MISSOURI PUBLIC SERVICE COMMISSION

STAFF

RATE DESIGN REPORT

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

CASE NO. ER-2026-0143

Jefferson City, Missouri
July 14, 2026

** Denotes Confidential Information **

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I. Executive Summary

Staff recommends an equal percentage increase to all customer classes for Evergy Metro, Inc., d/b/a Evergy Missouri Metro ("EMM") rates set in this case. Staff recommends the residential customer charge remain at $12.00 and does not recommend changes to the current peak adjustment charges of $0.01 for the summer on peak charge, $0.0025 for the non-summer on peak charge, and -$0.01 for all residential off-peak credits.[1]

Staff recommends an average residential increase of 3.67%[2].

A comparison of current, EMM requested, and Staff-recommended bills is set out below.

Table 1

Customer Using Seasonally Adjusted Average of 750 kWh per Month				
	Annual	Average Monthly Bill	Avg. Monthly Bill Increase %	Avg. Monthly Bill Increase $
Current	$ 1,263	$ 105	100.0%	$ -
EMM Requested	$ 1,455	$ 121	115.2%	$ 16.01
Staff Recommended	$ 1,319	$ 110	104.5%	$ 4.69

Customer Using Seasonally Adjusted Average of 1,000 kWh per Month				
	Annual	Average Monthly Bill	Avg. Monthly Bill Increase %	Avg. Monthly Bill Increase $
Current	$ 1,553	$ 129	100.0%	$ -
EMM Requested	$ 1,790	$ 149	115.2%	$ 19.70
Staff Recommended	$ 1,629	$ 136	104.9%	$ 6.31

Customer Using Seasonally Adjusted Average of 1,500 kWh per Month				
	Annual	Average Monthly Bill	Avg. Monthly Bill Increase %	Avg. Monthly Bill Increase $
Current	$ 2,175	$ 181	100.0%	$ -
EMM Requested	$ 2,506	$ 209	115.2%	$ 27.59
Staff Recommended	$ 2,293	$ 191	105.4%	$ 9.83

[1] EMM has requested a residential customer charge of $13.82.

[2] The recommended increase is 3.64%, but will vary due to the reallocation of economic development incentive revenues. Staff's current estimate is this will result in an increase of approximately 3.67% to individual rate elements.

As part of this rate case, EMM has requested restructuring of its non-residential rate classes. The requested restructuring is directionally consistent with the *Staff Report on Distributed Energy Resources*, filed April 5, 2018, in File No. EW-2017-0245, concerning rate structures and design. Because Staff is generally supportive of restructuring these rates, this direct testimony will provide Staff's recommended rate structure and rate design for the non-residential non-lighting classes in the general form requested by EMM, but with Staff's recommended modifications. This Report discusses factors to consider in implementation of the restructured rates including billing system preparation and customer education.

Conducting a reliable Class Cost of Service (CCOS) study is not feasible in this case due to EMM's class restructuring, and due to the incorporation of new load, capacity requirements, and revenue associated with large customers.

Staff recommends creating a new rider to bill a Critical Peak Rate, to become effective 12 months after the conclusion of this rate case. This delay is necessary to allow time for billing system programing and reasonable and appropriate customer education.

A glossary of ratemaking terms is attached as Schedule 2.

Staff Expert – Sarah L.K. Lange

Recommended Ordered Provisions

- Staff recommends an equal percentage increase to the rate responsibilities of the current EMM classes.
- Staff recommends retaining the existing residential customer charge of $12.00.

- Staff generally supports the rate structure modifications requested by EMM for non-residential, non-lighting classes modified as recommended herein and subject to:
  - Completion of a customer migration and determinants study.
  - Delayed implementation to provide an opportunity for customer notice, customer education, and billing system preparation.
- Staff recommends clean up and elimination of obsolete end-use rates and the underutilized infrastructure tariff.
- Staff recommends that EMM notify effected customers of issues related to interval estimation and take additional actions to ensure accurate billing.
- Staff recommends the Commission order EMM to implement a Critical Peak Rate ("CPR") tariff:
  - All CPR revenues should be incorporated into the Fuel Adjustment Clause ("FAC") calculations as a Missouri Jurisdictional offset to the otherwise applicable "Fuel and Purchased Power Adjustment."
  - To accommodate billing system programing and testing, and to facilitate time for reasonable and appropriate customer education, Staff recommends that the CPR tariffs include a provision that the CPR tariff will not be applicable to service prior to November 1, 2027.
- Staff recommends all Southwest Power Pool ("SPP") costs related to future Conditional High Impact Large Load Service ("CHILLS") customers should be tracked separately and provided to Staff in additional reporting requirements on a monthly basis. Additionally, if any of EMM's customers become CHILLS, Staff recommends that the Commission order that EMM must notify Staff within three business days and provide Staff with a copy of its filing to SPP or the Federal Energy Regulatory Commission ("FERC").

Staff Expert – Sarah L.K. Lange

II. Class Cost of Service Study and Recommended Revenue Responsibility

In a CCOS Study, cost allocation should ultimately follow cost causation. A CCOS study is a reasonable estimate of which customer or group of customers is causing the utility to incur certain costs or type of costs and to what degree, and to what extent any given group of customers should reasonably bear revenue responsibility for cost of service that is not directly caused by any customer.

A robust CCOS study is a useful tool for consideration in developing reasonable rates for customer classes. However, a CCOS study is only as reliable as the data it evaluates. In this case, it is not possible for any party to produce a useful CCOS study due to movement of customers between classes as a consequence of class restructuring and the incorporation of significant new load without sufficient information concerning that load's usage profile.

Staff recommends an equal percentage increase of 3.64% to the classes as currently constituted, subject to adjustment for finalization of the impacts of economic development incentives and the offset of new net revenue from large loads.[3] This adjustment is not applicable to revenues from charges such as solar block charges, and net metering credits. This approach is reasonable given the inability of any party to perform a meaningful CCOS study in this case,[4] and it is also consistent with the interest of minimizing the "moving pieces," while restructuring the non-residential classes. As will be discussed in greater

[3] This will require an iterative approach to solving for the net True-up Plug, as the introduction of an offset to the otherwise applicable increase modifies the percentage increase applicable.

[4] Staff will address the reasonableness of EMM's study in Staff's rebuttal testimony.

detail, it is unlikely that EMM will be able to provide the information needed to actually price out the newly-restructured rates during this case. For this reason, Staff recommends a two-step process. First, the existing rate elements for each existing class at each existing service level should be increased by a uniform percentage, with those rates to take effect as soon as practicable upon conclusion of this case. Then, 12 months later, the restructured rates should take effect. This time gap also allows an opportunity for reasonable and appropriate customer education, and to ensure proper preparation of billing systems. Specific details concerning these recommendations are discussed below.

Staff Expert – Sarah L.K. Lange

Current Revenues

Staff's direct-filed revenues are provided below in Table 2 and are discussed in further detail within the direct testimony of Staff Experts Kim Cox, Amanda Rucker, and Randall T. Jennings filed June 30, 2026. Staff's direct-filed revenues reflect the current class structures and do not account for EMM's proposed customer migrations.

Table 2 Staff's revenues filed at direct, Net of EDR discounts

Rate Class	Revenue
Residential	$365,533,663.02
SGS	$88,845,224.96
MGS	$125,166,480.07
LGS	$188,454,651.29
LPS	$122,116,633.58
Lighting	$7,845,081.08
CCN	$595,519.48
Total	$898,557,253.49

Table 3 provides Staff's direct testimony total revenues by class and the revenues comprised of only retail rates that are subject to adjustment in this case. Retail rates that are subject to adjustment include rates such as the customer charge, energy charges, and demand charges. Revenues associated with the Solar Block Cost,[5] Solar Credit Charge,[6] Net Metering, Parallel Generation, Residential Battery Energy Storage, and Economic Development Rider ("EDR") are not subject to adjustment.

Table 3

	Residential	SGS	MGS	LGS	LPS	Lighting	CCN	Total
Total Class Revenues before EDR discounts	$365,533,663.02	$ 88,849,037.96	$125,275,382.07	$188,614,554.29	$122,116,633.58	$7,845,081.08	$595,519.48	$898,829,871.49
Community Solar	$ (385,604.41)	$ (9,076.95)	$ -	$ -	$ -	$ -	$ -	$ (394,681.35)
Net Metering	$ 55,217.14	$ 17,211.92	$ 6,241.66	$ -	$ -	$ -	$ -	$ 78,670.72
Parallel Generation	$ -	$ 1,486.06	$ 9,845.02	$ 913.02	$ -	$ -	$ -	$ -
Battery	$ (3,600.00)	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,600.00)
EDR	$ -	$ (3,813.00)	$ (108,902.00)	$ (159,903.00)	$ -	$ -	$ -	$ (272,618.00)

Staff Expert – Marina Gonzales[7]

Class Revenues After Increase

Excluding (1) revenue from LLPS[8] Customer A, (2) revenue from LPS[9] Customer B in excess of the annualized update level, and (3) revenues from charges not subject to adjustment in this case (such as solar block charges, and net metering credits), and to account for grossed-up offsets to revenue from Economic Development Incentives, Staff recommends that rates in this case be calculated to recover the following revenues from each current class:[10]

Table 4

Residential	SGS	MGS	LGS	LPS	Lighting	CCN	Total
$ 378,909,484	$ 92,194,465	$ 129,994,983	$ 195,696,201	$ 126,700,963	$ 8,100,898	$ 617,876	$ 932,214,870

[5] P.S.C. MO. No 7 Sheet 39A Solar Subscription Rider Schedule SSP.

[6] Credited back at the Parallel Generation Rate (P.S.C. MO. No 7 Sheet 31A).

[7] Credentials of Marina Gonzales are attached as Schedule 1.

[8] Large Load Power Service (LLPS).

[9] Large Power Service (LPS).

[10] Staff's direct-filed revenues reflect the current class structures and do not account for EMM's proposed customer migrations.

The calculations to produce this target revenue are set out below:

Table 5

	Residential	SGS	MGS	LGS	LPS	Lighting	CCN	Total
Retail Rates Subject to Adjustment	$ 365,199,676	$ 88,854,846	$ 125,182,567	$ 188,455,564	$ 122,116,634	$ 7,845,081	$ 595,519	$ 898,237,643
Revenues before EDR	$ 365,199,676	$ 88,858,659	$ 125,291,469	$ 188,615,467	$ 122,116,634	$ 7,845,081	$ 595,519	$ 898,522,505
% of Revenue	40.64%	9.89%	13.94%	20.99%	13.59%	0.87%	0.07%	100%
	$ 13,289,054	$ 3,233,430	$ 4,559,164	$ 6,863,426	$ 4,443,636	$ 285,470	$ 21,670	$ 32,695,850
% Increase	3.64%	3.64%	3.64%	3.64%	3.64%	3.64%	3.64%	
Initial Target	$ 378,488,730	$ 92,092,089	$ 129,850,632	$ 195,478,894	$ 126,560,270	$ 8,130,552	$ 617,190	$ 931,218,355
% of new Target Revenue	40.64%	9.89%	13.94%	20.99%	13.59%	0.87%	0.07%	
Redistribute EDR	$ 110,804	$ 26,960	$ 38,014	$ 57,227	$ 37,051	$ 2,380	$ 181	$ 272,618
$ Increase	$ 13,399,858	$ 3,260,390	$ 4,597,178	$ 6,920,654	$ 4,480,687	$ 287,851	$ 21,851	$ 32,968,468
% Increase	3.67%	3.67%	3.67%	3.67%	3.67%	3.67%	3.67%	
Target Rate Revenue	$ 378,599,534	$ 92,119,049	$ 129,888,647	$ 195,536,121	$ 126,597,321	$ 8,132,932	$ 617,370	
New Revenue	$ 378,599,534	$ 92,119,049	$ 129,888,647	$ 195,536,121	$ 126,597,321	$ 8,094,272	$ 617,370	$ 931,452,313

Staff Expert – Sarah L.K. Lange

III. Functionalized Revenue Requirement

Staff performed a functionalized cost of service study, attached as Schedule 3, which allocated the cost of service calculated in the Staff Accounting Schedules filed June 30, 2026. This cost of service included approximately $51 million in new net revenue from large loads. [Table 4] summarizes Staff's functionalized CCOS by Production & Energy, Transmission, Distribution, and Other Costs, each of which are described in greater detail below. 'Production & Energy' includes accounts associated with Production 1, Production 2, and Nuclear.[11] Distribution includes distribution infrastructure, as well as accounts for meters and Electric Vehicle charging stations. 'Other' represents Administrative & Overhead costs, Plant in Service Accounting (PISA), and Deferred Income Tax.

[11] The function 'Production 1' is referred to as Dispatchable Fossil Generation and 'Production 2' as Renewable Generation in this testimony.

Table 6 Staff's summarized functionalized CCOS

Production & Energy	Transmission	Distribution	Other	Large Loads	Current Revenues	Increase
$ 557,470,482	$ 76,578,780	$ 244,095,912	$ 106,388,712	$ (51,026,843)	$ 898,658,443	$ 34,848,600

As illustrated in Figure 1, the components of the cost of service are the cost of Production & Energy (57%), Transmission (8%), Distribution (25%), and Other (11%). These functionalized amounts are net of associated revenues and offsets to cost of service. For example, the Production & Energy cost of service is net of the value of energy sold through the SPP market, the Transmission cost of service is net of the value of transmission revenue, and the "Other" function is net of the offset to cost of service provided by taxes prepaid by ratepayers. Notably, the cost of service associated with the "Other" function does not necessarily tie to the quantity of customers, energy sold, or total demand.

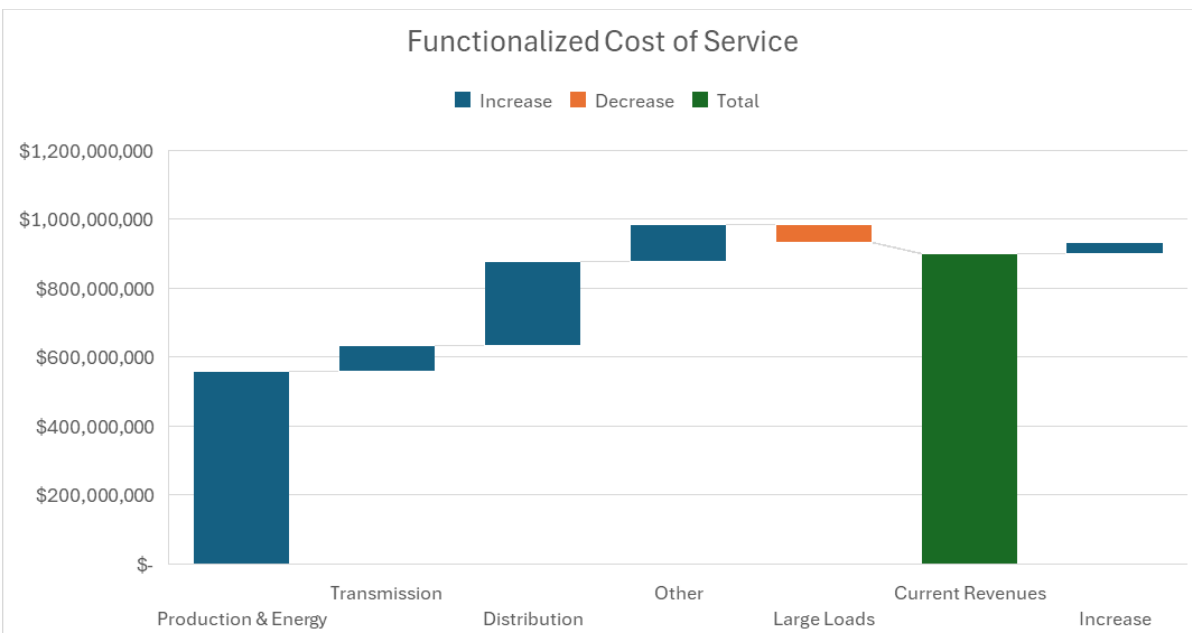

Figure 1

Staff Expert – Marina Gonzales

Production & Energy

The Missouri jurisdictional share of the net cost of service to own generation, operate power plants, honor purchased power agreements, and sell energy through the SPP energy markets is $289,328,839. This does include property taxes and income tax, but does not include PISA or administrative and overhead cost of service, and does not reflect offsets from deferred taxes.[12]

EMM's Missouri jurisdictional rate base reflects approximately $1.3 billion associated with dispatchable fossil fuel generation with an accredited summer 2026 capacity of **[redacted] ** MW, $37 million associated with renewable generation with an accredited summer 2026 capacity of ** [redacted] ** MW,[13] and $522 million associated with nuclear generation, with an accredited summer 2026 capacity of ** [redacted] ** MW.[14] For each type of generation, the revenue requirement for owning the generation, including property taxes and Operations & Maintenance Expenses (O&M) expenses, is set out in the table below. The table also includes the fuel and contract expenses, the market value of the energy generated, and the net cost of service for each type of generation and in total.

Table 7

	Cost to Own Generation	Fuel Expense	Renewable Contract Expense	Value of Energy Generated	Net Production Cost of Service
Dispatchable Fossil Generation	$ 274,619,791	$ 89,901,331	$ -	$ (185,327,663)	$ 179,193,459
Renewable Generation	$ 8,988,411	$ -	$ 57,580,434	$ (43,799,130)	$ 22,769,715
Nuclear Generation	$ 122,487,431	$ 14,029,936	$ -	$ (49,151,702)	$ 87,365,665
	$ 406,095,634	$ 103,931,266	$ 57,580,434	$ (278,278,495)	$ 289,328,839

[12] These values do not include the incremental energy required to serve new large loads described in the direct testimony of Sarah L.K. Lange filed June 30, 2026.

[13] EMM has also entered into multiple contracts for renewable energy, which do not contribute to rate base, with a summer 2026 accredited capacity of ** [redacted] ** MW.

[14] Dispatchable Fossil Generation appears in the attached CCOS as 'Production 1' and Renewable Generation appears as 'Production 2'.

The following confidential table provides the $/MW-Year and $/kW-Month for each type of generation and as a weighted average.

Table 8

** [redacted] **

Note, the $/kW-Month amounts are not directly comparable to rate design $/kW-Month rate values because (1) the denominator here is accredited capacity, not the total of the peak demands of each customer, and (2) the months here are equally weighted.

Staff Expert – Sarah L.K. Lange

Cost of Energy to Serve Load

The Missouri jurisdictional share of the market value of the energy consumed by EMM's load is $268,141,643. This is an average of $29.71 per MWh.

Staff Expert – Sarah L.K. Lange

Transmission Cost of Service

The functionalized transmission cost of service is $76,578,780. EMM's Transmission accounts include sub-accounts that are utilized under different functions. The amount of Transmission Net Plant that is used to interconnect generation facilities and that is used for specific customers are detailed in Table 9 below.

