. What is the purpose of the CCOS study and how does it fit into the overall rate case?

A. The CCOS study allocates the Company's total revenue requirement among customer classes in a manner that reflects the relative costs of providing service to each class. This is accomplished through analyzing the Company's costs and assigning each rate class its proportionate share of the utility's total revenues and costs within the Test Year. The results of the CCOS are then utilized to determine the relative cost of providing service to each customer class and to help determine the individual class revenue responsibility. It informs revenue responsibility and rate design proposals. The CCOS does not determine whether the overall revenue requirement should increase or decrease—that is addressed elsewhere in the case.

Q. Has the Company performed a CCOS study for this case?

A. Yes. The Company prepared two CCOS studies for this filing:

- Current Class Structure CCOS – Based on current rates and existing customer classifications.
- Proposed Class Structure CCOS – Reflecting changes to customer groupings based on the rate design proposals previously described, including revised maximum Demand Thresholds and adjustments to interval demand measurement (15-minute versus 30-minute).

Both studies are included in the direct filing. The Current Class Structure CCOS provides a baseline view of cost responsibility under current rates and serves as the primary basis for the Company's direct position. The Proposed Class Structure CCOS demonstrates how cost responsibility would change under the proposed class structure and reaffirms that the migration approach is reasonable.

Unless otherwise stated, all questions and answers in this testimony refer to both CCOS. Impacts and changes associated with the Proposed Class Structure will be addressed later in the testimony.

Q. Why did the Company prepare two CCOS studies?

A. The Company prepared separate CCOS studies to provide transparency and demonstrate how cost responsibility changes under the proposed class structure. This allows the Commission and stakeholders to compare present rates with the proposed design and understand the impact of structural changes.

Q. What Test Year was used, and under whose supervision was the study prepared?

A. The Test Year was July 1, 2024 through June 30, 2025. Both studies were prepared by Concentric Energy Advisors using Company-provided data under my direct supervision. A summary of the results is included in Schedules GAJ-06, GAJ-07, GAJ-08 and GAJ-09.

Q. Has the Company filed a CCOS in previous rate cases?

A. Yes. In all rate cases since 2005, the Company has filed a CCOS study. The methodologies used, described in further detail in this testimony, are consistent with the CCOS study methods used in the Company's last rate case in File No. ER-2022-0129.

Q. What classes are used as a basis for this CCOS study?

A. The primary classes analyzed are Residential, Small General Service, Medium General Service, Large General Service, Large Power Service, Electric Vehicle/CCN, and Lighting. A new sub class, Large Load Power Service, has been introduced into Large Power classes. This will be discussed further in the testimony.

Q. Do these classes conform to the proposed electric rate tariffs?

A. Generally, they do. The Residential class has different rate classifications available to it that include general use and time of use. The Small General Service, Medium General Service and Large General Service classes also currently have general usage rates and all electric rates, plus they can be specific to the voltage level at which the customer receives service. Similarly, the Large Power Service class is distinguished by the specific voltage at which the customer receives service.

Q. What is the guiding principle that you follow when performing a CCOS?

A. The fundamental principle underlying a CCOS is that cost allocation should follow cost causation. Cost causation addresses the question of which customer or group of customers causes the utility to incur particular types of costs. To answer this question, it is necessary to establish a relationship between the services used by a utility's customers and the particular costs incurred by the utility in providing services to those customers.

Q. What framework underlies the CCOS study and how was it developed?

A. The CCOS study follows the widely accepted embedded cost of service framework. An analysis was made of all cost elements as defined by FERC Uniform System of Accounts, including rate base and expense items for the purpose of allocating these items to the customer classes. To establish the cost responsibility of each customer class, a three-step analysis of the utility's total operating costs was undertaken. This framework consists of three primary steps: (1) cost functionalization; (2) cost classification; and (3) cost allocation:

- **Cost Functionalization** – Assigning costs to system functions such as production, transmission, distribution, and customer service.

- **Cost Classification** – Categorizing the functionalized costs as demand-related, energy-related, or customer-related.
- **Cost Allocation** – Distributing costs to customer classes using allocation factors derived from load research and system data, including coincident peak demand, non-coincident peak demand, energy usage, and customer counts or a weighted-customer basis.

This approach is consistent with industry standards and National Association of Regulatory Commissioners ("NARUC") guidelines, and it uses engineering and economic principles accepted by many regulatory commissions**.**

Q. How do the functional categories relate to the amount of costs incurred by the Company?

A. The Company's primary functional cost categories associated with distribution electric service include Production, Transmission, Distribution, and Customer Costs. Indirect costs that support these functions, such as General and Intangible Plant and Administrative and General Expenses, are allocated to functions using allocation factors related to plant and/or labor ratios. In some instances, the costs in an account are further split into separate functions or classifications if the costs in the account are incurred to perform more than one function, or the costs in an account can be said to vary significantly with respect to more than one factor. For example, the accounts for distribution system conductors and conduits have been separated into two functions: primary distribution and secondary distribution. While the Company has historically split these costs into primary and secondary voltage, further refinements were made in this case to isolate the single phase and three phase delineation associated with the primary distribution system. This sub functionalization helps to properly assign primary distribution and secondary distribution costs between primary voltage and secondary voltage customers.

Q. How are the classification categories related to the amount of costs incurred by the Company?

A. Costs classified as customer related are incurred to extend service to and attach a customer to the distribution system, meter any electric usage, and maintain the customer's account. Customer costs are largely a function of the number of customers served and continue to be incurred whether or not customers use any electricity. They may include capital costs associated with minimum size distribution systems, services, meters, and customer billing and accounting expenses. Demand-classified costs are capacity-related costs associated with plant that is designed, installed, and operated to meet maximum hourly or daily electric usage requirements, such as production plant, transmission lines, and substations. Demand costs are fixed in nature, and do not vary with the number of customers or the amount of energy that customers receive. In this case, the costs associated with the Company's transmission and distribution cost of service are fixed costs, which vary with the level of demand a customer class places on the system or the number of customers that are served by the system. These costs occur regardless of the number of kilowatt-hours (kWh) the Company sells. Energy-classified costs vary with the amount of kWh sold to customers, such as fuel costs. There are variable costs within the Company's CCOS.

Q. What is the process you followed to classify costs as Customer, Demand or Energy-related?

A. Typically, a determination on the classification of costs can be made simply by knowing the type of activities or assets that reside in a particular FERC account. In these instances, the account can be classified as either customer or demand. However, for some FERC account functions it is necessary to conduct classification studies to determine which portion of an account is associated with each classification. For example, secondary distribution costs are separated into demand and customer classifications.

Q. How are the allocation factors generally determined?

A. The Allocation factors were determined by analyzing the Company's electric system design, physical configuration and operations, its accounting records, and its system and customer load data. From this analysis, methods of direct assignment and common cost allocation methodologies were applied to the functionalized and classified plant and expense elements.

Q. Which allocation methods did you apply for major plant categories?

A. The Major plant categories are allocated in the CCOS as summarized below:

- Production Plant: Allocated using the Average & Excess Demand (A&E) method, incorporating a four coincident peak (4CP) component. Production plant is the largest cost component in the study, and the Company has used this method since 2018.
- Transmission Plant: Allocated using the Average & Excess Demand (A&E) method, incorporating a four coincident peak (4CP) component. The method for allocating transmission plant is consistent with that of production plant.
- Distribution Plant: Allocation varies by account:

- o Accounts 360–363: Demand-related and allocated using a Non-Coincident Peak (NCP) demand allocator based on class NCP demands.
- o Accounts 364–368: Include both demand and customer components. We use the minimum system method to split costs between demand and customer-related portions. Demand components are allocated using Class NCP allocators; customer components are allocated using a customer allocator.
- o Accounts 369–373: Allocated using a customer allocator. Services are considered customer-related and allocated based on the number of customers served at secondary voltage. Meter costs (Account 370) are also customer-related and are allocated using meter assignments to customer classes.

Q. How are O&M expenses allocated in the CCOS?

A. In general, these expenses were allocated on the basis of the cost allocation methods used for the Company's corresponding plant accounts. A utility's O&M expenses generally are thought to support the utility's corresponding plant in service accounts. Put differently, the existence of particular plant facilities necessitates the incurrence of operating cost, i.e., expenses by the utility to operate and maintain those facilities. As a result, the allocation basis used to allocate a particular plant account will be the same basis used to allocate the corresponding expense account. Administrative and General Expenses are allocated on the basis of functionalized and classified plant or labor expenses, depending on the type of expense. For example, property insurance is allocated on the same basis as plant in service, whereas employee pensions and benefits are allocated using payroll expenses as the basis.

Q. Why did the Company include the Large Load Power Service (LLPS) subclass in the CCOS study?

A. The LLPS tariff was approved by the Missouri Public Service Commission in December 2025.[5] The Company has included this subclass to reflect this recent development and begin the transition to a study inclusive of these customers. It is important to include this new subclass in the CCOS to ensure transparency in cost allocation and to implement revenue sharing mechanisms approved as part of the LLPS Rate Plan. Including LLPS will allow the Company to evaluate potential cost responsibility for customers who meet the tariff criteria.

Q. How did the Company develop the analysis for the Large Load Power Service (LLPS) subclass in the CCOS study?

A. To develop the analysis, the Company developed a proxy customer modeled off characteristics of the anticipated first LLPS customer to estimate usage and potential revenue as if the customer had been active during the Test Year. Fuel and revenue impacts were estimated for illustrative purposes; however, without an actual customer in the Test Year, it is too early to assume specific cost assets or finalize allocation factors for this subclass. This transitional approach provides an insight into how LLPS could affect class cost responsibility without prematurely assigning costs that are not yet incurred. Additionally, the Company estimated additional potential revenue that could be received from potential LLPS customers.

[5] EO-2025-0154, Report and Order, Issued 11/13/2025 and Effective 12/13/2025.

Q Please explain the impact of incorporating the Large Load Power Service subclass into the CCOS analysis?

A. The Company is not seeking recovery for any incremental fixed costs attributable to providing service to customers under the LLPS rate. The LLPS subclass is assigned the portion of the variable fuel costs associated with the anticipated LLPS energy usage. However, the Company has not assigned embedded demand-related costs to this class given that the expected level of demand the customer(s) taking service during the test period under this rate is still uncertain. Since this rate was only recently approved in late 2025, and customer(s) consumption is still in the ramp up phase, the customers(s) usage, demand and revenue patterns are not fully known or reliable. The Company believes it is appropriate to observe actual coincident and non-coincident peak demand levels for an entire 12-month test period before assigning the appropriate level of cost responsibility. Further, assigning demand costs based on an assumed level of annualized demand costs could result in a mismatch in the CCOS results if paired with revenues that are not annualized.

Given the partial assignment of costs to the LLPS subclass, for presentation purposes, the LLPS subclass is included within the LPS class in the CCOS class results. The Company has reviewed the LPS class returns at the subclass level for the purpose of determining the revenue allocation for the LPS class, as discussed further in the next section.

Q. What changes resulted from adding the Large Load Power Service subclass to the CCOS study?

A. The introduction of the LLPS subclass to the CCOS study has minimal impact on the class cost allocations, apart from assigning variable fuel costs to the LLPS subclass. The Company proposes to assign a portion of the LLPS revenues (approximately $3.8 million) as a premium that offsets the class cost responsibility of all other classes in the CCOS. This premium is allocated to the test revenue for each class in proportion to each class's share of Test Year revenues.

Q. How does the inclusion of the Large Load Power Service subclass influence cost allocation in the CCOS?

A. As previously discussed, only the fuel costs associated with the LLPS subclass have been allocated to that class. Absent the allocation of costs, such as demand-related costs, this analysis demonstrates the revenues from the LLPS class far exceed the variable cost of service to the LLPS subclass and therefore avoids any cross subsidization of these expenses to other classes that are associated with LLPS's share of overall load. Further, a portion of LLPS revenues is allocated across all other classes, providing a benefit to all existing rate customers in the form of incremental class revenue.

Q. What effect does the new Large Load Power Service subclass have on class cost responsibility in the CCOS?

A. All else equal, the application of the LLPS credit helps to lower the class cost responsibility by further offsetting a portion of their net revenue requirements that would not be otherwise covered by their current billed and other revenue contributions.

Q. What commitments from MO West ER-2024-0189 is the Company addressing in this testimony?

A. The company is addressing two commitments raised by intervenors in the prior proceeding. Specifically, my testimony addresses:

1. Fuel Allocation; and
2. Primary Single-Phase and Three-Phase Voltage Allocation

Commitment 1: Fuel Allocation

Q. Please describe the prior commitment related to Fuel Allocation.

A. As part of the MO West ER-2024-0189 rate case, the Company committed to include a fuel allocation similar to the E8760 allocator described by MECG, based on class hourly data, to the extent information is available and reliable, in the next EMW rate case. This commitment does not prevent any party from opposing this allocation approach.

Q. How did the Company perform the analysis for an hourly fuel allocator?

A. The Company developed an hourly fuel allocator by producing an 8,760-hour profile of fuel costs and allocating each hour's fuel cost to rate classes based on each class's load share for that hour. The hourly fuel costs were then summed by rate class to derive annual fuel costs, and the allocator was based on each class's proportional share of those annual fuel costs.

Q What were the results of the hourly fuel allocation analysis?

A. The analysis showed that less fuel cost is allocated to large loads at higher voltages because those loads receive a higher share of lower-cost hours and a lower share of higher-cost hours. However, the differences between the hourly fuel cost allocator and the monthly fuel cost allocator were only a relatively minor shift between C&I voltage levels, and a near zero impact to residential.

Q. What is the Company's recommendation regarding fuel allocation?

A. The Company recommends continuing to use the existing monthly fuel cost allocation. While the hourly analysis was performed as committed, the hourly approach introduces substantial modeling complexity and is highly sensitive to PROSYM fuel modeling inputs, which are often debated. Introducing additional layers of assumptions without a demonstrated material impact to class results does not support adoption at this time.

The Company will continue to evaluate potential refinements to fuel allocation methodologies in future cases; however, based on the results of this analysis, there is not sufficient evidence to warrant a change from the current monthly allocator.

Commitment 2: Primary Single-Phase and Three-Phase Voltage Allocation

Q. Please describe the commitment regarding Primary Single-Phase and Three-Phase Voltage Allocation.

A. In MO West ER-2024-0189, the Company agreed to evaluate whether the allocation of costs between primary single-phase and primary three-phase service appropriately reflects differences in facilities, usage characteristics, and cost to serve.

Q. How did the Company analyze cost allocation with respect to single-phase and three-phase utilization of the primary voltage distribution system?

A. To perform this allocation, the distribution conductor miles were split between primary and secondary voltages. Then the primary voltage conductor miles were further split between single-phase and three-phase configurations. A replacement cost (current dollars per mile) was estimated for single-phase primary, three-phase primary, and secondary conductors (both overhead and underground). The replacement cost estimates were then multiplied by the respective miles of conductors to compute a replacement cost of the distribution system conductors by voltage and phase configuration. This approach allows a consistent dollar basis to apportion the EMM actual per-book costs of conductors into conductors serving primary three-phase versus all other conductors, including primary single-phase and the secondary distribution system.

Q. What are your observations with respect to this proposed cost allocation approach?

A. This approach differentiates distribution system costs not only on the basis of primary and secondary voltage designation but also based on single-phase and three-phase configurations of the primary voltage system. The relevance of this differentiation is that while both single and three-phase primary circuit configurations are used to serve secondary customers, only the three-phase circuit configurations are used to serve customers at primary voltages. As a result of this differentiation, single-phase costs associated with the Company’s total miles of circuits are only allocated to secondary voltage customers.

Q. How does this change impact class cost responsibility within the CCOS study?

A. Single-phase primary costs that would otherwise have been allocated between primary and secondary classes are now allocated only amongst secondary customer classes. All else equal, this change results in less distribution costs allocable to primary customers for distribution system poles, towers and fixtures, and conductors and conduits. If the functional split were performed solely on the basis of voltage levels, the primary allocation would be 41.6% for overhead and 26.0% for underground. The Company’s analysis of incorporating a single-phase and three-phase allocator into the functional split reduces the primary allocation to 28.7% for overhead and 21.1% for underground, respectively.

Q. What is the Company's recommendation regarding the primary single-phase and three-phase voltage allocation?

A. The Company recommends delineating between single and three phase primary configurations, as this approach reflects cost causation by aligning cost allocations to customers with the infrastructure used to serve them. This change will continue to be monitored and reviewed for future Missouri rate cases to determine any refinement needs.

Q. What are the CCOS results for the Rate of Return under Present Rates and under Equalized Rates?

A. The overall jurisdictional rate of return at present rates is 4.90%. Individual customer classes earn different rates of return under current rates, as shown in Table 8. To achieve equalized rates of return of 7.65%, the classes should be adjusted by the percentages in the table below.

Table 8 – Current Class Structure CCOS Results

Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Lighting	CCN
Rate of Return by Customer Class at Present Rates						
0.51%	7.92%	8.43%	10.08%	14.73%	3.73%	-39.30%
Change Required to Achieve Equalized Rates by Customer Class						
52.3%	-1.3%	-3.7%	-10.4%	-23.4%	25.1%	369.7%

Q. What are the CCOS results for the Rate of Return under Proposed Class Structure Rates and under Equalized Rates?

A Under the Proposed Class Structure CCOS, the overall jurisdictional rate of return at present rates is 4.90%, while the individual customer classes rates of return under current rates vary somewhat from the Present Rate CCOS, as shown in Table 9. To achieve equalized rates of return of 7.65%, the Proposed class Structure revenues should be adjusted by the percentages in the table below.

Table 9 – Proposed Class Structure Rates CCOS Results

Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Lighting	CCN
Rate of Return by Customer Class at Present Rates						
0.51%	5.96%	7.57%	9.85%	15.89%	3.73%	-39.27%
Change Required to Achieve Equalized Rates by Customer Class						
52.3%	9.2%	0.4%	-9.5%	-26.9%	25.2%	369.0%

Q. How do the results of the two CCOS studies compare, and what does that indicate?

A. The proposed rate class structure impacts the SGS, MGS, LGS, and LPS customer classes. The Current Class Structure results indicate SGS and MGS require a small decrease to achieve equalized rates of return while LGS requires a more modest decrease and LPS a more pronounced decrease. The Proposed Class Structure results show similar results for LGS and LPS, however, suggests that SGS requires a moderate increase to achieve equalized rates of return. SGS requires a more moderate increase than MGS. This result is based on reasonable, but estimated, demand allocations for the proposed rate classes and should be monitored as actual CP and NCP data become available in the future.

Q. Is the Rate of Return at Current Rates within the Large Power class impacted by the inclusion of LLPS?

A. Yes. The inclusion of LLPS within the LPS class increases the relative return at current rates for the LPS class. However, as previously discussed, this does not factor in the share of fixed costs that could be apportioned in the future when LLPS customers begin taking service and the overall system demand is assessed. As expected, the CCOS study impacts of incorporating LLPS customers should be monitored as actual data becomes available in the future.

Q. What is the Company's proposed overall jurisdictional revenue requirement and the percentage increase by customer class?

A. The Company proposes an overall jurisdictional revenue requirement increase of 15.19%, or $140,353,035. As discussed earlier in my testimony, while the CCOS results provide valuable insight into relative cost responsibility, the Company is not basing class revenue increases directly on either the Current Class Structure or Proposed Class Structure CCOS. The Company respects the results of both studies; however, due to the factors described in the preceding section—particularly the evolving impacts of LLPS on cost allocation and revenue credit relationships, the Company believes it is more appropriate in this case to apply an equal percentage increase across all classes. The proposed class-specific percentage increases are presented and discussed further in the Revenue Allocation section below.

IV. Revenue Allocation

Q. Are you sponsoring the electric tariffs filed in this case?

A. Yes, I am.

Q. How do you propose the revenue allocation be applied by class?

A. In this case, Evergy is proposing to increase all classes by 15.19%.

Q. Please describe the decision to equally increase classes.

A. The Company acknowledges that the Class Cost of Service Study results indicate a significant revenue deficiency in the Residential class, which would typically support shifting revenue responsibility between classes to better align revenues with costs. However, the Company believes it is premature to implement such shifts at this time for four primary reasons:

1. LLPS Transition – Revenues and Costs Are Not Yet Established

No LLPS customer was active during the Test Year; all LLPS activity is pro forma and could occur late in the true-up period. Because LLPS represents a new and uniquely large subclass of customers, its actual cost and revenue contribution remain uncertain. Implementing inter-class revenue shifts before LLPS customers are operational would introduce unnecessary risk and could result in misalignment once actual data becomes available.

2. Incomplete Cost Allocation for LLPS

For CCOS purposes, LLPS was allocated fuel-related costs, but no other cost components were assigned, given the absence of actual customers. The Company intends to maintain LLPS's relationship with the Large Power Service (LPS) class until sufficient operational data is available to support a comprehensive cost allocation. This is consistent with the LLPS tariff settlement in docket EO-2025-0154. Making structural revenue alignment changes without a fully developed cost basis would be inappropriate and inconsistent with cost causation principles.

3. LLPS Revenue Credit to Other Classes

The Company has already incorporated a pro forma LLPS revenue credit of $3,834,861, distributed among other classes based on their proportional contribution to test-year revenues. As LLPS customers ramp up, this credit is expected to grow, exerting downward pressure on revenue deficiencies in other classes. This mechanism provides a transitional benefit to existing classes and mitigates the need for immediate inter-class revenue shifts.

Per the settlement agreement from Evergy's Missouri LLPS tariff case (EO-2025-0154), LLPS still remains under the "initial pricing" requirement. Until there is at least one LLPS customer over 75MW the LLPS rates will maintain their relationship to LPS.

4. Rate Design Proposals

The company has proposed a number of rate design changes simultaneously impacting the Commercial and Industrial customer classes including the distribution of which customers belong to which classes. With the exception of SGS and MGS, the CCOS results for current class and proposed class are consistent; however, any moves in revenue allocation at this time would be relying on behavior and billing determinants existing in the current composition. It is prudent to reassess revenue allocations for the proposed class structure after customers reactions to updated price signals and resulting actual determinants and cost allocation data are observed.

Considering these factors, the Company believes a cautious approach is warranted. Maintaining the current revenue allocation will minimize rate shock, preserve transparency, and allow for informed adjustments once LLPS operations mature and rate design changes are fully incorporated.

Q. In a typical case, what would a more traditional revenue allocation have looked like?

A. If not for the identified considerations, the Company would have proposed making some alignment moves between classes prioritizing gradualism. A hypothetical scenario might have reasonably been as shown in Table 10. This is fitting with past practice of taking positively correlated moves towards the equalized rate of return in the CCOS while maintaining consideration for gradualism.

<u>Table 10</u>

	Jurisdiction % Increase(A)	Revenue Shift %(B)	Traditional % (C)
LPS	15.19	93.07	14.14
LGS	15.19	93.07	14.14
SGS	15.19	96	14.58
MGS	15.19	96	14.58
RES	15.19	108.55	16.49
CCN	15.19	108.55	16.49
Lighting	15.19	108.55	16.49

Economic Development Rider

Q. What is the Economic Development Rider?

A. The Economic Development Rider is a provision designed to encourage business growth and job creation within the Company's service territory. It provides qualifying commercial and industrial customers with discounted electric rates to support new or expanded operations. The rider aligns with state economic development objectives by making energy costs more competitive for businesses considering investment in Missouri.

Q. What is the statutory basis for the Economic Development Rider?

A. The Economic Development Rider is authorized under Missouri law, specifically Section 393.355, RSMo, which permits electric utilities to offer economic development incentives through Commission-approved tariffs.

Q. Is the discount from EDR included in the overall revenue requirement?

A. In the Test Year, EDR Credits totaled $651,723.

Q. How should the cost of the Economic Development Rider discount be recovered among customer classes?

A. The discount provided under the Economic Development Rider is recovered through the utility's general rate structure, allocated across all customer classes in proportion to their share of jurisdictional revenue responsibility. This approach ensures compliance with Section 393.355, RSMo, which authorizes utilities to offer economic development incentives through Commission-approved tariffs while maintaining fairness and avoiding undue discrimination among classes.

1. The statute and Commission precedent emphasize that economic development programs serve a broad public interest by promoting job creation and capital investment. Therefore, recovery of the discount is treated as a system-wide cost, similar to other public policy programs, rather than being assigned solely to the benefiting customer or class. This method aligns with cost-of-service principles and Commission policy by preserving rate equity among classes.

2. Avoiding rate shock for any single group.

3. Recognizing that all customers benefit indirectly from economic growth and increased load, which helps stabilize rates over time.

Q. Does EDR have any other impact on the overall revenue requirement ?

A. Yes. When applying the requested increase to current rates, a proof of revenue is performed ensuring that the determinants provided would recover the revenue requirement. Due to the EDR discounts being a reduction in recovered revenue, the amount of EDR discounts provided must be grossed up for the acknowledgement of the new revenue requirement. Grossing this up for the revenue requirement equates to an additional $99,000 in revenue that must be applied to the final determinants in order to net back to $140,353,035 when final determinants are applied the new rates.

Proposed Rates

Q. How is the revenue increase applied to individual rate components?

A Proposed rates are generally the result of an equal increase across components with the exception of the following:

1. Consistent with identified moves towards alignment, the increase for commercial and industrial classes prioritizes the facilities charges resulting from the CCOS.
2. Peak adjustment charge and credit are maintained at $.01/kWh for establishment of the new structure.
3. Lighting applies a weighted increase to non-LED components in an effort to align price signals with technological efficiencies.

The full schedule of proposed rates is included as GAJ-11.

Q. What is the rationale for an equal increase across components?

A. Generally, this case represents a transition period towards jurisdictional alignment and preparation for coming LLPS activity. There are a number of rate design changes occurring simultaneously across non-residential classes and identified changes in cost allocation from a new class of customers. The desire to prioritize rate stability in this environment is an effort to avoid cost alignment prematurely. By largely applying an equal increase there is a less likely chance that future changes will undo action taken today or cause customer confusion/price volatility.

Q. What is the proposed Residential customer charge?

A. Current Residential customer charge is $12.00. The Company is proposing an increase of $1.82 to a new rate of $13.82. This is an increase of 15.17%. Per the CCOSS results Residential customer costs would suggest a customer charge of $18.33 is appropriate for purely cost driven rates. We will continue to make gradual moves towards aligning customer charge to costs however at this time no disproportional move is made to shift revenue to customer charge.

Net Margin Rates

Q. Are Net Margin Rates included in this filing?

A. Yes. Schedule GAJ-12 includes calculated net margin rates based on the proposed rates in this filing.

Q. Is the inclusion of Net Margin Rates calculation in direct something new for this case?

A. Yes, traditionally net margin rates are updated as an end of case process. This would not be filed until the conclusion of the case and final rates are determined. In the most recent Evergy Missouri West rate case a term of the settlement agreement stated "EMW shall provide net margin rate calculations, as applicable, in any future rate case, in operable spreadsheets, explained in its direct testimony." This is not a direct commitment for Missouri Metro however the Company is making a proactive effort to accommodate this request.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Evergy Metro, Inc. d/b/a Evergy Missouri Metro's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2026-0143

AFFIDAVIT OF GRAHAM A. JAYNES

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

Graham A. Jaynes, being first duly sworn on his oath, states:

1. My name is Graham A. Jaynes. I work in Kansas City, Missouri and I am employed by Evergy Metro, Inc. as Manager – Regulatory Affairs.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Evergy Missouri Metro consisting of fifty-four (54) 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.