Table 9 Total Transmission Net Plant

Total Transmission Net Plant	
Production 1	$ 16,092,373
Production 2	$ 6,307,498
Nuclear	$ 11,367,287
Customer Specific	$ 1,794,209
Network Transmission	$ 351,746,397

Figure 2 details the different asset types of Network Transmission including communication equipment, underground infrastructure, overhead infrastructure, and transmission substations.

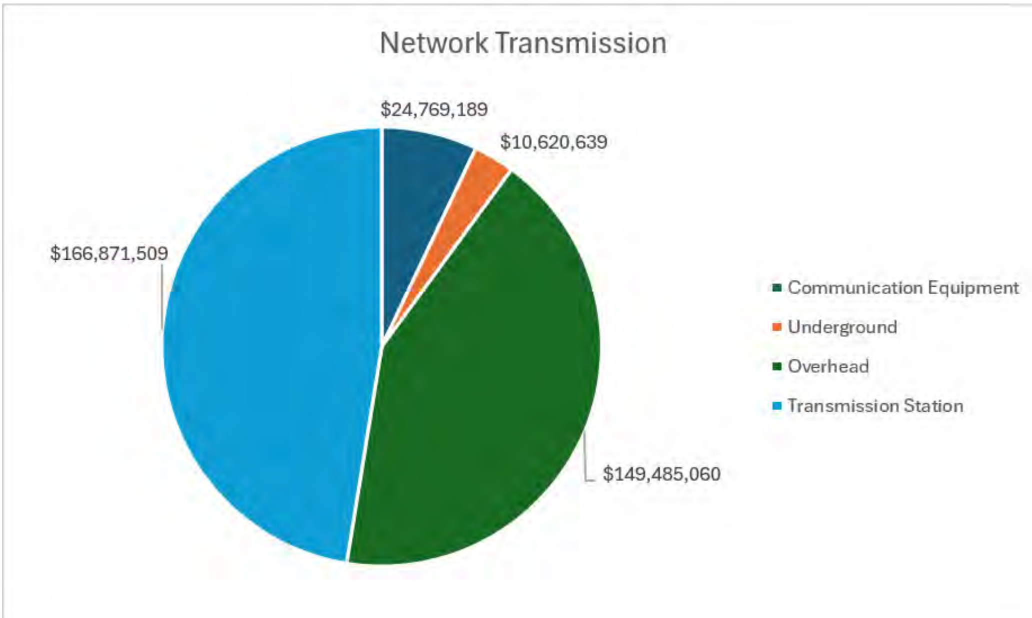

Figure 2

Staff Expert – Marina Gonzales

Distribution Cost of Service

The functionalized distribution cost of service is $244,095,912. EMM's Distribution accounts include sub-accounts that are utilized under different functions. The amount of Distribution Net Plant that is used to interconnect generation facilities and that is used for specific customers are detailed in Table 10 below.

Table 10 Total Distribution Net Plant

Total Distribution Net Plant	
Production 1	$ 5,714,939
Customer Specific	$ 22,989,398
EV Charging	$ 7,140,062
Lighting	$ 12,183,856
Network Distribution	$ 1,571,144,398

Figure 3 details the different asset types of Network Distribution including communication equipment, underground infrastructure, overhead infrastructure, line transformers, services, meters, and distribution substations.

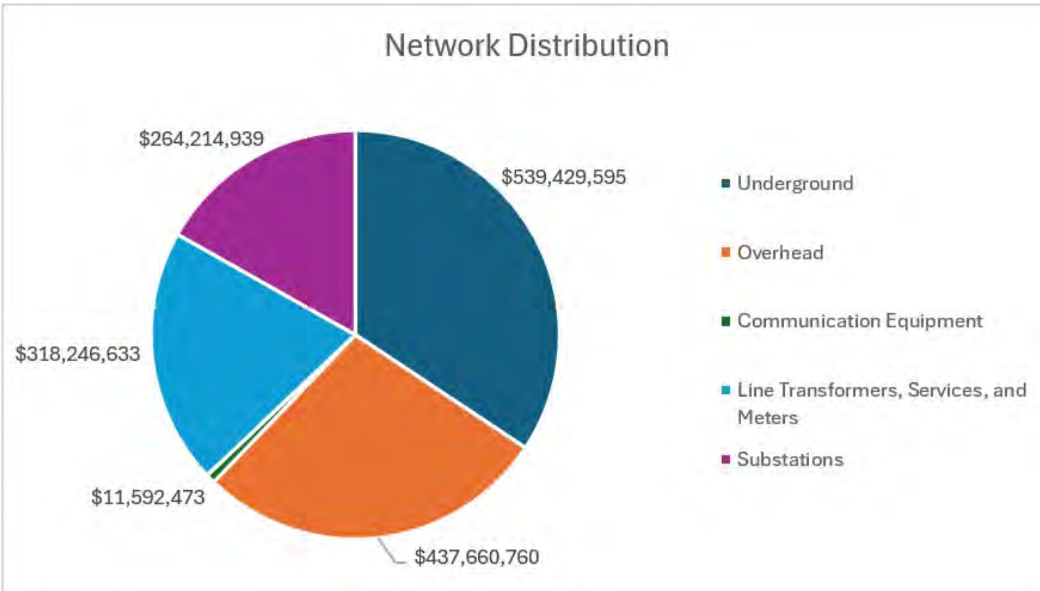

Figure 3

Staff Expert – Marina Gonzales

Other Cost of Service

The cost of service associated with EMM's computer systems, general office buildings, and other general costs of doing business, as well as the revenue requirements associated with PISA and deferred taxes nets to $106,388,712. The current rate impact of PISA is approximately $23.5 million dollars, and the value of taxes prepaid by EMM ratepayers reduces the revenue requirement by just over $86 million dollars. The general cost of doing business that is not clearly related to energy production, transmission, or distribution is approximately $169 million.

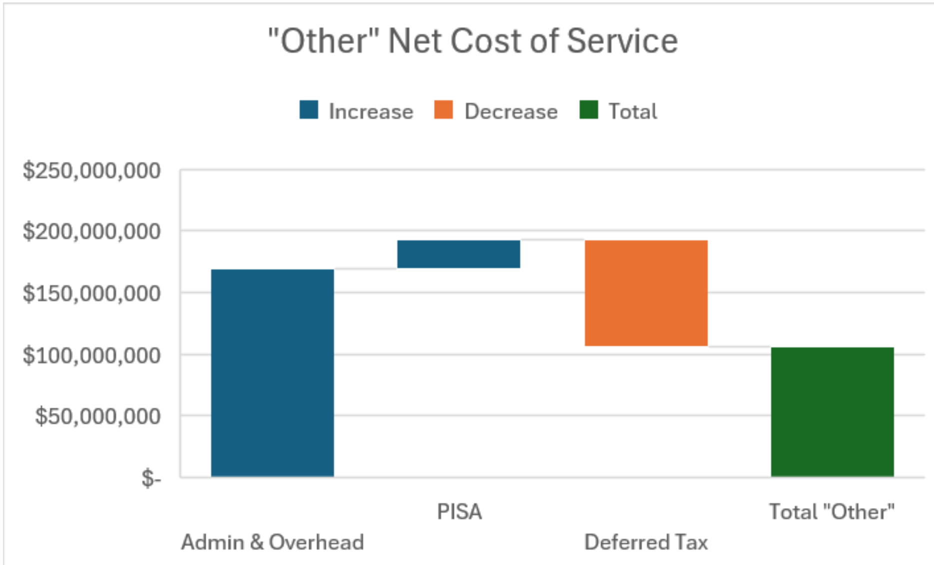

Figure 4

Staff Expert – Sarah L.K. Lange

IV. Residential Rates

Tariff Clean Up

Staff recommends that obsolete end-use rates "RESIDENTIAL GENERAL USE AND SPACE HEAT - ONE METER, 1RS6A (FROZEN)," and "RESIDENTIAL GENERAL USE AND SPACE HEAT - 2 METERS 1RS2A (FROZEN)," be removed from EMM's residential rate schedules. No customers are served on these rate schedules.

Staff also recommends that the currently frozen rate plan, "Residential Time of Day Service (RTOD)" be removed from the EMM tariff. Staff is not aware of any customers currently taking service on this schedule, which has been superseded by other available rate schedules.

Staff Expert – Sarah L.K. Lange

Residential Customer Charge

To determine whether a change in the residential customer charge is appropriate in this case, Staff reviewed the reasonableness of the current Residential customer charge of $12. For this review, Staff estimated the cost of service for a residential customer to be metered and to interconnect to the distribution grid through service lines and line transformers.[15] Staff does not recommend reducing residential customer charges in cases with an overall recommended rate increase because a reduction would require other costs to be recovered through the Residential energy charges and results in increased bill volatility.

To estimate the cost of service of the meter-related component for a single residential customer, Staff relied on an average AMI meter value as the retirement unit AMI Polyphase Meter, ("AMI Meter") in the EMM Continuing Property Record. To estimate the average cost of an AMI meter, Staff identified all AMI Meters under the Missouri and MoKan Jurisdiction. All AMI Meters in the Continuing Property Record were listed under MoKan Jurisdiction. Since the AMI meters are provided in the Continuing Property Record as a sum of meters in-service by a given date and not by rate class, Staff determined the average cost of an AMI Meter as the running average at the point where the cumulative value of all in-service AMI Meters reached 90%. This threshold ensures the average cost used in the customer charge study is representative of the majority of AMI Meters serving residential

[15]Where:

$$\begin{aligned} &Revenue\ Requirement \\ &\qquad = Cost\ of\ Debt + Cost\ of\ Equity + Income\ Tax + Depreication\ Expense \\ &\qquad + Operation\ Expense + Maintenace\ Expense \end{aligned}$$

customers today. The running average per unit cost in the Continuing Property Record at the 90% cumulative threshold is $99.10.

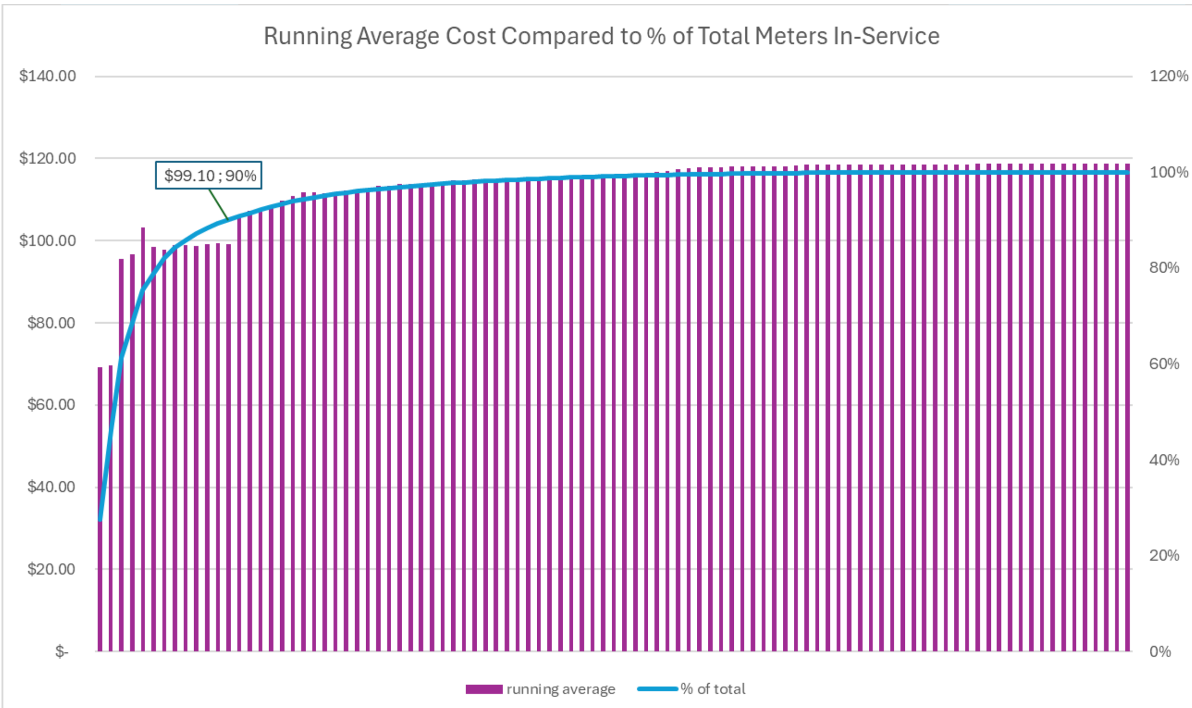

Figure 5

Staff found the relationship between the average AMI Meter cost to the total AMI Meter gross plant in service for the Missouri jurisdiction. Staff used this relationship to scale capital-related meter cost of service for the Missouri jurisdiction to estimate the annual capital-related cost of a single residential meter. This annual cost of service is divided by twelve to approximately $1.00 for the monthly meter capital component of the customer charge.

Staff determined the AMI meter maintenance expense component of the customer charge by dividing the Missouri jurisdictional annual expense for those accounts in the

Staff Accounting Schedules by the total number of EMM's customers, and by 12. The monthly AMI maintenance expense component of the customer charge totals $0.85.[16]

The Service Line component of the customer charge was calculated by dividing the Missouri jurisdictional cost of service for those accounts by the total number of secondary customers determined by EMM.[17] This approach produces the high-end valuation of the per-customer cost of service of service lines because the infrastructure to serve residential customers is less costly than the infrastructure to serve LGS[18], MGS[19], and many SGS[20] customers, as well as the infrastructure to serve LPS customers served at secondary. Further, this approach produces the high-end valuation of the per-customer cost of service of service lines because it is more common for multiple residential customers to be served on one service line than it is for multiples of other service types to be served on one service line, with a reasonable assumption that LPS, LGS, and MGS customers served at secondary will each require a dedicated service line.

The annual per customer value of the Service Line Revenue Requirement is divided by twelve to calculate Staff's monthly per customer service line component of the customer charge at $2.01.

Following the calculation that was applied for the AMI Meters and Service Lines, Staff adjusted the following values from Staff's Accounting Schedules to reflect EMM'S

[16] Staff did not include the annual Missouri jurisdictional operations expense in this calculation because it is a negative expense because of intra-corporate allocations.

[17] Graham Jaynes Workpaper: Current Class Structure External Allocators.xlsx, the count excludes all LGS, LPS, New Large Load, CCN, and Lighting customers.

[18] Large General Service (LGS).

[19] Medium General Service (MGS).

[20] Small General Service (SGS).

representation of the percentage of customer-related costs associated with a 25 kVA Transformer:[21]

- Line Transformer Net Plant
  - The Cost of Debt
  - Cost of Equity
- Income Tax
- Depreciation Expense
- Maintenance Expense

The resulting revenue requirement reflective of the customer-related line transformer costs was then divided by the total number of secondary customers determined by EMM and then by twelve to determine the monthly per customer component at $1.72.

For purposes of the customer charge calculation only, Staff relied on EMM's Transformer customer-related classification factor. Staff's use of the EMM classifier provides a high-end valuation of the appropriate recovery of line transformers in the residential customer charge quantification, in that it is more common for multiple residential customers to be served by one transformer than it is for multiples of other service types to be served on one transformer, with a reasonable assumption that LPS, LGS, and MGS customers served at secondary will each require a dedicated transformer.

Staff calculated the cost of service for the residential customer charge as approximately $5.59 per customer per month.[22] Reducing the residential customer charge

[21] Graham Jaynes Workpaper: CONFIDENTIAL Support Paper Transformer Min System Analysis.xlsx Mr. Jaynes used a 25 kVA transformer to calculate the customer classifier. A 25 kVA transformer is adequate to serve the average residential structure, and so no additional demand-related cost of service should be appropriately included in the residential customer charge calculation.

[22] Historically, the customer charge would also include the costs associated with mailing bills, processing payments, and meter reading. These costs are generally obsolete with the introduction of new technology. Given that the cost of computer software does not fluctuate with the addition of new customers, it is not reasonable to include a prorated share of the related cost of service in the customer charge.

would shift additional cost recovery onto already increasing residential energy charges. Since energy usage is inherently volatile, this could considerably exacerbate rate shock associated with the increase contemplated in this case, therefore, Staff recommends retaining the existing residential customer charge of $12.00.

Staff Expert – Marina Gonzales

Recommended Residential Rates

Staff recommends an overall 3.64% increase to the rates for the Residential customer class, subject to adjustment for finalization of the impacts of economic development incentives and the offset of new net revenue from large loads. This adjustment is not applicable to revenues from charges such as solar block charges, and net metering credits. Staff does not recommend changes to the current peak adjustment charges of $0.01 for the summer on peak charge, $0.0025 for the non-summer on peak charge, and -$0.01 for all residential off-peak credits.

continued on next page

Staff's recommended Residential Rates are set out in Table 11:

Table 11

	Rates	
	Summer	Non-Summer
CUSTOMER CHARGE	$ 12.00	
1RS1A		
600 kWh	$ 0.1463	$ 0.1301
next 400 kWh	$ 0.1463	$ 0.0801
over 1000 kWh	$ 0.1615	$ 0.0710
All RPK		
600 kWh	$ 0.1467	$ 0.1273
next 400 kWh	$ 0.1467	$ 0.0784
over 1000 kWh	$ 0.1571	$ 0.0695
Peak adj charge on-peak kWh	$ 0.0100	$ 0.0025
Peak adj credit super off-peak kWh	$ (0.0100)	$ (0.0100)
Solar Access	$ 0.0416	$ 0.0416
All RTOU		
PEAK	$ 0.3518	$ 0.2877
OFF-PEAK	$ 0.1173	$ 0.1128
SUPER OFF-PEAK	$ 0.0586	$ 0.0487
All RTOU 2		
PEAK	$ 0.3989	$ -
OFF-PEAK	$ 0.0997	$ 0.1177
SUPER OFF-PEAK	$ -	$ 0.0589
All RTOU 3		
PEAK	$ 0.3735	$ 0.2842
OFF-PEAK	$ 0.1245	$ 0.0947
SUPER OFF-PEAK	$ 0.0311	$ 0.0237
RTOU EV		
CUSTOMER CHARGE	$ 3.38	$ 3.38
PEAK	$ 0.3735	$ 0.2842
OFF-PEAK	$ 0.1245	$ 0.0947
SUPER OFF-PEAK	$ 0.0311	$ 0.0237

Staff Expert – Sarah L.K. Lange

Estimated Billing Interaction with Highly Differentiated Time-Based Rates

Related to the estimation procedure discussion provided in the direct testimony of Staff Expert Randall T. Jennings filed June 30, 2026, Staff is concerned that EMM lacks adequate metering and billing precision to ensure that customers are accurately billed for the energy consumed in each time-based rate period. This is of greatest concern for customers participating in rates such as Residential Time of Use – Three Period (RTOU), Residential High Differential Time of Use (RTOU-3), the Separately Metered Electric Vehicle Time of Use schedule (RTOU-EV), Residential Time of Use – Two Period (RTOU-2), and Residential Time of Day Service (RTOD).

Staff recommends that for any customer participating in these rate schedules for which EMM estimates interval data necessary for billing for three or more months in any twelve-month period, the Commission should order EMM to provide a notice to each effected customer, informing each customer that "Evergy is unable to ensure accurate billing for you due to the programing of the Evergy billing system. For this reason, you are no longer eligible to participate in your selected rate. If Evergy successfully obtains your meter reads for the next twelve months, an Evergy representative will contact you and discuss your rate plan options at that time."

A new tariff sheet should be included in EMM's compliance tariffs in this case to effectuate this recommendation as ordered.

Staff Expert – Sarah L.K. Lange

V. Non-Residential Class Structure and Recommended Rates

Use of Demands in Ratemaking

As discussed in more detail under the *Restructuring and Migrating Customers* section of this report, EMM is proposing to move from a 30-minute interval to relying on a 15-minute interval for measuring demand. This section serves to provide additional context as to how the length of time measured impacts metered demand, as well as the impact on billed demand when considering On-Peak and Off-Peak usage. As an illustration of how billing demands can be measured, assume a customer that operates a bakery. This bakery has a 24/7 proofing station which requires 5 kW, a large refrigerator that requires 50 kW (depending on how often the door is opened), and a double-decker oven that requires 60 kW (depending on the baking temperature). The proofing station is on 24 hours every day. The refrigerator compressor cycles off and on regularly throughout the day and night, but since the refrigerator door is opened frequently as the baker accesses supplies, it runs more from 2:00 - 4:00 AM as the baker prepares for the day. The baker sets the oven to pre-heat at 2:00 AM and runs it continuously until 5:00 AM while opening it occasionally.

[Figure 4] captures the key differences between the measures of demand as applied to this example customer, showing that the longer the measure of demand, the lower the demand in kW, and the shorter the measure of demand, the higher the measured demand in kW. Compare the demand for this same period with the usage detail for the same period, in the graphic "Morning Demand (kW)."

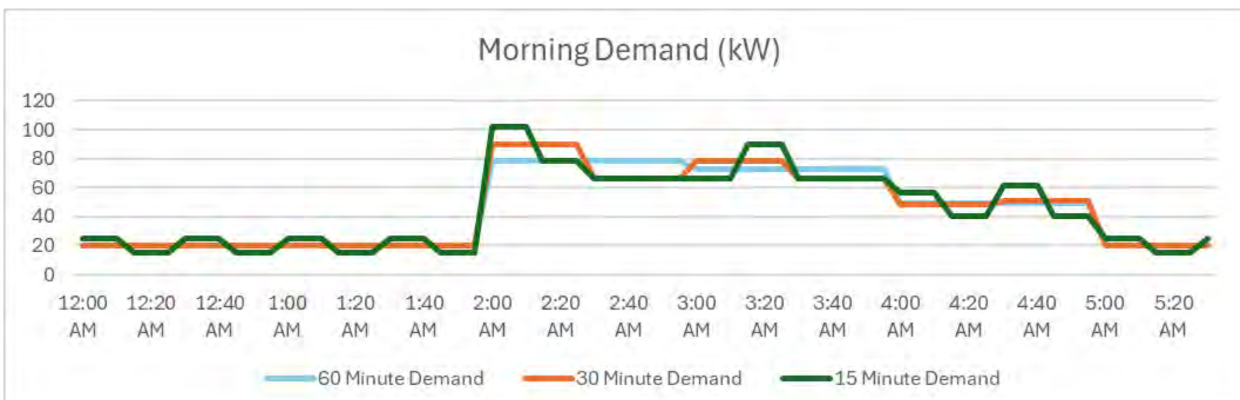

Figure 6

All else being equal, for most customers, the longer the duration of time used to measure demand, the lower the demand will be. Illustrated in [Figure 5], this customer would have a 60-minute peak maximum of 78.3 kw, a 30-minute maximum demand of 90 kW, and a 15-minute peak demand of 101.7 kW.

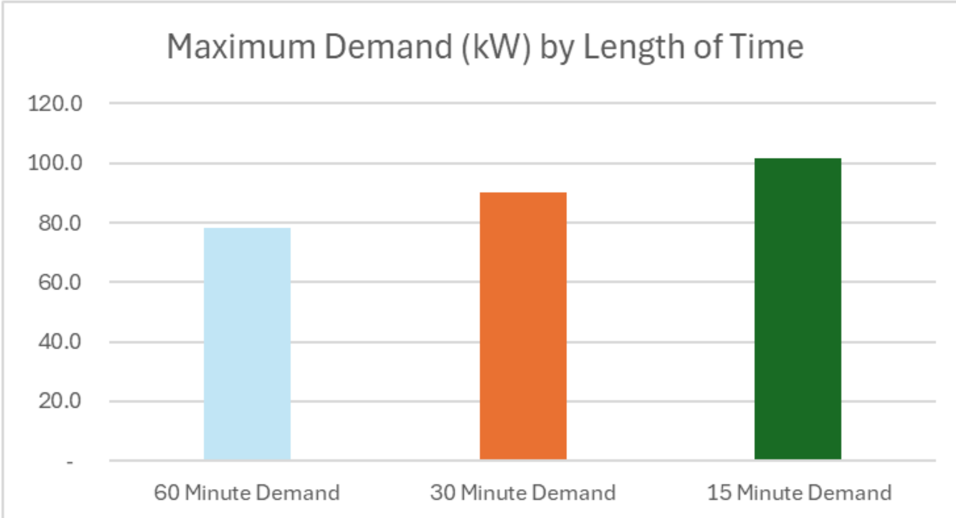

Figure 7

Let's assume there is a competing bakery (Bakery B) that uses all the same equipment. Bakery B does its preparation from 3:00 PM – 6:00 PM during on-peak hours. In this example, the Winter On-Peak period is 9:00 AM - 9:00 PM and the Summer On-Peak period is 3:00 PM - 7:00 PM. Table [10] illustrates that the bakeries are incurring the same level of monthly maximum demand, but their on-peak billing demand would be very different and the strain they put on the system takes place at crucially different times.

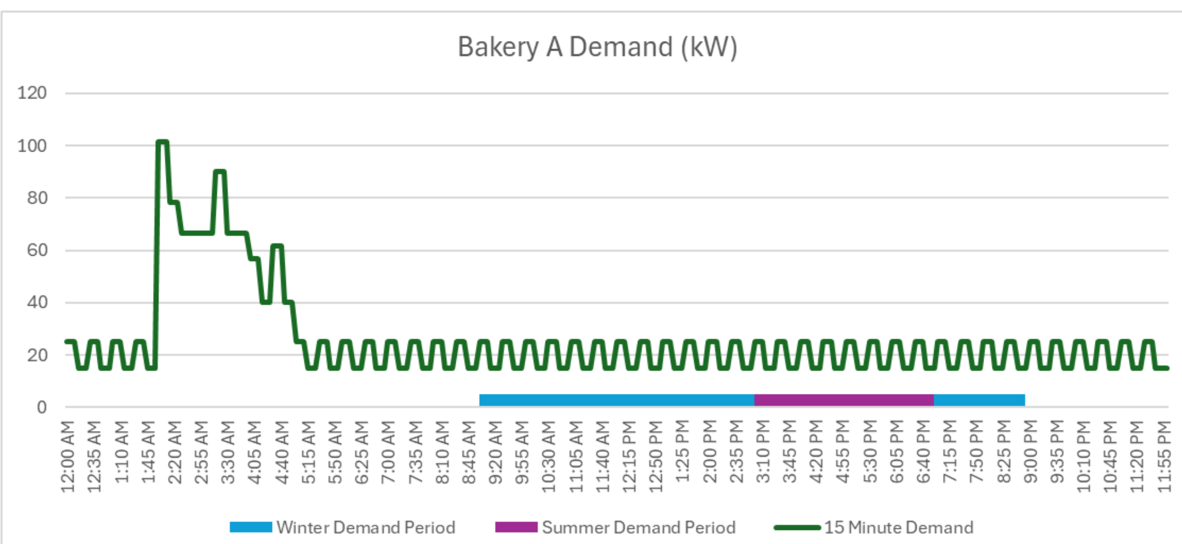

Figure 8

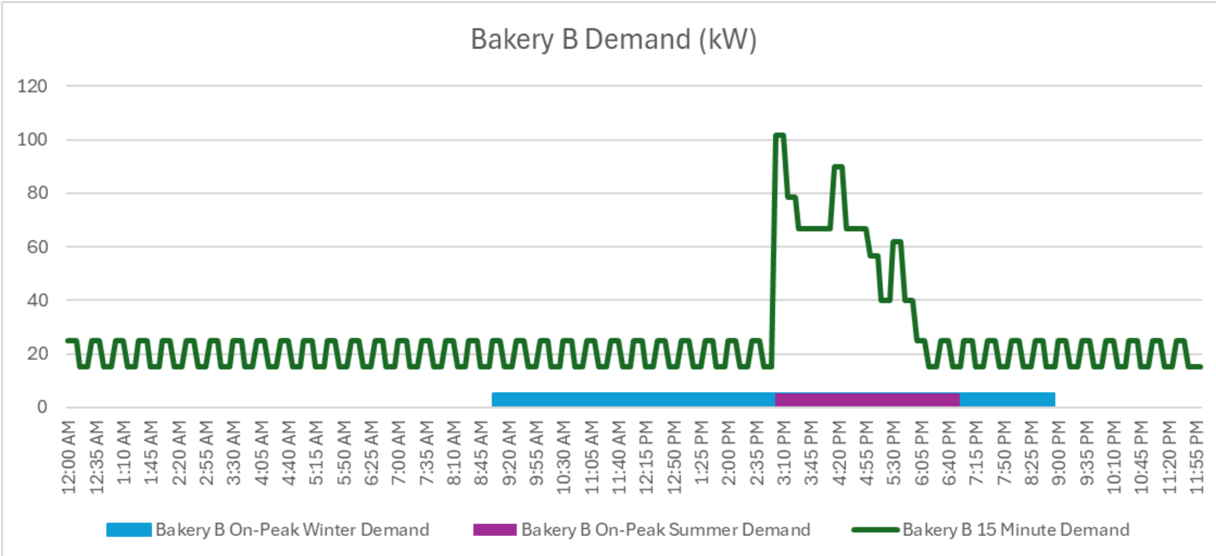

Figure 9

Bakery B's On-Peak demand is different from Bakery A's On-Peak demand, even though the overall demand of each bakery is identical.

Table 12 Comparison of Demands using 15-minute interval demand

	Bakery A	Bakery B
Monthly Maximum Demand (kW)*	101.67	101.67
On-Peak Billing Demand (kW)*	25.00	101.67

**Using 15-minute Interval Demand (kW)*

To estimate the determinants of each of EMM's non-residential customers under restructured rate elements, it will be necessary to use each customer's 15-minute demands during the selected on-peak periods, as opposed to 30-minute demands from any time of day.

Staff Expert – Marina Gonzales

Restructuring and Migrating Customers

EMM is proposing the establishment of Demand Thresholds that would reflect the "class-specific maximum demand levels based upon Non-Coincident Peak demand[23]" for non-residential customer classes.[24] With these new Demand Thresholds, also referred to as "Bright Lines," EMM is attempting to address uneconomic rate selection, mitigate opportunistic rate switching for non-residential customers, and improve class homogeneity for future jurisdictional alignment.[25]

Staff supports the general rate structure proposed by EMM, but with modifications.[26] Staff is not opposed to EMM's recommended "Bright Lines" thresholds of 31 MW, 250 MW, and 3,000 MW.

As discussed in detail above, all else being equal, shifting from 30-minute measured demand to 15-minute measured demand will increase the demand measured for most customers. Additionally, changing from 24-hour demand to on-peak demand will reduce the demand measured for many customers. Staff recommends that customer migrations be established using the highest 15-minute interval demand of the customers as it coincides with the on-peak demand period that is representative of EMM's system load.

A reasonable sequence of a customer migration and determinants study is set out below.

---

[23] Non-Coincident Peak (NCP) refers to a customer's or a group of customers' peak demand independent of the peak demand of the system.

[24] Graham Jaynes Direct Testimony page 10, lines 7-9.

[25] Graham Jaynes, Direct Testimony page 10, lines, 14-16.

[26] Staff reviewed the load characteristics and energy cost characteristics of all rate classes and voltage levels to identify the on-peak demand hours, this is discussed in greater detail in the *Demand Periods and Energy Periods* section.

1. Identify the applicable on-peak time interval and the applicable “Bright Lines”.
    a. Staff recommends the use of the demand occurring in summer billing months between 10:00 AM and Midnight, and in non-summer billing months between the hours of 6:00 AM and Midnight.
    b. Staff does not oppose EMM’s selection of the 31 MW, 250 MW, and 3,000 MW as reasonable “Bright Lines.”

2. Find the 15-minute on-peak demand of each customer for each of the 12 historic billing months. Determine which restructured rate class the customer should be served under based on that customer’s 15-minute on-peak demand and the selected “Bright Lines.”

3. For each restructured class, calculate the monthly determinants for each charge, as the sum of the determinants of the customers migrated to that restructured class based on 15-minute on-peak demand:
    a. Customer charge determinants,
    b. 15-minute facilities demand, by service voltage, and as applicable, billing block,
    c. 15-minute on peak billing demand, including minimum demands, by service voltage,
    d. Reactive demand,
    e. Total energy, by service voltage, and
    f. Energy by time period, by service voltage.
        i. Staff recommends that an additional charge be applied to each kWh of energy consumed in both summer and non-summer billing months beginning at 3:00 PM until 9:00 PM, with an additional period in non-summer billing months from 7:00 AM until noon.[27]
        ii. Staff recommends that a credit be applied against the otherwise applicable charge per kWh for energy consumed in summer billing months beginning at Midnight and continuing until 10:00 AM, and in non-summer billing months from midnight and continuing until 6:00 AM.[28]

Staff Expert – Marina Gonzales

[27] Discussed in further detail under the *Demand Periods and Energy Periods* section.

[28] Discussed in further detail under the *Demand Periods and Energy Periods* section.

Compliance Tariffs and Restructured Rates

Staff recommends that EMM perform the customer migration and determinants study promptly upon the filing of this testimony, so that rates can be calculated swiftly upon the entering of the Commission's order in this case. Preferably, the customer migration and determinants study should be performed using actual customer data for the period July 1, 2025 – June 30, 2026, to coincide with the billing determinants developed for true-up. These determinants must be scaled on the basis of existing classes' determinants and revenues, and that process will require extensive cooperation and collaboration.

Concerning the rates applicable to SGS, MGS, LGS, LPS, and related standby rate schedules, Staff recommends that the Commission order EMM as follows:

1. File one set of tariff sheets as currently numbered and paginated, with each rate increased by 3.64%, and with a heading indicating that the rates are applicable to service prior to November 1, 2027, including the frozen "All Electric" SGA, MGA, and LGA rate schedules, and the "Large Power Service Off-Peak Rider."[29]
2. File additional tariff sheets on new tariff sheet numbers, setting out restructured rates as recommended above, which are denominated as applicable to service on and after November 1, 2027.[30]
3. Staff does not recommend creation of highly-differentiated time-based non-residential rate schedules at this time.
4. Staff recommends that LLPS, Clean Charge Network, Electric Vehicle Charging rates, Lighting, and Time Related Pricing rates each be increased by the applicable 3.64% increase, without limitations on the timing of applicability, and without revision on November 1, 2027.
5. For standby rate schedules for service on and after November 1, 2027, Staff recommends the following:

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[29] This transition will also effectively eliminate end-use special rates such as currently-tariffed all electric rates after the restructuring takes effect, which will smooth the transition for effected customers.

[30] This will effectively eliminate the availability of the "All Electric" SGA, MGA, and LGA rate schedules for service after November 1, 2027. This will also effectively eliminate the availability of the Large Power Service Off peak Rider for service after November 1, 2027, which will become functionally obsolete through the rate restructuring.

a. Alignment of paragraph 11, “Standby Service Demand,” with the 15-minute demands, demand bright lines, and peak demand periods established for the SGS, MGS, LGS, and LPS restructured schedules.
b. Alignment of the rates for service structures and rates with those established for the SGS, MGS, LGS, and LPS restructured schedules.

The effect of these staggered effective dates not only provides time and opportunity for EMM to educate and prepare its customers, but for customers to begin to facilitate preparations for actions or equipment changes that will be economically efficient under the rates which will be taking effect in November of 2027. For example, customers may determine it is appropriate to adjust shift start times, or the timing of certain processes, or to purchase and install thermostats or HVAC equipment that supports precooling or preheating conditioned air.[31]

Staff Expert – Sarah L.K. Lange

Customer Impact Mitigations and Communication

Staff recommends that EMM inform its non-residential customers of the restructured rates and provide reasonable education to those customers. This should include a statement of the rate schedule the customer has been billed on, the rate schedule the customer will be billed on, simple and clear education concerning the time-based periods ordered in this case, an explanation of the recommended delay in restructuring until November 2027, and a one-time report of the following:

1. A statement of the total energy and 30-minute demand for 12 historic billing months,
2. A statement of the total energy, energy by time-based period, 15-minute NCP demand, and 15 minute on-peak demand for the same 12 historic billing months,

[31] Staff does not recommend promulgation of time-based rates except for those described above.

3. A calculation of the bill the customer would owe for the usage and demand for those 12 historic months on the increased non-restructured rates that are ordered in this case, and
4. A calculation of the bill the customer would owe for the usage and demand for those 12 historic months on the restructured rates that are ordered in this case and effectuate the rate increase.

The Commission should also order EMM to test its billing system's ability to accurately bill the restructured rates, and to inform the Commission and the parties of any shortcomings or delays in its ability to bill through a filing in this docket. Staff requested information from EMM related to its plans for customer education and billing system preparedness.

Staff Data Request 0238 requested that EMM:

> Please fully explain Evergy Missouri Metro's customer education plan including timelines for informing customers of its proposed rate restructuring, any rate restructuring ordered by the Commission, initial customer migration to restructured rates, and any short term re-migrations based on changes in customer characteristics or improper initial migration.

EMM's response was:

> Evergy does not normally prepare customer education plans as part of proposals made in its direct testimony. Historically, it has been common for intervenors in the general rate proceeding to disagree with all or part of a Company proposal. As a result, Company proposed rate changes can be changed dramatically during the course of the general rate proceeding. Efforts spent preparing detailed customer education plans would be imprudent. Instead, as the general rate proceeding progresses, if the Company believes a rate proposal is being found acceptable, more detailed planning, including the creation of customer education plans may occur. At its most extreme, should a proposal go to hearing and remain uncertain until the Final Order, detailed implementation planning will also wait.
>
> With respect to the proposals made in this case, the Company is prepared to establish detailed customer education plans when it judges the timing is right to expend this effort. Based on prior rate implementations it is reasonable to expect the customer education plans will include the following elements,

- Identification of customers affected by the approved rate design proposals
- Detailed talking points concerning the purpose, operation, and effect of the approved rate design proposals
- Educational materials (web-based, electronic or hard copy)
- Planned channels for communication
- Training of Company-representatives and Customer Support personnel

Staff Data Request 0239 requested that EMM:

Please fully explain Evergy Missouri Metro's actions to date to ready its billing system for its proposed rate restructuring. Please state whether or not Evergy Missouri Metro anticipates being able to bill on restructured rates within 10 calendar days of any Commission order approving restructuring, or the number of business days anticipated to be required. Please explain Evergy Missouri Metro's plan and process for testing its billing system for the restructured rates prior to the issuance of live customer bills.