Graham A. Jaynes

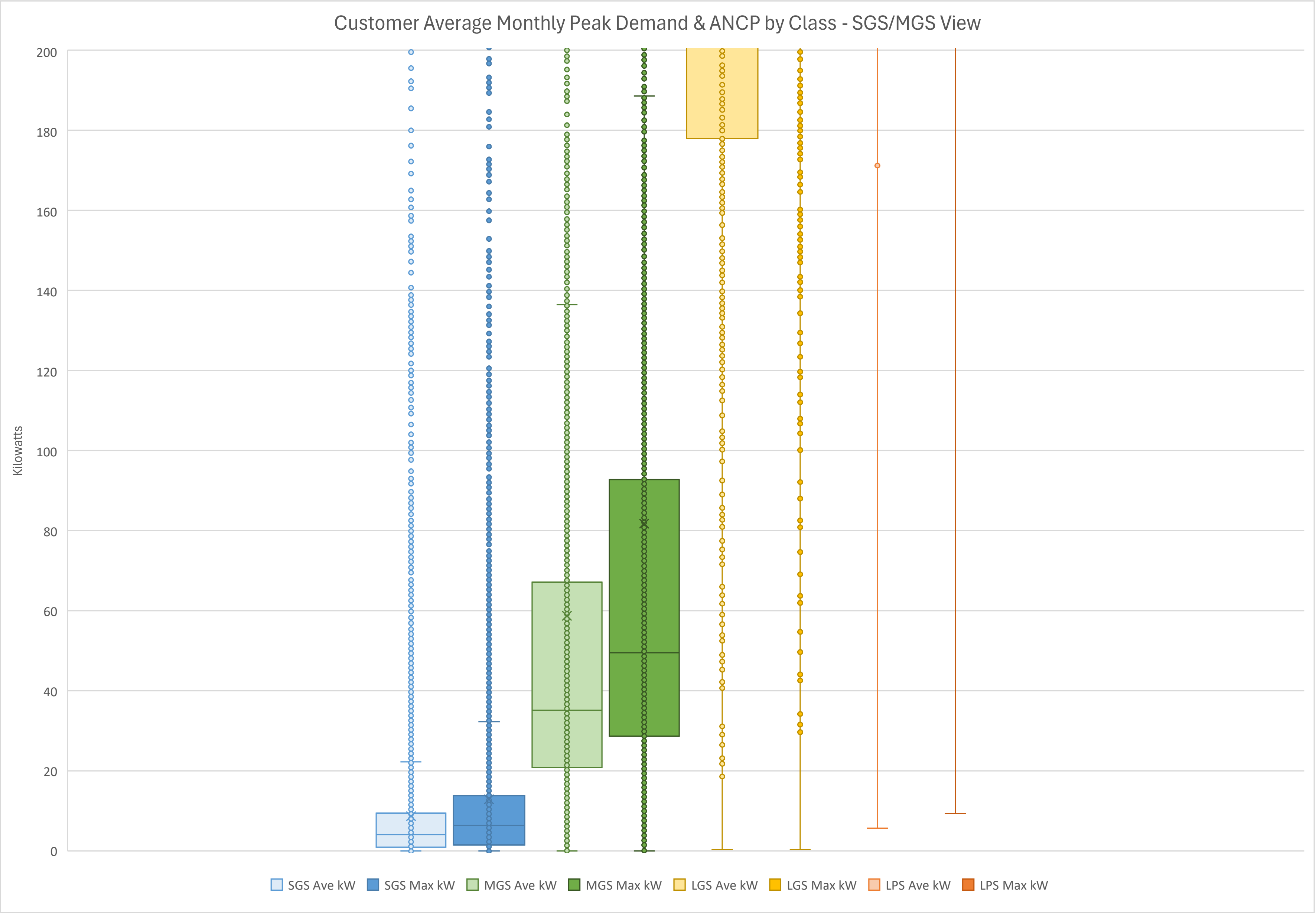
Subscribed and sworn before me this 6th day of February 2026.

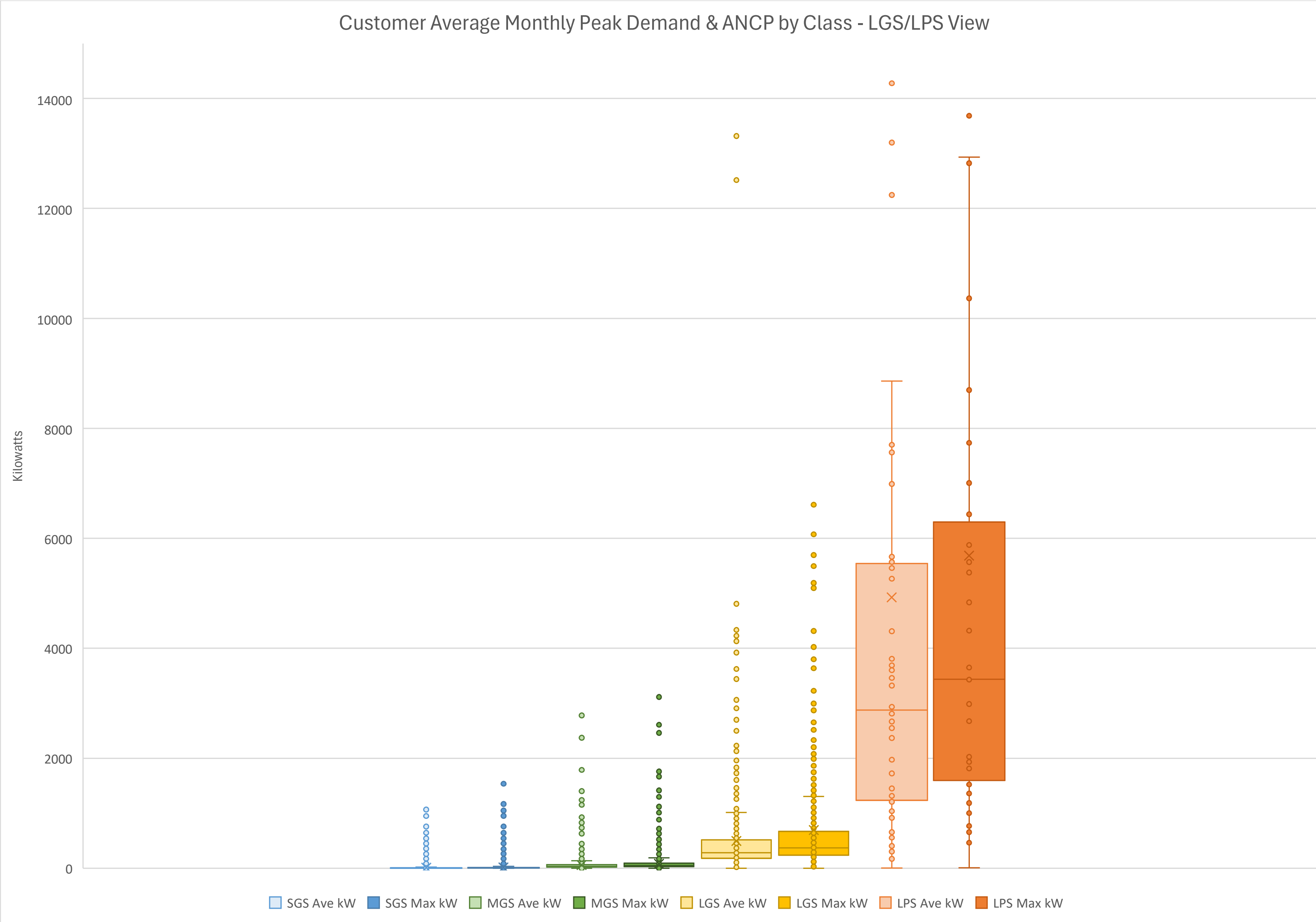
Notary Public

My commission expires: April 26, 2029

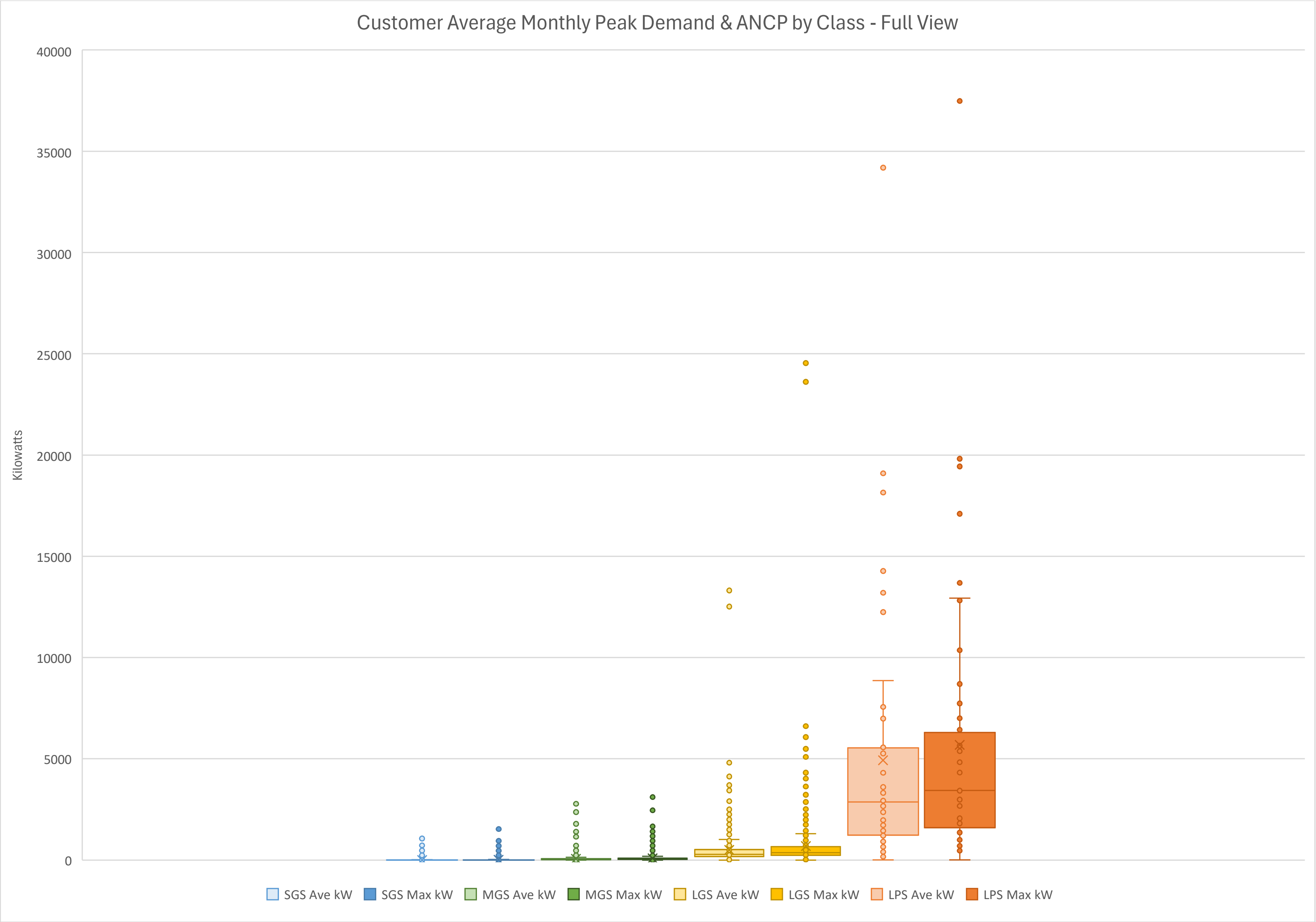
ANTHONY R WESTENKIRCHNER
NOTARY PUBLIC - NOTARY SEAL
STATE OF MISSOURI
MY COMMISSION EXPIRES APRIL 26, 2029
PLATTE COUNTY
COMMISSION #17279952

Rate Code	Bill Count	Customer Charge Count	kWh	kWh per Bill Count	kWh per Customer Charge Count	Difference	Percent Difference
1RS1A	30.09	29.60	36,845.23	1,224.67	1,244.90	20.23	1.64%
1RPKA	238,615.71	237,735.94	206,453,930.70	865.22	868.42	3.20	0.37%
1RPKALIS	15.49	15.53	12,347.57	797.05	794.85	2.19	0.28%
1RPKANM	3,675.60	3,673.80	2,394,185.62	651.37	651.69	0.32	0.05%
1RPKAS	482.27	484.46	352,220.13	730.33	727.03	3.30	0.45%
1RTOU	5,192.20	5,188.41	4,101,524.40	789.94	790.52	0.58	0.07%
1RTOU2	18,496.06	18,501.15	170,163,419.43	9,199.98	9,197.45	2.53	0.03%
1RTOU3	9,355.86	9,353.59	7,724,085.57	825.59	825.79	0.20	0.02%
1RTOUEV	10.80	10.88	31,438.59	2,912.10	2,888.76	23.34	0.80%
1SGSE	26,625.91	26,595.04	35,264,039.78	1,324.43	1,325.96	1.54	0.12%
1SGSES	1.01	1.01	1,006.36	1,000.06	1,000.06	-	0.00%
1SGSEW	0.75	0.75	2,717.17	3,602.12	3,602.12	-	0.00%
1SGSF	45.83	45.56	146,235.13	3,190.88	3,209.68	18.79	0.59%
1SUSE	1,205.97	1,205.95	553,391.65	458.88	458.89	0.01	0.00%
1MGSE	5,087.13	5,090.30	92,833,811.27	18,248.74	18,237.41	11.33	0.06%
1MGSF	39.59	39.56	4,657,558.98	117,641.55	117,737.15	95.59	0.08%
1LGSE	821.25	821.35	132,691,306.10	161,571.98	161,552.37	19.61	0.01%
1LGSF	90.36	90.02	35,555,236.65	393,495.12	394,954.21	1,459.09	0.37%
1LGSFP	1.02	1.02	294,382.77	288,595.91	288,595.91	-	0.00%
1EVC	408	N/A	2,024,452.86	4,961.89	N/A	N/A	N/A
1BEV	4.50	4.58	32,560.58	7,235.68	7,117.07	118.62	1.65%
1ETS	0.67	0.65	17,513.70	26,270.54	26,829.61	559.06	2.11%


Customer Average Monthly Peak Demand & ANCP by Class - SGS/MGS View
Kilowatts
200
180
160
140
120
100
80
60
40
20
0
SGS Ave kW
SGS Max kW
MGS Ave kW
MGS Max kW
LGS Ave kW
LGS Max kW
LPS Ave kW
LPS Max kW

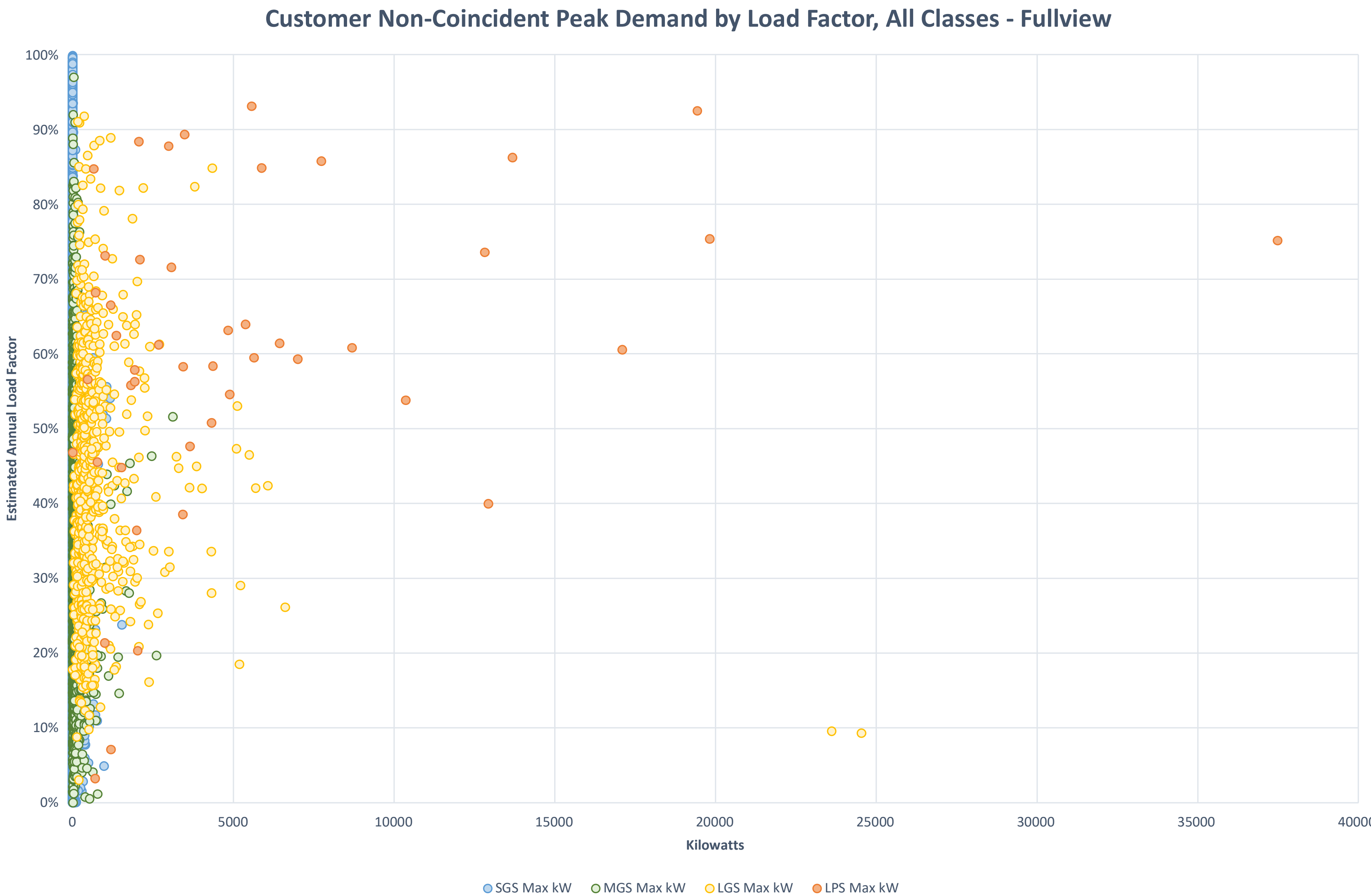


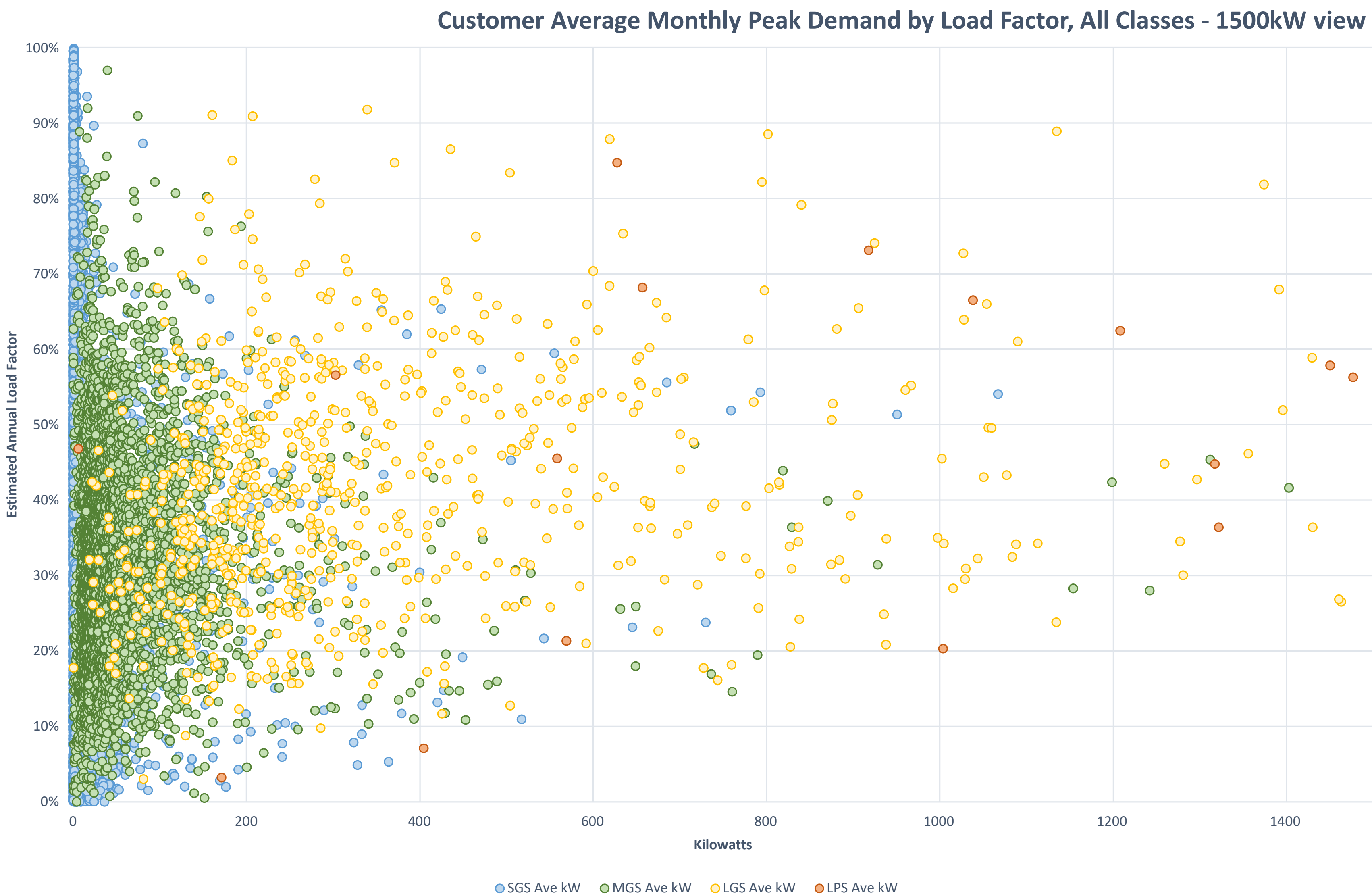
Customer Average Monthly Peak Demand & ANCP by Class - LGS/LPS View
Kilowatts
14000
12000
10000
8000
6000
4000
2000
0
SGS Ave kW
SGS Max kW
MGS Ave kW
MGS Max kW
LGS Ave kW
LGS Max kW
LPS Ave kW
LPS Max kW



Customer Average Monthly Peak Demand & ANCP by Class - Full View
Kilowatts
40000
35000
30000
25000
20000
15000
10000
5000
0
SGS Ave kW
SGS Max kW
MGS Ave kW
MGS Max kW
LGS Ave kW
LGS Max kW
LPS Ave kW
LPS Max kW


Customer Non-Coincident Peak Demand by Load Factor, All Classes - 1500kW view
Estimated Annual Load Factor
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
200
400
600
800
1000
1200
1400
Kilowatts
SGS Max kW
MGS Max kW
LGS Max kW
LPS Max kW


Customer Non-Coincident Peak Demand by Load Factor, All Classes - Fullview
Estimated Annual Load Factor
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
5000
10000
15000
20000
25000
30000
35000
40000
Kilowatts
SGS Max kW
MGS Max kW
LGS Max kW
LPS Max kW


Customer Average Monthly Peak Demand by Load Factor, All Classes - 1500kW view
Estimated Annual Load Factor
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
200
400
600
800
1000
1200
1400
Kilowatts
SGS Ave kW
MGS Ave kW
LGS Ave kW
LPS Ave kW

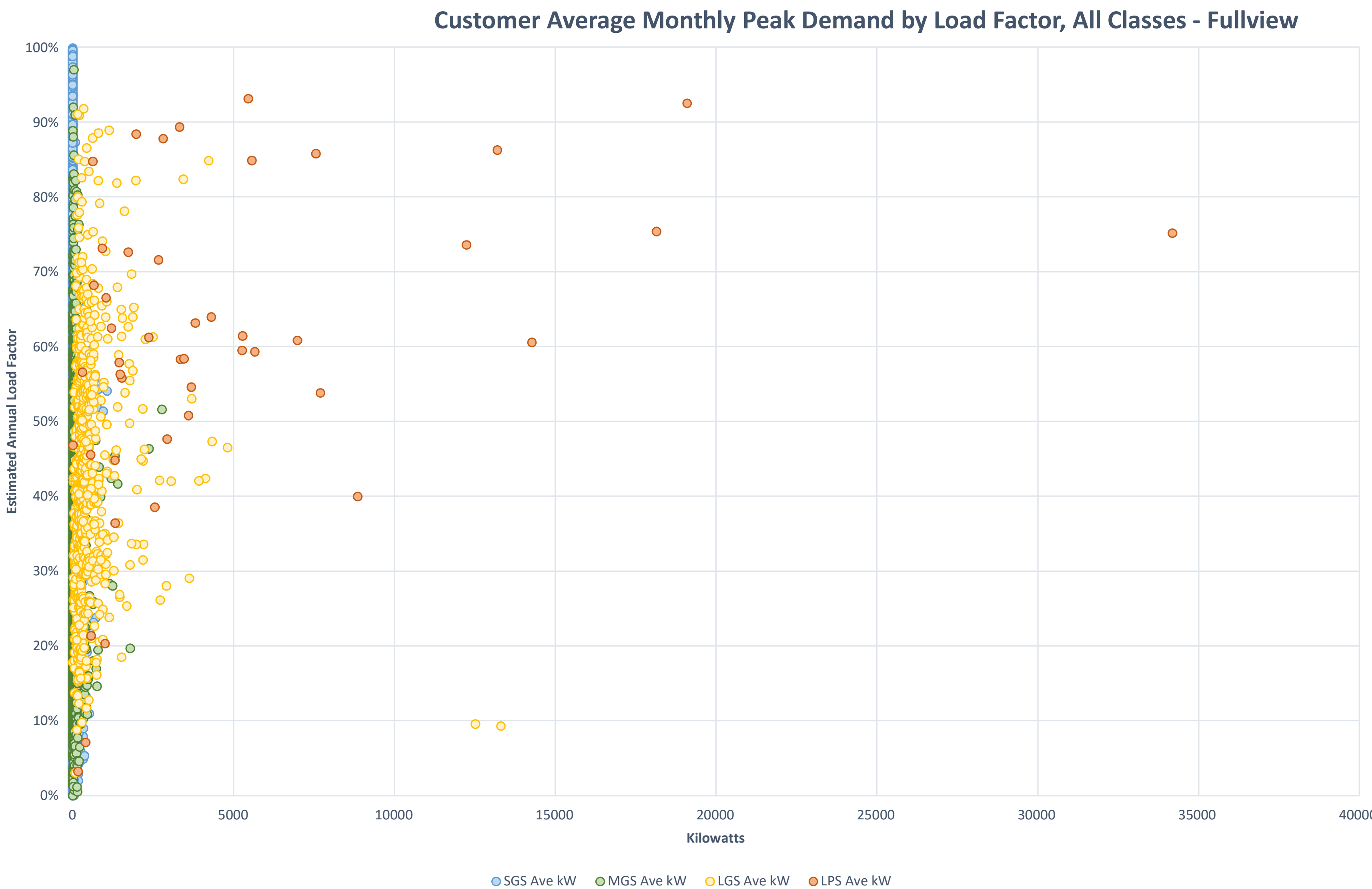

Customer Average Monthly Peak Demand by Load Factor, All Classes - Fullview
Estimated Annual Load Factor
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
5000
10000
15000
20000
25000
30000
35000
40000
Kilowatts
SGS Ave kW
MGS Ave kW
LGS Ave kW
LPS Ave kW

Table 1

Net Impacts to Class Sizes MO Metro C&I Classes					
	Under EKC Thresholds				
Classes	**Maximum**	**Current Class Size**	**New Class Size**	**Class Size Δ**	**Δ%**
SGS	300	30,239	35,906	5,667	18.74%
MGS	1,500	5,543	710	(4,833)	87.19%
LGS	25,000	908	119	(789)	86.89%
LPS		46	1	(45)	97.83%
		36,736	36,736	11,334	

Table 2

Impacted Individual Customers by Class MO Metro C&I Customers					
	Under EKC Thresholds				
Classes	**Maximum**	**Current Customer Count**	**Stay**	**Impacted Count**	**Impacted %**
SGS	300	30,239	30,148	91	0.30%
MGS	1,500	5,543	140	5,403	97.47%
LGS	25,000	908	75	833	91.74%
LPS		46	1	45	97.83%
		36,736	30,364	6,372	17.35%

Evergy Kansas Central max thresholds: SGS - 300kW, MGS - 1,500kW, LGS - 25,000kW

Table 1

Net Impacts to Class Sizes MO Metro C&I Classes					
		Under EKM Thresholds			
Classes	**Maximum**	**Current Class Size**	**New Class Size**	**Class Size Δ**	**Δ%**
SGS	30	30,239	29,958	(281)	0.93%
MGS	200	5,543	5,508	(35)	0.63%
LGS	1000	908	1,083	175	19.27%
LPS		46	187	141	306.52%
		36,736	36,736	632	

Table 2

Impacted Individual Customers by Class MO Metro C&I Customers					
		Under EKM Thresholds			
Classes	**Maximum**	**Current Customer Count**	**Stay**	**Impacted Count**	**Impacted %**
SGS	30	30,239	28,246	1,993	6.59%
MGS	200	5,543	3,496	2,047	36.93%
LGS	1000	908	642	266	29.30%
LPS		46	35	11	23.91%
		36,736	32,419	4,317	11.75%

Evergy Kansas Metro Max Thresholds: SGS - 30kW, MGS - 200kW, LGS - 1,000kW

Table 1

Net Impacts to Class Sizes MO Metro C&I Classes					
		Under Proposed Thresholds			
Classes	**Maximum**	**Current Class Size**	**New Class Size**	**Class Size Δ**	**Δ%**
SGS	31	30,239	30,150	(89)	0.29%
MGS	250	5,543	5,567	24	0.43%
LGS	3000	908	970	62	6.83%
LPS		46	49	3	6.52%
		36,736	36,736	178	

Table 2

Impacted Individual Customers by Class MO Metro C&I Customers					
		Under Proposed Thresholds			
Classes	**Maximum**	**Current Customer Count**	**Stay**	**Impacted Count**	**Impacted %**
SGS	31	30,239	28,348	1,891	6.25%
MGS	250	5,543	3,531	2,012	36.30%
LGS	3000	908	608	300	33.04%
LPS		46	25	21	45.65%
		36,736	32,512	4,224	11.50%

Demand per Customer															
	July 2024	August 2024	September 2024	October 2024	November 2024	December 2024	January 2025	February 2025	March 2025	April 2025	May 2025	June 2025	Average	Customer Count	Weighted Average
1MGSE	1.02	1.02	0.96	0.97	1.01	1.01	1.07	1.03	0.97	1.03	1.05	1.11	1.02	5,230.00	0.83
1MGSF	1.03	0.98	1.01	0.99	1.10	0.99	1.05	1.00	0.78	1.01	1.10	1.08	1.01	25.00	0.00
1MGAE	1.00	1.11	0.96	1.17	1.18	1.02	1.10	1.02	0.85	0.98	1.01	1.03	1.04	265.00	0.04
1MGAF	0.89	1.57	0.62	1.44	0.99	1.09	1.13	1.03	0.39				1.02	1.00	0.00
1LGSE	1.00	0.99	0.96	1.12	0.98	0.97	1.03	1.01	0.94	1.01	1.02	1.07	1.01	700.00	0.11
1LGSF	0.95	0.98	0.94	1.10	0.92	0.99	1.08	1.00	0.99	1.04	1.00	1.13	1.01	84.00	0.01
1LGSFP	0.92	1.01	1.05	1.01	1.04	1.03	1.03	1.02	0.77	1.12	1.00	1.09	1.01	1.00	0.00
1LGAE	1.06	1.00	1.00	1.23	1.20	1.08	1.15	1.02	0.85	0.97	1.00	1.06	1.05	113.00	0.02
1LGAF	1.25	0.96	0.79	1.03	1.17	1.01	1.10	1.05	0.84	1.00	0.98	1.10	1.02	10.00	0.00
1PGSE	0.99	0.99	0.95	0.92	0.95	0.91	1.04	1.08	1.06	1.01	1.04	1.10	1.00	13.00	0.00
1PGSF	1.03	0.99	0.96	1.02	0.97	0.97	1.01	1.03	1.01	1.04	1.06	1.13	1.02	24.00	0.00
1PGSV	1.03	0.99	1.00	0.94	0.99	1.02	1.02	1.02	1.02	1.03	1.01	1.00	1.01	1.00	0.00
1PGSZ	1.74	1.69	0.67	0.93	0.97	1.01	1.11	1.06	0.95	0.96	0.97	0.98	1.08	3.00	0.00
TOTAL AVERAGE													1.02319	6,470.00	1.02086

Demand per Customer															
	July 2024	August 2024	September 2024	October 2024	November 2024	December 2024	January 2025	February 2025	March 2025	April 2025	May 2025	June 2025	Average	Customer Count	Weighted Average
1MGSE	1.02	1.02			1.01	1.01	1.07	1.03		1.03	1.05		1.03	5,230.00	0.83
1MGSF	1.03		1.01		1.10		1.05	1.00		1.01		1.08	1.04	25.00	0.00
1MGAE	1.00					1.02	1.10	1.02			1.01	1.03	1.03	265.00	0.04
1MGAF						1.09		1.03					1.06	1.00	0.00
1LGSE							1.03	1.01		1.01	1.02	1.07	1.03	700.00	0.11
1LGSF							1.08	1.00		1.04	1.00		1.03	84.00	0.01
1LGSFP		1.01	1.05	1.01	1.04		1.03	1.02			1.00	1.09	1.03	1.00	0.00
1LGAE	1.06	1.00				1.08		1.02				1.06	1.05	113.00	0.02
1LGAF				1.03		1.01		1.05					1.03	10.00	0.00
1PGSE							1.04	1.08	1.06		1.04		1.05	13.00	0.00
1PGSF	1.03			1.02			1.01	1.03	1.01	1.04	1.06		1.03	24.00	0.00
1PGSV	1.03		1.00			1.02	1.02	1.02	1.02	1.03	1.01	1.00	1.02	1.00	0.00
1PGSZ						1.01		1.06					1.03	3.00	0.00
TOTAL AVERAGE													1.03533	6,470.00	1.03042

Options to Replace Evergy Missouri Metro's Hours Use Rates for Commercial and Industrial Customers

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TABLE OF CONTENTS

Executive Summary

Evergy engaged The Brattle Group to develop, evaluate, and recommend rate design options to replace the existing Hours Use rate that is currently applicable to commercial and industrial (C&I) customers its Missouri Metro jurisdiction.