EMM's response was:

Prior to filing, Evergy Missouri Metro evaluates whether the proposed rate designs can be configured and billed within the Company's billing system. The Regulatory department develops the business requirements, after which a cross-functional project team—consisting of Billing, IT, Regulatory, and other relevant groups—is formed to begin documenting and planning the implementation work.

As part of this preparation, the project team drafts configuration requirements, develops test scripts, and begins preliminary configuration for the components included in the Company's proposal.

All configuration work is performed in a dedicated test environment, separate from the production system used for customer billing. This environment allows the Company to verify that all edits, calculations, and billing rules perform correctly before any changes are promoted to production.

Rate implementation is labor intensive, and the complexity of the billing environment means that even simple pricing changes require significant configuration, testing, and validation to ensure accurate customer billing. As the Commission prepares its final order, Evergy respectfully requests that the Commission consider potential timing constraints associated with rate implementation.

The Company's ability to implement restructured rates within ten calendar days depends on the complexity and scope of the Commission's final order. If rates are ordered as proposed and without unforeseen changes then the ten calendar days is acceptable. Unexpected changes or additions may increase the work required and extend the time needed for configuration, testing, and validation. In most cases, Evergy can adjust prebuilt configurations quickly; in others, more extensive redevelopment is required. The Company identifies potential timing concerns during the case and will notify parties and the Commission in rebuttal testimony or post hearing briefs. When necessary, the Company may request additional time or a different effective date to ensure accurate and reliable billing implementation.

Staff's recommendation to stagger the implementation of the rate increase and the implementation of the non-residential rate restructuring are consistent with the delays anticipated for education and billing system preparation discussed in EMM's responses to Staff Data Requests 0238 and 0239.

Staff Expert – Sarah L.K. Lange

Non-Residential Customer Charges

Staff does not object to the revenue neutral customer charges relied upon by EMM in calculating its requested rates. Adjusted for Staff's recommended rate increase, the resulting charges are set out below:

Table 13

Customer Charges		
	Rev. Neutral	**Increased**
SGS	$ 21.41	$ 22.19
MGS	$ 60.08	$ 62.27
LGS	$ 228.29	$ 236.60
LPS	$ 1,170.79	$ 1,213.40

Staff Expert – Sarah L.K. Lange

Demand Periods and Energy Periods

Staff recommends basing billing demand on the minimum demand applicable to a given service classification, or the highest 15-minute demand occurring in summer billing months between 10:00 AM and Midnight, and in non-summer billing months between the hours of 6:00 AM and Midnight.

Staff recommends that an additional charge be applied to each kWh of energy consumed in both summer and non-summer billing months beginning at 3:00 PM until 9:00 PM, with an additional period in non-summer billing months from 7:00 AM until noon.

Staff recommends that a credit be applied against the otherwise applicable charge per kWh for energy consumed in summer billing months beginning at Midnight and continuing until 10:00 AM, and in non-summer billing months from midnight and continuing until 6:00 AM.

In developing these recommendations, Staff:

1. Ensured that any summer or winter hour that has historically been a system peak be included in both a higher energy charge and calculation of the billing demand charge.
2. Supported customer understandability by coinciding times to the extent reasonable and consistent with other priorities; for example, year round, Midnight is the start of the hours excluded from demand calculations and applicable to energy credits.
3. Recognized that while the “winter” billing season is 8 months long, the loads, peaks, and energy prices experienced in shoulder months are typically less than those experienced in the months of December, January, February, and March.
4. Avoided price signals that would create new issues, and provided price signals that support efficient customer responses.
5. Considered system-wide loads, energy prices for load, summer and winter peaks that drive capacity requirements, and monthly peaks that drive RTO expense.

The resulting rate structure is more complex than the default Residential rate structure, however, it is more understandable than the existing hours use rate structure, and it is not more complex than the rate structure proposed by EMM, to which Staff will respond in its Rebuttal Testimony.

Schedule 4 provides the following information for each season:

1. The recommended period for measuring billing demand, where a "0" indicates the interval is not included in determining billing demand, and a "1" indicates the interval is included in determining billing demand.
2. The recommended period for discounting energy sold, indicated with a "0," the recommended period for charging an additional amount for energy sold, indicated with a "2," and those times to which the energy rate is not adjusted, indicated with a "1."
3. The number of times from 2022-2026 that a system peak occurred in a given hour. The counts provided as "Non Summer Peak" include all months except the summer months of June, July, August, and September. The counts provided as "Winter Peak" include only the months of December, January, February, and March.
4. For each hour, across each indicated season, the average load as a percentage of the maximum load in that season.
5. For each hour, across each indicated season, the average market energy price as a percentage of the maximum energy price in that season, based on inflation-adjusted energy prices from January 2020 – December 2025.

The data relied upon to support these calculations is also provided in attached Schedule 4.

Staff Expert – Sarah L.K. Lange

Billing Demand Rates

Currently, the revenue from demand rates provides approximately 17% of MGS class revenue, 12% of LGS class revenue, and 17% of LPS revenue. The SGS class is not billed a demand rate under the rates as currently structured. Staff recommends that upon completion of the customer migration and determinants study, as scaled, EMM calculate rates that recover approximately 15% of the revenue in each restructured class from the billing demand charges, using the recommended demand periods set out above to calculate the determinants applicable to the on peak periods of 10:00 AM to midnight in summer billing months, and 6:00 AM to midnight in all other billing months. Staff recommends that summer demand rates in each class be approximately 150% - 175% of the winter demand rates in that class. The demand rates within a class should be differentiated by voltage in the amount of the voltage adjustment factors set out below:

Table 14

VAF Trans	VAF Sub	VAF Prim	VAF Sec
100.879%	100.982%	102.400%	104.920%

Staff Expert – Sarah L.K. Lange

Reactive Demand Charges

Staff generally recommends that the system average rate increase of 3.67% be applied to the reactive demand charges currently tariffed by EMM. Staff calculated annualized and normalized reactive demand charge revenue from the rates as currently structured as $644,648 per year. The current reactive demand charges by rate class are $0.803 for MGS customers, $0.874 for LGS customers, and $0.99294 for LPS customers. However, as described below due to the changes in demand measurement and class migrations, further work will be necessary to establish the appropriate rates for each rate class under the restructured rates.

The applicable EMM tariffs currently define the applicability of the reactive demand rate as:

> Company may determine the customer's monthly maximum 30-minute reactive demand in kilovars. In each month a charge of $0.xx per month shall be made for each kilovar by which such maximum reactive demand is greater than fifty percent (50%) of the customer's Monthly Maximum Demand (kW) in that month. The maximum reactive demand in kilovars shall be computed similarly to the Monthly Maximum Demand as defined in the Determination of Demands section.

Staff recommends these provisions be revised to the following:

> Company shall determine the customer's monthly maximum 15-minute reactive demand in kilovars. In each month a charge of $0.xx per month shall be made for each kilovar by which such maximum reactive demand is greater than fifty percent (50%) of the customer's highest 15-minute demand occurring at any time in that month.

Incorporation of this tariff change to the computation of both the reactive demand (in kV) and the relative customer demand (in kW) on a 15-minute basis instead of a 30-minute basis will result in a change in the determinants for the charge. Further, the customer migration associated with the change in billing demand determination and the incorporation of "Bright Lines," will modify the classes to which determinants of a given customer are applicable.

Staff recommends that upon completion of the customer migration and determinants study, as scaled, EMM calculates rates that recover approximately $668,113 across the MGS, LGS, and LPS customer classes from reactive demand, maintaining the general proportionality of reactive demand rates that exists across the customer classes currently. The rate determined for LPS customers should also be applied to LLPS customers.

Staff Expert – Sarah L.K. Lange

Facilities Demand Rates

Staff supports implementation of facilities demand rates for all non-residential classes and recommends that the determinant for those rates be a customer's demand on the highest 15-minute demand occurring at any time in the most recent 13 months. For purposes of this case, Staff is not opposed to the general range of facilities charge rates requested by EMM, including EMM's proposal to include the first 25 kW of facilities demand within the SGS customer charge. However, Staff recommends that facilities charge values be consistent across classes for a given voltage service level.[32]

The EMW facilities charges approved in ER-2024-0189 are set out below:

Table 15

EMW Facilities Charges				
	Transmission	**Substation**	**Primary**	**Secondary**
SGS			$ 2.60	$ 2.70
LGS			$ 2.67	$ 2.77
LPS		$ 1.00	$ 2.73	$ 2.84

The currently tariffed facilities charges for EMM's non-end use rates are set out below:

Table 16

Current EMM Facilities Charges				
	Transmission	**Substation**	**Primary**	**Secondary**
SGS				
MGS			$ 2.671	$ 3.223
LGS			$ 2.897	$ 3.494
LPS		$ 0.990	$ 3.279	$ 3.956

Staff recommends that upon completion of the customer migration and determinants study, as scaled, EMM calculate rates that are consistent across classes for each service voltage but generally proportionate across voltages to the current EMM rates. For example, the facilities charge rate for customers served at primary voltage under each rate class would be $3.00 per kW, and the facilities charge rate for customers served at secondary voltage under each rate class would be $3.50 per kW. Staff supports increasing the rates for substation voltage service to $1.00 per kW, consistent with rates applicable at EMW, and Staff supports the EMM request to not separately bill the first 25 kW of SGS facilities demand.

Staff Expert – Sarah L.K. Lange

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[32] In light of Evergy's stated interest in working to align rate components across utility jurisdictions, Staff notes that in the Unanimous Stipulation and Agreement in ER-2024-0189, Evergy Missouri West committed that, "In the next EMW rate case, the Company will take additional steps to align facilities charges across classes, and will maintain consistent customer charge pricing within each class."

Energy Rates

Based on Staff's recommended time-based energy rate periods, it is reasonable that during summer billing months the additional charge for energy consumed during on-peak hours be set at $0.02/kWh, and the credit for energy consumed during super off-peak hours be set at -$0.02/kWh. During non-summer billing months, the on-peak charge is reasonably set at $0.01/kWh, and the super off-peak credit be set at -$0.01/kWh.[33]

The historic average energy price by time of use time period, illustrated below, indicate an approximate 1 cent differential between time periods in non-summer billing months, and an approximate 2 cent differential between time periods in summer billing months, consistent with $10/MWh and $20/MWh, respectively:

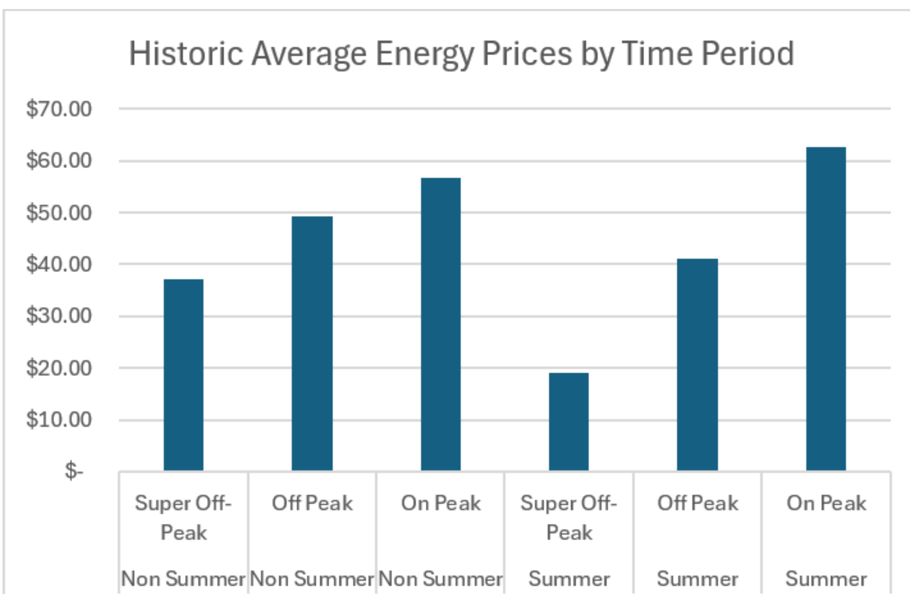

Figure 10

[33] The time periods recommended for non-residential rates are better tailored to variation in energy prices than those in place for EMM's residential time-differentiated rate plans. Thus, the cost-based differentials recommended here are greater than those in place for the Residential Peak Adjustment rate plan.

Staff also reviewed the load-weighted average market value of energy by classes as currently structured for each season, by voltage. As indicated below, generally the load-weighted average market values were highest for SGS customers served at secondary voltage, and lowest for LPS customers served at transmission voltage. Using the unadjusted test year loads, non-summer energy prices were slightly higher than summer energy prices, but the weighted energy expenses were higher for classes comprised of smaller customers, and relatively lower for classes comprised of larger customers, as illustrated below, with the values for customers served at secondary voltage illustrated in light blue, primary voltage in green, substation voltage in orange, and transmission voltage in dark blue:

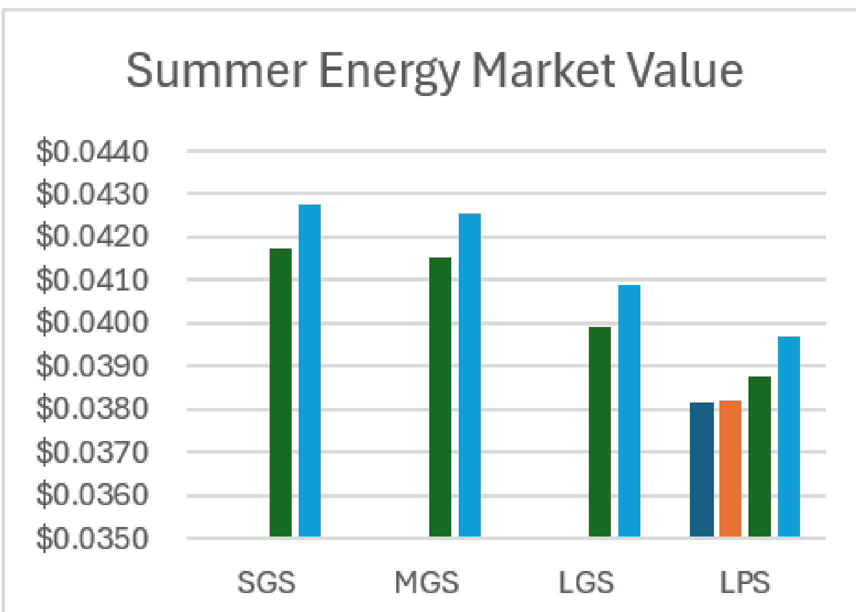

Figure 11

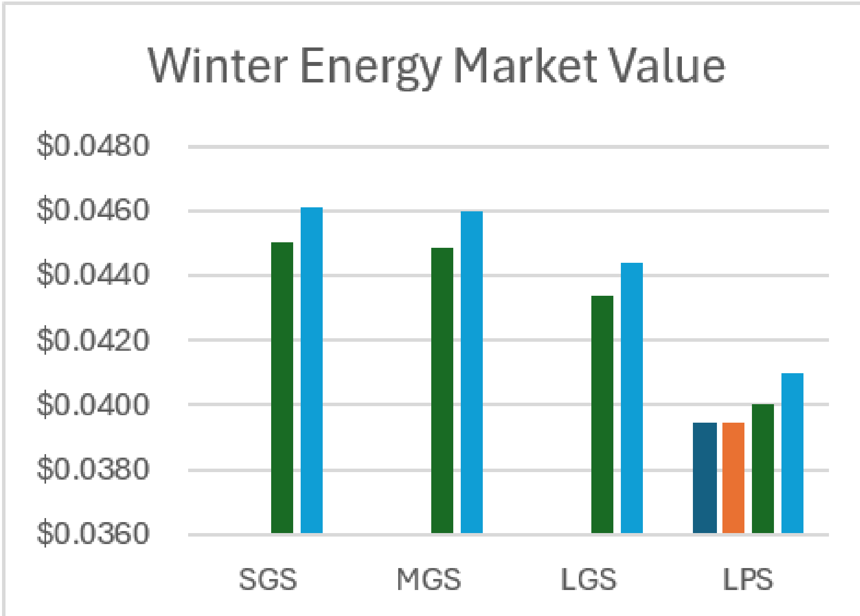

Figure 12

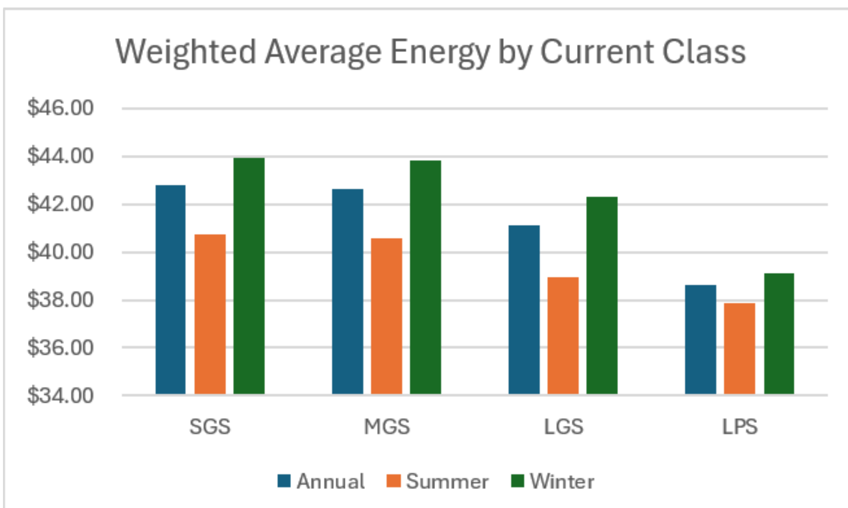

Figure 13

The following process will be used for calculating energy charges for each non-residential rate class:

1. Upon completion of the customer migration and determinants study, as scaled, EMM should calculate the hourly loads of each customer class at each voltage level.
2. EMM should use the hourly loads of each class at each voltage level to calculate the determinants applicable to each season and each time-based rate period.

3. Using the determinants for each time-based rate period and Staff's recommended time-based additional energy charges and credits, EMM should calculate the seasonal revenue impact of the time-based rates for each season for each rate class, by voltage level.
4. EMM should solve for energy rates that produce the required revenue for each class, irrespective of voltage level, maintaining a relationship between energy levels within each class that differ only by the applicable voltage adjustment factors.
5. EMM should target a seasonal relationship of the energy charge rates that results in the average as-billed rate per kWh (including time-based components) producing the same average revenue regardless of season.

Staff Expert – Sarah L.K. Lange

Underutilized Infrastructure Tariff

Staff recommends elimination of the Underutilized Infrastructure Tariff. The tariff was established to encourage beneficial load growth. In discussions between Staff and EMM related to recent updates to this tariff, EMM has been unable to provide objective explanation of the areas selected for application of the discount. Given EMM's projected generation capacity shortfalls and the availability of other economic development incentives, it is not reasonable to continue to offer this discount.

Staff Expert – Sarah L.K. Lange

VI. Critical Peak Rate Tariff

Recommendation

Staff recommends the Commission order EMM to implement a Critical Peak Rate ("CPR") tariff as described below. As discussed by Staff Expert Brooke Mastrogiannis, the compliance tariffs in this case should incorporate a change so that all CPR revenues are incorporated into the Fuel Adjustment Clause ("FAC") calculations as a Missouri Jurisdictional offset to the otherwise applicable "Fuel and Purchased Power Adjustment."

To accommodate billing system programing and testing, and to facilitate time for reasonable and appropriate customer education, Staff recommends that the CPR tariffs include a provision that the CPR tariff will not be applicable to service prior to November 1, 2027. Staff sets out two options below for the Commission's consideration, one with a higher rate and shorter duration, and one with a lower rate and longer duration. Staff recommends the Commission order one of the options to be included in EMM's compliance tariffs in this case, for service on and after November 1, 2027.

Overview

When a severe weather event occurs, EMM incurs higher than normal wholesale energy expenses both because its customers require more energy than usual, and because the wholesale value of energy is higher than usual. Staff is aware of the significant and ongoing FAC rate impacts of severe weather events such as Winter Storm Uri and the recent Winter Storm Fern.[34] Staff is also aware of the concerns raised by Office of the Public Counsel ("OPC") related to whether there are situations where ratepayers, as a whole, may be better off with periodic power shut-offs during severe weather as opposed to absorbing significant and ongoing rate impacts related to severe weather events.[35] A CPR mitigates both of these concerns by:

> (1) providing a signal that using the energy during a severe weather event is more expensive than using energy at other times. The CPR will send a

[34] Recently, in Case Nos. ER-2026-0260 and EO-2026-0261, concerning Winter Storm Fern, the Commission approved a "Global Stipulation and Agreement," concerning Empire's FAC, under which the FAC impact of Winter Storm Fern was split to an additional recovery period to mitigate the bill impact of the severe storm. The result of the bill mitigation is that Empire's customers will pay through May of 2027 for high market prices experienced in January of 2026.

[35] "Simply put, I believe there needs to be an agreed-to dollar amount in which economic curtailment is triggered." Rebuttal Testimony of Geoff Marke, Case No. ER-2024-0261, page 15.

> price signal for all ratepayers to make a decision regarding whether or not to conserve, and
>
> (2) capturing revenue from those ratepayers who are unable to conserve or who chose not to conserve. These additional revenues will be included in the FAC calculations and will partially offset the increase to wholesale energy expense caused by the weather event with the storm which will be recovered from ratepayers through the FAC.

The combined effect is that the bills for customers will better align revenue recovery through energy rates with expense incurred and included in the FAC in real time. While the FAC will continue to socialize severe weather energy expenses among all customers, the revenue from the new rate will offset that amount in part, and by encouraging conservation from customers who are able to safely conserve, the overall level of severe weather energy expenses will possibly be less than it otherwise would be.[36]

As discussed below, Staff provides two alternatives for the Commission's consideration. Under Option 1, a CPR event is only for 6 hours of a day, and the applicable rate is $0.10 per kWh. Under Option 2, a CPR event is all day, and the applicable rate is $0.025 per kWh. The result under either option would be that during an extreme pricing event such as a winter storm or extreme summer heat, a typical residential customer's bill would increase roughly $1.50 – $3.00 per day if the customer did not conserve or is unable to conserve. That revenue will go directly into the FAC and will help to mitigate a portion of the excess wholesale energy expense that will also occur during the event. The rate should

[36] It is important to note that this is not a Missouri Energy Efficiency Investment Act (MEEIA) program and it should not be offered as a MEEIA program, as there is no reasonable or reliable way to quantify, evaluate, or verify the amounts of energy expense avoided or sales avoided. Further, during sustained severe weather it is reasonable to assume that EMM will not be harmed by potentially selling less excess energy than the amounts of excess energy required by customers without the price signals of a CPR rate, therefore no earnings opportunity or throughput disincentive can be considered reasonable, or conscionable.

be priced to produce a bill impact to align cost causation with revenue responsibility, but not cause deprivation or result in unhealthy living conditions to residential customers, or undue economic hardship to business customers.

Wholesale Pricing Review and Triggering Language

Staff reviewed wholesale pricing since March 1, 2014, to observe pricing trends of sustained excessive market prices during severe weather events. Based on this review, Staff recommends the tariff include the following language to trigger a CPR event:

> If the DA-LMP has exceeded $100 in each hour of a given operating day and is $100 or more in each hour of the subsequent operating day, EMM shall issue a CPR notice.

In the table below, each column shows the number of hours in each year that the EMM Load Node DA-LMP[37] exceeded the price shown in the leftmost column. Each hour is counted only once, meaning an hour priced at $105 is counted for the "$100" count, but not for the "$50" count.[38]

Table 17

Start History:	5/1/2026	1/1/2026	1/1/2025	1/1/2024	1/1/2023	1/1/2022	1/1/2021	1/1/2020	1/1/2019	1/1/2018	1/1/2017	1/1/2016	1/1/2015
End History:	1/1/2026	1/1/2025	1/1/2024	1/1/2023	1/1/2022	1/1/2021	1/1/2020	1/1/2019	1/1/2018	1/1/2017	1/1/2016	1/1/2015	3/1/2014
$ 1,000	24	2	-	120	-	129	-	3	-	-	-	-	-
$ 500	2	-	5	-	-	10	-	-	-	-	-	-	-
$ 175	95	36	79	21	68	29	-	-	-	-	-	-	1
$ 150	15	21	1	11	87	12	-	-	-	-	1	-	2
$ 100	60	99	46	26	761	41	8	8	5	-	17	-	8
$ 50	244	1,383	436	453	2,366	1,140	242	221	504	154	153	58	774

Shown below are the number of times the daily average LMP was greater than $50 per MWh. The leftmost column indicates the average LMP for that operating day, with the "Excess" row indicating the number of days in which the daily average LMP exceeded $200:

[37] Day Ahead (DA)-Locational Marginal Price (LMP).

[38] Storm Uri occurred in February of 2021. The January 2014 polar vortex event preceded the launch of the SPP integrated market on March 1, 2014.

Table 18

Start History:	5/1/2026	1/1/2026	1/1/2025	1/1/2024	1/1/2023	1/1/2022	1/1/2021	1/1/2020	1/1/2019	1/1/2018	1/1/2017	1/1/2016	1/1/2015	1/1/2015
End History:	1/1/2026	1/1/2025	1/1/2024	1/1/2023	1/1/2022	1/1/2021	1/1/2020	1/1/2019	1/1/2018	1/1/2017	1/1/2016	1/1/2015	3/1/2014	3/1/2014
Excess	4	1	3	-	-	7	-	-	-	-	-	-	-	-
$ 200	1	-	-	-	-	-	-	-	-	-	-	-	-	-
$ 190	-	-	-	-	-	-	-	-	-	-	-	-	-	-
$ 180	-	-	-	-	1	-	-	-	-	-	-	-	-	-
$ 170	-	-	-	-	-	1	-	-	-	-	-	-	-	-
$ 160	-	-	1	-	-	-	-	-	-	-	-	-	-	-
$ 150	-	1	-	-	1	-	-	-	-	-	-	-	-	-
$ 140	-	1	-	-	-	-	-	-	-	-	-	-	-	-
$ 130	-	-	-	-	-	-	-	-	-	-	-	-	-	-
$ 120	-	-	-	-	1	-	-	-	-	-	-	-	-	-
$ 110	1	1	-	1	3	-	-	-	-	-	-	-	-	-
$ 100	1	1	-	-	11	1	-	-	-	-	-	-	-	-
$ 90	1	2	1	1	13	-	-	-	-	-	-	-	-	-
$ 80	1	2	1	1	24	1	-	-	-	-	-	-	2	-
$ 70	1	4	1	2	42	3	-	1	1	-	-	-	1	-
$ 60	2	11	-	2	33	7	2	2	4	-	-	-	-	-
$ 50	3	25	5	6	41	11	1	1	6	-	5	-	13	-

Shown below are the number of times the average LMP was a given value, following a day when the average LMP exceeded $100:[39]

Table 19

Start History:	5/1/2026	1/1/2026	1/1/2025	1/1/2024	1/1/2023	1/1/2022	1/1/2021	1/1/2020	1/1/2019	1/1/2018	1/1/2017	1/1/2016	1/1/2015
End History:	1/1/2026	1/1/2025	1/1/2024	1/1/2023	1/1/2022	1/1/2021	1/1/2020	1/1/2019	1/1/2018	1/1/2017	1/1/2016	1/1/2015	3/1/2014
Excess	4	1	3	-	-	6	-	-	-	-	-	-	-
$ 200	-	-	-	-	-	-	-	-	-	-	-	-	-
$ 190	-	-	-	-	-	-	-	-	-	-	-	-	-
$ 180	-	-	-	-	-	-	-	-	-	-	-	-	-
$ 170	-	-	-	-	-	1	-	-	-	-	-	-	-
$ 160	-	-	-	-	-	-	-	-	-	-	-	-	-
$ 150	-	1	-	-	1	-	-	-	-	-	-	-	-
$ 140	-	-	-	-	-	-	-	-	-	-	-	-	-
$ 130	-	-	-	-	-	-	-	-	-	-	-	-	-
$ 120	-	-	-	-	-	-	-	-	-	-	-	-	-
$ 110	1	-	-	-	1	-	-	-	-	-	-	-	-
$ 100	-	-	-	-	1	-	-	-	-	-	-	-	-
$ 90	-	2	1	-	1	-	-	-	-	-	-	-	-
$ 80	-	-	-	-	-	1	-	-	-	-	-	-	-
$ 70	-	-	-	-	1	-	-	-	-	-	-	-	-
$ 60	-	-	-	-	-	-	-	-	-	-	-	-	-
$ 50	-	-	-	1	1	-	-	-	-	-	-	-	-

In the portion of 2026 included in these tables, there were seven individual days with an average DA LMP in excess of $100. That means there were seven days when EMM would have needed to review for a potential CPR notice. There were five instances of consecutive $100+ average LMP days, so there would have been five CPR event days,

[39] Due to rounding, the amounts here rely on an average of $95 as a surrogate for the cut off of $100.

January 24 – January 28. The actual LMPs for the EMM load node for January 23 – January 29 are provided below:

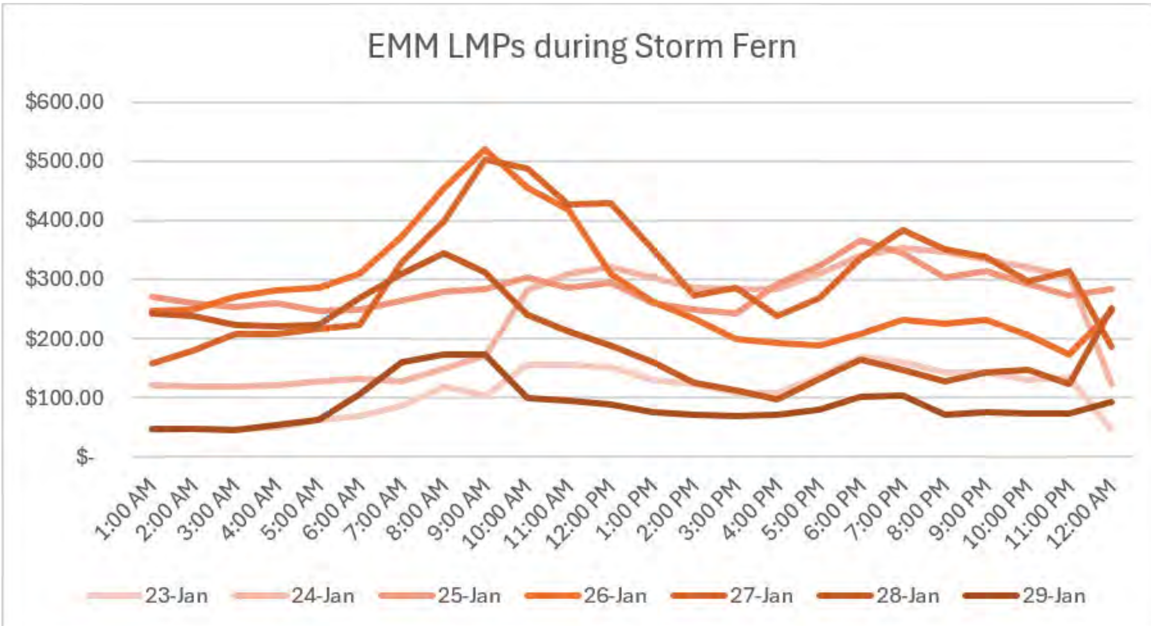

Figure 14

The DA prices for a given day for each hour will be known by EMM when SPP releases the Day 2 prices for an operating day on the day prior.

Option 1

Option 1 is to bill the CPR rate on events that are a portion of the day. Relative to Option 2, this results in fewer hours being subject to the rate, with a higher-priced rate during the hours the rate is applicable. Staff's recommended tariff language is:

> If the DA-LMP has exceeded $100 in each hour of a given operating day and is $100 or more in each hour of the subsequent operating day, EMM shall issue a CPR notice for the 6 consecutive hours with the highest DA-LMP in that subsequent operating day. The CPR will be $0.10 per kWh.

The advantages of Option 1 are that it can be targeted to the most extreme hours within a day, and the duration is short enough that customers have a meaningful opportunity to conserve energy during those hours through load shifting. As a residential example, this could include delaying laundry or dishwashing until the event has concluded. As a business example, this could include accelerating or delaying the timing of a process, sending employees home for an afternoon or requesting they come in late, or adjusting lighting or other discretionary uses.

Disadvantages of Option 1 are that the notice would have to specify the applicable hours to customers, which will require more complex communications. The event hours may be very early in the day, for example 6:00 AM to 12:00 AM, and that information may not be available to customers until nearly midnight of the preceding day. Detailed AMI reads will be necessary to accurately bill customers, and practices such as estimating usage in missing intervals based on prior usage are wholly inapplicable to a rate which may induce usage changes. As discussed above, EMM has issues with obtaining accurate AMI reads for intervals.[40]

Option 2

Option 2 is to bill a relatively low CPR rate for an entire event day. Staff's recommended tariff language is:

> If the DA-LMP has exceeded $100 in each hour of a given operating day and is $100 or more in each hour of the subsequent operating day, EMM shall issue a CPR notice for the next day, for all hours in that day. The CPR will be $0.03 per kWh.

[40] Details related to the estimation procedures relied upon by EMM are discussed in the direct testimony of Staff Expert Randall T. Jennings, pages 9 – 23.

The biggest advantage to Option 2 is that it is easily communicated and is expected to be more understandable. The biggest disadvantage of Option 2 is that customers may not feel empowered to respond to the event given the length of the event.

Effectively, the benefit to Option 1 is that more customers are likely to conserve, but less revenue will be produced to offset the energy expense of the severe weather as a whole. The benefit of Option 2 is that more revenue will be produced to offset the severe weather as a whole, but less conservation is likely to occur. Staff considered combining these two approaches to optimize conservation and aligning revenue with expense but is concerned that would result in rates that are too complex to introduce at this time. Staff recommends that the Commission select an option for initial implementation, and in the future the other option may also be introduced at an appropriate rate level.

Public Notice and Customer Education

The worst outcome of a CPR rollout would be that customers are not adequately educated ahead of time, resulting in panic and potentially dangerous conditions during a severe weather event. To avoid this outcome, Staff recommends the rate implementation be delayed until November 1, 2027. This also provides time for EMM to develop and test its billing system to accommodate billing the CPR rate and ensure that accurate billing occurs.

Staff is aware of other utilities, including Columbia Water and Light, running "peak alert" notifications requesting voluntary curtailments, since at least the 1990s. Staff recommends alerts for CPR events be issued across social media, local media, and the customer's preferred communication channel in a non-alarmist, impartial manner.

Applicability

The following customers should be exempted from paying the CPR:

1. Critical medical needs registered customers,
2. Customer with Registered Medical Equipment,
3. Economic Relief Pilot Program customers, and
4. Customers meeting income eligible criteria the Commission may establish in this case.

For clarification, Staff provided an FAC mitigation option in the direct - revenue requirement testimonies of Sarah L.K. Lange and Brooke Mastrogiannis under which LLPS customers would be removed from the EMM FAC. Regardless of whether LLPS customers are included in the FAC or excluded from the FAC, LLPS customers should be responsible for payment of the CPR charges, and that revenue should be included in the FAC.

Staff Expert – Sarah L.K. Lange

VII. FAC

FAC Changes Related to CPR Tariff Implementation

As described above, Staff recommends the Commission order EMM to implement a CPR tariff to mitigate significant and ongoing FAC rate impacts of severe weather events such as Winter Storm Uri and the recent Winter Storm Fern.[41] Prior to the most recent case concerning Winter Storm Fern and Empire's FAC, Evergy Missouri West ("EMW") experienced a significant under-recovery in AP31, due to changes in weather, domestic and international natural gas markets, and coal supply and transportation constraints caused

[41] Recently, in Case Nos. ER-2026-0260 and EO-2026-0261, concerning Winter Storm Fern, the Commission approved a "Global Stipulation and Agreement," concerning Empire's FAC, under which the FAC impact of Winter Storm Fern was split to an additional recovery period to mitigate the bill impact of the severe storm. The result of the bill mitigation is that Empire's customers will pay through May of 2027 for high market prices experienced in January of 2026.

by rail service issues.[42] Although the gas markets and coal supply and transportation constraints are not applicable for Staff's recommended CPR tariff, the changes in weather are. As a result of that case, the parties agreed to change the proposed Fuel Adjustment Rate ("FAR"), and to defer the remaining fuel and purchased power adjustment to two future accumulation periods to mitigate the rate impact on EMW customers. In addition, in ER-2021-0240, because of OPC concerns,[43] the Commission approved a Stipulation and Agreement which included language in its FAC tariff to allow Ameren Missouri to defer extraordinary costs beyond its normal eight-month recovery period.

With all these ongoing concerns to defer current Accumulation Period under-recovered costs beyond the original recovery period, and to mitigate bill impacts for customers after a large winter storm, Staff has proposed Critical Peak Rate options for the Commission to consider (explained above). If the Commission accepts either of Staff's recommended CPR options explained above, Staff recommends including a new line in the proposed 5th Revised Sheet No. 50.10, with a line description of "Critical Peak Rate Revenue". Staff recommends this line would be below the current line 10 "Prudence Adjustment Amount" and above the current line 11, "Fuel and Purchased Power Adjustment".