The existing Hours Use rate was designed to promote efficient utilization of Evergy's energy infrastructure, but its complexity limits customer understanding and engagement. More transparent and actionable price signals can help customers align their consumption patterns with their preferences while providing the Company with an additional tool to manage an increasingly dynamic power system. Importantly, well-structured rate designs also advance cost causation principles by aligning more closely what customers pay with the costs that they impose on the system.

We began our analysis with a targeted review of C&I tariffs from jurisdictions across the United States, together making up a broad menu of potential rate design options. We then established a set of evaluation metrics and assessed each rate design option's performance against them. This screening process resulted in a short list of alternatives suitable to replace the Hours Use rate structure. These shortlisted options were then advanced for further development and analysis. They include:

1. A rate with a seasonal, flat volumetric energy charge;
2. A rate with a seasonal, flat volumetric energy charge + a full on-peak demand charge;
3. A rate with a seasonal, flat volumetric energy charge + a partial on-peak demand charge[1];
4. A rate with a seasonal, flat volumetric energy charge + a partial non-coincident demand charge;
5. A rate with a time-of-use (TOU) energy charge and no demand charge; and
6. A rate with a TOU energy charge and an on-peak demand charge.

[1] In our report, a "full" demand charge recovers all relevant capacity costs through the demand charge, whereas a "partial" demand charge recovers only a portion of those costs, with the rest being recovered through other charges.

For the non-TOU options, we applied a Peak Adjustment charge to the energy charge in the peak period of the summer, and a Peak Adjustment credit to the energy charges during the summer and winter super-off-peak periods, to reflect intraday variations in electricity prices. After designing the shortlisted options, we evaluated them against the Hours Use rate across several metrics, including cost reflectivity, strength of price signals for customer response, and overall simplicity and transparency (see Figure 1 below). In addition, we also examined the impacts of customer bills when transitioning from the Hours Use rate to the alternative rate options (see Figures 2 to 5 below).[2]

The resulting assessment informs our recommended replacements for the Hours Use charge for each C&I rate class.

FIGURE 1: EVALUATION OF REPLACEMENT OPTIONS ACROSS VARIOUS CRITERIA

	Cost Reflective	Valuable Price Response	Simple & Transparent
0. Existing (Hours Use)	■■■	■■■	■
1. Seasonal, Flat Volumetric Energy Charge (No Demand)	■■	■	■■■■■
2. Seasonal Volumetric Energy + On-Peak Demand	■■■■	■■■■■	■■■■
3. Seasonal Volumetric Energy + Partial On-Peak Demand	■■■■	■■■■■	■■■■
4. Seasonal Volumetric Energy + Partial Non-Coincident Demand	■■■	■■■■	■■■■
5. TOU Energy (No Demand)	■■■■	■■■	■■■■
6. TOU Energy + Partial On-Peak Demand	■■■■■	■■■■■	■■■■

■ = Least Favorable

■■■■■ = Most Favorable

2 We designed the alternative rate options to be seasonally revenue neutral to Evergy's updated Hours Use rates using customer-specific AMI load data. We developed rates for each voltage level with data for existing customers within the four rate classes: SGS, MGS, LGS, and LPS.

FIGURE 2: EVALUATION OF HOURS USE ALTERNATIVES FOR SGS

	Stability: Mitigates Extreme Bill Impacts		Stability: Produces Majority Bill Savings	
	% of customers w/ bill increases >10%	Bill increase for 95th percentile non-benefitter	% of customers w/ bill savings	Non-benefitters avg bill increase %
0. Existing (Hours Use)	n/a	n/a	n/a	n/a
1. Seasonal, Flat Volumetric Energy Charge (No Demand)	15%	19%	60%	9%
2. Seasonal Volumetric Energy + On-Peak Demand	29%	82%	57%	38%
3. Seasonal Volumetric Energy + Partial On-Peak Demand	15%	33%	57%	14%
4. Seasonal Volumetric Energy + Partial Non-Coincident Demand	16%	38%	57%	16%
5. TOU Energy (No Demand)	13%	17%	67%	9%
6. TOU Energy + Partial On-Peak Demand	15%	34%	58%	15%

= Least Favorable

= Most Favorable

Note: Please refer to the Appendix for bill impact evaluation of alternatives for each voltage level.

FIGURE 3: EVALUATION OF HOURS USE ALTERNATIVES FOR MGS

	Stability: Mitigates Extreme Bill Impacts		Stability: Produces Majority Bill Savings	
	% of customers w/ bill increases >10%	Bill increase for 95th percentile non-benefitter	% of customers w/ bill savings	Non-benefitters avg bill increase %
0. Existing (Hours Use)	n/a	n/a	n/a	n/a
1. Seasonal, Flat Volumetric Energy Charge (No Demand)	7%	11%	68%	6%
2. Seasonal Volumetric Energy + On-Peak Demand	36%	79%	40%	26%
3. Seasonal Volumetric Energy + Partial On-Peak Demand	13%	27%	43%	8%
4. Seasonal Volumetric Energy + Partial Non-Coincident Demand	13%	28%	57%	10%
5. TOU Energy (No Demand)	4%	9%	66%	5%
6. TOU Energy + Partial On-Peak Demand	13%	27%	39%	8%

= Least Favorable

= Most Favorable

FIGURE 4: EVALUATION OF HOURS USE ALTERNATIVES FOR LGS

	Stability: Mitigates Extreme Bill Impacts		Stability: Produces Majority Bill Savings	
	% of customers w/ bill increases >10%	Bill increase for 95th percentile non-benefitter	% of customers w/ bill savings	Non-benefitters avg bill increase %
0. Existing (Hours Use)	n/a	n/a	n/a	n/a
1. Seasonal, Flat Volumetric Energy Charge (No Demand)	■■■ 10%	■■■■■ 13%	■■■■■ 66%	■■■■■ 8%
2. Seasonal Volumetric Energy + On-Peak Demand	■ 24%	■ 52%	■■■ 44%	■■ 19%
3. Seasonal Volumetric Energy + Partial On-Peak Demand	■■■■■ 6%	■■■■■ 12%	■■■ 48%	■■■■■ 6%
4. Seasonal Volumetric Energy + Partial Non-Coincident Demand	■■■■■ 5%	■■■■■ 12%	■■■■ 56%	■■■■■ 6%
5. TOU Energy (No Demand)	■■■■ 8%	■■■■■ 12%	■■■■■ 66%	■■■■■ 7%
6. TOU Energy + Partial On-Peak Demand	■■■■■ 6%	■■■■■ 12%	■■■ 47%	■■■■■ 6%

■ = Least Favorable

■■■■■ = Most Favorable

FIGURE 5: EVALUATION OF HOURS USE ALTERNATIVES FOR LPS CUSTOMERS

	Stability: Mitigates Extreme Bill Impacts		Stability: Produces Majority Bill Savings	
	% of customers w/ bill increases >10%	Bill increase for 95th percentile non-benefitter	% of customers w/ bill savings	Non-benefitters avg bill increase %
0. Existing (Hours Use)	n/a	n/a	n/a	n/a
1. Seasonal, Flat Volumetric Energy Charge (No Demand)	■■■■ 6%	■■■■ 10%	■■■■ 75%	■■■■ 7%
2. Seasonal Volumetric Energy + On-Peak Demand	■ 31%	■ 50%	■■■■ 63%	■ 30%
3. Seasonal Volumetric Energy + Partial On-Peak Demand	■■■■■ 0%	■■■■■ 3%	■■■■■ 81%	■■■■■ 3%
4. Seasonal Volumetric Energy + Partial Non-Coincident Demand	■■■■■ 0%	■■■■■ 3%	■■■■■ 81%	■■■■■ 3%
5. TOU Energy (No Demand)	■■■■ 6%	■■■■ 10%	■■■■■ 75%	■■■■ 7%
6. TOU Energy + Partial On-Peak Demand	■■■■■ 0%	■■■■■ 3%	■■■■■ 81%	■■■■■ 3%

■ = Least Favorable

■■■■■ = Most Favorable

Based on our analysis, we recommend replacing the current Hours Use structure for all C&I customers (i.e., small, medium, and large customers), with the rate that includes a seasonal, flat volumetric energy charge and a partial on-peak demand charge (Option 3 from the list above). Some utilities develop different default rates for small commercial and industrial (C&I) customers who can lack the tools or flexibility to actively manage energy usage; however, given the relatively mild bill impacts across small C&I customers, we recommend developing a consistent rate structure across all classes.

Balancing cost-reflectivity and simplicity, our recommended Hours Use replacement rate is designed to recover demand-related costs associated with peak system hours through an on-peak demand charge while recovering remaining costs through a seasonal flat volumetric charge. It also provides customers with specific actionable price signals to reduce electricity consumption during the system peak period. Further, relative to the Hours use rate structure, customers are not required to understand their load factor at any given moment or perform additional calculations to manage their usage and their bills. The recommended rate structure also produces more stable and favorable bill impacts, with fewer customers experiencing extreme bill change when transitioning from the existing Hours Use rate than would occur with some of the other rate options considered in our analysis.

Additionally, we recommend that Evergy apply a seasonal peak adjustment charge/credit to the energy charge. Reflecting the time-varying nature of energy costs, this mechanism would help to familiarize customers with the important concept of intraday energy price variability.

We also recommend that Evergy introduce, as an optional (i.e., opt-in) rate, a rate structure that features a TOU energy charge and an on-peak demand charge (Option 6). This optional rate provides stronger energy and demand price signals, offering interested customers greater incentives to manage usage and reduce their electricity costs.

I. Introduction: The Hours Use Charge

Evergy engaged The Brattle Group to develop, evaluate, and recommend rate design options to replace the existing Hours Use energy charge structure that is currently applicable to commercial and industrial (C&I) customers in its Missouri Metro jurisdiction. The existing rate design encourages efficient use of the Company's energy infrastructure, but its complexity can limit customer understanding and engagement. Sharper, more actionable price signals can help customers shape their consumption to match their preferences and provide Evergy with an additional tool to manage an evolving power system. Importantly, more cost-reflective rates also align more closely what customers pay with the costs that they impose on the system.

All C&I customers in Evergy's Missouri Metro service territory are currently on rate schedules that feature a three-tiered Hours Use charge. This charge is designed to recover both generation energy and generation demand costs, and is based on the number of "hours use", or a billing determinant derived from a customer's total monthly kWh energy usage and maximum monthly kW demand. Structurally, the Hours Use charge functions as a declining block rate: customers pay a higher per-kWh price for the first 180 hours use, a lower price for the next 180 hours use, and a further reduced price for usage over 360 hours use.[3]

A customer's total number of hours use is calculated as the customer's total monthly kWh energy consumption divided by their highest kW demand in that month. As an example, consider a customer with the total monthly usage of 20,000 kWh and a monthly peak kW demand of 100 kW. This customer's total hours use would be 200. They would pay 18,000 kWh of their total monthly usage under the first $/kWh pricing tier. The remaining 2,000 kWh under the second pricing tier.[4] (No usage would be assigned to the third tier the monthly hours use number does not exceed 360 hours use.) As another example, consider a different customer with the same 20,000 kWh of monthly consumption but a lower peak monthly kW demand of 50 kW. This customer's total number of hours use is 400, representing a higher load factor. They would pay 9,000 kWh under the first pricing tier, 9,000 kWh under the second pricing tier, and the remaining 2,000 kWh under the third tier. Driven by a higher load factor, this customer would pay a lower

3 The monthly maximum of hours use is 720 (30 days multiplied by 24 hours), which happens when a customer consumes the same amount of energy in each hour throughout the month.

4 They would have 18,000 kWh (i.e., 100 kW multiplied by the minimum of the total hours use [200] and bucket one's stated threshold [180]) assessed in bucket one and 2,000 kWh (i.e., 100 kW multiplied by the minimum of the remaining total hours use [20] and bucket two's stated threshold [180]) assessed in bucket two.

all-in average electricity price. In general, customers with higher load factors (i.e., flatter load profiles) have a greater share of their kWh consumption assigned to the second and third tiers with lower pricing levels, resulting in a lower average electricity rate.

Beyond the Hours Use charge, existing C&I rates also include a demand charge, a facilities charge, and a customer charge under the current rate structure. Designed to recover fixed costs to serve each customer, the customer charge is a fixed monthly charge which in some cases varies slightly based on facilities demand (i.e., the highest monthly demand occurring over the last twelve months). The facilities charge is designed to recover distribution-related costs and is assessed based on each customer's highest demand in the last 12 months. Finally, the demand charge is based on a monthly peak kW demand, and is designed to recover other transmission and generation capacity-related costs.[5]

Given the substantial overlap between the Hours Use charge and the existing demand charge, in this study we explored options to replace both charges simultaneously. Throughout this report, references to alternatives to the Hours Use charge should be understood as replacements for both components together.[6] All other rate components, including the customer charge, facilities charge, and all other applicable riders, remain unchanged.

A clear benefit of the existing Hours Use rate is that the declining block rate structure incentivizes more efficient use of the power system, rewarding customers with a flatter monthly load. This *generally* helps to align what customers pay with the costs that they incur: customers with a flatter load profile more efficiently utilize the system compared to peakier customers and therefore pay a lower electricity rate on average. However, the cost to serve a customer is not always commensurate with their load factor. For example, a customer with significant peak usage overnight could impose lower costs on the system compared to one who consumes electricity around the clock, including during higher demand afternoon hours. Under the existing Hours Use rate, the former would have a higher number of hours use and therefore pay a higher average $/kWh electricity rate.

Indeed, the lack of a temporal price signal is a key limitation of the Hours Use rate design. In particular, as renewable generation continues to expand within the SPP system and intraday cost volatility increases, *when* a customer uses energy becomes increasingly important. However, the

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[5] As a result of historical ratemaking proceedings and negotiated outcomes over the years, there may be some misalignment between the cost categories in the cost-of-service study and individual charges within the Hours Use rate structure.

[6] SGS does not have a demand charge.

Hours Use rate design does not account for when usage and peak demand occur.[7] In addition to the absence of time-based price signals, the Hours Use rate combines the recovery of energy- and capacity-related costs into a single charge. This blending reduces transparency and complicates efforts to align cost recovery with cost causation. Finally, the Hours Use structure is not customer-friendly. It is complex, offers an opaque price signal, and requires customers to understand rather technical concepts such as load factor. Taken together, the Hour Use rate design creates a barrier to informed decision-making and effective usage management.

In the remainder of the report, we explore and evaluate rate options that Evergy may consider as replacements for the Hours Use rate. We begin by reviewing existing rate structures across similarly sized and geographically proximate utilities to identify a broad set of existing rates and any trends in rate design (Section II). Next, we discuss the metrics used to evaluate each rate option as a potential replacement for the Hours Use rate and identify a short list of rate alternatives for Large Power Service (LPS), Large General Service (LGS), Medium General Service (MGS), and Small General Service (SGS) customers. We then discuss rate design considerations that apply to all alternatives, including seasonality, peak period timing, and cost allocation strategies (Section III). After, we discuss specific rate design structures associated with each rate and design each of the rates using Evergy system and customer data. Then, we evaluate each rate option using the metrics discussed in the earlier section including full bill impacts for each of the rates (Section IV). Finally, we conclude with recommendations for replacing the Hours Use rate (Section V).

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7 As of November 2025, there were 554 generation projects totaling 135 GW in the SPP interconnection queue. 24% of that capacity is solar, 15% is wind, and 21% is storage.

II. Identify Rate Options to Replace Hours-Use Charge

A. Review of Rates in Other Jurisdictions

To identify the prevalence of existing rate structures, we first surveyed 10 neighboring utilities and 11 additional utilities with bundled sales volumes similar to that of Evergy Missouri Metro. In total, we examined 74 small, medium and large C&I rates. For each jurisdiction, we catalogued the different available energy charges and demand charges.

Based on the survey results and our own rate design experience, we identified the following volumetric rate components (ordered from most prevalent to least prevalent):

- **Flat Volumetric**: Customers pay the same per-kWh charge for all usage. Variations of this rate include a flat volumetric charge that changes by season.
- **Inclining Block Rate**: Customers pay different per-kWh charge for different blocks or tiers of usage. Specifically, under inclining block rates, customers pay a higher rate for a higher usage tier over the course of each billing period.
- **Declining Block Rate:** Similar to an inclining block rate, but customers pay less for a higher usage tier over the course of each billing period.
- **Hours Use**: A modified declining block rate structure where block thresholds are scaled based on customer monthly peak kW demand (see above).[8]
- **Time-of-Use (TOU)**: Customers pay a higher rate for energy consumed during on-peak periods when the energy supply is more expensive, and a lower rate during off-peak periods. TOU structures may vary in the number of pricing periods and in how those periods are defined.

[8] Beyond Evergy Missouri Metro, rate options offered by a few other utilities have similar structure. *See* Ameren, Service Classification No. 3(M) Large General Service Rate; MidAmerican Energy Company, Rate GD – General Demand Service; MidAmerican Energy Company, Rate LS – Large Electric Service; Nebraska Public Power District, General Service Demand Rate Schedule. In addition, rate Generation Substitution Service in Evergy Kansas Central also features the Hours Use structure.

- **Critical Peak Pricing (CPP)**: Customers pay a high rate during “critical events” when the power system encounters critical conditions, or when the power grid is severely stressed. This rate can be coupled with TOU.
- **Variable Peak Pricing (VPP)**: Similar to Critical Peak Pricing, but the peak price varies from one “critical event” to the next.
- **Real Time Pricing (RTP)**: Customers pay a rate that varies on an hourly or sub-hourly basis, based on market prices or marginal system costs.

Among the rates surveyed, about 45% of them also had components that were based on some measure of peak demand. Designed to align cost recovery with demand-driven system impacts, these demand-based charges help improve cost reflectivity. Based on the survey findings and our experience with rate design, we identified the following variations in demand-based charges:

- **Flat Demand Charge**: Customers pay a charge assessed based on the monthly maximum kW demand. The pricing level may vary by season.
- **Declining Block Rate:** Similar to the declining block design for energy charges (see above), customers pay a lower rate for a higher tier of demand.
- **Time-Varying (i.e., On-Peak Demand):** Customer monthly maximum kW demand is determined based on a narrower set of pre-determined peak period hours rather than all monthly hours. This peak period generally aligns with system peak hours to discourage high system utilization during capacity-constrained windows.
- **Annual (i.e., Ratchet Demand):** Customers pay a rate that uses annual rolling maximum kW demand based on the last twelve months of usage.

In addition, we documented significant rate design changes implemented by utilities over the last three years. Of the utilities surveyed, we identified three notable cases:

- Oklahoma Gas & Electric (OGE) replaced their summer inclining rate with a flat summer rate and included an optional TOU rate;
- Interstate Power & Light (IPL) replaced their default general service declining block rate with a flat volumetric rate; and
- Liberty-Empire in Missouri updated their TOU offering to include a daily off-peak credit during overnight hours.

While the sample is limited to only three instances, these examples suggest a possible trend away from block rate structures.

Figure 6 below summarizes the prevalence of the various rate design offerings across small, medium, and large C&I customer classes for the utilities we surveyed.

FIGURE 6: PREVALENCE OF VARIOUS RATE DESIGN FEATURES IN UTILITY SURVEY

Rate Design	No. of Rates
Demand Charge	33
Flat Demand	30
Time-varying Demand	3
Declining Block Rate	22
Time of Use	25
Flat Volumetric Rate	25
Hours Use	4
Inclining Block Rate	1
Critical Peak Pricing	1
Variable Peak Pricing	1
Real-Time Pricing	1
Guaranteed Flat Bill	1

Note: Different features that exist within the same rate (*e.g.,* rate with a time-of-use energy charge and a demand charge) are counted separately, leading to a higher total in the figure than the number of rates we reviewed. Neighboring utilities in our survey include: Ameren (MO and IL), Entergy Arkansas, Interstate Power & Light (IA), Liberty-Empire (MO), MidAmerican (IA), Nebraska Public Power District, Mississippi County Co-operative, Oklahoma Gas & Electric, and Public Service Company of Oklahoma. Similarly-sized utilities in our survey include: Commonwealth Edison Company, Entergy Mississippi, Idaho Power, Indiana Michigan Power (IN), Indianapolis Power & Light, Kentucky Utilities, Louisville Gas & Electric, Monongahela Power, Niagara Mohawk, NIPSCO, and Southwestern Electric.

B. Criteria for Evaluating Rate Options

We established a set of criteria to evaluate each of the rate options so that we can objectively assess each rate. Figure 7 presents each of the criteria and the objective of each metric.

FIGURE 7: CRITERIA USED TO EVALUATE RATE OPTIONS

Criteria	Description	How it is evaluated
Bill Stability	Minimize large, sudden increases in customer bills	Compare the percent or $/year change in bills under replacement rate relative to bills under the current Hours Use rate
Cost Reflective	The extent to which a rate design aligns with the structure and nature of costs it is intended to collect i.e., whether customers pay their “fair share”	Subjective metric to evaluate a rate design’s alignment with the underlying structure of the costs is it intended to recover
Valuable Price Response	The alternative rate designs should provide price signals to customers to adjust their usage pattern in response to system conditions (*e.g.*, reduce usage when the cost of generating and delivering electricity is highest)	Subjective metric to evaluate rate design based on the strength and alignment of high-priced periods with the expected timing of high system cost hours
Simple and Transparent	The rate options should be simple and straightforward for customers to understand	Subjective metric to evaluate a rate design is understandable and actionable to customers

C. Rate Options

Based on survey results, the capabilities of Evergy’s current billing system, and our initial screening assessment of the rate options using the metrics described above, we focused on a subset of the rate design options that are most suitable to replace Evergy’s current Hours Use rate.[9] The subset of six rate options and their descriptions are shown in Figure 8 below.

9 Note that we design these rate options to replace only the Hours Use charge and the demand charge. Other applicable charges, such as facilities charge and customer charge, are not within the scope of our analysis.

FIGURE 8: SHORT LIST OF HOURS USE CHARGE ALTERNATIVES

Rate Option	Description	Advantages
1. Seasonal, Flat Volumetric Energy Charge (No Demand)	Flat volumetric energy charge recovers all costs and varies by season	• Extremely simple rate
2. Seasonal Volumetric Energy + On-Peak Demand	Flat volumetric energy charge varies by season; all demand costs are recovered via a seasonal demand charge based on kW demand during on-peak hours	• Underlying energy- and demand-costs are recovered by energy charge and demand charge, respectively • Highly cost-reflective • On-peak demand window introduces temporal element to signal grid constraint periods
3. Seasonal Volumetric Energy + Partial On-Peak Demand*	Flat volumetric energy charge varies by season; demand costs associated with peak system hours are recovered through a seasonal demand charge based on kW demand during on-peak hours	• Underlying energy- and demand-costs are recovered by energy charge and demand charge, respectively • On-peak demand window introduces temporal elements to signal capacity-constrained periods • Demand charge pricing consistent with levels found in other jurisdictions
4. Seasonal Volumetric Energy + Partial Non-Coincident Demand	Flat volumetric energy charge. Demand costs associated with peak system hours recovered through a seasonal demand charge based on monthly maximum demand	• Underlying energy- and demand-costs are recovered by energy charge and demand charge, respectively • Demand charge pricing consistent with levels found in other jurisdictions
5. TOU Energy (No Demand)	TOU energy charge recovers all costs and varies by season	• Relatively simple rate • Reflective of temporal energy costs
6. TOU Energy + Partial On-Peak Demand⁺	TOU energy charge varies by season; demand costs associated with peak system hours are recovered through a seasonal demand charge based on kW demand during on-peak hours	• Underlying energy- and demand-costs are recovered by energy charge and demand charge, respectively • Reflective of temporal energy costs • Demand charge pricing consistent with levels found in other jurisdictions

Note: (*) indicates the default rate design that we recommend through this study; ⁺ indicates our recommendation for an optional rate offering.

For the **Seasonal Volumetric** rate option (Option 1), we designed a rate that recovers all energy and capacity costs through a single volumetric energy charge. The seasonal nature of the energy charge reflects the differences in costs that occur during peak summer months and during non-summer months. The simplicity of this rate has both benefits and limitations. For small customers with more limited control over their consumption, this can be a simple and easy-to-understand rate. However, demand-based costs such as generation capacity costs driven by peak system demand are also recovered through a volumetric charge, resulting in customers not paying their "fair share" of costs during certain times throughout the year.

The **Seasonal Volumetric + On-Peak Demand** rate option (Option 2) includes a seasonal energy charge (similar to Option 1) and a seasonal demand charge, which is assessed based on customer monthly maximum peak demand during the on-peak hours. The demand charge recovers all costs associated with generation and transmission demand while the energy charge recovers variable costs associated with energy generation. This option creates better alignment between what customers pay and the cost to serve them than the purely volumetric rate (Option 1). In addition, it provides customers with improved price signals about how their peak demand and overall usage impact their energy bills.

Applying the demand charge to on-peak usage adds a temporal element to the rate, further ensuring that customers are responsible for their share of costs in the hours that drive the marginal cost of generation and transmission procurement. We also used different pricing levels and different peak period definitions in each season to reflect both the magnitude of costs that drive capacity procurement in each season as well as the set of hours that drive this peak demand in each period.

While this rate design aligns closely with how underlying generation capacity and transmission costs are incurred, assigning all demand-related costs to a demand charge could result in a demand pricing level that is much higher than the levels to which Evergy customers are accustomed. Such pricing level could also fall outside the range of demand charges observed in other jurisdictions. Put differently, because the demand charges that Evergy's C&I customers currently pay do not recover all demand-related costs, a fully cost-reflective demand charge (designed to recover all demand-related costs) would be much higher than the existing demand charges.

The **Seasonal Volumetric + Partial On-Peak Demand** rate option (Option 3) preserves the benefits of the Option 2 but shifts demand costs not associated with peak system hours back onto the energy charge. This results in a slightly higher energy charge and a lower demand charge that could be more in line with pricing levels observed in other utilities and to which Evergy C&I customers are accustomed. By recovering demand-related costs associated with the highest system cost hours through a demand charge assessed based on customers' kW usage during the top system hours, this design would still advance the cost-reflectivity objective.

A slight variation of Option 3, the **Seasonal Volumetric + Partial Non-Coincident Demand** rate option (Option 4) applies a demand charge based on each customer's monthly highest demand, regardless of when it occurs. Commonly used by the utilities that we surveyed, this design offers a slightly simpler approach, eliminating the need to define and measure demand within a specified on-peak window. However, the absence of a time-specific demand component means that there is no price signal to encourage load reductions during critical system peak hours. As a result, this structure may lead to inequitable cost recovery. For example, if one customer's peak occurs overnight while another customer's peak happens during system peak hours, they would incur the same charge, despite materially different costs to serve each.

In addition, we developed a **TOU only** option (Option 5), where all energy and capacity costs are recovered through an energy charge. The energy charge is designed to vary across seasons and pricing periods, with higher rates during system peak hours to reflect the higher costs of serving load during those periods. Commonly offered by the surveyed utilities as an opt-in rate, this structure provides clear price signals to encourage load reductions during system constrained hours. However, because this rate option lacks a demand charge, all demand-related costs are recovered through the volumetric energy charge. This may result in cost recovery outcomes that are not fully cost-reflective.

We also developed a **TOU + Partial On-Peak Demand** rate option (Option 6), which features a time-varying energy charge (similar to Option 5) and an on-peak demand charge (similar to Option 3). Relative to other time-varying options, this option provides additional temporal price signals to customer to reduce their energy consumption and save even more during system peak hours. However, with this design, customers who are not able to shift their energy usage patterns can experience large bill increases relative to other rate options.

Finally, we applied a peak adjustment charge and credit to the flat energy charge (i.e., Option 1 through 4). This mechanism reflects the intraday variations in electricity prices, and by introducing a mild time-based price signal, it also helps raise awareness among customers of intraday cost variability.

III. Design the Hours Use Alternatives

Our first step in designing the replacement rate options was to analyze Evergy's system load and cost data to establish definitions for seasons and peak periods, which apply to options with a TOU energy charge and/or an on-peak demand charge. In this analysis, we assigned energy- and demand-related costs to the appropriate pricing periods.

A. Calculate Demand-Related Costs

We developed a method to assign demand related costs to the hours of the year that drive those costs, which we refer to as the "delta net load cubed" method. Starting with the hourly net load (gross system load less non-dispatchable renewable generation), we calculated the difference between each hourly net load value and the lowest hourly net load in the year. For each hour *i*, we calculated a cost allocator by dividing in each hour the cube of the difference by the total sum of the cube of each of hourly difference across the year, as shown in the following formula:

$$Gen\ Capacity\ Cost\ Allocator_{\ i} = \frac{(Net\ Load_i\ -\ Annual\ Min\ Net\ Load\ )^3}{\sum_n^{8760}(Net\ Load_n\ -\ Annual\ Min\ Net\ Load\ )^3}$$

The cubic transformation of net load in each hour reflects the fact that the highest load hours incur a disproportionately larger share of system costs. We then aggregated these hourly cost allocators to calculate costs associated with each season and each TOU pricing period of interest.

B. Establish Season Definitions

Evergy's costs to serve customers vary throughout the year, depending on available generation capacity, network constraints, fuel costs, system demand, among other factors.[10] When establishing season definitions for the purpose of rate design, we split the year into periods of similar underlying cost patterns. Specifically, we separately assigned generation energy, generation demand, transmission, and distribution costs to each hour of the year based on

[10] Currently Evergy defines summer as June through September, and non-summer months as October through May.

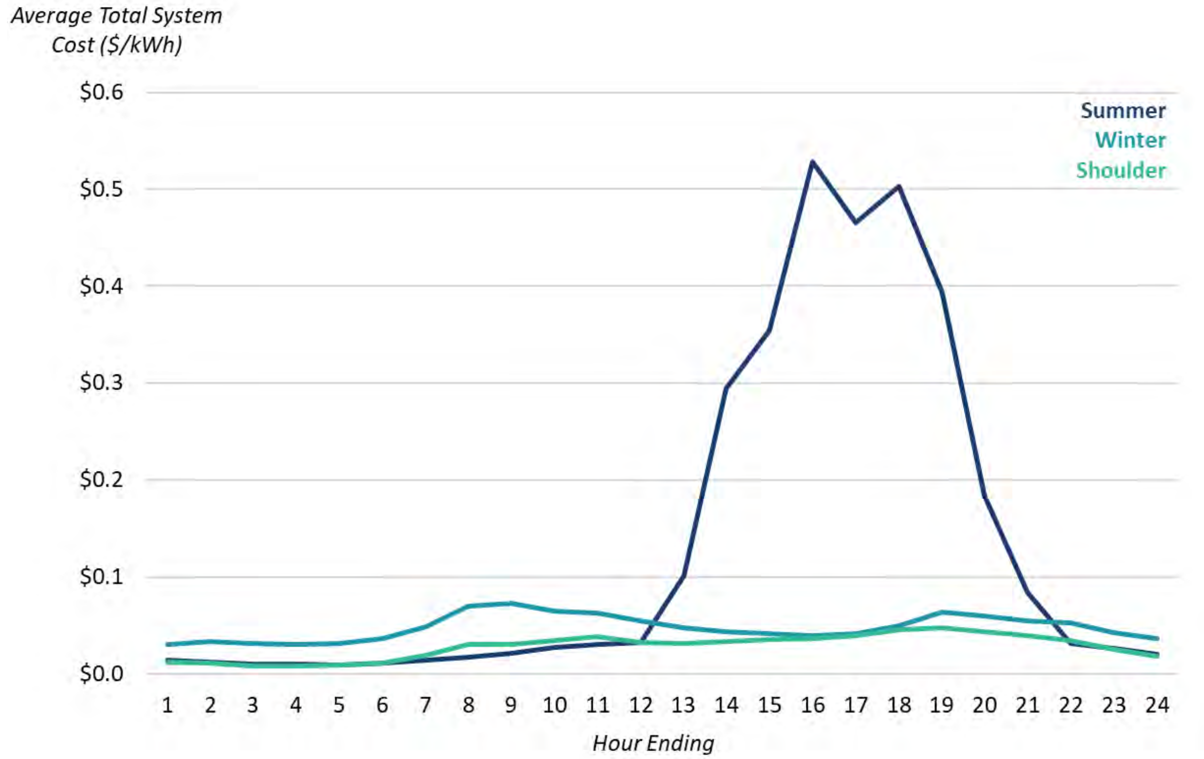
when the system incurred these costs. This approach enables appropriate cost assignment and consequently appropriate rate calculations.

Figure 9 presents the average daily cost profiles for different seasons in Evergy's Missouri Metro system, based on forward-looking costs. Although rates are designed to recover embedded historical costs, defining seasonality and peak periods using forward-looking cost data results in rate designs that send effective price signals and help mitigate future marginal system costs. We assigned costs using the following approach:

- **Generation Energy**: We assigned generation energy costs to each hour based on the system locational marginal price (LMP).[11]
- **Generation Capacity**: We assigned generation capacity costs to the top 100 system net load hours of the year based on Evergy Missouri Metro's system load profile. These hours represent periods most likely to drive marginal generation capacity procurement. Under the delta net load cubed approach, a greater share of costs is assigned to the more constrained hours. We used a marginal cost of generation capacity of $298/kW-year based on Evergy's 2028 combined cycle gas turbine costs.
- **Transmission**: We assigned Evergy's embedded transmission costs across the top 25 system load hours in each month, approximating the driver of SPP transmission charges. Costs are assigned to each hour using delta gross load cubed allocators, with a greater share of costs being assigned to the more constrained hours. We used system gross load instead of net load because transmission costs are driven by total system peak demand inclusive of non-dispatchable generation.
- **Distribution**: We assigned 25% of Evergy's total embedded distribution costs to the top 500 C&I class load hours, reflecting an approximated marginal distribution cost and greater temporal diversity in load drivers of distribution capacity investment. Costs are assigned to each hour using the delta load cubed method similar to the transmission cost assignment method, but we used class load instead of gross system load.

[11] LMPs from the test year July 2024 – June 2025 for KCPL node.

FIGURE 9: SEASONAL SYSTEM COSTS FOR EVERGY MO METRO SYSTEM



Note: Summer = June-Sept, Winter = Dec-Feb, Shoulder = March-May, Oct-Nov

Our analysis indicates that Evergy's current summer and non-summer seasonal definitions remain appropriate for its system.[12] System costs in Evergy Missouri are primarily driven by high-demand hours during the existing summer period, which require procurement of additional generation capacity. Although energy prices vary between the colder winter months and the shoulder months within the non-summer period, we do not consider these differences to be sufficiently pronounced to justify departing from the two-season framework used across Evergy's existing rate structures.

C. Determine the System Peak Period

We defined pricing periods to achieve several key objectives. First, the periods must be cost-reflective, aligning peak pricing with hours when system costs are highest. Under this definition, customers using electricity during system peak hours would pay a higher rate. As a result, this design promotes a more equitable allocation of system costs. Second, a well-defined peak period

[12] We performed a series of robustness tests across a range of generation cost assignment hours to ensure that our findings are not sensitive to our use of 100 system load hours for generation costs.

provides customers with a clear opportunity to reduce usage during the most expensive hours, thereby lowering their bills and contributing to system efficiency. In addition, a well-defined peak period improves customer understanding and strengthens behavioral response to peak pricing.[13]

To determine the system peak period, we analyzed hourly system costs using the same method used to define seasonal periods. Our findings indicate that, during the summer months, the highest-cost hours occur in the afternoon and evening, corresponding with peak system load and the associated high cost of serving demand during those times. In contrast, system costs in the non-summer months are more evenly distributed across the day. This is because non-summer loads do not typically drive generation capacity requirements.

Based on this analysis, we recommend establishing for the summer months an on-peak period of 3 pm to 7 pm for non-holiday weekdays, a super-off-peak period of midnight to 6 am every day, and an off-peak period in the remaining hours (see Figure 10 below). Given the more uniform system cost profile in non-summer months, we recommend a 9 am to 9 pm. peak period for the on-peak demand charge design. For the energy charge, early morning hours exhibit the lowest costs; accordingly, we propose a super-off-peak period from midnight to 6 am, with all other hours designated as off-peak.

The difference between the summer and winter designs help to align our rate alternatives with underlying cost drivers in each season as follows:

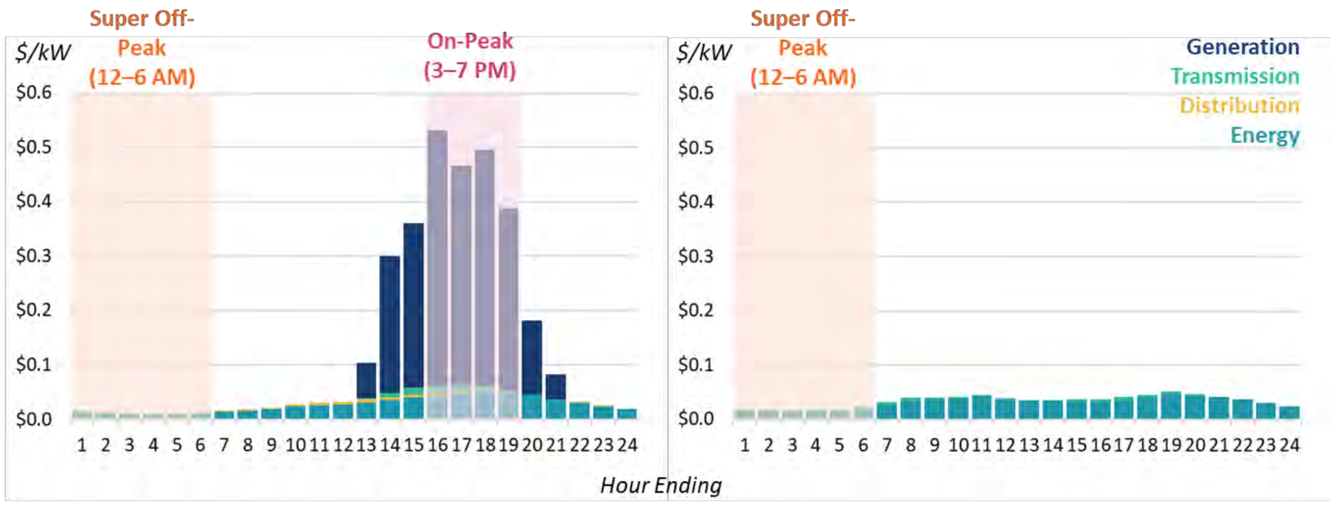
- **Summer:** A short peak window during the summer provides a strong price signal to reduce load during that block of hours and provides opportunities for load shifting. Our recommended peak window keeps the duration of the peak period reasonable while accounting for a number of considerations. First, commercial loads tend to peak earlier in the day. Capturing some of this class peak within the peak period can help to diffuse system peak load hours that are primarily driven by commercial loads. Second, Evergy is planning to add 450 MW of additional solar capacity to its Metro jurisdictions, which could shift the net system peak (i.e., net of expected renewable generation output) later into the afternoon.[14] Therefore, setting a peak period of 3 pm to 7 pm balances these two competing temporal considerations.
- **Winter:** Underlying costs during the winter period are flatter because costs are not driven by generation capacity costs, and energy costs are flatter throughout the day. Although we recommend a wider peak period, there is value in differentiating these hours from overnight hours. While winter demand is not currently driving generation capacity costs, constrained

13 Peak periods can also be designed to help address distribution-level constraints.

14 Evergy, 2025 Integrated Resource Plan Update, May 2025, EVRG 2025 IRP Update.

system events are becoming more common in the winter primarily because of reliability concerns driven by thermal outages. This is reflected in SPP's decision to approve a winter planning reserve margin of 36% in the winter starting in 2026/27 winter, higher than the summer PRM of 16%.[15]

FIGURE 10: HOURLY SUMMER (LEFT) AND NON-SUMMER SYSTEM COSTS FOR C&I CUSTOMERS



D. Designing Alternative Rate Options

For each of the C&I customer classes and for each voltage level within each class, we designed the six rate options discussed above. As a preliminary step to designing the rate options, we processed all available AMI load data for C&I customers served by the Evergy Missouri Metro system during the test year of July 2024 – June 2025. Only customers with a full year of data are represented in our processed sample. This processing step creates an unbiased class load shape by removing customers with missing AMI data or customers who joined or left mid-year. We used updated class definitions for the year when these rates are expected to go into effect.

We assumed that the Hours Use charge alternatives will need to collect the same revenue produced by the Hours Use charge in each season (i.e., they will be seasonally revenue neutral to the Hours Use charge, which comprises of the existing volumetric $/kWh charge and the demand charge), and will be used to recover Evergy's generation and transmission costs.[16] Below we

15 https://www.spp.org/news-list/spp-board-approves-new-planning-reserve-margins-to-protect-against-high-winter-summer-use/

16 We designed the alternative rate options to be seasonally revenue neutral to Evergy MO Metro's proposed Hours Use rates in its 2026 rate case.

provide additional methodological details for each alternative rate design that we developed and evaluated.

1. SEASONAL, FLAT VOLUMETRIC ENERGY CHARGE (NO DEMAND CHARGE)

We designed the seasonal volumetric energy charge to recover all costs within each season (i.e., revenue neutral on a season basis). We calculated the volumetric charge for each class by dividing its total seasonal revenue requirement by its seasonal kWh. In addition, we applied a summer on-peak adjustment adder of 1 cent per kWh and a super-off-peak credit of 1 cent per kWh; any shortfall or surplus from the adder/credit mechanism is incorporated into the base energy charge. Similarly, we applied a 1 cent per kWh super-off-peak credit for the non-summer months and adjusted the base energy charge to maintain revenue neutrality.

2. SEASONAL VOLUMETRIC ENERGY + ON-PEAK DEMAND

We designed the seasonal volumetric energy charge to recover only generation-energy-related costs. First, we estimated the hourly kWh usage of each class using its total billing determinants in the Blue Sheets and its hourly load profile derived from AMI data.[17] Next, for each hour, we multiplied the hourly class load by the hourly LMP to derive an estimate of energy costs that Evergy incurs to serve that class in that hour. We used test-year LMP values for the KCPL hub of SPP, the power hub closest to Evergy MO Metro. Finally, for each voltage level, we calculated the volumetric charge by dividing the sum of hourly costs across each season by the seasonal kWh usage. This volumetric energy charge is also the load-weighted average LMP across each season. We also applied a peak adjustment adder/credit using the same method as in Option 1.

We calculated the demand revenue requirement as the total revenue collected from the existing Hours Use charge and the demand charge *less* the revenue collected from the energy charge (estimated in the previous step). To develop the demand billing determinant, we started with the monthly demand billing determinants from the Blue Sheets, which are the sum of each customer's highest 15-minute kW demand in each month. We multiplied this sum by the ratio of seasonal on-peak demand to peak demand, both of which are calculated using the AMI sample of existing customers. The on-peak demand for each customer is the maximum demand observed during the peak periods identified in the above section (i.e., 3 pm to 7 pm for summer non-holiday weekdays and 9 am to 9 pm for non-summer non-holiday weekdays). The seasonal demand charge ($/kW-month) is calculated by dividing the demand-related revenue requirement for each season by the sum of the on-peak demand billing determinant for that season.

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[17] We only used customers with complete data to ensure that the load shape is accurately represented and is not impacted by new customers or AMI data challenges.

3. SEASONAL VOLUMETRIC ENERGY + PARTIAL ON-PEAK DEMAND

We calculated an initial seasonal volumetric charge using the same method as in Option 2. When calculating the partial demand charge, we used only demand-related costs associated with top 400 system hours (instead of all demand-related costs); the remaining costs were recovered by the energy charge. To do this, we used the delta net load cubed approach discussed earlier to assign a share of the demand revenue requirement to each hour of the year. The seasonal demand charge ($/kW) is calculated by dividing the demand-related revenue requirement associated with the top 400 hours in each season by the sum of estimated on-peak demand billing determinant for that season.

We reassigned the remaining demand revenue requirement not associated with the top 400 system net load hours back to the energy-related costs and recalculated the energy charge so that the final energy charge is the load-weighted average LMP plus the remaining demand revenue requirement divided by the total kWh usage within the season. We applied a peak adjustment adder/credit using the same method as in Option 1.

4. SEASONAL VOLUMETRIC ENERGY + PARTIAL NON-COINCIDENT DEMAND

We developed this rate option using the same method as in Option 3; however, we used the non-coincident demand billing determinant from the Blue Sheets. The seasonal demand charge ($/kW-month) for each season is calculated by dividing the demand-related revenue requirement by the sum of monthly demand billing determinants.

5. TOU ENERGY (NO DEMAND)

We designed this rate option using a similar method used to develop Option 1. However, we designed the energy charge with three periods in the summer season and two periods in the non-summer season. The price ratios mirror the price ratios of the load-weighted LMPs across the pricing periods. We did not apply a peak adjustment adder/credit to this rate option because the energy charge already has a temporal element.

6. TOU ENERGY + PARTIAL ON-PEAK DEMAND

This rate option features a demand charge that is identical to the demand charge in Option 3. We designed and calculated the time-varying energy charge using a similar method applied in Option 5, ensuring the final energy charge designed to recover generation energy costs and demand related costs not assigned to the top 400 system hours mirrors the price ratios of the load-weighted LMPs across the pricing periods. We did not apply a peak adjustment adder/credit to this rate option.

IV. Evaluate Hours Use Replacement Options

After designing the rate alternatives, we analyzed the options using the evaluation criteria discussed in Section II. Figure 11 below provides a summary of our assessment of the rate options under consideration.

From a rate design perspective, the existing Hours Use charge places an emphasis on incentivizing customers to improve their load factors. Such a design is moderately cost-reflective and provides a moderately valuable price signal to customers. However, the Hours Use structure is significantly more complex than the alternative rate options.

In comparison, the Seasonal Volumetric Energy + On-Peak Demand (Option 2) improves upon the existing Hours Use charge by having a separate demand charge designed to recover capacity costs and an energy charge to recover energy costs. Such a design aligns cost recovery more closely with Evergy's underlying cost structure and is simpler to understand from the customer's perspective.

The Seasonal Volumetric Energy + Partial On-Peak Demand (Option 3) is based on Option 2 design, but its lower demand charge helps improve customer acceptance and mitigate extreme bill impacts (defined as an annual bill increase of at least 10%).

The Seasonal Volumetric Energy + Partial NCP Demand (Option 4) is similar to Option 3, but the demand charge is assessed based on customer highest kW usage, regardless of whether it occurs during system peak. Although simpler for customers to understand and less restrictive in appearance, this design does not reflect underlying cost drivers.

By excluding a demand-based charge, the TOU energy-only option (Option 5) is simpler in structure; however, in practice it is not substantially simpler because customers are still subject to a facilities charge, which is demand-based. Moreover, the design is not cost-reflective, as all demand-related costs are recovered through an energy charge.

In contrast, the TOU Energy + Partial On-Peak Demand option (Option 6) is highly cost-reflective and provides customers with meaningful opportunities to respond to price signals and save throughout the year. However, this rate can have significant bill impacts for customers who are not able to adjust their energy consumption pattern and lower their electricity demand during peak hours.

FIGURE 11: EVALUATION OF REPLACEMENT RATE OPTIONS ACROSS VARIOUS CRITERIA

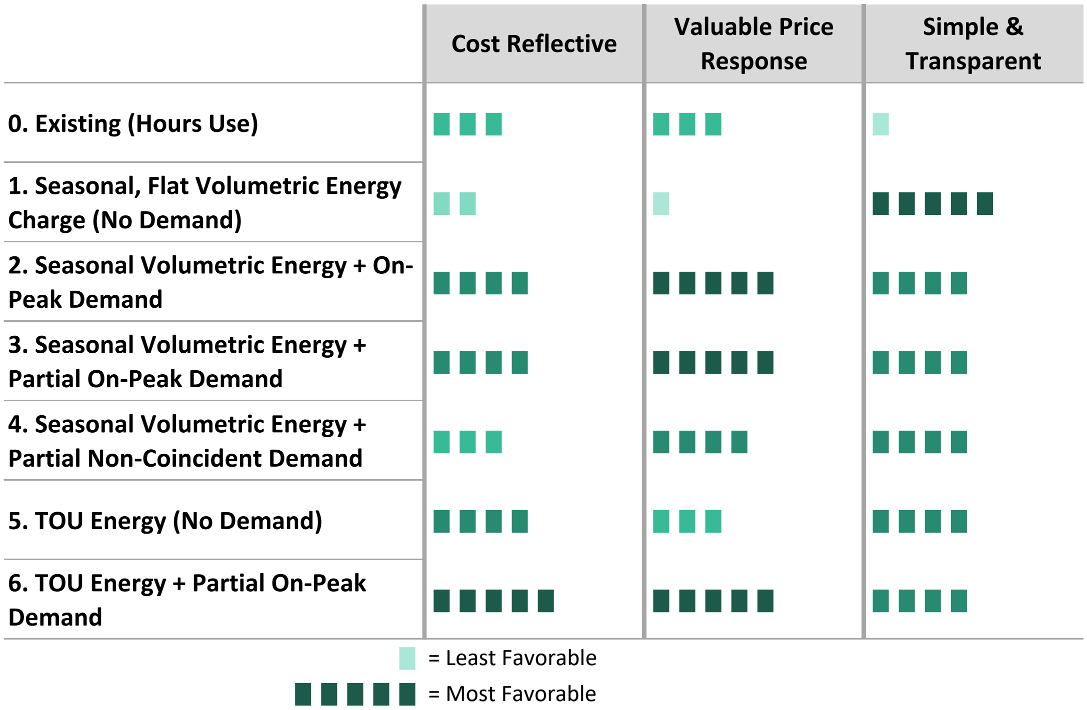

Figure 12 below provides a summary of customer bill impacts when transitioning from the current Hours Use rate to one of the replacement rate options. We evaluated customer bill impacts across four dimensions: percent of customers with annual bill increases greater than 10%, annual percent bill increase for the 95th percentile non-benefiter, percent of customers with annual bill savings, and the average annual percent bill increase among non-benefits.[18] Rate options without demand charges (such as Options 1 and 5) generally yield the highest shares of benefiters relative to other alternatives.

Across all customer classes, the rate option with the full demand charge (Option 2) consistently has the lowest performance in terms of bill stability. It results in the highest share of customers experiencing bill increases greater than 10% and the most severe increases among non-benefiters, with bill increases reaching up to 82% for the 95th percentile for SGS non-benefiters. This outcome reflects the underlying rate design, which recovers all demand-related costs through the on-peak demand charge. Under this rate option, customers who are shielded somewhat from the demand charge under the Hours Use rate are now exposed to the full demand charge; those whose maximum demand coincides with the system peak experience particularly large bill increases.

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[18] Bill impacts are calculated for all customers with complete AMI data. Bill impacts can be updated in the future as the quality of data continues to improve.

The options with partial demand charges (Options 3, 4, and 6) result in substantially greater bill stability than Option 2. Under these three options, the percent bill increase for the 95th percentile non-benefiter is much smaller (e.g., 33-38% for SGS compared to 82% under Option 2; or 52% versus 12% for LGS). Overall, these three rate options perform similarly across the four bill impact dimensions, with limited exceptions. For example, Option 4 is expected to result in the highest share of MGS benefiters (57%), followed by Option 3 (43%) and Option 6 (39%). The same ranking holds for LGS customers, though the differences in the share of benefiters across the three options are more modest.

FIGURE 12: BILL IMPACTS RESULTS
SGS CUSTOMERS

	Stability: Mitigates Extreme Bill Impacts		Stability: Produces Majority Bill Savings	
	% of customers w/ bill increases >10%	Bill increase for 95th percentile non-benefitter	% of customers w/ bill savings	Non-benefitters avg bill increase %
0. Existing (Hours Use)	n/a	n/a	n/a	n/a
1. Seasonal, Flat Volumetric Energy Charge (No Demand)	15%	19%	60%	9%
2. Seasonal Volumetric Energy + On-Peak Demand	29%	82%	57%	38%
3. Seasonal Volumetric Energy + Partial On-Peak Demand	15%	33%	57%	14%
4. Seasonal Volumetric Energy + Partial Non-Coincident Demand	16%	38%	57%	16%
5. TOU Energy (No Demand)	13%	17%	67%	9%
6. TOU Energy + Partial On-Peak Demand	15%	34%	58%	15%

= Least Favorable

= Most Favorable

Note: Bill impact results are shown for the whole rate class. Voltage level results are reported in the appendix. Options are compared within each rate class, not across rate classes.