These revenues will come from an accumulated revenues balance from the CPR tariff, which allows for a separate rate during winter storms. These revenues can then be

[42] Direct Testimony of Darrin Ives, ER-2023-0210.

[43] Rebuttal Testimony of Lena Mantle, Case No. ER-2021-0240.

distributed and socialized to all customers in EMM's next FAR filing, with the intention to mitigate the bill impact for customers after a large winter storm.

Staff Expert – Brooke Mastrogiannis

Conditional High Impact Large Loads (CHILLS)

Staff Expert Claire M. Eubanks, PE, addresses Staff's concerns with the future CHILLS customers in her direct testimony. The FERC Order that approved CHILLS is attached to Mrs. Eubanks corrected direct testimony as Schedule CME-d2. It is Staff's understanding that according to EMM's response to Staff Data Request 0447, attached as Schedule 5, future CHILLS customers, ***or the applicable Transmission Customer or Network Customer serving such load***, would be responsible for transmission-related charges under the SPP Open Access Transmission Tariff through the Schedule 15 rate structure, including associated Schedule 11 charges, and would also be subject to Schedule 8 and Schedule 11-based charges in the event of usage exceeding the reserved CHILLS capacity. Therefore, EMM and future CHILLS customers are responsible for those charges, and they will not be included for recovery in the FAC. Staff recommends all SPP costs related to future CHILLS customers should be tracked separately and provided to Staff in additional reporting requirements on a monthly basis. Additionally, if any of EMM's customers become CHILLS, Staff recommends that the Commission order that EMM must notify Staff within three business days, and provide Staff with a copy of its filing to SPP or FERC.

Staff Expert – Brooke Mastrogiannis

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 MARINA GONZALES

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW MARINA GONZALES and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff Rate Design Report*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

MARINA GONZALES

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 10th day of July 2026.

Dianna L. Vaught
Notary Public

DIANNA L. VAUGHT
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: July 18, 2027
Commission Number: 15207377

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 SARAH L.K. LANGE

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

COMES NOW SARAH L.K. LANGE and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff Rate Design Report*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Sarah L.K. Lange
SARAH L.K. LANGE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 10th day of July 2026.

DIANNA L. VAUGHT
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: July 18, 2027
Commission Number: 15207377

Dianna L. Vaught
Notary Public

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 BROOKE MASTROGIANNIS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Further the Affiant sayeth not.

Brooke Mastrogiannis
BROOKE MASTROGIANNIS

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 10th day of July 2026.

DIANNA L. VAUGHT
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: July 18, 2027
Commission Number: 15207377

Dianna L. Vaught
Notary Public

Credentials and Background of
Marina Gonzales

I have a Master of Science in Environmental and Natural Resource Economics from the University of Rhode Island. Additionally, I hold a Bachelor of Science in Business Administration with a concentration in Economics from the University of Central Missouri. My work experience prior to becoming a member of the Missouri Public Service Commission Staff includes two years as an Energy Analyst at Missouri's Department of Natural Resources- Division of Energy, as well as one year as an Economic Development Specialist at Missouri's Department of Economic Development.

I am currently employed as an Economist in the Tariff/Rate Design Department of the Industry Analysis Division of the Missouri Public Service Commission Staff. I have been employed at the Missouri Public Service Commission since October 2023 and am responsible for preparing staff recommendations and ensuring that Staff presents recommendations in a neutral, independent manner to inform the Commission of Staff's position and possible alternatives.

Case Number	Company	Issues
ER-2024-0112	Ameren Missouri	RESRAM Rate Adjustment
ER-2024-0187	Ameren Missouri	MEEIA EEIC Rider Adjustment
GR-2024-0106	Liberty Midstates	General Rate Increase
GO-2024-0180	Spire Missouri	Carbon Offset Initiative
ER-2024-0319	Ameren Missouri	General Rate Increase
ER-2024-0189	Evergy West	General Rate Increase
EO-2025-0154	Evergy	Large Load Customers
EO-2025-0046	Liberty	DSIM Rider Rate Adjustment
EO-2023-0136	Ameren Missouri	MEEIA Regulatory Changes
ER-2024-0261	Empire Electric	General Rate Increase
EA-2024-0292	Evergy West	Solar CCN and Green Solutions Connection Program

Continued Marina Gonzales

Case Number	Company	Issues
EO-2025-0154	Evergy	New and Modified LLPS Tariffs
EO-2026-0010	Liberty	PPA Replacement Value
EA-2025-0238	Ameren Missouri	CTG and Battery Energy Storage System CCN
ER-2026-0143	Evergy Metro	General Rate Increase

Glossary of Ratemaking Terms

Energy – measured in kWh or MWh, energy is the amount of electricity used over a relatively long period of time, like a day, a month, or a year.

Demand – measured in kW or MW, demand is the amount of electricity used in an instant or over a relatively short period of time, like 15 minutes, 30 minutes, or one hour.

Class Cost of Service Study **–** a review of a utility's cost of service and customer characteristics conducted to reasonably estimate which customer or group of customers is causing the utility to incur certain costs or type of costs and to what degree, and to what extent any given group of customers should reasonably bear revenue responsibility for cost of service that is not directly caused by any customer.

A Class Cost of Service Study typically consists of the following steps:

1. Functionalization
   - Identify the general causation of costs and expenses by the function served, including, but not limited to the general areas of Production, Transmission, Distribution, and Administrative & General.
2. Classification
   - As necessary, subdivide USOA accounts to facilitate allocating portions of those accounts using discrete allocators.
3. Allocation
   - Allocate costs and expenses to customer classes using factors based on load and system data including but not limited to:
     - Coincident Peak (CP) demand;
     - Non-Coincident Peak (NCP) demand;
     - Energy Usage;
     - Customer Counts;
     - Time of energy consumption;
     - Size of infrastructure serving customers.

System Peak – the average demand over a given amount of time (such as 15 minutes, 30 minutes, or one hour), at the time that the system as a whole has the highest peak.

Customer Non Coincident Peak – the average demand of a given customer over a given amount of time (such as 15 minutes, 30 minutes, or one hour), without regard to the usage of other customers at that time.

Customer Coincident Peak – the average demand of a given customer over a given amount of time (such as 15 minutes, 30 minutes, or one hour), at the time that the system as a whole or a particular class has the highest peak.

Class Non Coincident Peak – the average demand of a rate class over a given amount of time (such as 15 minutes, 30 minutes, or one hour), without regard to the usage of other customers at that time.

Class Coincident Peak – the average demand of a rate class over a given amount of time (such as 15 minutes, 30 minutes, or one hour), at the time that the system as a whole has the highest peak.

Locational Marginal Price (LMP) – value wholesale value of energy at a given point in time at a given location on the transmission system. The Day Ahead (or Day 2) LMP is calculated by SPP based on the load forecasts of load responsible entities and the offers of participants in the energy supply market. The Real Time (or Day 1) LMP is calculated by SPP based on the discrepancies between forecast and actual load and the cost to mitigate that difference.

Account Number	Account Description	Functional Allocator	Gross Plant	Net Plant	Depreciation Expense
	INTANGIBLE PLANT				
301.000	Organization	7-Admin & Overhead	$39,378	$39,378	$0
302.000	Franchises and Consents	7-Admin & Overhead	$22,937	$22,937	$0
303.000	Misc Intang-Wolf Creek	4-Nuclear	$15,195,815	$12,264,969	$0
303.001	Miscellaneous Intangibles (Like 353)	5-Transmission	$1,082,018	$644,341	$0
303.002	5 Year - Customer Related		$0	$0	$0
303.002	5 Year - Energy Related		$0	$0	$0
303.002	5 Year - Demand Related		$0	$0	$0
303.002	5 Year - Corporate Software		$0	$0	$0
303.002	5 Year - Transmission Related		$0	$0	$0
303.002	5 Year - MEEIA Uplight - 100% MO		$0	$0	$0
303.003	10 Year - Customer Related		$0	$0	$0
303.003	10 Year - Energy Related		$0	$0	$0
303.003	10 Year - Demand Related		$0	$0	$0
303.003	10 Year - Corporate Software		$0	$0	$0
303.005	Misc Intang- 5 yr Software - Wolf Creek		$0	$0	$0
303.007	Misc Intang- Steam Prod-Strc -(like 312)	1-Production 1	$18,609	$7,538	$0
303.008	Misc Intang- Trans Line (like 355)	5-Transmission	$3,657,089	$2,241,058	$0
303.009	Misc Intang- Trans MINT Line	5-Transmission	$29,371	$5,094	$0
303.010	Misc Intang- Iatan Hwy & Bridge	1-Production 1	$1,725,672	$1,187,213	$0
303.011	Misc Intang- LaCygne Road Overpass	1-Production 1	$463,293	$341,352	$0
303.013	Misc Intang- Radio Frequencies	7-Admin & Overhead	$779,015	$0	$0
303.014	Misc Intang- Radio Frequencies 2041	7-Admin & Overhead	$5,875,600	$5,000,914	$0
303.015	Misc Intang Plant - 15 yr Software		$0	$0	$0
303.016	3 Year - Customer Related		$0	$0	$0
303.016	3 Year - Demand Related		$0	$0	$0
303.016	3 Year - Corporate Software		$0	$0	$0
303.017	Misc Intang- Front Street Road Improvement	7-Admin & Overhead	$502,453	$463,805	$0
	Intangible-Salvage & Removal: Retirements not classified		$0	$2,435	$0
	TOTAL INTANGIBLE PLANT		$29,391,250	$22,218,599	$0

Account Number	Account Description	Functional Allocator	Gross Plant	Net Plant	Depreciation Expense
	PRODUCTION PLANT				
	STEAM PRODUCTION				
	PRODUCTION-STM-HAWTHORN COMMON				
311.000	Steam Prod-Structures- Haw Common	1-Production 1	$9,677,378	$6,723,333	$377,418
312.000	Steam Prod-Boiler Plant Equip- Haw Common	1-Production 1	$1,664,449	$1,417,406	$76,898
314.000	Steam Prod- Turbogenerator- Haw Common	1-Production 1	$65,338	$38,652	$2,254
315.000	Steam Prod-Accessory Equip- Haw Common	1-Production 1	$2,189,385	$1,499,686	$84,510
315.010	Steam Prod-Computer Hardware - FERC 898 31500	1-Production 1	$124,079	-$120,545	$5,124
315.010	Steam Prod-Computer Hardware - FERC 898 39102	1-Production 1	$253,754	$97,224	$10,480
315.020	Steam Prod-Computer Software5yrs - FERC 898 30302	1-Production 1	$88,319	$0	$0
315.030	Steam Prod-Communication Equip FERC 898 39700	1-Production 1	$133,919	$38,575	$3,187
316.000	Steam Prod-Misc Pwr Plt Equip- Haw Common	1-Production 1	$5,891,250	$3,604,680	$216,209
	TOTAL PRODUCTION-STM-HAWTHORN COMMON		$20,087,871	$13,299,011	$776,080
	PRODUCTION-STM-HAWTHORN UNIT 5				
310.000	Steam Prod- Land- Haw 5	1-Production 1	$429,473	$429,473	$0
311.000	Steam Prod-Structures- Haw 5	1-Production 1	$13,699,507	$9,453,310	$552,090
311.002	Steam Prod-Structures- Haw 5 Rebuild	1-Production 1	$4,561,102	$95,123	$22,806
312.000	Steam Prod-Boiler Plant Equip- Haw 5	1-Production 1	$86,465,084	$67,659,366	$4,141,678
312.001	Steam Prod- Unit Trains- Haw 5	1-Production 1	$9,752,570	$4,921,667	$291,602
312.002	Stm Pr-Boiler AQC Equip	1-Production 1	$338,703	$346,399	$20,017
312.003	Steam Prod-Boiler Plant - Haw 5 Rebuild	1-Production 1	$108,243,061	$27,361,924	$2,013,321
314.000	Steam Prod- Turbogenerator- Haw 5	1-Production 1	$61,632,311	$34,859,505	$2,169,457
315.000	Steam Prod-Accessory Equip- Haw 5	1-Production 1	$16,289,101	$9,562,259	$682,513
315.001	Steam Prod-Accessory Equip - Haw 5 Rebuild	1-Production 1	$17,630,063	$1,019,104	$130,462
315.010	Stm Pr-Computer Hardware FERC 898 31200	1-Production 1	$2,136,103	$1,757,818	$46,140
315.010	Stm Pr-Computer Hardware FERC 898 31500	1-Production 1	$124,207	$43,347	$2,683
315.011	Stm Pr-Comp Hrdw Haw5 Retire FERC 898 31501	1-Production 1	$515,906	$278,692	$0
315.020	Stm Pr-Computer Software5yrs FERC 898 30302	1-Production 1	$533,403	$0	$0
315.030	Stm Pr-Communication Equip FERC 898 39700	1-Production 1	$902,926	$239,237	$18,691
316.000	Steam Prod-Misc Pwr Plt Equip- Haw 5	1-Production 1	$3,713,034	$2,506,251	$167,087
316.001	Steam Prod-Misc Equip - Haw 5 Rebuild	1-Production 1	$992,964	$67,780	$7,547
	TOTAL PRODUCTION-STM-HAWTHORN UNIT 5		$327,959,518	$160,601,255	$10,266,094

Account Number	Account Description	Functional Allocator	Gross Plant	Net Plant	Depreciation Expense
	PRODUCTION-IATAN 1				
310.000	Steam Prod- Land- Iatan 1	1-Production 1	$2,017,632	$2,017,632	$0
311.000	Steam Prod-Structures- Iatan 1	1-Production 1	$7,299,249	$5,328,788	$383,940
312.000	Steam Prod-Boiler Plant Equip- Iatan 1	1-Production 1	$237,019,224	$130,209,989	$10,902,884
312.005	Steam Prod-Boiler Plt Eq- Iatan 1 MO Juris Disallow	1-Production 1	-$16,365	-$8,860	$0
314.000	Steam Prod- Turbogenerator- Iatan 1	1-Production 1	$54,085,495	$36,291,015	$2,779,994
315.000	Steam Prod-Accessory Equipment- Iatan 1	1-Production 1	$32,100,322	$14,704,355	$1,274,383
315.005	Steam Prod-Accessory Eq- Iatan 1 MO Juris Disallow	1-Production 1	-$622,572	-$301,714	$0
315.010	Iatan Stm Pr-Computer Hardware FERC 898 31200	1-Production 1	$863,916	$146,319	$0
315.010	Iatan Stm Pr-Computer Hardware FERC 898 31500	1-Production 1	$845,856	$178,502	$0
315.020	Iatan Stm Pr-Computer Software5yrs FERC 898 30302	1-Production 1	$446,626	$0	$0
315.020	Iatan Stm Pr-Computer Software5yrs FERC 898 31500	1-Production 1	$954,249	$276,080	$0
315.030	Iatan Stm Pr-Communication Equip FERC 898 31500	1-Production 1	$4,958	$1,123	$106
315.030	Iatan Stm Pr-Communication Equip FERC 898 39700	1-Production 1	$37,840	$15,325	$806
316.000	Steam Prod-Misc Pwr Plt Equip- Iatan 1	1-Production 1	$5,500,643	$3,954,782	$113,863
316.005	Steam Prod-Misc Pwr Plt Eq- Iatan 1 MO Juris Disallow	1-Production 1	-$11	-$6	$0
	TOTAL PRODUCTION-IATAN 1		$340,537,062	$192,813,330	$15,455,976
	PRODUCTION-IATAN COMMON				
310.000	Steam Prod- Land- Iatan Common	1-Production 1	$356,519	$356,519	$0
311.000	Steam Prod- Structures- Iatan Common	1-Production 1	$70,078,231	$56,104,863	$1,639,831
312.000	Steam Prod-Boiler Plant Equip- Iatan Common	1-Production 1	$115,756,852	$77,055,332	$2,893,921
312.001	Steam Prod-Unit Trains- Iatan Common	1-Production 1	$826,775	$417,235	$24,721
312.002	Steam Prod-Boiler AQC Equip-Iatan Common	1-Production 1	$30,743	$30,431	$932
314.000	Steam Prod- Turbogenerator- Iatan Common	1-Production 1	$3,173,913	$2,218,434	$70,461
315.000	Steam Prod-Accessory Equip- Iatan Common	1-Production 1	$15,398,758	$10,162,699	$366,490
315.010	Iatan Comm Stm Pr-Computer Hardware FERC 898 31200	1-Production 1	$570,847	$353,012	$21,692
315.010	Iatan Comm Stm Pr-Computer Hardware FERC 898 31500	1-Production 1	$62,767	$38,876	$2,385
315.010	Stm Pr-Computer Hardware FERC 898 31600	1-Production 1	$31,507	$28,050	$1,197
315.010	Stm Pr-Computer Hardware FERC 898 39102	1-Production 1	$388,683	$209,606	$14,770
315.020	Stm Pr-Computer Software5yrs FERC 30302	1-Production 1	$851,143	$0	$0
315.020	Stm Pr-Computer Software5yrs FERC 898 31500	1-Production 1	$63,301	$39,207	$0
315.030	Iatan Comm Stm Pr-Communication Equip FERC 898 39700	1-Production 1	$271,702	$85,464	$4,999
316.000	Steam Prod-Misc Pwr Plt Equip- Iatan Common	1-Production 1	$3,244,292	$2,588,608	$95,382
	TOTAL PRODUCTION-IATAN COMMON		$211,106,033	$149,688,336	$5,136,781