MGS CUSTOMERS

	Stability: Mitigates Extreme Bill Impacts		Stability: Produces Majority Bill Savings	
	% of customers w/ bill increases >10%	Bill increase for 95th percentile non-benefitter	% of customers w/ bill savings	Non-benefitters avg bill increase %
0. Existing (Hours Use)	n/a	n/a	n/a	n/a
1. Seasonal, Flat Volumetric Energy Charge (No Demand)	■■■■ 7%	■■■■■ 11%	■■■■■ 68%	■■■■■ 6%
2. Seasonal Volumetric Energy + On-Peak Demand	■ 36%	■ 79%	■■■ 40%	■ 26%
3. Seasonal Volumetric Energy + Partial On-Peak Demand	■■■ 13%	■■■ 27%	■■■ 43%	■■■■ 8%
4. Seasonal Volumetric Energy + Partial Non-Coincident Demand	■■■ 13%	■■■ 28%	■■■■ 57%	■■■ 10%
5. TOU Energy (No Demand)	■■■■■ 4%	■■■■■ 9%	■■■■■ 66%	■■■■■ 5%
6. TOU Energy + Partial On-Peak Demand	■■■ 13%	■■■ 27%	■■■ 39%	■■■■ 8%

■ = Least Favorable

■■■■■ = Most Favorable

LGS CUSTOMERS

	Stability: Mitigates Extreme Bill Impacts		Stability: Produces Majority Bill Savings	
	% of customers w/ bill increases >10%	Bill increase for 95th percentile non-benefitter	% of customers w/ bill savings	Non-benefitters avg bill increase %
0. Existing (Hours Use)	n/a	n/a	n/a	n/a
1. Seasonal, Flat Volumetric Energy Charge (No Demand)	■■■ 10%	■■■■■ 13%	■■■■■ 66%	■■■■■ 8%
2. Seasonal Volumetric Energy + On-Peak Demand	■ 24%	■ 52%	■■■ 44%	■■ 19%
3. Seasonal Volumetric Energy + Partial On-Peak Demand	■■■■■ 6%	■■■■■ 12%	■■■ 48%	■■■■■ 6%
4. Seasonal Volumetric Energy + Partial Non-Coincident Demand	■■■■■ 5%	■■■■■ 12%	■■■■ 56%	■■■■■ 6%
5. TOU Energy (No Demand)	■■■■ 8%	■■■■■ 12%	■■■■■ 66%	■■■■■ 7%
6. TOU Energy + Partial On-Peak Demand	■■■■■ 6%	■■■■■ 12%	■■■ 47%	■■■■■ 6%

■ = Least Favorable

■■■■■ = Most Favorable

LPS CUSTOMERS

	Stability: Mitigates Extreme Bill Impacts		Stability: Produces Majority Bill Savings	
	% of customers w/ bill increases >10%	Bill increase for 95th percentile non-benefitter	% of customers w/ bill savings	Non-benefitters avg bill increase %
0. Existing (Hours Use)	n/a	n/a	n/a	n/a
1. Seasonal, Flat Volumetric Energy Charge (No Demand)	■■■■ 6%	■■■■ 10%	■■■■ 75%	■■■■ 7%
2. Seasonal Volumetric Energy + On-Peak Demand	■ 31%	■ 50%	■■■■ 63%	■ 30%
3. Seasonal Volumetric Energy + Partial On-Peak Demand	■■■■■ 0%	■■■■■ 3%	■■■■■ 81%	■■■■■ 3%
4. Seasonal Volumetric Energy + Partial Non-Coincident Demand	■■■■■ 0%	■■■■■ 3%	■■■■■ 81%	■■■■■ 3%
5. TOU Energy (No Demand)	■■■■ 6%	■■■■ 10%	■■■■■ 75%	■■■■ 7%
6. TOU Energy + Partial On-Peak Demand	■■■■■ 0%	■■■■■ 3%	■■■■■ 81%	■■■■■ 3%

■ = Least Favorable

■■■■■ = Most Favorable

V. Recommended Alternatives to Hours Use Charge

Based on our evaluation of the alternative rate designs provided in the prior section, we recommend that all C&I customers be transitioned to the Seasonal Volumetric Energy + On-Peak Demand Charge (Option 3). Figure 13 below summarizes the proposed rates using Evergy's requested revenue requirement numbers.

The recommended option balances cost reflectivity and simplicity. It recovers demand-related costs associated with system peak hours through an on-peak demand charge, while recovering remaining costs through a seasonal flat volumetric energy charge. The structure provides clear, actionable price signals that encourage customers to reduce consumption during system peak periods, without requiring them to monitor load factors in real time or perform additional calculations to manage their bills. Some small C&I customers may lack the tools or operational flexibility to actively manage energy usage, but the bill impacts observed for small C&I customers under this rate option are relatively modest. For customers who are able to respond to price signals, they can also expect to save on their electricity bills. Relative to the current Hours Use rate, this option also results in more stable and favorable bill outcomes, with fewer customers experiencing extreme bill changes during the transition. Further, rates featuring on-peak demand charges are increasingly common for C&I customers across the US.

In addition, we recommend that Evergy apply a seasonal peak adjustment charge or credit to the energy charge. By reflecting the time-varying nature of energy costs, this mechanism would help familiarize customers with the concept of intraday price variability, and the relatively low pricing levels would minimize customer bill impacts.

Finally, we recommend that Evergy introduce, as an optional offering, a rate structure featuring a time-of-use (TOU) energy charge combined with an on-peak demand charge (Option 6). This optional rate would provide more dynamic energy and demand price signals, creating stronger incentives for customers to actively manage usage and reduce electricity costs.

FIGURE 13: PROPOSED DEFAULT RATE TO REPLACE HOURS USE RATE

Proposed Rates		SGS	MGS	LGS	LPS
Customer Charge: amount customer pays per month		$21.415	$60.084	$228.288	$1,170.787
Facilities Charge: per kW of Facilities Demand		$2.981*	$3.189	$3.440	3.921
Demand Charge: per kW of Billing Demand	Summer	$15.044	$14.640	$15.277	$13.925
	Winter	$6.607	$6.336	$6.705	$7.250
Energy Charge: per kWh of monthly usage	Summer Energy Charge	$0.07519	$0.06301	$0.05762	$0.05966
	Summer Peak Adder	$0.01000	$0.01000	$0.01000	$0.01000
	Summer Super Off-Peak Credit	-$0.01000	-$0.01000	-$0.01000	-$0.01000
	Winter Energy Charge	$0.07624	$0.06421	$0.05991	$0.06033
	Winter Super Off-Peak Credit	-$0.01000	-$0.01000	-$0.01000	-$0.01000

Note: The prices shown in the table are for secondary voltage and do not include riders, taxes, and other applicable fees. Please refer to the Appendix for prices for other voltage levels. Rates shown are indicative and calculated based on proposed Hours Use charges for SGSE, MGSE, LGSE and PGSE in this rate case. The final rates will be based on the Commission's approved revenue requirement and corresponding billing determinants for the rate class.

* SGS facilities charge is only assessed for demand beyond 25 kW.

VI. Appendix

A. Pricing Details of Recommended Rates

FIGURE 14: RECOMMENDED SGS REPLACEMENT RATE (OPTION 3) AND OPT-IN RATE (OPTION 6)

Rate	Voltage	Summer Volumetric ($/kWh) Peak	Summer Volumetric ($/kWh) Off	Summer Volumetric ($/kWh) Super Off	Summer Demand ($/kW-month)	Winter Volumetric ($/kWh) Off	Winter Volumetric ($/kWh) Super Off	Winter Demand ($/kW-month)
3. Seasonal Volumetric Energy + Partial On-Peak Demand	Secondary	$0.07519	$0.07519	$0.07519	$15.044	$0.07624	$0.07624	$6.607
	Primary	$0.07516	$0.07516	$0.07516	$15.037	$0.07409	$0.07409	$6.248
6. TOU Energy + Partial On-Peak Demand	Secondary	$0.13306	$0.07504	$0.02920	$15.044	$0.08287	$0.04288	$6.607
	Primary	$0.13302	$0.07501	$0.02919	$15.037	$0.08047	$0.04164	$6.248
Peak Adder/Super Off-Peak Credit (Applies to Option 3)		$0.01000		-$0.01000			-$0.01000	

Note: In addition to the charges presented above, bills will include a customer charge, a facilities charge, riders, taxes, and any applicable fees.

FIGURE 15: RECOMMENDED MGS REPLACEMENT RATE (OPTION 3) AND OPT-IN RATE (OPTION 6)

Rate	Voltage	Summer Volumetric ($/kWh) Peak	Summer Volumetric ($/kWh) Off	Summer Volumetric ($/kWh) Super Off	Summer Demand ($/kW-month)	Winter Volumetric ($/kWh) Off	Winter Volumetric ($/kWh) Super Off	Winter Demand ($/kW-month)
3. Seasonal Volumetric Energy + Partial On-Peak Demand	Secondary	$0.06301	$0.06301	$0.06301	$14.640	$0.06421	$0.06421	$6.336
	Primary	$0.06466	$0.06466	$0.06466	$12.823	$0.06553	$0.06553	$6.001
6. TOU Energy + Partial On-Peak Demand	Secondary	$0.11171	$0.06260	$0.02465	$14.640	$0.06910	$0.03567	$6.336
	Primary	$0.11465	$0.06424	$0.02530	$12.823	$0.07057	$0.03643	$6.001
Peak Adder/Super Off-Peak Credit (Applies to Option 3)		$0.01000		-$0.01000			-$0.01000	

Note: In addition to the charges presented above, bills will include a customer charge, a facilities charge, riders, taxes, and any applicable fees.

FIGURE 16: RECOMMENDED LGS REPLACEMENT RATE (OPTION 3) AND OPT-IN RATE (OPTION 6)

Rate	Voltage	Summer				Winter		
		Volumetric ($/kWh)			Demand ($/kW-month)	Volumetric ($/kWh)		Demand ($/kW-month)
		Peak	Off	Super Off		Off	Super Off	
3. Seasonal Volumetric Energy + Partial On-Peak Demand	Secondary	$0.05762	$0.05762	$0.05762	$15.277	$0.05991	$0.05991	$6.705
	Primary	$0.05549	$0.05549	$0.05549	$16.386	$0.05673	$0.05673	$7.139
6. TOU Energy + Partial On-Peak Demand	Secondary	$0.10395	$0.05786	$0.02312	$15.277	$0.06482	$0.03268	$6.705
	Primary	$0.10006	$0.05569	$0.02226	$16.386	$0.06126	$0.03088	$7.139
Peak Adder/Super Off-Peak Credit (Applies to Option 3)		$0.01000		-$0.01000			-$0.01000	

Note: In addition to the charges presented above, bills will include a customer charge, a facilities charge, riders, taxes, and any applicable fees.

FIGURE 17: RECOMMENDED LPS REPLACEMENT RATE (OPTION 3) AND OPT-IN RATE (OPTION 6)

Rate	Voltage	Summer				Winter		
		Volumetric ($/kWh)			Demand ($/kW-month)	Volumetric ($/kWh)		Demand ($/kW-month)
		Peak	Off	Super Off		Off	Super Off	
3. Seasonal Volumetric Energy + Partial On-Peak Demand	Secondary	$0.05966	$0.05966	$0.05966	$13.925	$0.06033	$0.06033	$7.250
	Primary	$0.05320	$0.05320	$0.05320	$14.944	$0.05433	$0.05433	$7.515
	Substation	$0.04685	$0.04685	$0.04685	$13.385	$0.04874	$0.04874	$6.525
	Transmission	$0.04762	$0.04762	$0.04762	$13.784	$0.05016	$0.05016	$6.777
6. TOU Energy + Partial On-Peak Demand	Secondary	$0.11133	$0.06166	$0.02491	$13.925	$0.06645	$0.03173	$7.250
	Primary	$0.09900	$0.05483	$0.02215	$14.944	$0.05955	$0.02844	$7.515
	Substation	$0.08689	$0.04812	$0.01944	$13.385	$0.05313	$0.02537	$6.525
	Transmission	$0.08836	$0.04894	$0.01977	$13.784	$0.05476	$0.02615	$6.777
Peak Adder/Super Off-Peak Credit (Applies to Option 3)		$0.01000		-$0.01000			-$0.01000	

Note: In addition to the charges presented above, bills will include a customer charge, a facilities charge, riders, taxes, and any applicable fees.

B. Bill Impacts by Voltage Level

Below are the customer bill impacts by voltage level. Note that given the small number of LPS customers, we do not report bill impacts for that class by voltage level.

FIGURE 18: SGS SECONDARY BILL IMPACTS

Replacement Option	% of customers with bill increases >10%	% bill increase for 95th percentile customer	% of customers with bill savings	Avg. % bill increase among non-benefiters
1. Seasonal, Flat Volumetric Energy Charge (No Demand)	15%	19%	60%	9%
2. Seasonal Volumetric Energy + On-Peak Demand	29%	82%	57%	39%
3. Seasonal Volumetric Energy + Partial On-Peak Demand	15%	33%	57%	14%
4. Seasonal Volumetric Energy + Partial Non-Coincident Demand	16%	38%	57%	16%
5. TOU Energy (No Demand)	13%	17%	67%	9%
6. TOU Energy + Partial On-Peak Demand	15%	34%	58%	15%

FIGURE 19: SGS PRIMARY BILL IMPACTS

Replacement Option	% of customers with bill increases >10%	% bill increase for 95th percentile customer	% of customers with bill savings	Avg. % bill increase among non-benefiters
1. Seasonal, Flat Volumetric Energy Charge (No Demand)	10%	15%	67%	8%
2. Seasonal Volumetric Energy + On-Peak Demand	15%	34%	62%	17%
3. Seasonal Volumetric Energy + Partial On-Peak Demand	5%	11%	82%	10%
4. Seasonal Volumetric Energy + Partial Non-Coincident Demand	10%	23%	74%	13%
5. TOU Energy (No Demand)	13%	12%	67%	8%
6. TOU Energy + Partial On-Peak Demand	5%	11%	79%	8%

FIGURE 20: MGS SECONDARY BILL IMPACTS

Replacement Option	% of customers with bill increases >10%	% bill increase for 95th percentile customer	% of customers with bill savings	Avg. % bill increase among non-benefiters
1. Seasonal, Flat Volumetric Energy Charge (No Demand)	7%	11%	68%	6%
2. Seasonal Volumetric Energy + On-Peak Demand	36%	79%	40%	26%
3. Seasonal Volumetric Energy + Partial On-Peak Demand	13%	27%	44%	8%
4. Seasonal Volumetric Energy + Partial Non-Coincident Demand	13%	28%	57%	10%
5. TOU Energy (No Demand)	4%	9%	66%	5%
6. TOU Energy + Partial On-Peak Demand	13%	27%	39%	8%

FIGURE 21: MGS PRIMARY BILL IMPACTS

Replacement Option	% of customers with bill increases >10%	% bill increase for 95th percentile customer	% of customers with bill savings	Avg. % bill increase among non-benefiters
1. Seasonal, Flat Volumetric Energy Charge (No Demand)	22%	17%	57%	11%
2. Seasonal Volumetric Energy + On-Peak Demand	32%	53%	46%	21%
3. Seasonal Volumetric Energy + Partial On-Peak Demand	11%	18%	22%	5%
4. Seasonal Volumetric Energy + Partial Non-Coincident Demand	22%	19%	35%	7%
5. TOU Energy (No Demand)	22%	15%	54%	9%
6. TOU Energy + Partial On-Peak Demand	8%	18%	24%	5%

FIGURE 22: LGS SECONDARY BILL IMPACTS

Replacement Option	% of customers with bill increases >10%	% bill increase for 95th percentile customer	% of customers with bill savings	Avg. % bill increase among non-benefiters
1. Seasonal, Flat Volumetric Energy Charge (No Demand)	10%	13%	66%	8%
2. Seasonal Volumetric Energy + On-Peak Demand	25%	51%	46%	19%
3. Seasonal Volumetric Energy + Partial On-Peak Demand	6%	12%	49%	6%
4. Seasonal Volumetric Energy + Partial Non-Coincident Demand	5%	11%	56%	5%
5. TOU Energy (No Demand)	8%	12%	66%	7%
6. TOU Energy + Partial On-Peak Demand	6%	12%	46%	5%

FIGURE 23: LGS PRIMARY BILL IMPACTS

Replacement Option	% of customers with bill increases >10%	% bill increase for 95th percentile customer	% of customers with bill savings	Avg. % bill increase among non-benefiters
1. Seasonal, Flat Volumetric Energy Charge (No Demand)	7%	11%	71%	6%
2. Seasonal Volumetric Energy + On-Peak Demand	22%	91%	19%	18%
3. Seasonal Volumetric Energy + Partial On-Peak Demand	7%	28%	47%	8%
4. Seasonal Volumetric Energy + Partial Non-Coincident Demand	7%	24%	58%	9%
5. TOU Energy (No Demand)	6%	10%	74%	6%
6. TOU Energy + Partial On-Peak Demand	7%	28%	53%	9%

			Current Rates Post-Rate Design Billing Determinants			Step 1: Demand Threshold Demand Interval		Step 2: Eliminations	
						-0.89%		Secondary -0.10% Primary 3.14%	
Rate Code	Voltage	Component	Billing Determinants	Current Rate	Current Revenue	Rate	Revenue	Rate	Revenue
1SGSE	SGS Secondary	Customer Charge 1	**291,816**	$ 18.69	$ 5,454,045.27	$21.41	$ 6,249,183.14	$ 21.41	$ 6,249,183.14
1SGSE	SGS Secondary	Customer Charge 2	**27,155**	$ 51.81	$ 1,406,891.61	$21.41	$ 581,514.92	$ 21.41	$ 581,514.92
1SGSE	SGS Secondary	Customer Charge 3	**157**	$ 105.24	$ 16,562.33	$21.41	$ 3,370.19	$ 21.41	$ 3,370.19
1SGSE	SGS Secondary	Customer Charge 4	**12**	$ 898.57	$ 10,850.77	$21.41	$ 258.60	$ 21.41	$ 258.60
1SGSE	SGS Secondary	Facilities Charge - Block 1	**2,397,075**	$ -	$ -	$ -	$ -	$ -	$ -
1SGSE	SGS Secondary	Facilities Charge - Block 2	**95,513**	$ 3.011	$ 287,588.76	$ 2.98	$ 285,034.14	$ 2.981	$ 284,761.27
1SGSE	SGS Secondary	Energy Charge - Summer - Blk 1	**99,308,201**	$ 0.16583	$ 16,468,279.01	$ 0.16	$16,321,992.64	$0.16420	$16,306,367.10
1SGSE	SGS Secondary	Energy Charge - Summer - Blk 2	**47,737,712**	$ 0.07871	$ 3,757,435.29	$ 0.08	$ 3,724,058.30	$0.07794	$ 3,720,493.15
1SGSE	SGS Secondary	Energy Charge - Summer - Blk 3	**15,562,359**	$ 0.07010	$ 1,090,921.37	$ 0.07	$ 1,081,230.81	$0.06941	$ 1,080,195.71
1SGSE	SGS Secondary	Energy Charge - Winter - Blk 1	**161,404,278**	$ 0.12885	$ 20,796,941.18	$ 0.13	$20,612,203.66	$0.12758	$20,592,470.97
1SGSE	SGS Secondary	Energy Charge -Winter - Blk 2	**72,394,110**	$ 0.06291	$ 4,554,313.47	$ 0.06	$ 4,513,857.88	$0.06229	$ 4,509,536.62
1SGSE	SGS Secondary	Energy Charge -Winter - Blk 3	**26,761,817**	$ 0.05679	$ 1,519,803.61	$ 0.06	$ 1,506,303.32	$0.05623	$ 1,504,861.29
1SGSE	SGS Secondary	On-Peak Adjustment - Summer	**0**	$ 0.14397	$ -	$ 0.14	$ -	$0.14255	$ -
1SGSE	SGS Secondary	Off-Peak Adjustment - Summer	**0**	$ 0.06179	$ -	$ 0.06	$ -	$0.06118	$ -
1SGSE	SGS Secondary	On-Peak Adjustment - Winter	**0**	$ 0.05574	$ -	$ 0.06	$ -	$0.05519	$ -
1SGSE	SGS Secondary	Off-Peak Adjustment - Winter	**0**	$ 0.04810	$ -	$ 0.05	$ -	$0.04763	$ -
1SGSE	SGS Secondary	Net Meter Credit			$ (19,605.85)		$ (19,605.85)		$ (19,605.85)
1SGSE	SGS Secondary	Parallel Generation Credit			$ (683.28)		$ (683.28)		$ (683.28)
1SGSE	SGS Secondary	EDR Credit			$ (3,073.16)	$ -	$ (3,073.16)	$ -	$ (3,073.16)
1SGSES	SGS Secondary	Customer Charge 1	**12**	$ 18.69	$ 225.69	$21.41	$ 258.60	$ 21.41	$ 258.60
1SGSES	SGS Secondary	Customer Charge 2	**0**	$ 51.81	$ -	$21.41	$ -	$ 21.41	$ -
1SGSES	SGS Secondary	Customer Charge 3	**0**	$ 105.24	$ -	$21.41	$ -	$ 21.41	$ -
1SGSES	SGS Secondary	Customer Charge 4	**0**	$ 898.57	$ -	$21.41	$ -	$ 21.41	$ -
1SGSES	SGS Secondary	Facilities Charge - Block 1	**156**	$ -	$ -	$ -	$ -	$ -	$ -
1SGSES	SGS Secondary	Facilities Charge - Block 2	**0**	$ 3.011	$ -	$ 2.98	$ -	$ 2.981	$ -
1SGSES	SGS Secondary	Energy Charge - Summer - Blk 1	**1,746**	$ 0.16583	$ 289.56	$ 0.16	$ 286.98	$0.16420	$ 286.71
1SGSES	SGS Secondary	Energy Charge - Summer - Blk 2	**0**	$ 0.07871	$ -	$ 0.08	$ -	$0.07794	$ -
1SGSES	SGS Secondary	Energy Charge - Summer - Blk 3	**39**	$ 0.07010	$ 2.70	$ 0.07	$ 2.68	$0.06941	$ 2.68
1SGSES	SGS Secondary	Energy Charge - Winter - Blk 1	**9,638**	$ 0.12885	$ 1,241.79	$ 0.13	$ 1,230.76	$0.12758	$ 1,229.58
1SGSES	SGS Secondary	Energy Charge -Winter - Blk 2	**481**	$ 0.06291	$ 30.23	$ 0.06	$ 29.96	$0.06229	$ 29.93
1SGSES	SGS Secondary	Energy Charge -Winter - Blk 3	**174**	$ 0.05679	$ 9.86	$ 0.06	$ 9.77	$0.05623	$ 9.76
1SGSES	SGS Secondary	On-Peak Adjustment - Summer	**0**	$ -	$ -	$ -	$ -	$ -	$ -
1SGSES	SGS Secondary	Off-Peak Adjustment - Summer	**0**	$ -	$ -	$ -	$ -	$ -	$ -
1SGSES	SGS Secondary	On-Peak Adjustment - Winter	**0**	$ -	$ -	$ -	$ -	$ -	$ -
1SGSES	SGS Secondary	Off-Peak Adjustment - Winter	**0**	$ -	$ -	$ -	$ -	$ -	$ -
1SGSE	SGS Secondary	Solar Access Charge			$ 545.35		$ 545.35		$ 545.35
1SGSE	SGS Secondary	Solar Farm Block			$ 2,454.20		$ 2,454.20		$ 2,454.20
1SGSE	SGS Secondary	Solar Credit Charge			$ (2.59)		$ (2.59)		$ (2.59)
1SGSEW	SGS Secondary	Customer Charge 1	**9**	$ 18.69	$ 169.18	$21.41	$ 193.84	$ 21.41	$ 193.84
1SGSEW	SGS Secondary	Customer Charge 2	**0**	$ 51.81	$ -	$21.41	$ -	$ 21.41	$ -
1SGSEW	SGS Secondary	Customer Charge 3	**0**	$ 105.24	$ -	$21.41	$ -	$ 21.41	$ -
1SGSEW	SGS Secondary	Customer Charge 4	**0**	$ 898.57	$ -	$21.41	$ -	$ 21.41	$ -
1SGSEW	SGS Secondary	Facilities Charge - Block 1	**170**	$ -	$ -	$ -	$ -	$ -	$ -
1SGSEW	SGS Secondary	Facilities Charge - Block 2	**0**	$ 3.011	$ -	$ 2.98	$ -	$ 2.981	$ -
1SGSEW	SGS Secondary	Energy Charge - Summer - Blk 1	**1,233**	$ 0.16583	$ 204.55	$ 0.16	$ 202.73	$0.16420	$ 202.54
1SGSEW	SGS Secondary	Energy Charge - Summer - Blk 2	**110**	$ 0.07871	$ 8.66	$ 0.08	$ 8.58	$0.07794	$ 8.57
1SGSEW	SGS Secondary	Energy Charge - Summer - Blk 3	**0**	$ 0.07010	$ -	$ 0.07	$ -	$0.06941	$ -
1SGSEW	SGS Secondary	Energy Charge - Winter - Blk 1	**19,122**	$ 0.12885	$ 2,463.89	$ 0.13	$ 2,442.00	$0.12758	$ 2,439.67
1SGSEW	SGS Secondary	Energy Charge -Winter - Blk 2	**11,697**	$ 0.06291	$ 735.87	$ 0.06	$ 729.33	$0.06229	$ 728.63
1SGSEW	SGS Secondary	Energy Charge -Winter - Blk 3	**443**	$ 0.05679	$ 25.17	$ 0.06	$ 24.95	$0.05623	$ 24.93
1SGSEW	SGS Secondary	On-Peak Adjustment - Summer	**0**	$ 0.14397	$ -	$ 0.14	$ -	$0.14255	$ -
1SGSEW	SGS Secondary	Off-Peak Adjustment - Summer	**0**	$ 0.06179	$ -	$ 0.06	$ -	$0.06118	$ -
1SGSEW	SGS Secondary	On-Peak Adjustment - Winter	**0**	$ 0.05574	$ -	$ 0.06	$ -	$0.05519	$ -
1SGSEW	SGS Secondary	Off-Peak Adjustment - Winter	**0**	$ 0.04810	$ -	$ 0.05	$ -	$0.04763	$ -
1SUSE	SGS Secondary	Customer Charge 1	**14,471**	$ 7.84	$ 113,455.61	$ 7.77	$ 112,447.79	$ 8.11	$ 117,415.79
1SUSE	SGS Secondary	Customer Charge 2	**0**	$ -	$ -	$ -	$ -	$ -	$ -
1SUSE	SGS Secondary	Customer Charge 3	**0**	$ -	$ -	$ -	$ -	$ -	$ -
1SUSE	SGS Secondary	Customer Charge 4	**0**	$ -	$ -	$ -	$ -	$ -	$ -
1SUSE	SGS Secondary	Facilities Charge - Block 1	**29,897**	$ -	$ -	$ -	$ -	$ -	$ -
1SUSE	SGS Secondary	Facilities Charge - Block 2	**0**	$ 3.011	$ -	$ 2.98	$ -	$ 2.981	$ -
1SUSE	SGS Secondary	Energy Charge - Summer - Blk 1	**1,354,205**	$ 0.16583	$ 224,567.75	$ 0.16	$ 222,572.93	$0.16420	$ 222,359.86
1SUSE	SGS Secondary	Energy Charge - Summer - Blk 2	**850,813**	$ 0.07871	$ 66,967.53	$ 0.08	$ 66,372.66	$0.07794	$ 66,309.12
1SUSE	SGS Secondary	Energy Charge - Summer - Blk 3	**51,757**	$ 0.07010	$ 3,628.17	$ 0.07	$ 3,595.94	$0.06941	$ 3,592.49
1SUSE	SGS Secondary	Energy Charge - Winter - Blk 1	**2,616,498**	$ 0.12885	$ 337,135.77	$ 0.13	$ 334,141.02	$0.12758	$ 333,821.14
1SUSE	SGS Secondary	Energy Charge -Winter - Blk 2	**1,665,268**	$ 0.06291	$ 104,762.01	$ 0.06	$ 103,831.42	$0.06229	$ 103,732.02
1SUSE	SGS Secondary	Energy Charge -Winter - Blk 3	**102,159**	$ 0.05679	$ 5,801.59	$ 0.06	$ 5,750.06	$0.05623	$ 5,744.55
1SUSE	SGS Secondary	On-Peak Adjustment - Summer	**0**	$ 0.14397	$ -	$ 0.14	$ -	$0.14255	$ -
1SUSE	SGS Secondary	Off-Peak Adjustment - Summer	**0**	$ 0.06179	$ -	$ 0.06	$ -	$0.06118	$ -
1SUSE	SGS Secondary	On-Peak Adjustment - Winter	**0**	$ 0.05574	$ -	$ 0.06	$ -	$0.05519	$ -
1SUSE	SGS Secondary	Off-Peak Adjustment - Winter	**0**	$ 0.04810	$ -	$ 0.05	$ -	$0.04763	$ -
1SGSF	SGS Primary	Customer Charge 1	**345**	$ 18.69	$ 6,447.91	$21.41	$ 7,387.94	$ 21.41	$ 7,387.94
1SGSF	SGS Primary	Customer Charge 2	**160**	$ 51.81	$ 8,314.30	$21.41	$ 3,436.57	$ 21.41	$ 3,436.57
1SGSF	SGS Primary	Customer Charge 3	**41**	$ 105.24	$ 4,342.17	$21.41	$ 883.57	$ 21.41	$ 883.57
1SGSF	SGS Primary	Customer Charge 4	**0**	$ 898.57	$ -	$21.41	$ -	$ 21.41	$ -
1SGSF	SGS Primary	Facilities Charge - Block 1	**6,727**	$ -	$ -	$ -	$ -	$ -	$ -
1SGSF	SGS Primary	Facilities Charge - Block 2	**15,084**	$ 2.94	$ 44,345.61	$ 2.91	$ 43,951.69	$ 3.005	$ 45,331.32
1SGSF	SGS Primary	Energy Charge - Summer - Blk 1	**371,996**	$ 0.16	$ 60,281.95	$ 0.16	$ 59,746.47	$0.16565	$ 61,621.88
1SGSF	SGS Primary	Energy Charge - Summer - Blk 2	**194,685**	$ 0.08	$ 14,969.37	$ 0.08	$ 14,836.39	$0.07860	$ 15,302.10
1SGSF	SGS Primary	Energy Charge - Summer - Blk 3	**56,868**	$ 0.07	$ 3,894.88	$ 0.07	$ 3,860.28	$0.07001	$ 3,981.45
1SGSF	SGS Primary	Energy Charge - Winter - Blk 1	**627,177**	$ 0.13	$ 78,974.17	$ 0.12	$ 78,272.64	$0.12872	$ 80,729.59
1SGSF	SGS Primary	Energy Charge -Winter - Blk 2	**332,345**	$ 0.061	$ 20,429.26	$ 0.06	$ 20,247.79	$0.06284	$ 20,883.36
1SGSF	SGS Primary	Energy Charge -Winter - Blk 3	**171,750**	$ 0.055	$ 9,526.97	$ 0.05	$ 9,442.34	$0.05670	$ 9,738.73