Account Number	Account Description	Functional Allocator	Gross Plant	Net Plant	Depreciation Expense
	PRODUCTION- IATAN 2				
311.004	Steam Prod- Structures- Iatan 2	1-Production 1	$50,390,679	$39,087,573	$362,813
311.006	Steam Prod- Structures- Iatan 2 - MO Juris Disallow	1-Production 1	-$720,114	-$574,051	$0
311.099	311 Regulatory Plan-EO-2005-0329-Cum Addl Amort		$0	-$19,240,688	$0
312.004	Steam Prod-Boiler Plant Equip- Iatan 2	1-Production 1	$362,282,712	$291,158,696	$6,122,578
312.006	Steam Prod-Boiler Plant Equip- Iatan 2-MO Juris Disallow	1-Production 1	-$5,175,688	-$3,939,992	$0
312.099	312 Regulatory Plan-EO-2005-0329-Cum Addl Amort	1-Production 1	$0	-$137,897,545	$0
314.004	Steam Prod-Turbogenerator- Iatan 2	1-Production 1	$129,923,242	$98,324,471	$2,585,473
314.006	Steam Prod-Turbogenerator- Iatan 2-MO Juris Disallow	1-Production 1	-$715,476	-$522,083	$0
314.099	314 Regulatory Plan-EO-2005-0329-Cum Addl Amort	1-Production 1	$0	-$19,135,918	$0
315.004	Steam Prod-Accessory Equip- Iatan 2	1-Production 1	$32,783,332	$24,597,981	$662,223
315.006	Steam Prod-Accessory Equip- Iatan 2-MO Juris Disallow	1-Production 1	-$239,102	-$171,628	$0
315.010	Stm Pr-Computer Hardware FERC 898 31204	1-Production 1	$667,598	$370,337	$0
315.010	Stm Pr-Computer Hardware FERC 898 31504	1-Production 1	$100,829	$61,628	$0
315.020	Iatan 2 Stm Pr-Computer Software5yrs FERC 898 30302	1-Production 1	$398,791	$0	$0
315.020	Stm Pr-Computer Software5yrs FERC 898 31504	1-Production 1	$68,584	$41,919	$0
315.030	Iatan 2 Stm Pr-Communication Equip FERC 898 39700	1-Production 1	$4,558	$3,175	$143
315.099	Regulatory Plan-EO-2005-0329-Cum Addl Amort	1-Production 1	$0	-$6,399,672	$0
316.004	Steam Prod- Misc Power Plant Equip- Iatan 2	1-Production 1	$2,869,485	$2,209,482	$57,677
316.006	Steam Prod- Misc Pwr Plt Eq- Iatan 2-MO Juris Disallow	1-Production 1	-$26,736	-$20,381	$0
316.099	Iatan 2 316 Regulatory Plan-EO-2005-0329-Cum Addl Amort	1-Production 1	$0	-$704,779	$0
	TOTAL PRODUCTION- IATAN 2		$572,612,694	$286,489,213	$9,790,907
	LACYGNE COMMON PLANT				
310.000	Steam Prod- Land- LaCygne Common	1-Production 1	$510,265	$510,265	$0
311.000	Steam Prod- Structures- LaCygne Common	1-Production 1	$63,155,414	$43,947,896	$3,265,135
312.000	Steam Prod-Boiler Plant Equip- LaCygne Common	1-Production 1	$74,316,258	$46,991,867	$3,671,223
312.001	Steam Prod-Unit Trains- LaCygne Common	1-Production 1	$242,927	$122,594	$7,264
312.002	Steam Prod-Boiler AQC Equip-LaCygne Common	1-Production 1	$101,650	$82,466	$7,471
314.000	Steam Prod- Turbogenerator- LaCygne Common	1-Production 1	$530,703	$341,201	$25,951
315.000	Steam Prod-Accessory Equip- LaCygne Common	1-Production 1	$3,640,499	$2,391,970	$250,102
315.010	LACYGNE Stm Pr-Computer Hardware FERC 898 31200	1-Production 1	$2,690,264	$1,829,031	$14,527
315.010	LACYGNE Stm Pr-Computer Hardware FERC 898 31500	1-Production 1	$7,702	$2	$42
315.010	LACYGNE Stm Pr-Computer Hardware FERC 898 39102	1-Production 1	$167,188	$76,211	$903
315.020	LACYGNE Stm Pr-Computer Software5yrs FERC 898 30302	1-Production 1	$626,572	$0	$0
315.020	LACYGNE Stm Pr-Computer Software5yrs FERC 898 31500	1-Production 1	$3,577	$1,618	$0
315.030	LACYGNE Stm Pr-Communication Equip FERC 898 39700	1-Production 1	$398,564	$136,329	$7,254

Account Number	Account Description	Functional Allocator	Gross Plant	Net Plant	Depreciation Expense
316.000	Steam Prod-Misc Pwr Plt Equip- LaCygne Common	1-Production 1	$3,636,225	$2,671,003	$209,810
	TOTAL LACYGNE COMMON PLANT		$150,027,808	$99,102,453	$7,459,682
	PRODUCTION-STM-LACYGNE 1				
310.000	Steam Prod- Land- LaCygne 1	1-Production 1	$1,030,863	$1,030,863	$0
311.000	Steam Prod- Structures- LaCygne 1	1-Production 1	$11,211,674	$5,157,516	$493,314
312.000	Steam Prod-Boiler Plant Equip- LaCygne 1	1-Production 1	$210,729,290	$105,543,222	$10,051,787
312.002	Steam Prod-Boiler AQC Equip.-LaCygne 1	1-Production 1	$2,699,533	$1,325,423	$109,871
314.000	Steam Prod- Turbogenerator- LaCygne 1	1-Production 1	$30,919,235	$16,540,426	$1,533,594
315.000	Steam Prod-Accessory Equip- LaCygne 1	1-Production 1	$11,021,791	$3,246,389	$430,952
315.010	Lacygne 1 Stm Pr-Computer Hardware FERC 898 31200	1-Production 1	$900,376	$212,835	$0
315.010	Lacygne 1 Stm Pr-Computer Hardware FERC 898 31202	1-Production 1	$25,139	-$123	$0
315.010	Lacygne 1 Stm Pr-Computer Hardware FERC 898 31500	1-Production 1	$72,082	$50,112	$0
315.020	Lacygne 1 Stm Pr-Computer Software5yrs FERC 898 30302	1-Production 1	$159,412	$0	$0
315.020	Lacygne 1 Stm Pr-Computer Software5yrs FERC 898 31200	1-Production 1	$1,267,511	$638,582	$0
315.030	Lacygne 1 Stm Pr-Communication Equip FERC 898 39700	1-Production 1	$2,414	$312	$69
316.000	Steam Prod-Misc Pwr Plt Equip- LaCygne 1	1-Production 1	$1,569,790	$995,512	$95,286
	TOTAL PRODUCTION-STM-LACYGNE 1		$271,609,110	$134,741,069	$12,714,873
	PRODUCTION-STM-LACYGNE 2				
311.000	Steam Prod- Structures- LaCygne 2	1-Production 1	$3,256,542	$2,170,999	$167,061
312.000	Steam Prod-Boiler Plant Equip- LaCygne 2	1-Production 1	$187,470,737	$122,928,224	$10,029,684
312.002	Steam Prod-Boiler AQC Equip-Lacynge 2	1-Production 1	$246,161	$233,541	$18,167
314.000	Steam Prod- Turbogenerator- LaCygne 2	1-Production 1	$21,982,916	$11,700,814	$938,671
315.000	Steam Prod-Accessory Equip- LaCygne 2	1-Production 1	$9,134,288	$3,024,366	$372,679
315.010	Lacygne 2 Stm Pr-Computer Hardware FERC 898 31200	1-Production 1	$7,511	$3,103	$0
315.010	Lacygne 2 Stm Pr-Computer Hardware FERC 898 31500	1-Production 1	$546,677	$74,135	$0
315.020	Lacygne 2 Stm Pr-Computer Software5yrs FERC 898 30302	1-Production 1	$346,333	$0	$0
315.020	Lacygne 2 Stm Pr-Computer Software5yrs FERC 898 31200	1-Production 1	$1,240,195	$817,607	$0
315.030	Lacygne 2 Stm Pr-Communication Equip FERC 898 31500	1-Production 1	$413	$40	$10
315.030	Lacygne 2 Stm Pr-Communication Equip FERC 898 39700	1-Production 1	$210,468	$42,585	$4,946
316.000	Steam Prod-Misc Pwr Plt Equip- LaCygne 2	1-Production 1	$889,623	$594,026	$51,687
	TOTAL PRODUCTION-STM-LACYGNE 2		$225,331,864	$141,589,440	$11,582,905
	PRODUCTION STM- MONTROSE COMMON				
310.000	Steam Prod- Land- Montrose Common	1-Production 1	$862,288	$862,288	$0
311.000	Steam Prod- Structures- Montrose Common	1-Production 1	$3,574,716	$2,918,347	$58,983

Account Number	Account Description	Functional Allocator	Gross Plant	Net Plant	Depreciation Expense
312.000	Steam Prod-Boiler Plant Equip- Montrose Common	1-Production 1	$0	-$4,725	$0
316.000	Steam Prod-Misc Pwr Plt Equip- Montrose Common	1-Production 1	$12,836	$11,620	$293
	TOTAL PRODUCTION STM- MONTROSE COMMON		$4,449,840	$3,787,530	$59,276
	TOTAL STEAM PRODUCTION		$2,123,721,800	$1,182,111,637	$73,242,574
	NUCLEAR PRODUCTION				
	WOLF CREEK NUCLEAR PRODUCTION				
320.000	Nucl Prod - Land & Land Rights	4-Nuclear	$2,229,416	$2,229,416	$0
321.000	Nucl Prod - Structures & Improvements	4-Nuclear	$258,358,836	$88,267,890	$4,908,818
321.001	Nucl Prod - Structures MO Gross Up AFDC	4-Nuclear	$18,948,007	$4,232,546	$0
322.000	Nucl Prod - Reactor Plant Equipment	4-Nuclear	$525,439,646	$244,867,553	$13,293,623
322.001	Nucl Prod - Reactor - MO Gross Up AFDC	4-Nuclear	$47,040,652	$8,503,210	$0
322.002	Nucl Prod - MO Juris deprec 40 to 60 yr EO-05-0359	4-Nuclear	$0	-$7,762,767	$0
323.000	Nucl Prod - Turbogenerator Units	4-Nuclear	$119,740,025	$50,129,889	$3,388,643
323.001	Nucl Prod - Turbogenerator MO Gross Up AFDC	4-Nuclear	$4,081,807	-$747,394	$0
324.000	Nucl Prod - Accessory Equip	4-Nuclear	$91,443,323	$39,582,663	$2,624,423
324.001	Nucl Prod - Accessory Equip - MO Gross Up AFDC	4-Nuclear	$5,812,279	$1,139,593	$0
324.010	Nucl Pr-Computer Hardware FERC 898 32400	4-Nuclear	$5,963,214	$3,353,760	$353,619
324.010	Nucl Pr-Computer Hardware FERC 898 32500	4-Nuclear	$32,458,368	$18,262,427	$1,924,781
324.010	Nucl Pr-Computer Hardware FERC 898 39101	4-Nuclear	$8,232	$6,192	$488
324.010	Nucl Pr-Computer Hardware FERC 898 39102	4-Nuclear	$4,638,118	$470,457	$275,040
324.020	Nucl Pr-Computer Software5yr FERC 898 30300	4-Nuclear	$126,789	$86,729	$0
324.020	Nucl Pr-Computer Software5yr FERC 898 30302	4-Nuclear	$543,087	$340,315	$0
324.020	Nucl Pr-Computer Software5yr FERC 898 30305	4-Nuclear	$19,397,269	$2,394,739	$0
324.023	Nucl Pr-Computer Softwar10yr FERC 898 30303	4-Nuclear	$16,880,887	$12,585,395	$0
324.030	Nucl Pr-Communication Equip FERC 898 39700	4-Nuclear	$3,429,549	$1,934,459	$101,515
325.000	Nucl Prod - Misc Power Plant Equip	4-Nuclear	$42,626,395	$21,479,627	$1,649,641
325.001	Nucl Prod - Misc Pwr Plt Equip - MO Gross Up AFDC	4-Nuclear	$1,046,860	$98,206	$0
328.000	Nucl Prod - Disallow - MO Gross Up AFDC 100% MO	4-Nuclear	-$7,835,257	-$1,448,588	$0
328.001	Nucl Prod - MPSC Disallow - MO Basis	4-Nuclear	-$67,117,611	-$17,679,875	$0
328.005	Nucl Prod - Disallow - Pre 1988 Res	4-Nuclear	$0	$5,365,755	$0
	TOTAL WOLF CREEK NUCLEAR PRODUCTION		$1,125,259,891	$477,692,197	$28,520,591
	TOTAL NUCLEAR PRODUCTION		$1,125,259,891	$477,692,197	$28,520,591

Account Number	Account Description	Functional Allocator	Gross Plant	Net Plant	Depreciation Expense
	HYDRAULIC PRODUCTION				
	TOTAL HYDRAULIC PRODUCTION		$0	$0	$0
	OTHER PRODUCTION				
	PRODUCTION- HAWTHORN 6 COMBINED CYCL				
341.000	Other Prod - Structures Haw 6	1-Production 1	$124,411	$66,434	$4,093
342.000	Other Prod - Fuel Holders Haw 6	1-Production 1	$576,280	$236,726	$14,580
344.000	Other Prod - Generators Haw 6	1-Production 1	$32,243,253	$16,622,665	$873,792
345.000	Other Prod - Accessory Equip - Haw 6	1-Production 1	$1,309,385	$434,252	$43,995
345.010	Hawthorn 6 Oth Prod-Computer Hardware FERC 898 34400	1-Production 1	$258,576	$84,227	$0
345.020	Hawthorn 6 Oth Prod-Computer Softwar5yr FERC 898 30302	1-Production 1	$279,738	$261,824	$0
346.000	Other Prod - Misc Pwr Plt Equip - Haw 6	1-Production 1	$37,504	$38,883	$2,048
	TOTAL PRODUCTION- HAWTHORN 6 COMBINED CYCL		$34,829,147	$17,745,011	$938,508
	PRODUCTION - HAWTHORN 9 COMBINED CYCL				
311.000	Steam Prod- Structures- Haw 9	1-Production 1	$1,225,767	$736,776	$44,618
312.000	Steam Prod-Boiler Plant Equip- Haw 9	1-Production 1	$23,407,920	$12,149,043	$819,277
314.000	Steam Prod- Turbogenerator- Haw 9	1-Production 1	$11,039,500	$7,151,063	$408,462
315.000	Steam Prod-Accessory Equip- Haw 9	1-Production 1	$8,538,822	$3,989,185	$280,073
315.010	Hawthorn 9 Stm Pr-Computer Hardware FERC 898 31200	1-Production 1	$558,361	$367,936	$0
315.010	Hawthorn 9 Stm Pr-Computer Hardware FERC 898 31500	1-Production 1	$115,150	$71,950	$0
316.000	Steam Prod-Misc Pwr Plt Equip- Haw 9	1-Production 1	$253,857	$199,381	$11,754
	TOTAL PRODUCTION - HAWTHORN 9 COMBINED CYCL		$45,139,377	$24,665,334	$1,564,184
	PRODUCTION - NORTHEAST STATION				
340.000	Other Prod - Land -NE	1-Production 1	$72,645	$72,645	$0
341.000	Other Prod - Structures - NE	1-Production 1	$952,827	$314,307	$25,631
342.000	Other Prod - Fuel Holders - NE	1-Production 1	$1,226,865	$415,616	$38,278
344.000	Other Prod - Generators - NE	1-Production 1	$41,437,321	$14,989,880	$1,259,695
345.000	Other Prod - Accessory Equip - NE	1-Production 1	$9,944,333	$5,960,489	$398,768
345.010	Oth Prod-Computer Hardware FERC 898 39102	1-Production 1	$14,017	$4,784	$419
345.010	Oth Prod-Computer Hardware FERC 898 39700	1-Production 1	$64,780	$31,865	$1,937
345.030	Oth Prod-Communication Equip FERC 898 39700	1-Production 1	$17,001	$11,478	$459
346.000	Other Prod - Misc Pwr Plt Equip - NE	1-Production 1	$166,286	$68,409	$5,654
	TOTAL PRODUCTION - NORTHEAST STATION		$53,896,075	$21,869,473	$1,730,841

Account Number	Account Description	Functional Allocator	Gross Plant	Net Plant	Depreciation Expense
	PRODUCTION-HAWTHORN 7 COMBUSTION TURBINE				
341.000	Other Prod - Structures - Haw 7	1-Production 1	$385,529	$191,681	$11,026
342.000	Other Prod - Fuel Holders - Haw 7	1-Production 1	$1,822,647	$1,260,357	$71,812
344.000	Other Prod - Generators - Haw 7	1-Production 1	$14,863,533	$6,537,091	$292,812
345.000	Other Prod - Accessory Equip - Haw 7	1-Production 1	$1,244,862	$487,238	$31,868
345.010	Haw 7 Oth Prod-Computer Hardware FERC 898 34400	1-Production 1	$89,629	$46,625	$0
346.000	Other Prod - Misc Pwr Plt Equip - Haw 7	1-Production 1	$1,876	$1,749	$96
	TOTAL PRODUCTION-HAWTHORN 7 COMBUSTION TURBINE		$18,408,076	$8,524,741	$407,614
	PRODUCTION-HAWTHORN 8 COMBUSTION TURBINE				
341.000	Other Prod - Structures - Haw 8	1-Production 1	$336,396	$296,656	$16,181
342.000	Other Prod - Fuel Holders - Haw 8	1-Production 1	$1,754,225	$1,309,745	$73,677
344.000	Other Prod - Generators - Haw 8	1-Production 1	$15,433,962	$6,783,149	$392,023
345.000	Other Prod - Accessory Equip - Haw 8	1-Production 1	$801,969	$306,858	$20,450
345.010	Haw 8 Oth Prod-Computer Hardware FERC 898 34400	1-Production 1	$81,531	$37,997	$0
346.000	Other Prod - Misc Pwr Plt Equip - Haw 8	1-Production 1	$0	$0	$0
	TOTAL PRODUCTION-HAWTHORN 8 COMBUSTION TURBINE		$18,408,083	$8,734,405	$502,331
	PROD OTHER - WEST GARDNER 1, 2, 3 & 4				
340.000	Other Prod - Land - W. Gardner	1-Production 1	$94,609	$94,609	$0
340.001	Other Prod- Land Rights-Easements - W. Gardner	1-Production 1	$49,619	$36,272	$0
341.000	Other Prod - Structures- W. Gardner	1-Production 1	$2,387,390	$1,478,386	$72,338
342.000	Other Prod- Fuel Holders- W. Gardner	1-Production 1	$1,764,650	$846,472	$44,646
344.000	Other Prod - Generators- W. Gardner	1-Production 1	$71,861,336	$36,937,244	$1,731,858
345.000	Other Prod- Accessory Equip - W. Gardner	1-Production 1	$3,990,717	$1,893,322	$102,960
345.010	Oth Prod-Computer Hardware FERC 898 34400	1-Production 1	$161,339	$109,313	$8,874
345.020	Oth Prod-Computer Softwar5yr FERC 898 30302	1-Production 1	$57,255	$0	$0
345.030	Oth Prod-Communication Equip FERC 898 39102	1-Production 1	$15,983	$4,029	$222
345.030	WG 1-4 Oth Prod-Communication Equip FERC 898 39700	1-Production 1	$23,052	$10,144	$320
346.000	Other Prod- Misc Pwr Plt Equip - W. Gardner	1-Production 1	$145,139	$108,541	$5,501
	TOTAL PROD OTHER - WEST GARDNER 1, 2, 3 & 4		$80,551,089	$41,518,332	$1,966,719
	PROD OTHER - MIAMI/OSAWATOMIE 1				
340.000	Other Prod - Land- Osawatomie	1-Production 1	$369,498	$369,498	$0
341.000	Other Prod - Structures- Osawatomie	1-Production 1	$1,232,328	$778,605	$43,748
342.000	Other Prod - Fuel Holders- Osawatomie	1-Production 1	$1,080,806	$502,838	$27,020