			Current Rates Post-Rate Design Billing Determinants			Step 1: Demand Threshold Demand Interval		Step 2: Eliminations	
								Secondary	-0.10%
						-0.89%		Primary	3.14%
1SGSF	SGS Primary	On-Peak Adjustment - Summer	**0**	$ 0.133	$ -	$ 0.13	$ -	$0.13586	$ -
1SGSF	SGS Primary	Off-Peak Adjustment - Summer	**0**	$ 0.058	$ -	$ 0.06	$ -	$0.05967	$ -
1SGSF	SGS Primary	On-Peak Adjustment - Winter	**0**	$ 0.054	$ -	$ 0.05	$ -	$0.05528	$ -
1SGSF	SGS Primary	Off-Peak Adjustment - Winter	**0**	$ 0.047	$ -	$ 0.05	$ -	$0.04772	$ -
1SGSF	SGS Primary	Net Meter Credit			$ (370.66)		$ (370.66)		$ (370.66)
1SGAE	SGA Secondary	Customer Charge 1	**0**	$ 18.69	$ -				
1SGAE	SGA Secondary	Customer Charge 2	**0**	$ 51.81	$ -				
1SGAE	SGA Secondary	Customer Charge 3	**0**	$ 105.24	$ -				
1SGAE	SGA Secondary	Customer Charge 4	**0**	$ 898.57	$ -				
1SGAE	SGA Secondary	Facilities Charge - Block 1	**0**	$ -	$ -				
1SGAE	SGA Secondary	Facilities Charge - Block 2	**0**	$ 3.01	$ -				
1SGAE	SGA Secondary	Energy Charge - Summer - Blk 1	**0**	$ 0.17	$ -				
1SGAE	SGA Secondary	Energy Charge - Summer - Blk 2	**0**	$ 0.08	$ -				
1SGAE	SGA Secondary	Energy Charge - Summer - Blk 3	**0**	$ 0.07	$ -				
1SGAE	SGA Secondary	Energy Charge - Winter - Blk 1	**0**	$ 0.118	$ -				
1SGAE	SGA Secondary	Energy Charge -Winter - Blk 2	**0**	$ 0.063	$ -				
1SGAE	SGA Secondary	Energy Charge -Winter - Blk 3	**0**	$ 0.057	$ -				
1SGAE	SGA Secondary	On-Peak Adjustment - Summer	**0**	$ 0.144	$ -				
1SGAE	SGA Secondary	Off-Peak Adjustment - Summer	**0**	$ 0.062	$ -				
1SGAE	SGA Secondary	On-Peak Adjustment - Winter	**0**	$ 0.056	$ -				
1SGAE	SGA Secondary	Off-Peak Adjustment - Winter	**0**	$ 0.04810	$ -				
1SGAF	SGA Primary	Customer Charge 1	**0**	$ 18.69	$ -				
1SGAF	SGA Primary	Customer Charge 2	**0**	$ 51.81	$ -				
1SGAF	SGA Primary	Customer Charge 3	**0**	$ 105.24	$ -				
1SGAF	SGA Primary	Customer Charge 4	**0**	$ 898.57	$ -				
1SGAF	SGA Primary	Facilities Charge - Block 1	**0**	$ -	$ -				
1SGAF	SGA Primary	Facilities Charge - Block 2	**0**	$ 2.94	$ -				
1SGAF	SGA Primary	Energy Charge - Summer - Blk 1	**0**	$ 0.16	$ -				
1SGAF	SGA Primary	Energy Charge - Summer - Blk 2	**0**	$ 0.08	$ -				
1SGAF	SGA Primary	Energy Charge - Summer - Blk 3	**0**	$ 0.07	$ -				
1SGAF	SGA Primary	Energy Charge - Winter - Blk 1	**0**	$ 0.11	$ -				
1SGAF	SGA Primary	Energy Charge -Winter - Blk 2	**0**	$ 0.060	$ -				
1SGAF	SGA Primary	Energy Charge -Winter - Blk 3	**0**	$ 0.054	$ -				
1SGAF	SGA Primary	On-Peak Adjustment - Summer	**0**	$ 0.133	$ -				
1SGAF	SGA Primary	Off-Peak Adjustment - Summer	**0**	$ 0.058	$ -				
1SGAF	SGA Primary	On-Peak Adjustment - Winter	**0**	$ 0.054	$ -				
1SGAF	SGA Primary	Off-Peak Adjustment - Winter	**0**	$ 0.047	$ -				

				Current Rates Post-Rate Design Billing Determinants		Step 1: Demand Threshold Demand Interval		Step 2: Eliminations	
								Secondary	-0.18%
							-0.89%	Primary	-0.62%
Rate Code	Voltage	Charges from UI Extract	Billing Determinants	Current Rate	Current Revenue	Rate	Revenue	Rate	Revenue
1MGSE	MGS Secondary	Customer Charge 1	**837**	$ 55.47	$ 46,421.24	$ 60.08	$ 50,282.18	$ 60.08	$ 50,282.18
1MGSE	MGS Secondary	Customer Charge 2	**55,626**	$ 55.47	$ 3,085,568.29	$ 60.08	$ 3,342,201.26	$ 60.08	$ 3,342,201.26
1MGSE	MGS Secondary	Customer Charge 3	**4,621**	$ 112.65	$ 520,531.02	$ 60.08	$ 277,632.96	$ 60.08	$ 277,632.96
1MGSE	MGS Secondary	Customer Charge 4	**0**	$ 961.83	$ -	$ 60.08	$ -	$ 60.08	$ -
1MGSE	MGS Secondary	Facilities Charge - Block 1	**5,029,359**	$ 3.223	$ 16,209,623.28	$ 3.19	$16,065,634.53	$ 3.189	$ 16,037,434.61
1MGSE	MGS Secondary	Demand Charge - Summer - Blk 1	**1,245,709**	$ 4.217	$ 5,253,154.63	$ 4.18	$ 5,206,491.29	$ 4.172	$ 5,197,352.36
1MGSE	MGS Secondary	Demand Charge - Winter - Blk 1	**2,259,227**	$ 2.145	$ 4,846,042.90	$ 2.13	$ 4,802,995.90	$ 2.122	$ 4,794,565.22
1MGSE	MGS Secondary	Energy Charge - Summer - Blk 1	**216,241,219**	$ 0.10953	$ 23,684,900.69	$ 0.11	$23,474,509.67	$ 0.10837	$ 23,433,304.99
1MGSE	MGS Secondary	Energy Charge - Summer - Blk 2	**150,117,739**	$ 0.07492	$ 11,246,821.00	$ 0.07	$11,146,916.41	$ 0.07412	$ 11,127,350.29
1MGSE	MGS Secondary	Energy Charge - Summer - Blk 3	**49,753,811**	$ 0.06319	$ 3,143,943.34	$ 0.06	$ 3,116,015.95	$ 0.06252	$ 3,110,546.43
1MGSE	MGS Secondary	Energy Charge - Winter - Blk 1	**370,464,015**	$ 0.09464	$ 35,060,714.35	$ 0.09	$34,749,272.91	$ 0.09363	$ 34,688,277.70
1MGSE	MGS Secondary	Energy Charge -Winter - Blk 2	**245,273,567**	$ 0.05664	$ 13,892,294.83	$ 0.06	$13,768,890.72	$ 0.05604	$ 13,744,722.25
1MGSE	MGS Secondary	Energy Charge -Winter - Blk 3	**82,155,385**	$ 0.04751	$ 3,903,202.32	$ 0.05	$ 3,868,530.49	$ 0.04701	$ 3,861,740.08
1MGSE	MGS Secondary	Reactive Demand Adj	**0**	$ 0.80300	$ -		$ -	$ -	$ -
1MGSE	MGS Secondary	Net Metering Credit			$ (6,187.97)		$ (6,187.97)		$ (6,187.97)
1MGSE	MGS Secondary	Parallel Generation Credit			$ (5,059.53)		$ (5,059.53)		$ (5,059.53)
1MGSE	MGS Secondary	EDR Credit			$ (26,892.70)		$ (26,892.70)		$ (26,892.70)
1MGSF	MGS Primary	Customer Charge 1	**3**	$ 55.47	$ 175.03	$ 60.08	$ 189.59	$ 60.08	$ 189.59
1MGSF	MGS Primary	Customer Charge 2	**266**	$ 55.47	$ 14,779.65	$ 60.08	$ 16,008.91	$ 60.08	$ 16,008.91
1MGSF	MGS Primary	Customer Charge 3	**157**	$ 112.65	$ 17,639.00	$ 60.08	$ 9,408.02	$ 60.08	$ 9,408.02
1MGSF	MGS Primary	Customer Charge 4	**49**	$ 961.83	$ 46,673.45	$ 60.08	$ 2,915.59	$ 60.08	$ 2,915.59
1MGSF	MGS Primary	Facilities Charge - Block 1	**352,842**	$ 2.67	$ 942,440.87	$ 2.65	$ 934,069.24	$ 2.631	$ 928,258.75
1MGSF	MGS Primary	Demand Charge - Summer - Blk 1	**68,761**	$ 4.118	$ 283,157.72	$ 4.08	$ 280,642.45	$ 4.056	$ 278,896.68
1MGSF	MGS Primary	Demand Charge - Winter - Blk 1	**131,552**	$ 2.094	$ 275,470.22	$ 2.08	$ 273,023.24	$ 2.062	$ 271,324.87
1MGSF	MGS Primary	Energy Charge - Summer - Blk 1	**12,006,216**	$ 0.107	$ 1,283,584.55	$ 0.11	$ 1,272,182.58	$ 0.10530	$ 1,264,268.82
1MGSF	MGS Primary	Energy Charge - Summer - Blk 2	**5,820,303**	$ 0.07323	$ 426,220.77	$ 0.07	$ 422,434.69	$ 0.07213	$ 419,806.88
1MGSF	MGS Primary	Energy Charge - Summer - Blk 3	**1,326,156**	$ 0.06174	$ 81,876.89	$ 0.06	$ 81,149.59	$ 0.06081	$ 80,644.79
1MGSF	MGS Primary	Energy Charge - Winter - Blk 1	**23,086,020**	$ 0.09242	$ 2,133,609.99	$ 0.09	$ 2,114,657.31	$ 0.09103	$ 2,101,502.84
1MGSF	MGS Primary	Energy Charge -Winter - Blk 2	**10,333,936**	$ 0.05533	$ 571,776.67	$ 0.05	$ 566,697.62	$ 0.05450	$ 563,172.41
1MGSF	MGS Primary	Energy Charge -Winter - Blk 3	**3,318,077**	$ 0.04660	$ 154,622.37	$ 0.05	$ 153,248.87	$ 0.04590	$ 152,295.57
1MGSF	MGS Primary	Reactive Demand Adj	**0**	$ 0.80300	$ -				
1MGSF	MGS Primary	Net Metering Credit			$ (151.14)		$ (151.14)		$ (151.14)
1MGAE	MGA Secondary	Customer Charge 1	**0**	$ 55.47	$ -				
1MGAE	MGA Secondary	Customer Charge 2	**0**	$ 55.47	$ -				
1MGAE	MGA Secondary	Customer Charge 3	**0**	$ 112.65	$ -				
1MGAE	MGA Secondary	Customer Charge 4	**0**	$ 961.83	$ -				
1MGAE	MGA Secondary	Facilities Charge - Block 1	**0**	$ 3.22	$ -				
1MGAE	MGA Secondary	Demand Charge - Summer - Blk 1	**0**	$ 4.22	$ -				
1MGAE	MGA Secondary	Demand Charge - Winter - Blk 1	**0**	$ 3.04	$ -				
1MGAE	MGA Secondary	Energy Charge - Summer - Blk 1	**0**	$ 0.11	$ -				
1MGAE	MGA Secondary	Energy Charge - Summer - Blk 2	**0**	$ 0.07	$ -				
1MGAE	MGA Secondary	Energy Charge - Summer - Blk 3	**0**	$ 0.06	$ -				
1MGAE	MGA Secondary	Energy Charge - Winter - Blk 1	**0**	$ 0.083	$ -				
1MGAE	MGA Secondary	Energy Charge -Winter - Blk 2	**0**	$ 0.048	$ -				
1MGAE	MGA Secondary	Energy Charge -Winter - Blk 3	**0**	$ 0.041	$ -				
1MGAE	MGA Secondary	Reactive Demand Adj	**0**	$ 0.803	$ -				
1MGAF	MGA Primary	Customer Charge 1	**0**	$ 55.47	$ -				
1MGAF	MGA Primary	Customer Charge 2	**0**	$ 55.47	$ -				
1MGAF	MGA Primary	Customer Charge 3	**0**	$ 112.65	$ -				
1MGAF	MGA Primary	Customer Charge 4	**0**	$ 961.83	$ -				
1MGAF	MGA Primary	Facilities Charge - Block 1	**0**	$ 2.67	$ -				
1MGAF	MGA Primary	Demand Charge - Summer - Blk 1	**0**	$ 4.12	$ -				
1MGAF	MGA Primary	Demand Charge - Winter - Blk 1	**0**	$ 2.97	$ -				
1MGAF	MGA Primary	Energy Charge - Summer - Blk 1	**0**	$ 0.11	$ -				
1MGAF	MGA Primary	Energy Charge - Summer - Blk 2	**0**	$ 0.07	$ -				
1MGAF	MGA Primary	Energy Charge - Summer - Blk 3	**0**	$ 0.06	$ -				
1MGAF	MGA Primary	Energy Charge - Winter - Blk 1	**0**	$ 0.081	$ -				
1MGAF	MGA Primary	Energy Charge -Winter - Blk 2	**0**	$ 0.046	$ -				
1MGAF	MGA Primary	Energy Charge -Winter - Blk 3	**0**	$ 0.040	$ -				
1MGAF	MGA Primary	Reactive Demand Adj	**0**	$ 0.803	$ -				

						Step 1: Demand Threshold Demand Interval		Step 2: Eliminations	
			Current Rates Post-Rate Design Billing Determinants			-0.89%		Secondary -0.67% Primary 0.56%	
Rate Code	Voltage	Charges from UI Extract	Billing Determinants	Current Rate	Current Revenue	Rate	Revenue	Rate	Revenue
1LGSE	LGS Secondary	Customer Charge 1	**83**	$ 122.14	$ 10,173.17	$228.29	$ 19,014.34	$ 228.29	$ 19,014.34
1LGSE	LGS Secondary	Customer Charge 2	**194**	$ 122.14	$ 23,703.57	$228.29	$ 44,303.58	$ 228.29	$ 44,303.58
1LGSE	LGS Secondary	Customer Charge 3	**8,655**	$ 122.14	$ 1,057,161.19	$228.29	$ 1,975,905.73	$ 228.29	$ 1,975,905.73
1LGSE	LGS Secondary	Customer Charge 4	**924**	$ 1,042.78	$ 963,045.46	$228.29	$ 210,832.24	$ 228.29	$ 210,832.24
1LGSE	LGS Secondary	Facilities Charge - Block 1	**5,651,411**	$ 3.494	$ 19,746,030.03	$ 3.46	$19,570,627.67	$ 3.440	$19,439,960.97
1LGSE	LGS Secondary	Demand Charge - Summer - Blk 1	**1,385,368**	$ 6.978	$ 9,667,096.81	$ 6.92	$ 9,581,224.78	$ 6.870	$ 9,517,254.07
1LGSE	LGS Secondary	Demand Charge - Winter - Blk 1	**2,747,337**	$ 3.754	$ 10,313,501.69	$ 3.72	$10,221,887.71	$ 3.696	$10,153,639.50
1LGSE	LGS Secondary	Energy Charge - Summer - Blk 1	**243,148,379**	$ 0.09803	$ 23,835,835.57	$ 0.10	$23,624,103.80	$0.09651	$23,466,373.37
1LGSE	LGS Secondary	Energy Charge - Summer - Blk 2	**201,372,251**	$ 0.06758	$ 13,608,736.70	$ 0.07	$13,487,851.41	$0.06653	$13,397,797.43
1LGSE	LGS Secondary	Energy Charge - Summer - Blk 3	**116,062,781**	$ 0.04352	$ 5,051,052.23	$ 0.04	$ 5,006,184.15	$0.04285	$ 4,972,759.49
1LGSE	LGS Secondary	Energy Charge - Winter - Blk 1	**462,111,555**	$ 0.09008	$ 41,627,008.89	$ 0.09	$41,257,239.59	$0.08868	$40,981,778.46
1LGSE	LGS Secondary	Energy Charge -Winter - Blk 2	**370,061,430**	$ 0.05194	$ 19,220,990.66	$ 0.05	$19,050,252.18	$0.05113	$18,923,059.86
1LGSE	LGS Secondary	Energy Charge -Winter - Blk 3	**199,539,278**	$ 0.03657	$ 7,297,151.40	$ 0.04	$ 7,232,331.40	$0.03600	$ 7,184,043.48
1LGSE	LGS Secondary	Reactive Demand Adj	**0**	$ 0.874	$ -		$ -	$ -	$ -
1LGSE	LGS Secondary	Parallel Generation Credit			$ (6,209.80)		$ (6,209.80)		$ (6,209.80)
1LGSE	LGS Secondary	EDR Credit			$ (223,589.40)		$ (223,589.40)		$ (223,589.40)
1LGSF	LGS Primary	Customer Charge 1	**135**	$ 122.14	$ 16,445.76	$228.29	$ 30,738.24	$ 228.29	$ 30,738.24
1LGSF	LGS Primary	Customer Charge 2	**0**	$ 122.14	$ -	$228.29	$ -	$ 228.29	$ -
1LGSF	LGS Primary	Customer Charge 3	**582**	$ 122.14	$ 71,143.31	$228.29	$ 132,971.66	$ 228.29	$ 132,971.66
1LGSF	LGS Primary	Customer Charge 4	**363**	$ 1,042.78	$ 378,700.15	$228.29	$ 82,905.95	$ 228.29	$ 82,905.95
1LGSF	LGS Primary	Facilities Charge - Block 1	**1,282,828**	$ 2.897	$ 3,716,351.84	$ 2.87	$ 3,683,339.80	$ 2.887	$ 3,703,900.05
1LGSF	LGS Primary	Demand Charge - Summer - Blk 1	**336,785**	$ 6.819	$ 2,296,535.30	$ 6.76	$ 2,276,135.37	$ 6.796	$ 2,288,840.67
1LGSF	LGS Primary	Demand Charge - Winter - Blk 1	**583,508**	$ 3.669	$ 2,140,892.10	$ 3.64	$ 2,121,874.73	$ 3.657	$ 2,133,718.95
1LGSF	LGS Primary	Energy Charge - Summer - Blk 1	**64,114,244**	$ 0.09584	$ 6,144,709.16	$ 0.09	$ 6,090,126.22	$0.09552	$ 6,124,121.05
1LGSF	LGS Primary	Energy Charge - Summer - Blk 2	**57,332,642**	$ 0.06597	$ 3,782,234.41	$ 0.07	$ 3,748,637.14	$0.06575	$ 3,769,561.88
1LGSF	LGS Primary	Energy Charge - Summer - Blk 3	**36,678,927**	$ 0.04250	$ 1,558,854.40	$ 0.04	$ 1,545,007.22	$0.04236	$ 1,553,631.39
1LGSF	LGS Primary	Energy Charge - Winter - Blk 1	**106,057,773**	$ 0.08802	$ 9,335,205.15	$ 0.09	$ 9,252,281.29	$0.08773	$ 9,303,927.16
1LGSF	LGS Primary	Energy Charge -Winter - Blk 2	**94,950,617**	$ 0.05070	$ 4,813,996.27	$ 0.05	$ 4,771,233.94	$0.05053	$ 4,797,866.77
1LGSF	LGS Primary	Energy Charge -Winter - Blk 3	**67,528,637**	$ 0.03586	$ 2,421,576.92	$ 0.04	$ 2,400,066.25	$0.03574	$ 2,413,463.32
1LGSF	LGS Primary	Reactive Demand Adj	**0**	$ 0.87400	$ -		$ -	$ -	$ -
1LGSF	LGS Primary	EDR Credit			$ (369,314.08)		$ (369,314.08)		$ (369,314.08)
1LGSFP	LGS Primary	Customer Charge 1	**0**	$ 122.14	$ -	$228.29	$ -	$ 228.29	$ -
1LGSFP	LGS Primary	Customer Charge 2	**0**	$ 122.14	$ -	$228.29	$ -	$ 228.29	$ -
1LGSFP	LGS Primary	Customer Charge 3	**12**	$ 122.14	$ 1,495.07	$228.29	$ 2,794.39	$ 228.29	$ 2,794.39
1LGSFP	LGS Primary	Customer Charge 4	**0**	$ 1,042.78	$ -	$228.29	$ -	$ 228.29	$ -
1LGSFP	LGS Primary	Facilities Charge - Block 1	**8,597**	$ 2.897	$ 24,906.44	$ 2.87	$ 24,685.19	$ 2.887	$ 24,822.99
1LGSFP	LGS Primary	Demand Charge - Summer - Blk 1	**2,363**	$ 6.819	$ 16,113.05	$ 6.76	$ 15,969.92	$ 6.796	$ 16,059.06
1LGSFP	LGS Primary	Demand Charge - Winter - Blk 1	**4,918**	$ 3.669	$ 18,042.56	$ 3.64	$ 17,882.29	$ 3.657	$ 17,982.11
1LGSFP	LGS Primary	Energy Charge - Summer - Blk 1	**414,293**	$ 0.09584	$ 39,705.82	$ 0.09	$ 39,353.12	$0.09552	$ 39,572.79
1LGSFP	LGS Primary	Energy Charge - Summer - Blk 2	**414,293**	$ 0.06597	$ 27,330.90	$ 0.07	$ 27,088.12	$0.06575	$ 27,239.32
1LGSFP	LGS Primary	Energy Charge - Summer - Blk 3	**369,490**	$ 0.04250	$ 15,703.32	$ 0.04	$ 15,563.82	$0.04236	$ 15,650.70
1LGSFP	LGS Primary	Energy Charge - Winter - Blk 1	**856,401**	$ 0.08802	$ 75,380.44	$ 0.09	$ 74,710.84	$0.08773	$ 75,127.88
1LGSFP	LGS Primary	Energy Charge -Winter - Blk 2	**854,626**	$ 0.05070	$ 43,329.52	$ 0.05	$ 42,944.62	$0.05053	$ 43,184.34
1LGSFP	LGS Primary	Energy Charge -Winter - Blk 3	**623,491**	$ 0.03586	$ 22,358.39	$ 0.04	$ 22,159.78	$0.03574	$ 22,283.47
1LGSFP	LGS Primary	Reactive Demand Adj	**0**	$ 0.87400	$ -				
1LGSFP	LGS Primary	Parallel Generation Credit			$ (0.08)		$ (0.08)		$ (0.08)
1LGAE	LGA Secondary	Customer Charge 1	**0**	$ 122.14	$ -				
1LGAE	LGA Secondary	Customer Charge 2	**0**	$ 122.14	$ -				
1LGAE	LGA Secondary	Customer Charge 3	**0**	$ 122.14	$ -				
1LGAE	LGA Secondary	Customer Charge 4	**0**	$ 1,042.78	$ -				
1LGAE	LGA Secondary	Facilities Charge - Block 1	**0**	$ 3.49	$ -				
1LGAE	LGA Secondary	Demand Charge - Summer - Blk 1	**0**	$ 6.98	$ -				
1LGAE	LGA Secondary	Demand Charge - Winter - Blk 1	**0**	$ 3.48	$ -				
1LGAE	LGA Secondary	Energy Charge - Summer - Blk 1	**0**	$ 0.10	$ -				
1LGAE	LGA Secondary	Energy Charge - Summer - Blk 2	**0**	$ 0.07	$ -				
1LGAE	LGA Secondary	Energy Charge - Summer - Blk 3	**0**	$ 0.04	$ -				
1LGAE	LGA Secondary	Energy Charge - Winter - Blk 1	**0**	$ 0.087	$ -				
1LGAE	LGA Secondary	Energy Charge -Winter - Blk 2	**0**	$ 0.046	$ -				
1LGAE	LGA Secondary	Energy Charge -Winter - Blk 3	**0**	$ 0.036	$ -				
1LGAE	LGA Secondary	Reactive Demand Adj	**0**	$ 0.874	$ -				
1LGAF	LGA Primary	Customer Charge 1	**0**	$ 122.14	$ -				
1LGAF	LGA Primary	Customer Charge 2	**0**	$ 122.14	$ -				
1LGAF	LGA Primary	Customer Charge 3	**0**	$ 122.14	$ -				
1LGAF	LGA Primary	Customer Charge 4	**0**	$ 1,042.78	$ -				
1LGAF	LGA Primary	Facilities Charge - Block 1	**0**	$ 2.90	$ -				
1LGAF	LGA Primary	Demand Charge - Summer - Blk 1	**0**	$ 6.82	$ -				
1LGAF	LGA Primary	Demand Charge - Winter - Blk 1	**0**	$ 3.39	$ -				
1LGAF	LGA Primary	Energy Charge - Summer - Blk 1	**0**	$ 0.10	$ -				
1LGAF	LGA Primary	Energy Charge - Summer - Blk 2	**0**	$ 0.07	$ -				
1LGAF	LGA Primary	Energy Charge - Summer - Blk 3	**0**	$ 0.04	$ -				
1LGAF	LGA Primary	Energy Charge - Winter - Blk 1	**0**	$ 0.085	$ -				
1LGAF	LGA Primary	Energy Charge -Winter - Blk 2	**0**	$ 0.045	$ -				
1LGAF	LGA Primary	Energy Charge -Winter - Blk 3	**0**	$ 0.036	$ -				
1LGAF	LGA Primary	Reactive Demand Adj	**0**	$ 0.874	$ -				

	Current Rates Post-Rate Design Billing Determinants	Step 1: Demand Threshold Demand Interval	Step 2: Eliminations
		-0.89%	PGSE 0.00% PGSF -0.45% PGSV 0.00% PGSZ 0.12%

Rate Code	Voltage	Charges from Billed Revenues	Billing Determinants	Current Rate	Current Revenue	Rate	Revenue	Rate	Revenue
1PGSE	LPS Secondary	Customer Charge	**168.00**	$1,181.280	$ 198,455.04	$1,170.79	$ 196,692.18	$1,170.79	$ 196,692.18
1PGSE	LPS Secondary	Facilities Charge - Block 1	**974,944.59**	$ 3.956	$ 3,856,880.79	$ 3.92	$ 3,822,620.44	$ 3.921	$ 3,822,607.63
1PGSE	LPS Secondary	Demand - Summer - Block 1	**135,972.37**	$ 15.348	$ 2,086,903.94	$ 15.21	$ 2,068,366.14	$ 15.212	$ 2,068,359.21
1PGSE	LPS Secondary	Demand - Summer - Block 2	**97,585.43**	$ 12.277	$ 1,198,056.28	$ 12.17	$ 1,187,414.05	$ 12.168	$ 1,187,410.07
1PGSE	LPS Secondary	Demand - Summer - Block 3	**46,724.77**	$ 10.285	$ 480,564.25	$ 10.19	$ 476,295.44	$ 10.194	$ 476,293.85
1PGSE	LPS Secondary	Demand - Summer - Block 4	**73,013.15**	$ 7.508	$ 548,182.75	$ 7.44	$ 543,313.29	$ 7.441	$ 543,311.47
1PGSE	LPS Secondary	Demand - Winter - Block 1	**259,443.98**	$ 10.433	$ 2,706,779.01	$ 10.34	$ 2,682,734.92	$ 10.340	$ 2,682,725.93
1PGSE	LPS Secondary	Demand - Winter - Block 2	**160,603.04**	$ 8.141	$ 1,307,469.38	$ 8.07	$ 1,295,855.24	$ 8.069	$ 1,295,850.90
1PGSE	LPS Secondary	Demand - Winter - Block 3	**65,994.05**	$ 7.182	$ 473,969.25	$ 7.12	$ 469,759.02	$ 7.118	$ 469,757.45
1PGSE	LPS Secondary	Demand - Winter - Block 4	**90,741.95**	$ 5.52900	$ 501,712.27	$ 5.48	$ 497,255.60	$ 5.480	$ 497,253.93
1PGSE	LPS Secondary	Energy - Summer - First 180 HU	**54,983,516.40**	$ 0.09127	$ 5,018,345.54	$ 0.09	$ 4,973,767.99	$ 0.09046	$ 4,973,751.33
1PGSE	LPS Secondary	Energy - Summer - Next 180 HU	**35,950,968.27**	$ 0.05425	$ 1,950,340.03	$ 0.05	$ 1,933,015.32	$ 0.05377	$ 1,933,008.84
1PGSE	LPS Secondary	Energy - Summer - Over 360 HU	**33,021,184.99**	$ 0.02603	$ 859,541.45	$ 0.03	$ 851,906.21	$ 0.02580	$ 851,903.36
1PGSE	LPS Secondary	Energy - Winter - First 180 HU	**92,186,632.18**	$ 0.07737	$ 7,132,479.73	$ 0.08	$ 7,069,122.50	$ 0.07668	$ 7,069,098.82
1PGSE	LPS Secondary	Energy - Winter - Next 180 HU	**62,288,982.86**	$ 0.04934	$ 3,073,338.41	$ 0.05	$ 3,046,038.20	$ 0.04890	$ 3,046,028.00
1PGSE	LPS Secondary	Energy - Winter - Over 360 HU	**61,467,850.95**	$ 0.02577	$ 1,584,026.52	$ 0.03	$ 1,569,955.74	$ 0.02554	$ 1,569,950.48
1PGSE	LPS Secondary	Reactive Demand Adj	**15,240.99**	$ 0.993	$ 15,133.38	$ 0.98	$ 14,998.96	$ 0.984	$ 14,998.91
1PGSF	LPS Primary	Customer Charge	**360.43**	$1,181.280	$ 425,772.69	$1,170.79	$ 421,990.58	$1,170.79	$ 421,990.58
1PGSF	LPS Primary	Facilities Charge - Block 1	**2,213,103.74**	$ 3.279	$ 7,256,767.17	$ 3.25	$ 7,192,305.90	$ 3.235	$ 7,160,234.45
1PGSF	LPS Primary	Demand - Summer - Block 1	**296,437.81**	$ 14.996	$ 4,445,381.33	$ 14.86	$ 4,405,893.37	$ 14.797	$ 4,386,246.91
1PGSF	LPS Primary	Demand - Summer - Block 2	**193,163.78**	$ 11.998	$ 2,317,579.03	$ 11.89	$ 2,296,992.17	$ 11.838	$ 2,286,749.57
1PGSF	LPS Primary	Demand - Summer - Block 3	**96,699.97**	$ 10.049	$ 971,738.03	$ 9.96	$ 963,106.16	$ 9.915	$ 958,811.55
1PGSF	LPS Primary	Demand - Summer - Block 4	**135,812.44**	$ 7.337	$ 996,455.87	$ 7.27	$ 987,604.44	$ 7.239	$ 983,200.58
1PGSF	LPS Primary	Demand - Winter - Block 1	**556,872.83**	$ 10.192	$ 5,675,647.89	$ 10.10	$ 5,625,231.58	$ 10.056	$ 5,600,147.92
1PGSF	LPS Primary	Demand - Winter - Block 2	**311,216.46**	$ 7.956	$ 2,476,038.18	$ 7.89	$ 2,454,043.74	$ 7.850	$ 2,443,100.83
1PGSF	LPS Primary	Demand - Winter - Block 3	**138,301.42**	$ 7.017	$ 970,461.04	$ 6.95	$ 961,840.52	$ 6.924	$ 957,551.54
1PGSF	LPS Primary	Demand - Winter - Block 4	**204,082.72**	$ 5.404	$ 1,102,863.01	$ 5.36	$ 1,093,066.37	$ 5.332	$ 1,088,192.24
1PGSF	LPS Primary	Energy - Summer - First 180 HU	**127,899,684.23**	$ 0.08918	$ 11,406,093.84	$ 0.09	$11,304,774.45	$ 0.08799	$11,254,364.95
1PGSF	LPS Primary	Energy - Summer - Next 180 HU	**112,422,293.56**	$ 0.05302	$ 5,960,630.00	$ 0.05	$ 5,907,682.22	$ 0.05231	$ 5,881,339.08
1PGSF	LPS Primary	Energy - Summer - Over 360 HU	**102,549,754.96**	$ 0.02541	$ 2,605,789.27	$ 0.03	$ 2,582,642.26	$ 0.02507	$ 2,571,125.92
1PGSF	LPS Primary	Energy - Winter - First 180 HU	**215,621,056.06**	$ 0.07559	$ 16,298,795.63	$ 0.07	$16,154,014.77	$ 0.07458	$16,081,981.87
1PGSF	LPS Primary	Energy - Winter - Next 180 HU	**198,851,969.20**	$ 0.04820	$ 9,584,664.92	$ 0.05	$ 9,499,525.13	$ 0.04756	$ 9,457,165.48
1PGSF	LPS Primary	Energy - Winter - Over 360 HU	**190,093,030.89**	$ 0.02518	$ 4,786,542.52	$ 0.02	$ 4,744,024.05	$ 0.02485	$ 4,722,869.82
1PGSF	LPS Primary	Reactive Demand Adj	**110,236.36**	$ 0.99294	$ 109,458.09	$ 0.98	$ 108,485.79	$ 0.980	$ 108,002.03
1PGSV	LPS Substation	Customer Charge	**24.00**	$1,181.280	$ 28,350.72	$1,170.79	$ 28,098.88	$1,170.79	$ 28,098.88
1PGSV	LPS Substation	Facilities Charge - Block 1	**526,607.50**	$ 0.990	$ 521,341.43	$ 0.98	$ 516,710.39	$ 0.981	$ 516,708.67
1PGSV	LPS Substation	Demand - Summer - Block 1	**20,319.06**	$ 14.817	$ 301,067.55	$ 14.69	$ 298,393.19	$ 14.685	$ 298,392.20
1PGSV	LPS Substation	Demand - Summer - Block 2	**19,732.75**	$ 11.854	$ 233,912.07	$ 11.75	$ 231,834.25	$ 11.749	$ 231,833.48
1PGSV	LPS Substation	Demand - Summer - Block 3	**10,871.57**	$ 9.929	$ 107,943.87	$ 9.84	$ 106,985.01	$ 9.841	$ 106,984.65
1PGSV	LPS Substation	Demand - Summer - Block 4	**120,937.27**	$ 7.251	$ 876,916.14	$ 7.19	$ 869,126.57	$ 7.187	$ 869,123.67
1PGSV	LPS Substation	Demand - Winter - Block 1	**40,400.94**	$ 10.073	$ 406,958.64	$ 9.98	$ 403,343.66	$ 9.983	$ 403,342.32
1PGSV	LPS Substation	Demand - Winter - Block 2	**32,492.06**	$ 7.862	$ 255,452.55	$ 7.79	$ 253,183.39	$ 7.792	$ 253,182.54
1PGSV	LPS Substation	Demand - Winter - Block 3	**20,567.60**	$ 6.936	$ 142,656.89	$ 6.87	$ 141,389.68	$ 6.874	$ 141,389.21
1PGSV	LPS Substation	Demand - Winter - Block 4	**210,713.90**	$ 5.340	$ 1,125,212.20	$ 5.29	$ 1,115,217.04	$ 5.293	$ 1,115,213.32
1PGSV	LPS Substation	Energy - Summer - First 180 HU	**30,934,919.00**	$ 0.08813	$ 2,726,294.41	$ 0.09	$ 2,702,076.96	$ 0.08735	$ 2,702,067.95
1PGSV	LPS Substation	Energy - Summer - Next 180 HU	**30,934,919.00**	$ 0.05239	$ 1,620,680.41	$ 0.05	$ 1,606,284.04	$ 0.05192	$ 1,606,278.68
1PGSV	LPS Substation	Energy - Summer - Over 360 HU	**36,427,236.14**	$ 0.02512	$ 915,052.17	$ 0.02	$ 906,923.84	$ 0.02490	$ 906,920.81
1PGSV	LPS Substation	Energy - Winter - First 180 HU	**54,751,408.66**	$ 0.07473	$ 4,091,572.77	$ 0.07	$ 4,055,227.66	$ 0.07407	$ 4,055,214.14
1PGSV	LPS Substation	Energy - Winter - Next 180 HU	**54,751,408.66**	$ 0.04764	$ 2,608,357.11	$ 0.05	$ 2,585,187.29	$ 0.04722	$ 2,585,178.66
1PGSV	LPS Substation	Energy - Winter - Over 360 HU	**70,523,115.25**	$ 0.02488	$ 1,754,615.11	$ 0.02	$ 1,739,029.01	$ 0.02466	$ 1,739,023.21
1PGSV	LPS Substation	Reactive Demand Adj	**43,471.08**	$ 0.99294	$ 43,164.18	$ 0.98	$ 42,780.75	$ 0.984	$ 42,780.61
1PGSZ	LPS Transmission	Customer Charge	**60.00**	$1,181.280	$ 70,876.80	$1,170.79	$ 70,247.21	$1,170.79	$ 70,247.21
1PGSZ	LPS Transmission	Facilities Charge - Block 1	**758,824.42**	$ -	$ -	$ -	$ -	$ -	$ -
1PGSZ	LPS Transmission	Demand - Summer - Block 1	**51,309.24**	$ 14.690	$ 753,732.76	$ 14.56	$ 747,037.41	$ 14.577	$ 747,919.71
1PGSZ	LPS Transmission	Demand - Summer - Block 2	**35,388.39**	$ 11.748	$ 415,742.76	$ 11.64	$ 412,049.75	$ 11.657	$ 412,536.41
1PGSZ	LPS Transmission	Demand - Summer - Block 3	**30,553.65**	$ 9.839	$ 300,617.31	$ 9.75	$ 297,946.96	$ 9.763	$ 298,298.85
1PGSZ	LPS Transmission	Demand - Summer - Block 4	**122,485.37**	$ 7.185	$ 880,057.36	$ 7.12	$ 872,239.88	$ 7.130	$ 873,270.05
1PGSZ	LPS Transmission	Demand - Winter - Block 1	**101,870.76**	$ 9.983	$ 1,016,975.78	$ 9.89	$ 1,007,942.07	$ 9.906	$ 1,009,132.51
1PGSZ	LPS Transmission	Demand - Winter - Block 2	**69,402.93**	$ 7.791	$ 540,718.25	$ 7.72	$ 535,915.10	$ 7.731	$ 536,548.05
1PGSZ	LPS Transmission	Demand - Winter - Block 3	**61,354.35**	$ 6.875	$ 421,811.19	$ 6.81	$ 418,064.28	$ 6.822	$ 418,558.04
1PGSZ	LPS Transmission	Demand - Winter - Block 4	**210,509.55**	$ 5.292	$ 1,114,016.56	$ 5.24	$ 1,104,120.84	$ 5.251	$ 1,105,424.88
1PGSZ	LPS Transmission	Energy - Summer - First 180 HU	**43,152,595.07**	$ 0.087	$ 3,769,379.18	$ 0.09	$ 3,735,896.09	$ 0.08668	$ 3,740,308.42
1PGSZ	LPS Transmission	Energy - Summer - Next 180 HU	**42,772,616.84**	$ 0.052	$ 2,220,754.27	$ 0.05	$ 2,201,027.49	$ 0.05152	$ 2,203,627.04
1PGSZ	LPS Transmission	Energy - Summer - Over 360 HU	**49,611,368.88**	$ 0.02490	$ 1,235,323.09	$ 0.02	$ 1,224,349.81	$ 0.02471	$ 1,225,795.85
1PGSZ	LPS Transmission	Energy - Winter - First 180 HU	**79,764,768.01**	$ 0.07403	$ 5,904,985.78	$ 0.07	$ 5,852,532.27	$ 0.07346	$ 5,859,444.48
1PGSZ	LPS Transmission	Energy - Winter - Next 180 HU	**79,639,826.16**	$ 0.04721	$ 3,759,796.19	$ 0.05	$ 3,726,398.23	$ 0.04685	$ 3,730,799.34
1PGSZ	LPS Transmission	Energy - Winter - Over 360 HU	**89,877,585.72**	$ 0.02465	$ 2,215,482.49	$ 0.02	$ 2,195,802.54	$ 0.02446	$ 2,198,395.92
1PGSZ	LPS Transmission	Reactive Demand Adj	**30,413.84**	$ 0.99294	$ 30,199.11	$ 0.98	$ 29,930.86	$ 0.985	$ 29,966.21
1PGSZ	LPS Transmission	EDR Credit			$ (28,853.54)		$ (28,853.54)		$ (28,853.54)

Evergy Missouri Metro Class Cost of Service Study
Summary of Results at Class Level - Current Rates
Test Year ending June 30, 2025

Line No.	Description	System Total	Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Lighting	CCN
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	REVENUE REQUIREMENT SUMMARY								
1	Retail Sales Revenue	$ 920,123,208	$ 371,316,551	$ 87,213,295	$ 125,528,420	$ 185,903,096	$ 141,828,327	$ 7,824,086	$ 509,432
2	LLPS Credit	3,834,861	1,584,371	372,131	535,617	793,230	513,954	33,385	2,174
3	Test Year Revenue	$ 923,958,069	$ 372,900,922	$87,585,426	$126,064,038	$186,696,326	$ 142,342,281	$7,857,471	$511,605
3	Gross Revenue Requirements	$ 831,585,418	$ 398,225,075	$ 69,225,529	$ 100,332,521	$ 147,772,968	$ 107,294,970	$ 6,980,146	$ 1,754,209
4	Less Other Revenue	$ (97,684,917)	$ (35,878,712)	$ (7,969,460)	$ (13,185,911)	$ (22,330,187)	$ (17,730,226)	$ (553,583)	$ (36,838)
5	Net Revenue Requirements	$ 733,900,501	$ 362,346,364	$61,256,069	$87,146,610	$125,442,781	$ 89,564,744	$6,426,563	$1,717,370
6	**Net Operating Income**	$ 190,057,567	$ 10,554,558	$ 26,329,357	$ 38,917,428	$ 61,253,545	$ 52,777,537	$ 1,430,907	$ (1,205,765)
	RETURN AT PRESENT RATES								
7	Rate Base	$ 3,879,303,485	$ 2,077,778,069	$ 332,237,033	$ 461,637,856	$ 607,920,003	$ 358,313,599	$ 38,348,891	$ 3,068,032
8	Net Operating Income at Present Rates	$ 190,057,567	$ 10,554,558	$ 26,329,357	$ 38,917,428	$ 61,253,545	$ 52,777,537	$1,430,907	$ (1,205,765)
9	Return at Current Rates	4.90%	0.51%	7.92%	8.43%	10.08%	14.73%	3.73%	-39.30%
10	Relative Rate of Return	1.00	0.10	1.62	1.72	2.06	3.01	0.76	(8.02)
	EQUALIZED RATE OF RETURN								
11	Rate Base	$ 3,879,303,485	$ 2,077,778,069	$ 332,237,033	$ 461,637,856	$ 607,920,003	$ 358,313,599	$ 38,348,891	$ 3,068,032
12	Equalized Rate of Return	7.6546%	7.6546%	7.6546%	7.6546%	7.6546%	7.6546%	7.6546%	7.6546%
13	Return Required @ Equalized Rate of Return	$296,945,165	$159,045,600	$25,431,416	$35,336,531	$46,533,845	$27,427,473	$2,935,454	$234,846
14	Operating Income Deficiency/(Surplus)	$106,887,597	$148,491,042	($897,941)	($3,580,897)	($14,719,701)	($25,350,064)	$1,504,547	$1,440,610
15	Additional Current Tax Required	$33,465,438	$46,491,060	($281,136)	($1,121,143)	($4,608,591)	($7,936,851)	$471,059	$451,041
16	Revenue Deficiency/ (Surplus)	$140,353,035	$194,982,102	($1,179,077)	($4,702,040)	($19,328,292)	($33,286,915)	$1,975,606	$1,891,651
17	Percent Revenue Change - Equal Rates of Return	15.19%	52.3%	-1.3%	-3.7%	-10.4%	-23.4%	25.1%	369.7%

Evergy Missouri Metro Class Cost of Service Study
Table 1 - Summary of Results - Current Rates
Test Year ending June 30, 2025

Line No.	Description	MO Metro Retail	Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Lighting	CCN	Check Zero	Check Zero
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)		
1	**REVENUE REQUIREMENT SUMMARY**										
2	Test Year Revenue	$920,123,208	$371,316,551	$87,213,295	$125,528,420	$185,903,096	$141,828,327	$7,824,086	$509,432	-	-
3	Gross Revenue Requirements	$831,585,418	$398,225,075	$69,225,529	$100,332,521	$147,772,968	$107,294,970	$6,980,146	$1,754,209	-	-
4	Less Other Revenue	($97,684,917)	$ (35,878,712)	$ (7,969,460)	$ (13,185,911)	$ (22,330,187)	$ (17,730,226)	$ (553,583)	$ (36,838)	-	-
5	Net Revenue Requirements	$733,900,501	$362,346,364	$61,256,069	$87,146,610	$125,442,781	$89,564,744	$6,426,563	$1,717,370	-	-
6	Net Operating Income	$ 190,057,567	$ 10,554,558	$ 26,329,357	$ 38,917,428	$ 61,253,545	$ 52,777,537	$ 1,430,907	$ (1,205,765)	-	-
7	**RETURN AT PRESENT RATES**										
8	Rate Base	$3,879,303,485	$ 2,077,778,069	$ 332,237,033	$ 461,637,856	$ 607,920,003	$ 358,313,599	$ 38,348,891	$ 3,068,032	-	-
9	Net Operating Income at Present Rates	$190,057,567	$ 10,554,558	$ 26,329,357	$ 38,917,428	$ 61,253,545	$ 52,777,537	$ 1,430,907	$ (1,205,765)	-	-
10	Rate of Return at Present Rates	4.90%	0.51%	7.92%	8.43%	10.08%	14.73%	3.73%	-39.30%		
11	Relative Rate of Return	1.00	0.10	1.62	1.72	2.06	3.01	0.76	(8.02)		

Evergy Missouri Metro Class Cost of Service Study
Summary of Results at Class Level - Current Rates
Test Year ending June 30, 2025

Line No.	Description	System Total	Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Lighting	CCN
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	REVENUE REQUIREMENT SUMMARY								
1	Retail Sales Revenue	$ 920,123,208	$ 371,316,244	$ 55,926,068	$ 125,729,536	$ 186,328,310	$ 172,488,779	$ 7,824,080	$ 510,191
2	LLPS Credit	3,834,861	1,584,370	238,631	536,476	795,044	644,779	33,385	2,177
3	Test Year Revenue	$ 923,958,069	$ 372,900,614	$56,164,699	$126,266,011	$187,123,355	$ 173,133,557	$7,857,464	$512,368
3	Gross Revenue Requirements	$ 831,585,418	$ 398,274,732	$ 47,396,623	$ 103,429,695	$ 148,468,481	$ 125,280,297	$ 6,981,282	$ 1,754,308
4	Less Other Revenue	$ (97,684,917)	$ (35,879,298)	$ (5,061,619)	$ (13,464,775)	$ (22,192,792)	$ (20,495,998)	$ (553,596)	$ (36,840)
5	Net Revenue Requirements	$ 733,900,501	$ 362,395,433	$42,335,005	$89,964,920	$126,275,690	$ 104,784,299	$6,427,686	$1,717,468
6	**Net Operating Income**	$ 190,057,567	$ 10,505,181	$ 13,829,694	$ 36,301,091	$ 60,847,665	$ 68,349,258	$ 1,429,778	$ (1,205,100)
	RETURN AT PRESENT RATES								
7	Rate Base	$ 3,879,303,485	$ 2,078,321,749	$ 232,095,461	$ 479,427,466	$ 618,018,241	$ 430,010,534	$ 38,360,958	$ 3,069,077
8	Net Operating Income at Present Rates	$ 190,057,567	$ 10,505,181	$ 13,829,694	$ 36,301,091	$ 60,847,665	$ 68,349,258	$1,429,778	$ (1,205,100)
9	Return at Current Rates	4.90%	0.51%	5.96%	7.57%	9.85%	15.89%	3.73%	-39.27%
10	Relative Rate of Return	1.00	0.10	1.22	1.55	2.01	3.24	0.76	(8.01)
	EQUALIZED RATE OF RETURN								
11	Rate Base	$ 3,879,303,485	$ 2,078,321,749	$ 232,095,461	$ 479,427,466	$ 618,018,241	$ 430,010,534	$ 38,360,958	$ 3,069,077
12	Equalized Rate of Return	7.6546%	7.6546%	7.6546%	7.6546%	7.6546%	7.6546%	7.6546%	7.6546%
13	Return Required @ Equalized Rate of Return	$296,945,165	$159,087,217	$17,765,979	$36,698,255	$47,306,824	$32,915,586	$2,936,378	$234,926
14	Operating Income Deficiency/(Surplus)	$106,887,597	$148,582,036	$3,936,285	$397,164	($13,540,841)	($35,433,672)	$1,506,600	$1,440,026
15	Additional Current Tax Required	$33,465,438	$46,519,550	$1,232,411	$124,348	($4,239,502)	($11,093,928)	$471,701	$450,858
16	Revenue Deficiency/ (Surplus)	$140,353,035	$195,101,586	$5,168,696	$521,512	($17,780,343)	($46,527,601)	$1,978,301	$1,890,883
17	Percent Revenue Change - Equal Rates of Return	15.19%	52.3%	9.2%	0.4%	-9.5%	-26.9%	25.2%	369.0%

Evergy Missouri Metro Class Cost of Service Study
Table 1 - Summary of Results - Current Rates
Test Year ending June 30, 2025

Line No.	Description	MO West Retail	Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Lighting	CCN	Check Zero	Check Zero
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)		
1	**REVENUE REQUIREMENT SUMMARY**										
2	Test Year Revenue	$920,123,208	$371,316,244	$55,926,068	$125,729,536	$186,328,310	$172,488,779	$7,824,080	$510,191	-	-
3	Gross Revenue Requirements	$831,585,418	$398,274,732	$47,396,623	$103,429,695	$148,468,481	$125,280,297	$6,981,282	$1,754,308	-	-
4	Less Other Revenue	($97,684,917)	$ (35,879,298)	$ (5,061,619)	$ (13,464,775)	$ (22,192,792)	$ (20,495,998)	$ (553,596)	$ (36,840)	-	-
5	Net Revenue Requirements	$733,900,501	$362,395,433	$42,335,005	$89,964,920	$126,275,690	$104,784,299	$6,427,686	$1,717,468	-	-
6	Net Operating Income	$ 190,057,567	$ 10,505,181	$ 13,829,694	$ 36,301,091	$ 60,847,665	$ 68,349,258	$ 1,429,778	$ (1,205,100)	-	-
7	**RETURN AT PRESENT RATES**										
8	Rate Base	$3,879,303,485	$ 2,078,321,749	$ 232,095,461	$ 479,427,466	$ 618,018,241	$ 430,010,534	$ 38,360,958	$ 3,069,077	-	-
9	Net Operating Income at Present Rates	$190,057,567	$ 10,505,181	$ 13,829,694	$ 36,301,091	$ 60,847,665	$ 68,349,258	$ 1,429,778	$ (1,205,100)	-	-
10	Rate of Return at Present Rates	4.90%	0.51%	5.96%	7.57%	9.85%	15.89%	3.73%	-39.27%		
11	Relative Rate of Return	1.00	0.10	1.22	1.55	2.01	3.24	0.76	(8.01)		

MO Metro - Missouri Jurisdiction Class REVENUE SUMMARY - For Direct filing - ER-2026-XXXX

Full Increase: 15.19%

Adj Inc Excl Net Fuel: 14.94%

MISSOURI RATE GROUP	Weather Normalized CG kWh	(A) % Weighting	(B) Revenue from Existing Rates (Including FAC, DSIM, EDR)(1)	(C) FAC Rider/Adjustments	(D) DSIM Rider/Adjustments	(E) EDR Credits*	F=B-(C+D) Revenue from Existing Rates less FAC & DSIM adjustments	(G) EDR Allocation	(H) Revenue from Existing Rates grossed up to reflect EDR credits (1)	I=F*(%) Requested Increase-from Rev Model excluding EDR gross-up (Equal increase)	Requested Increase-Including EDR Gross Up	Revenue Shift	Full Requested Increase-Revenue Shifts with EDR gross up	Adj Request-excluding Net Fuel	Proposed Revenue (1) Reg increase only-excluding Net Fuel	Proposed Revenue -Full Increase
LARGE POWER TOTAL	1,950,478,692	23%	$ 177,998,894.45	$1,051,947	$642,510	($28,854)	$ 176,304,437	$ (124,386)	$ 176,428,823	$ 26,787,448	$ 26,806,347	100.0%	$26,806,347	$26,231,470	$202,660,294	$203,235,170
LARGE GEN SVC TOTAL	2,022,491,106	24%	$ 191,910,905.08	$1,456,848	$4,196,445	($592,903)	$ 186,257,612	$ (131,408)	$ 186,389,020	$ 28,299,719	$ 28,319,685	100.0%	$28,319,685	$27,723,584	$214,112,604	$214,708,706
MEDIUM GEN SVC TOTAL	1,169,896,443	14%	$ 130,740,956.91	$833,591	$4,236,739	($26,893)	$ 125,670,627	$ (88,663)	$ 125,759,290	$ 19,094,218	$ 19,107,690	100.0%	$19,107,690	$18,762,879	$144,522,169	$144,866,980
SMALL GEN SVC TOTAL	431,608,681	5%	$ 57,379,307.49	$296,373	$1,176,266	($3,073)	$ 55,906,669	$ (39,443)	$ 55,946,113	$ 8,494,381	$ 8,500,374	100.0%	$8,500,374	$8,373,163	$64,319,275	$64,446,486
RESIDENTIAL TOTAL	2,823,096,529	34%	$383,475,367	$1,785,991	$10,413,660	$0	$ 371,275,716	$ (261,942)	$ 371,537,659	$ 56,411,110	$ 56,450,909	100.0%	$56,450,909	$55,618,840	$427,156,499	$427,988,568
ELECTRIC VEHICLE	2,625,344	0%	$519,619	$2,373	$7,111	$0	$ 510,135	$ (360)	$ 510,495	$ 77,509	$ 77,564	100.0%	$77,564	$77,564	$588,059	$588,059
MO Metered TOTALS	**8,400,196,795**		**$942,025,050**	**$5,427,123**	**$20,672,730**	**($651,723)**	**$915,925,197**	**($646,203)**	**$ 916,576,920**	**$ 139,164,385**	**$ 139,262,568**		**$ 139,262,568**	**$ 136,787,500**	**$ 1,053,358,900**	**$ 1,055,833,969**
MO Lighting TOTAL:	47,434,766		$7,859,385	$36,160	$0	$0	$ 7,823,226	$ (5,519)	$ 7,828,745	$ 1,188,650	$ 1,189,489	100.0%	$1,189,489	$1,175,508	$9,004,253	$9,018,234
MO TOTAL*	**8,447,631,561**	**100.00%**	**$949,884,435**	**$5,463,283**	**$20,672,730**	**($651,723)**	**$ 923,748,423**	**$ (651,723)**	**$ 924,400,146**	**$ 140,353,035**	**$ 140,452,057**		**$ 140,452,057**	**$ 137,963,008**	**$ 1,062,363,153**	**$ 1,064,852,203**
													$ (0)			

(1) All classes' revenues reflect both EDR/Mpower(DRI) credits and Manual Bill revenue. $ 0 Tie Out

* EDR credits are applied top side. In order to recover the expected and allowed RR/increase, revenues must be grossed up to reflect revenues prior to reduction in order to adjust the pricing to receive the needed RR.

Incremental Revenue Requirement	$	140,353,035
Revenue Requirement Less LLPS Premium	$	136,518,175
EDR gross up	$	99,022

Class Cost of Service LLPS Premium		
LLPS Adjustment A	$	16,109,583
LLPS Adjustment B	$	9,100,000
LLPS Adjustment Total	$	25,209,583
LPS TY $/KWH	$	0.07110
LLPS Forecasted $/KWH	$	0.08192
	$	0.01082
LLPS Premium %		15.2119%
	$	**3,834,861**

	Original	Rev Shift	Full Increase w/ EDR & Rev Shift
LPS	15.19%	100.00%	15.19%
LGS	15.19%	100.00%	15.19%
SGS	15.19%	100.00%	15.19%
MGS	15.19%	100.00%	15.19%
RES	15.19%	100.00%	15.19%
EV	15.19%	100.00%	15.19%
Lighting	15.19%	100.00%	15.19%

FAC-related revenue requirement				Percentage increase excl FAC-blue sheet		
LPS	$	574,877	23.10%	LPS	14.87%	19.00%
LGS	$	596,101	23.95%	LGS	14.87%	20.08%
MGS	$	344,811	13.85%	MGS	14.92%	13.59%
SGS	$	127,211	5.11%	SGS	14.97%	6.07%
RES	$	832,069	33.43%	RES	14.97%	40.29%
LIGHTING	$	13,981	0.56%	LIGHTING	15.02%	0.85%
	$	**2,489,049**				

FAC Rev Rqmt	**$**	**2,489,823**
$/kWh		**0.00029**

Evergy - MO Metro

Case No:	ER-2026-0143
Status:	Direct
Determinants:	As Filed

Class	Charge	Rate	Rate Codes	Block	Current Rates	Post Rate Design Revenue Neutralization Proposed Rates
Residential	Customer Charge	General Use (RESA)	1RS1A ;1RS1AS ;1RLIS	One Meter	12.00	13.82
	Customer Charge	General Use & Space Heat (RESB)	1RS6A ;1RS6AS ;1RHLIS	One Meter	12.00	13.82
	Customer Charge	General Use & Separate Meter Heating (RESC	1RS2A ;1RS2AS ;1RSHLIS	Two Meters	15.25	17.56
	Customer Charge	Peak Adjustment Service (RPKA)	1RPKA ;1RPKANM ;1RPKAPG ; 1RPKALIS ;1RPKA	One Meter	12.00	13.82
	Customer Charge	Time of Use (RTOU)	1RTOU ;1RTOUN	One Meter	12.00	13.82
	Customer Charge	Time of Use - Two Period (RTOU)	1RTOU2 ;1RTOU2N	One Meter	12.00	13.82
	Customer Charge	Time of Use - High Differential (RTOU)	1RTOU3 ;1RTOU3N	One Meter	12.00	13.82
	Customer Charge	Electric Vehicle Time of Use (RTOU-EV)	1RTOUEV	One Meter	3.25	3.74
	Energy Charge - Summer - Blk 1/On Peak	General Use (RESA)	1RS1A ;1RS1AS ;1RLIS	First 600 kWh per month	0.14053	0.16192
	Energy Charge - Summer - Blk 2/Off Peak	General Use (RESA)	1RS1A ;1RS1AS ;1RLIS	Next 400 kWh per month	0.14053	0.16192
	Energy Charge - Summer - Blk 3/Super O	General Use (RESA)	1RS1A ;1RS1AS ;1RLIS	Over 1000 kWh per month	0.15515	0.17877
	Energy Charge - Summer - Blk 1/Off Peak	General Use	1RS6A	First 600 kWh per month	0.14360	0.16546
	Energy Charge - Summer - Blk 2/On Peak	General Use	1RS6A	Next 400 kWh per month	0.14360	0.16546
	Energy Charge - Summer - Blk 3/Super O	General Use	1RS6A	Over 1000 kWh per month	0.14360	0.16546
	Energy Charge - Summer - Blk 1/Off Peak	General Use	1RS2A	First 600 kWh per month	0.14360	0.16546
	Energy Charge - Summer - Blk 2/On Peak	General Use	1RS2A	Next 400 kWh per month	0.14360	0.16546
	Energy Charge - Summer - Blk 3/Super O	General Use	1RS2A	Over 1000 kWh per month	0.14360	0.16546
	Energy Charge - Summer - Blk 1/On Peak	Peak Adjustment Service (RPKA)	1RPKA ;1RPKANM ;1RPKAPG ; 1RPKALIS ;1RPKA	First 600 kWh per month	0.14094	0.16239
	Energy Charge - Summer - Blk 2/Off Peak	Peak Adjustment Service (RPKA)	1RPKA ;1RPKANM ;1RPKAPG ; 1RPKALIS ;1RPKA	Next 400 kWh per month	0.14094	0.16239
	Energy Charge - Summer - Blk 3/Super O	Peak Adjustment Service (RPKA)	1RPKA ;1RPKANM ;1RPKAPG ; 1RPKALIS ;1RPKA	Over 1000 kWh per month	0.15094	0.17392
	Energy Charge - Winter - Blk 1/On Peak	General Use (RESA)	1RS1A ;1RS1AS ;1RLIS	First 600 kWh per month	0.12495	0.14397
	Energy Charge - Winter - Blk 2/Off Peak	General Use (RESA)	1RS1A ;1RS1AS ;1RLIS	Next 400 kWh per month	0.07693	0.08864
	Energy Charge - Winter - Blk 3/Super Off	General Use (RESA)	1RS1A ;1RS1AS ;1RLIS	Over 1000 kWh per month	0.06824	0.07863
	Energy Charge - Winter - Blk 1/Off Peak	General Use	1RS6A	First 600 kWh per month	0.10093	0.11629
	Energy Charge -Winter - Blk 2/On Peak	General Use	1RS6A	Next 400 kWh per month	0.10093	0.11629
	Energy Charge -Winter - Blk 3/Super Off P	General Use	1RS6A	Over 1000 kWh per month	0.06553	0.07551
	Energy Charge - Winter - Blk 1/Off Peak	General Use	1RS2A	First 600 kWh per month	0.12495	0.14397
	Energy Charge -Winter - Blk 2/On Peak	General Use	1RS2A	Next 400 kWh per month	0.07693	0.08864
	Energy Charge -Winter - Blk 3/Super Off P	General Use	1RS2A	Over 1000 kWh per month	0.06608	0.07614
	Energy Charge - Winter - Blk 1/On Peak	Peak Adjustment Service (RPKA)	1RPKA ;1RPKANM ;1RPKAPG ; 1RPKALIS ;1RPKA	First 600 kWh per month	0.12233	0.14095
	Energy Charge - Winter - Blk 2/Off Peak	Peak Adjustment Service (RPKA)	1RPKA ;1RPKANM ;1RPKAPG ; 1RPKALIS ;1RPKA	Next 400 kWh per month	0.07532	0.08679
	Energy Charge - Winter - Blk 3/Super Off	Peak Adjustment Service (RPKA)	1RPKA ;1RPKANM ;1RPKAPG ; 1RPKALIS ;1RPKA	Over 1000 kWh per month	0.06681	0.07698
	Energy Charge - Winter - Blk 1/Off Peak	Other Use (ROU)	1RO1A	All kWh	0.14509	0.16718
	Energy Charge - Summer - Blk 1/Off Peak	Other Use (ROU)	1RO1A	All kWh	0.18672	0.21514
	Energy Charge - Summer - Blk 2/On Peak	Time of Day (RTOD)	1TE1A	On-Peak	0.22048	0.25404
	Energy Charge - Summer - Blk 1/Off Peak	Time of Day (RTOD)	1TE1A	Off-Peak	0.12283	0.14153
	Energy Charge - Winter - Blk 1/Off Peak	Time of Day (RTOD)	1TE1A	All kWh	0.09079	0.10461
	Energy Charge - Summer - Blk 1/On Peak	Time of Use (RTOU)	1RTOU ;1RTOUN	On-Peak	0.33803	0.38949
	Energy Charge - Summer - Blk 2/Off Peak	Time of Use (RTOU)	1RTOU ;1RTOUN	Off-Peak	0.11268	0.12983
	Energy Charge - Summer - Blk 3/Super O	Time of Use (RTOU)	1RTOU ;1RTOUN	Super Off-Peak	0.05633	0.06490
	Energy Charge - Winter - Blk 1/On Peak	Time of Use (RTOU)	1RTOU ;1RTOUN	On-Peak	0.27642	0.31850
	Energy Charge - Winter - Blk 2/Off Peak	Time of Use (RTOU)	1RTOU ;1RTOUN	Off-Peak	0.10840	0.12490
	Energy Charge - Winter - Blk 3/Super Off	Time of Use (RTOU)	1RTOU ;1RTOUN	Super Off-Peak	0.04675	0.05387
	Energy Charge - Summer - Blk 1/On Peak	Time of Use - Two Period (RTOU)	1RTOU2 ;1RTOU2N	On-Peak	0.38328	0.44163
	Energy Charge - Summer - Blk 2/Off Peak	Time of Use - Two Period (RTOU)	1RTOU2 ;1RTOU2N	Off-Peak	0.09582	0.11041
	Energy Charge - Winter - Blk 2/Off Peak	Time of Use - Two Period (RTOU)	1RTOU2 ;1RTOU2N	Off-Peak	0.11311	0.13033
	Energy Charge - Winter - Blk 3/Super Off	Time of Use - Two Period (RTOU)	1RTOU2 ;1RTOU2N	Super Off-Peak	0.05656	0.06517
	Energy Charge - Summer - Blk 1/On Peak	Time of Use - High Differential (RTOU)	1RTOU3 ;1RTOU3N	On-Peak	0.35879	0.41341
	Energy Charge - Summer - Blk 2/Off Peak	Time of Use - High Differential (RTOU)	1RTOU3 ;1RTOU3N	Off-Peak	0.11960	0.13781
	Energy Charge - Summer - Blk 3/Super O	Time of Use - High Differential (RTOU)	1RTOU3 ;1RTOU3N	Super Off-Peak	0.02990	0.03445
	Energy Charge - Winter - Blk 1/On Peak	Time of Use - High Differential (RTOU)	1RTOU3 ;1RTOU3N	On-Peak	0.27305	0.31462
	Energy Charge - Winter - Blk 2/Off Peak	Time of Use - High Differential (RTOU)	1RTOU3 ;1RTOU3N	Off-Peak	0.09102	0.10488
	Energy Charge - Winter - Blk 3/Super Off	Time of Use - High Differential (RTOU)	1RTOU3 ;1RTOU3N	Super Off-Peak	0.02275	0.02621
	Energy Charge - Summer - Blk 1/On Peak	Electric Vehicle Time of Use (RTOU-EV)	1RTOUEV	On-Peak	0.35879	0.41341
	Energy Charge - Summer - Blk 2/Off Peak	Electric Vehicle Time of Use (RTOU-EV)	1RTOUEV	Off-Peak	0.11960	0.13781
	Energy Charge - Summer - Blk 3/Super O	Electric Vehicle Time of Use (RTOU-EV)	1RTOUEV	Super Off-Peak	0.02990	0.03445
	Energy Charge - Winter - Blk 1/On Peak	Electric Vehicle Time of Use (RTOU-EV)	1RTOUEV	On-Peak	0.27305	0.31462
	Energy Charge - Winter - Blk 2/Off Peak	Electric Vehicle Time of Use (RTOU-EV)	1RTOUEV	Off-Peak	0.09102	0.10488
	Energy Charge - Winter - Blk 3/Super Off	Electric Vehicle Time of Use (RTOU-EV)	1RTOUEV	Super Off-Peak	0.02275	0.02621
	Peak Adjustment Charge - Summer	Peak Adjustment Service (RPKA)	1RPKA ;1RPKANM ;1RPKAPG ; 1RPKALIS ;1RPKA	On-Peak	0.01000	0.01152
	Peak Adjustment Credit - Summer	Peak Adjustment Service (RPKA)	1RPKA ;1RPKANM ;1RPKAPG ; 1RPKALIS ;1RPKA	Super Off-Peak	-0.01000	(0.01152)
	Peak Adjustment Charge - Winter	Peak Adjustment Service (RPKA)	1RPKA ;1RPKANM ;1RPKAPG ; 1RPKALIS ;1RPKA	On-Peak	0.00250	0.00288
	Peak Adjustment Credit - Winter	Peak Adjustment Service (RPKA)	1RPKA ;1RPKANM ;1RPKAPG ; 1RPKALIS ;1RPKA	Super Off-Peak	-0.01000	(0.01152)
ral Service	Customer Charge	Secondary/Primary	1SGSE ;1SGSEW ;1SGSF ;1SGSFW ;1SGAE ;1SGAEW ;1SGAF ;1SGAFW ;1SGHE ;1SGHEW ;1SGSES	Customer Charge	21.41	24.55
	Customer Charge	Secondary/Primary	1SUSE	Unmetered Service	8.11	9.30
	Facilities Charge - Block 1	Secondary	1SGSE ;1SGSEW ;1SGAE ;1SGAEW ;1SGHE ;1SGHEW ;1SUSE ;1SGSES	First 25 KW	-	-
	Facilities Charge - Block 2	Secondary	1SGSE ;1SGSEW ;1SGAE ;1SGAEW ;1SGHE ;1SGHEW ;1SUSE ;1SGSES	All KW over 25 KW	2.981	5.963
	Facilities Charge - Block 1	Primary	1SGSF ;1SGSFW ;1SGAF ;1SGAFW	First 26 KW	-	-
	Facilities Charge - Block 2	Primary	1SGSF ;1SGSFW ;1SGAF ;1SGAFW	All KW over 26 KW	3.005	1.497
	Demand Charge - Summer - Block 1	Secondary	1SGSE ;1SGSEW ;1SGAE ;1SGAEW ;1SGHE ;1SGHEW ;1SUSE ;1SGSES	All KW	15.044	17.246
	Demand Charge - Winter - Block 1	Secondary	1SGSE ;1SGSEW ;1SGAE ;1SGAEW ;1SGHE ;1SGHEW ;1SUSE ;1SGSES	All KW	6.607	7.574
	Demand Charge - Summer - Block 1	Primary	1SGSF ;1SGSFW ;1SGAF ;1SGAFW	All KW	15.037	17.238
	Demand Charge - Winter - Block 1	Primary	1SGSF ;1SGSFW ;1SGAF ;1SGAFW	All KW	6.248	7.163

Small General Service	Energy Charge - Summer - Blk 1	Secondary	1SGSE ;1SGSEW ;1SGAE ;1SGAEW ;1SGHE ;1SG	All KWH	0.07519	0.08619
	Energy Charge - Winter - Blk 1	Secondary	1SGSE ;1SGSEW ;1SGHE ;1SGHEW ;1SUSE ;1SG	All KWH	0.07624	0.08739
	Energy Charge - Summer - Blk 1	Primary	1SGSF ;1SGSFW ;1SGAF ;1SGAFW	All KWH	0.07516	0.08616
	Energy Charge - Winter - Blk 1	Primary	1SGSF ;1SGSFW	All KWH	0.07409	0.08494
	Peak Adjustment Charge - Summer	Secondary	1SGSE ;1SGSEW ;1SGAE ;1SGAEW ;1SGHE ;1SG	On-Peak	0.01000	0.01000
	Peak Adjustment Credit - Summer	Secondary	1SGSE ;1SGSEW ;1SGAE ;1SGAEW ;1SGHE ;1SG	Super Off-Peak	(0.01000)	-0.01000
	Peak Adjustment Charge - Winter	Secondary	1SGSE ;1SGSEW ;1SGAE ;1SGAEW ;1SGHE ;1SG	On-Peak	-	0.00000
	Peak Adjustment Credit - Winter	Secondary	1SGSE ;1SGSEW ;1SGAE ;1SGAEW ;1SGHE ;1SG	Super Off-Peak	(0.01000)	-0.01000
	Peak Adjustment Charge - Summer	Primary	1SGSF ;1SGSFW ;1SGAF ;1SGAFW	On-Peak	0.01000	0.01000
	Peak Adjustment Credit - Summer	Primary	1SGSF ;1SGSFW ;1SGAF ;1SGAFW	Super Off-Peak	(0.01000)	-0.01000
	Peak Adjustment Charge - Winter	Primary	1SGSF ;1SGSFW ;1SGAF ;1SGAFW	On-Peak	-	0.00000
	Peak Adjustment Credit - Winter	Primary	1SGSF ;1SGSFW ;1SGAF ;1SGAFW	Super Off-Peak	(0.01000)	-0.01000
Medium General Service	Customer Charge	Secondary/Primary	1MGSE ;1MGSEW ;1MGSF ;1MGSFW ;1MGAE ;1M	Customer Charge	60.08	64.91
	Facilities Charge - Block 1	Secondary	1MGSE ;1MGSEW ;1MGAE ;1MGAEW ;1MGHE ;1M	All KW	3.189	5.303
	Facilities Charge - Block 1	Primary	1MGSF ;1MGSFW ;1MGAF ;1MGAFW	All KW	2.631	1.468
	Demand Charge - Summer - Blk 1	Secondary	1MGSE ;1MGSEW ;1MGHE ;1MGHEW ;1MGAE ;1M	All KW	14.640	15.816
	Demand Charge - Winter - Blk 1	Secondary	1MGSE ;1MGSEW ;1MGHE ;1MGHEW	All KW	6.336	6.845
	Demand Charge - Summer - Blk 1	Primary	1MGSF ;1MGSFW ;1MGAF ;1MGAFW	All KW	12.823	13.853
	Demand Charge - Winter - Blk 1	Primary	1MGSF ;1MGSFW	All KW	6.001	6.483
	Energy Charge - Summer - Blk 1	Secondary	1MGSE ;1MGSEW ;1MGHE ;1MGHEW ;1MGAE ;1	All KWH	0.06301	0.06808
	Energy Charge - Winter - Blk 1	Secondary	1MGSE ;1MGSEW ;1MGHE ;1MGHEW	All KWH	0.06421	0.06937
	Energy Charge - Summer - Blk 1	Primary	1MGSF ;1MGSFW ;1MGAF ;1MGAFW	All KWH	0.06466	0.06985
	Energy Charge - Winter - Blk 1	Primary	1MGSF ;1MGSFW	All KWH	0.06553	0.07079
	Peak Adjustment Charge - Summer	Secondary	1MGSE ;1MGSEW ;1MGHE ;1MGHEW ;1MGAE ;1	On-Peak	0.01000	0.01000
	Peak Adjustment Credit - Summer	Secondary	1MGSE ;1MGSEW ;1MGHE ;1MGHEW ;1MGAE ;1	Super Off-Peak	(0.01000)	-0.01000
	Peak Adjustment Charge - Winter	Secondary	1MGSE ;1MGSEW ;1MGHE ;1MGHEW ;1MGAE ;1	On-Peak	-	0.00000
	Peak Adjustment Credit - Winter	Secondary	1MGSE ;1MGSEW ;1MGHE ;1MGHEW ;1MGAE ;1	Super Off-Peak	(0.01000)	-0.01000
	Peak Adjustment Charge - Summer	Primary	1MGSF ;1MGSFW ;1MGAF ;1MGAFW	On-Peak	0.01000	0.01000
	Peak Adjustment Credit - Summer	Primary	1MGSF ;1MGSFW ;1MGAF ;1MGAFW	Super Off-Peak	(0.01000)	-0.01000
	Peak Adjustment Charge - Winter	Primary	1MGSF ;1MGSFW ;1MGAF ;1MGAFW	On-Peak	-	0.00000
	Peak Adjustment Credit - Winter	Primary	1MGSF ;1MGSFW ;1MGAF ;1MGAFW	Super Off-Peak	(0.01000)	-0.01000
Large General Service	Customer Charge	Secondary/Primary	1LGSE ;1LGSEW ;1LGSF ;1LGSFW ;1LGAE ;1LGA	Customer Charge	228.29	255.25
	Facilities Charge - Block 1	Secondary	1LGSE ;1LGSEW ;1LGAE ;1LGAEW ;1LGHE ;1LGH	All KW	3.440	5.120
	Facilities Charge - Block 1	Primary	1LGSF ;1LGSFW ;1LGAF ;1LGAFW ;1LGSFP	All KW	2.887	2.175
	Demand Charge - Summer - Blk 1	Secondary	1LGSE ;1LGSEW ;1LGAE ;1LGAEW ;1LGHE ;1LGH	All KW	15.277	17.082
	Demand Charge - Winter - Blk 1	Secondary	1LGSE ;1LGSEW ;1LGHE ;1LGHEW	All KW	6.705	7.497
	Demand Charge - Summer - Blk 1	Primary	1LGSF ;1LGSFW ;1LGAF ;1LGAFW ;1LGSFP	All KW	16.386	18.321
	Demand Charge - Winter - Blk 1	Primary	1LGSF ;1LGSFW ;1LGSFP	All KW	7.139	7.982
	Energy Charge - Summer - Blk 1	Secondary	1LGSE ;1LGSEW ;1LGAE ;1LGAEW ;1LGHE ;1LGH	All KWH	0.05762	0.06443
	Energy Charge - Winter - Blk 1	Secondary	1LGSE ;1LGSEW ;1LGHE ;1LGHEW	All KWH	0.05991	0.06698
	Energy Charge - Summer - Blk 1	Primary	1LGSF ;1LGSFW ;1LGAF ;1LGAFW ;1LGSFP	All KWH	0.05549	0.06204
	Energy Charge - Winter - Blk 1	Primary	1LGSF ;1LGSFW ;1LGSFP	All KWH	0.05673	0.06343
	Peak Adjustment Charge - Summer	Secondary	1LGSE ;1LGSEW ;1LGAE ;1LGAEW ;1LGHE ;1LGH	On-Peak	0.01000	0.01000
	Peak Adjustment Credit - Summer	Secondary	1LGSE ;1LGSEW ;1LGAE ;1LGAEW ;1LGHE ;1LGH	Super Off-Peak	(0.01000)	-0.01000
	Peak Adjustment Charge - Winter	Secondary	1LGSE ;1LGSEW ;1LGAE ;1LGAEW ;1LGHE ;1LGH	On-Peak	-	0.00000
	Peak Adjustment Credit - Winter	Secondary	1LGSE ;1LGSEW ;1LGAE ;1LGAEW ;1LGHE ;1LGH	Super Off-Peak	(0.01000)	-0.01000
	Peak Adjustment Charge - Summer	Primary	1LGSF ;1LGSFW ;1LGAF ;1LGAFW ;1LGSFP	On-Peak	0.01000	0.01000
	Peak Adjustment Credit - Summer	Primary	1LGSF ;1LGSFW ;1LGAF ;1LGAFW ;1LGSFP	Super Off-Peak	(0.01000)	-0.01000
	Peak Adjustment Charge - Winter	Primary	1LGSF ;1LGSFW ;1LGAF ;1LGAFW ;1LGSFP	On-Peak	-	0.00000
	Peak Adjustment Credit - Winter	Primary	1LGSF ;1LGSFW ;1LGAF ;1LGAFW ;1LGSFP	Super Off-Peak	(0.01000)	-0.01000
Large Power Service	Customer Charge	Secondary/Primary/ Substation/Transmission	1PGSE; 1PGSF; 1PGSV; 1PGSZ ;1PGSEW ;1PGSFW ;1PGSVW ;1PGSZW	CUSTOMER CHARGE	1,170.79	1353.12
	Facilities Charge - Block 1	Secondary	1PGSE ;1PGSEW	SECONDARY	3.921	7.842
	Facilities Charge - Block 1	Primary	1PGSF ;1PGSFW	PRIMARY	3.235	3.285
	Facilities Charge - Block 1	Substation	1PGSV ;1PGSVW	SUBSTATION	0.981	1.875
	Facilities Charge - Block 1	Transmission	1PGSZ ;1PGSZW	TRANSMISSION		
	Demand - Summer - Block 1	Secondary	1PGSE ;1PGSEW	All KW	13.925	16.094
	Demand - Winter - Block 1	Secondary	1PGSE ;1PGSEW	All KW	7.250	8.379
	Demand - Summer - Block 1	Primary	1PGSF ;1PGSFW	All KW	14.944	17.271
	Demand - Winter - Block 1	Primary	1PGSF ;1PGSFW	All KW	7.515	8.686
	Demand - Summer - Block 1	Substation	1PGSV ;1PGSVW	All KW	13.385	15.470
	Demand - Winter - Block 1	Substation	1PGSV ;1PGSVW	All KW	6.525	7.541
	Demand - Summer - Block 1	Transmission	1PGSZ ;1PGSZW	All KW	13.784	15.931
	Demand - Winter - Block 1	Transmission	1PGSZ ;1PGSZW	All KW	6.777	7.832
	Energy Charge - Summer - Blk 1	Secondary	1PGSE ;1PGSEW	All KWH	0.05966	0.06896
	Energy Charge - Winter - Blk 1	Secondary	1PGSE ;1PGSEW	All KWH	0.06033	0.06973
	Energy Charge - Summer - Blk 1	Primary	1PGSF ;1PGSFW	All KWH	0.05320	0.06149
	Energy Charge - Winter - Blk 1	Primary	1PGSF ;1PGSFW	All KWH	0.05433	0.06279
	Energy Charge - Summer - Blk 1	Substation	1PGSV ;1PGSVW	All KWH	0.04685	0.05415
	Energy Charge - Winter - Blk 1	Substation	1PGSV ;1PGSVW	All KWH	0.04874	0.05633
	Energy Charge - Summer - Blk 1	Transmission	1PGSZ ;1PGSZW	All KWH	0.04762	0.05504
	Energy Charge - Winter - Blk 1	Transmission	1PGSZ ;1PGSZW	All KWH	0.05016	0.05797
	Peak Adjustment Charge - Summer	Secondary	1PGSE ;1PGSEW	On-Peak	0.01000	0.01000

	Peak Adjustment Credit - Summer	Secondary	1PGSE ;1PGSEW	Super Off-Peak	(0.01000)	-0.01000
	Peak Adjustment Charge - Winter	Secondary	1PGSE ;1PGSEW	On-Peak	-	0.00000
	Peak Adjustment Credit - Winter	Secondary	1PGSE ;1PGSEW	Super Off-Peak	(0.01000)	-0.01000
	Peak Adjustment Charge - Summer	Primary	1PGSF ;1PGSFW	On-Peak	0.01000	0.01000
	Peak Adjustment Credit - Summer	Primary	1PGSF ;1PGSFW	Super Off-Peak	(0.01000)	-0.01000
	Peak Adjustment Charge - Winter	Primary	1PGSF ;1PGSFW	On-Peak	-	0.00000
	Peak Adjustment Credit - Winter	Primary	1PGSF ;1PGSFW	Super Off-Peak	(0.01000)	-0.01000
	Peak Adjustment Charge - Summer	Substation	1PGSV ;1PGSVW	On-Peak	0.01000	0.01000
	Peak Adjustment Credit - Summer	Substation	1PGSV ;1PGSVW	Super Off-Peak	(0.01000)	-0.01000
	Peak Adjustment Charge - Winter	Substation	1PGSV ;1PGSVW	On-Peak	-	0.00000
	Peak Adjustment Credit - Winter	Substation	1PGSV ;1PGSVW	Super Off-Peak	(0.01000)	-0.01000
	Peak Adjustment Charge - Summer	Transmission	1PGSZ ;1PGSZW	On-Peak	0.01000	0.01000
	Peak Adjustment Credit - Summer	Transmission	1PGSZ ;1PGSZW	Super Off-Peak	(0.01000)	-0.01000
	Peak Adjustment Charge - Winter	Transmission	1PGSZ ;1PGSZW	On-Peak	-	0.00000
	Peak Adjustment Credit - Winter	Transmission	1PGSZ ;1PGSZW	Super Off-Peak	(0.01000)	-0.01000
	Reactive Demand Adj	Secondary/Primary/ Substation/Transmission	1PGSE; 1PGSF; 1PGSV; 1PGSZ	KVR	0.993	1.148
CCN	Customer Charge	Business Electric Vehicle	1BEVCS	Customer Charge	122.14	139.74
	Customer Charge	Electric Transit Service	1ETS	Customer Charge	122.37	140.00
	Facilities Charge	Business Electric Vehicle	1BEVCS	Facilities Charge	3.494	3.997
	Facilities Charge	Electric Transit Service	1ETS	Facilities Charge	3.501	4.005
	Energy Charge - Summer - Blk 1/Off Peak	Business Electric Vehicle	1BEVCS	Off-Peak	0.11520	0.13180
	Energy Charge - Summer - Blk 2/On Peak	Business Electric Vehicle	1BEVCS	On-Peak	0.21942	0.25103
	Energy Charge - Summer - Blk 3/Super O	Business Electric Vehicle	1BEVCS	Super Off-Peak	0.03657	0.04184
	Energy Charge - Winter - Blk 1/Off Peak	Business Electric Vehicle	1BEVCS	Off-Peak	0.09143	0.1046
	Energy Charge -Winter - Blk 2/On Peak	Business Electric Vehicle	1BEVCS	On-Peak	0.17159	0.19631
	Energy Charge -Winter - Blk 3/Super Off P	Business Electric Vehicle	1BEVCS	Super Off-Peak	0.03657	0.04184
	Energy Charge - Summer - Blk 1/Off Peak	Electric Transit Service	1ETS	Off-Peak	0.04375	0.05005
	Energy Charge - Summer - Blk 2/On Peak	Electric Transit Service	1ETS	On-Peak	0.24281	0.27779
	Energy Charge - Winter - Blk 1/Off Peak	Electric Transit Service	1ETS	Off-Peak	0.03677	0.04207
	Energy Charge -Winter - Blk 2/On Peak	Electric Transit Service	1ETS	On-Peak	0.18936	0.21664
	Carbon Free Energy Option	Electric Transit Service	1ETS	All kWh	0.00260	0.00297
	Energy Charge - Blk 1/ On-Peak	Clean Charge Network	CCN	Energy Level 2 Charge	0.20820	0.23819
	Energy Charge - Blk 2/ Off-Peak	Clean Charge Network	CCN	Energy Level 3 Charge	0.26025	0.29774

Schedule LLPS Monthly Pricing - ER-2026-0143				
Charges	Missouri Metro-Current		Missouri Metro-Proposed	
	Summer	Winter	Summer	Winter
Customer	$ 1,181.28	$ 1,181.28	$ 1,360.72	$ 1,360.72
Grid ($/kW) Substation Voltage	$ 3.003	$ 3.003	$ 3.460	$ 3.460
Grid ($/kW) Transmission Voltage	$ 2.200	$ 2.200	$ 2.534	$ 2.534
Demand ($/kW)	$ 21.038	$ 19.038	$ 24.234	$ 21.930
Energy ($/kWh)	$ 0.02988	$ 0.02988	$ 0.034419	$ 0.034419

Evergy Missouri Metro 2026 Rate Case

Net Margin Rate Calculation

Summary Table

Class	Total	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25
Small General Service	0.06608	0.06708	0.06708	0.06708	0.06810	0.06810	0.06810	0.06810	0.06810	0.06810	0.06810	0.06810	0.06708
Medium General Service	0.05667	0.05606	0.05606	0.05606	0.05995	0.05995	0.05995	0.05995	0.05995	0.05995	0.05995	0.05995	0.05606
Large General Service	0.05075	0.04989	0.04989	0.04989	0.05393	0.05393	0.05393	0.05393	0.05393	0.05393	0.05393	0.05393	0.04989
Large Power Service	0.04412	0.04439	0.04439	0.04439	0.04676	0.04676	0.04676	0.04676	0.04676	0.04676	0.04676	0.04676	0.04439

Note: Demonstrative calculation for non Residential rates at the time of Direct Filing.