Account Number	Account Description	Functional Allocator	Gross Plant	Net Plant	Depreciation Expense
344.000	Other Prod - Generators- Osawatomie	1-Production 1	$15,031,329	$6,238,967	$321,670
345.000	Other Prod - Accessory Equip - Osawatomie	1-Production 1	$1,156,843	$547,548	$31,003
345.010	OSA Oth Prod-Computer Hardware FERC 898 34400	1-Production 1	$87,184	$55,855	$0
345.020	OSAOth Prod-Computer Softwar5yr FERC 898 30302	1-Production 1	$13,973	$0	$0
346.000	Other Prod- Misc Pwr Plt Equip - Osawatomie	1-Production 1	$46,919	$34,501	$1,722
	TOTAL PROD OTHER - MIAMI/OSAWATOMIE 1		$19,018,880	$8,527,812	$425,163
	PRODUCTION PLANT - WIND GEN-SPEARVILLE CMN				
338.210	Wind-Structures FERC 898 34102	2-Production 2	$2,698,926	$541,314	$69,093
338.210	Wind-Structures FERC 898 34402	2-Production 2	$623,987	$155,440	$15,974
338.230	Wind-Turbines FERC 898 34402	2-Production 2	$334,345	$89,836	$9,261
338.260	Wind-Collector System FERC 898 34402	2-Production 2	$6,702,621	$1,116,428	$157,512
338.290	Wind-Accessory Equip FERC 898 34402	2-Production 2	$3,294,237	$414,959	$63,249
338.290	Wind-Accessory Equip FERC 898 34502	2-Production 2	$18,403	$14,991	$353
338.300	Wind-Computer Hardware FERC 898 34502	2-Production 2	$379,802	$82,134	$26,168
338.300	Wind-Computer Hardware FERC 898 34602	2-Production 2	$11,107	$10,959	$765
338.300	Wind-Computer Hardware FERC 898 39102	2-Production 2	$5,273	$1,395	$363
338.320	Wind-Communication Equip FERC 898 39700	2-Production 2	$1,207,753	$600,956	$34,783
338.330	Wind-Misc Pwr Plant Equip FERC 898 34402	2-Production 2	$61,731	-$27,023	$982
338.330	Wind-Misc Pwr Plant Equip FERC 898 34602	2-Production 2	$91,768	$42,568	$1,459
341.002	Other Prod - Structures - Elec Wind	2-Production 2	$0	$0	$0
344.002	Other Prod - Generators - Elec Wind	2-Production 2	$0	$0	$0
345.002	Other Prod-Accessory Equip-Wind	2-Production 2	$0	$0	$0
346.002	Other Prod - Misc Pwr Plt Equip-Wind	2-Production 2	$0	$0	$0
	TOTAL PRODUCTION PLANT - WIND GEN-SPEARVILLE CMN		$15,429,953	$3,043,957	$379,962
	PRODUCTION PLANT - WIND GEN-SPEARVILLE 1				
338.210	S1 Wind-Structures FERC 898 34402	2-Production 2	$3,706,904	$781,930	$8,155
338.230	S1 Wind-Turbines FERC 898 34402	2-Production 2	$76,369,057	$21,673,349	$824,786
338.240	S1 Wind-Towers and Fixtures FERC 898 34102	2-Production 2	$339,638	$276,592	$33,251
338.270	S1 Wind-Generater Step-Up (GSU) FERC 898 34402	2-Production 2	$4,722	$3,484	$380
338.290	S1 Wind-Accessory Equip FERC 898 34402	2-Production 2	$89,576	$134,415	$12,102
341.002	S1 Other Prod - Structures - Elec Wind	2-Production 2	$0	$0	$0
344.002	S1 Other Prod - Generators - Elec Wind	2-Production 2	$0	$0	$0
345.002	S1 Other Prod-Accessory Equip-Wind	2-Production 2	$0	$0	$0
346.002	S1 Other Prod - Misc Pwr Plt Equip-Wind	2-Production 2	$0	$0	$0
	TOTAL PRODUCTION PLANT - WIND GEN-SPEARVILLE 1		$80,509,897	$22,869,770	$878,674

Account Number	Account Description	Functional Allocator	Gross Plant	Net Plant	Depreciation Expense
	PRODUCTION PLANT - WIND GEN-SPEARVILLE 2				
338.210	S2 Wind-Structures FERC 898 34402	2-Production 2	$2,104,326	-$25,462	$58,500
338.230	S2 Wind-Turbines FERC 898 34402	2-Production 2	$49,623,220	-$1,508,644	$1,483,734
338.240	S2 Wind-Towers and Fixtures FERC 898 34102	2-Production 2	$179,146	$140,530	$12,504
338.270	S2 Wind-Generater Step-Up (GSU) FERC 898 34402	2-Production 2	$4,567	-$147	$157
338.290	S2 Wind-Accessory Equip 34402	2-Production 2	$124,300	$7,287	$1,790
341.002	S2 Other Prod - Structures - Elec Wind	2-Production 2	$0	$0	$0
344.002	S2 Other Prod - Generators - Elec Wind	2-Production 2	$0	$0	$0
346.002	S2 Other Prod - Misc Pwr Plt Equip-Wind	2-Production 2	$0	$0	$0
	TOTAL PRODUCTION PLANT - WIND GEN-SPEARVILLE 2		$52,035,559	-$1,386,436	$1,556,685
	PRODUCTION PLANT - SOLAR				
338.040	Solar-Panels FERC 898 34401	2-Production 2	$496,832	$42,697	$22,010
344.001	Greenwood Solar	2-Production 2	$2,833,849	$1,591,430	$124,123
	TOTAL PRODUCTION PLANT - SOLAR		$3,330,681	$1,634,127	$146,133
	PRODUCTION PLANT - HAWTHORN SOLAR				
338.020	HAW SOL Solar-Structures FERC 898 34401	2-Production 2	$900,958	$773,857	$31,443
338.040	HAW SOL Solar-Panels FERC 898 34401	2-Production 2	$4,203,782	$3,773,576	$164,368
338.050	HAW SOL Solar-Collector System FERC 898 34401	2-Production 2	$1,352,700	$1,161,870	$53,567
338.070	HAW SOL Solar-Inverters FERC 898 34401	2-Production 2	$374,022	$321,258	$50,493
338.080	HAW SOL Solar-Accessory Equip FERC 898 34401	2-Production 2	$901,311	$774,160	$39,928
344.001	HAW SOL Other Prod - Generators - Elec Solar	2-Production 2	$0	$0	$0
	TOTAL PRODUCTION PLANT - HAWTHORN SOLAR		$7,732,773	$6,804,721	$339,799
	GENERAL PLANT- GENERAL EQUIP/TOOLS				
316.000	GEN PLANT Steam Prod-Misc Power Plt Equip	1-Production 1	$879,046	$616,052	$16,878
	TOTAL GENERAL PLANT- GENERAL EQUIP/TOOLS		$879,046	$616,052	$16,878
	BULK OIL FACILITY NE				
310.000	Steam Prod- Land- Bulk Oil NE	1-Production 1	$79,215	$79,215	$0
311.000	Steam Prod-Structures- Bulk Oil NE	1-Production 1	$529,755	$491,761	$8,741
312.000	Steam Prod- Boiler Plt Equip- Bulk Oil NE	1-Production 1	$320,317	$91,433	$8,745
315.000	Steam Prod- Accessory Equip- Bulk Oil NE	1-Production 1	$13,272	$1,652	$427
316.000	Steam Prod-Misc Pwr Plt Equip- Bulk Oil NE	1-Production 1	$103,869	$83,356	$2,368
	TOTAL BULK OIL FACILITY NE		$1,046,428	$747,417	$20,281

Account Number	Account Description	Functional Allocator	Gross Plant	Net Plant	Depreciation Expense
	RETIREMENTS WORK IN PROGRESS-PROD				
	Production - Salvage & Removal Retirements not classified-Nuclear and Steam	1-Production 1	$0	$25,998,205	$0
	TOTAL RETIREMENTS WORK IN PROGRESS-PROD		$0	$25,998,205	$0
	OTHER PRODUCTION PLANT				
	TOTAL OTHER PRODUCTION PLANT		$0	$0	$0
	TOTAL OTHER PRODUCTION		$431,215,064	$191,912,921	$10,873,772
	TOTAL PRODUCTION PLANT		$3,680,196,755	$1,851,716,755	$112,636,937
	TRANSMISSION PLANT				
350.000	Trsm-Land-Elec	5-Transmission	$1,257,860	$1,257,860	$0
350.001	Trsm-Land Rights-Elec	5-Transmission	$20,550,973	$14,316,715	$0
350.002	Trsm-Land Rights-Wolf Creek-Elec	4-Nuclear	$189	$102	$5
351.010	Trsm-Computer Hardware FERC 898 39102	5-Transmission	$5,937	$1,496	$742
351.030	Trsm-Communication Equip FERC 898 35300	5-Transmission	$6,015,163	$5,215,509	$243,013
351.030	Trsm-Communication Equip FERC 898 35303	5-Transmission	$1,906,279	-$547,045	$77,014
351.030	Trsm-Communication Equip FERC 898 35600	5-Transmission	$23,751,072	$19,814,989	$959,543
351.030	Trsm-Communication Equip FERC 898 39102	5-Transmission	$2,480	$954	$100
351.030	Trsm-Communication Equip FERC 898 39700	5-Transmission	$233,211	$184,083	$9,422
351.035	Trsm-Communication Eq 34.5kV FERC 898 35605	5-Transmission	$886	$571	$0
351.037	Trsm-Communication Eq Retire FERC 898 35303	5-Transmission	$1,106,272	-$474,118	$0
352.000	Trsm-Structures & Impr-Elec	12-352 split	$5,282,500	$3,166,636	$81,351
352.001	Trsm-Structures & Impr - Wolf Creek -Elec	4-Nuclear	$133,253	$60,534	$0
352.002	Trsm-Structures & Impr - WC-MO Gross Up AFDC	4-Nuclear	$0	$0	$0
352.003	Trsm-Structures & Impr - WC-MO Gross Up FERC 898 35202	4-Nuclear	$15,694	$7,268	$0
353.000	Trsm-Station Equip-Elec	13-353 split	$201,105,962	$170,651,016	$4,203,115
353.001	Trsm-Station Equip-Wolf Creek-Elec	4-Nuclear	$14,812,662	$10,033,094	$0
353.002	Trsm-Station Equip- WC- MO Gross Up AFDC	4-Nuclear	$0	$0	$0
353.003	Trsm-Station Equip-Communication	5-Transmission	$0	$0	$0
353.003	Trsm-Station Equip- WC- MO Gross Up FERC 898 35302	4-Nuclear	$530,838	$79,019	$0
354.000	Trsm-Towers & Fixtures-Elec	5-Transmission	$2,378,270	-$3,359	$9,751
354.005	Trsm-Towers & Fixtures-Elec - SubTransm - 34.5kv	5-Transmission	$5,533	-$334	$33
355.000	Trsm-Poles & Fixtures-Elec	5-Transmission	$153,573,002	$108,760,030	$4,699,334

Account Number	Account Description	Functional Allocator	Gross Plant	Net Plant	Depreciation Expense
355.001	Trsm-Poles & Fixtures- Wolf Creek -Elec	4-Nuclear	$28,806	-$5,675	$0
355.002	Trsm-Poles & Fixtures- WC- MO Gross Up AFDC	4-Nuclear	$0	$0	$0
355.003	Trsm-Poles & Fixtures- WC- MO Gross Up FERC 898 35502	4-Nuclear	$3,506	-$987	$0
355.005	Trsm-Poles & Fixtures-Elec-SubTransm - 34.5kv	5-Transmission	$12,328,644	$5,336,740	$615,199
356.000	Trsm-OH Conductors & Devices-Elec	5-Transmission	$59,683,945	$28,817,192	$1,521,941
356.001	Trsm-OH Conductors & Devices-Wolf Creek-Elec	4-Nuclear	$20,970	$3,066	$0
356.002	Trsm-OH Conductors & Dev-WC-MO Gross Up AFDC	4-Nuclear	$0	$0	$0
356.003	Trsm-OH Conductors & Dev-WC-MO Gross Up FERC 898 35602	4-Nuclear	$2,552	$480	$0
356.005	Trsm-OH Conductors & Devices-Elec-SubTransm - 34.5kv	5-Transmission	$11,641,036	$6,002,041	$382,990
357.000	Trsm-UG Conduit-Elec	5-Transmission	$5,978,191	$4,707,381	$110,597
357.005	Trsm-UG Conduit-Elec - SubTransmission	5-Transmission	$542,841	$425,774	$7,708
358.000	Trsm-UG Conductors & Devices-Elec	5-Transmission	$6,168,325	$4,757,690	$109,179
358.005	Trsm-UG Conductors & Devices-Elec-SubTransm - 34.5kv	5-Transmission	$196,837	$157,044	$3,346
	Transmission-Salvage & Removal : Retirements not classified	5-Transmission	$0	$4,581,999	$0
	TOTAL TRANSMISSION PLANT		$529,263,689	$387,307,765	$13,034,383
	DISTRIBUTION PLANT				
360.000	Dist-Land-Elec	6-Distribution	$13,178,041	$13,178,041	$0
360.001	Dist-Land Rights-Elec	6-Distribution	$12,506,600	$5,246,174	$312,665
361.000	Dist-Structures & Improvements-Elec	6-Distribution	$9,331,468	$4,473,988	$116,643
362.000	Dist-Station Equipment-Elec	14-362 SE main split	$296,615,362	$242,858,462	$6,228,923
362.003	Dist-Station Equipment-Communications	15-362_03 SE Com Split	$0	$0	$0
363.000	Dist-Energy Storage Equipment	16-363 E Stor Split	$0	$0	$0
363.010	Dist-Computer Hardware FERC 898 39102	6-Distribution	$0	$0	$0
363.030	Dist-Communication Equip FERC 898 36200	6-Distribution	$5,388,109	$5,014,935	$122,310
363.030	Dist-Communication Equip FERC 898 36203	6-Distribution	$2,282,596	$324,437	$51,815
363.030	Dist-Communication Equip FERC 898 39102	6-Distribution	$41,379	$38,855	$939
363.030	Dist-Communication Equip FERC 898 39700	6-Distribution	$81,188	$45,529	$1,843
363.037	Dist-Communication Eq Retire FERC 898 39700	6-Distribution	$1,119,805	$915,136	$27,995
364.000	Dist-Poles,Towers & Fixtures-Elec	6-Distribution	$353,476,442	$219,536,359	$13,043,281
365.000	Dist-OH Conductor-Elec	6-Distribution	$270,200,692	$212,870,820	$8,079,001
366.000	Dist-UG Circuit-Elec	6-Distribution	$276,570,531	$197,922,416	$6,056,895
367.000	Dist-UG Conductors & Devices-Elec	6-Distribution	$446,062,976	$336,253,598	$9,411,929
368.000	Dist-Line Transformers-Elec	6-Distribution	$270,874,258	$177,086,493	$6,988,556
369.000	Dist-Services-Elec	6-Distribution	$139,384,228	$69,674,699	$1,547,165
370.000	Dist-Meters-Elec	6-Distribution	$29,349,731	$7,902,605	$481,336
370.002	Dist-AMI Meters-Elec	6-Distribution	$72,780,096	$58,329,255	$3,922,847

Account Number	Account Description	Functional Allocator	Gross Plant	Net Plant	Depreciation Expense
371.000	Dist-Customer Premises-Elec	17-Specific Cust	$16,540,289	$11,401,867	$916,332
371.001	Dist-Electric Vehicle Charging Stations	17-Specific Cust	$7,019,491	$1,886,481	$856,378
373.000	Dist-Street Light & Traffic Signals-Elec	17-Specific Cust	$15,705,141	$6,930,275	$637,629
	Distribution-Salvage and removal: Retirements not classified	6-Distribution	$0	$47,282,226	$0
	TOTAL DISTRIBUTION PLANT		$2,238,508,423	$1,619,172,651	$58,804,482
	INCENTIVE COMPENSATION CAPITALIZATION				
0.000	Incentive Compensation Capitalization Adj.		$0	$0	$0
	TOTAL INCENTIVE COMPENSATION CAPITALIZATION		$0	$0	$0
	ENERGY STORAGE				
387.010	Storg-Land		$0	$0	$0
387.011	Storg-Land Rights Easements		$0	$0	$0
387.020	Storg-Structures Improvments		$0	$0	$0
387.030	Storg-Energy Storage Equipmt	17-Specific Cust	$878,987	$524,470	$44,916
387.050	Storg-Collector System		$0	$0	$0
387.060	Storg-Generator Step-Up Tfmr		$0	$0	$0
387.070	Storg-Inverters		$0	$0	$0
387.080	Storg-Computer Hardware		$0	$0	$0
387.090	Storg-Computer Software 5yrs		$0	$0	$0
387.100	Storg-Communication Equipmnt		$0	$0	$0
387.110	Storg-Misc PwrPlt Equipment		$0	$0	$0
	TOTAL ENERGY STORAGE		$878,987	$524,470	$44,916
	GENERAL PLANT				
389.000	Gen-Land & Land Rights-Elec	7-Admin & Overhead	$2,093,758	$2,093,757	$52,344
390.000	Gen-Structures & Improvements-Elec	7-Admin & Overhead	$87,676,190	$62,945,101	$2,060,390
390.003	Gen-Struc-Leasehold Improv - (801 Charlotte)	7-Admin & Overhead	$3,589,506	$0	$0
390.005	Gen-Struc-Leasehold Improv - (One KC Place)	7-Admin & Overhead	$16,047,159	$4,498,208	$0
391.000	Gen-Office Furniture & Equip-Elec	7-Admin & Overhead	$10,131,441	$5,976,867	$506,572
391.001	Gen-Office Furniture & Equip- Elec - Wolf Creek	4-Nuclear	$3,207,533	$1,465,219	$160,377
391.002	Gen-Office Furniture-Computer	7-Admin & Overhead	$0	$0	$0
391.002	Gen-Office Furniture-Computer - Wolf Creek	4-Nuclear	$0	$0	$0
392.000	Gen-Transportation Equip- Autos -Elec	7-Admin & Overhead	$479,507	-$19,617	$43,060
392.001	Gen-Transportation Equip- Light Trucks -Elec	7-Admin & Overhead	$3,785,777	-$276,051	$51,865
392.002	Gen-Transportation Equip- Heavy Trucks -Elec	7-Admin & Overhead	$20,121,413	$9,267,853	$641,873
392.003	Gen-Transportation Equip- Tractors -Elec	7-Admin & Overhead	$659,939	$305,741	$17,422

Account Number	Account Description	Functional Allocator	Gross Plant	Net Plant	Depreciation Expense
392.004	Gen-Transportation Equip- Trailers-Elec	7-Admin & Overhead	$2,279,969	$1,740,392	$53,123
393.000	Gen-Stores Equip-Elec	7-Admin & Overhead	$283,871	$91,778	$11,355
394.000	Gen-Tools, Shop and Garage Equip-Elec	7-Admin & Overhead	$7,842,257	$5,851,100	$261,147
395.000	Gen-Laboratory Equip-Elec	7-Admin & Overhead	$5,069,881	$2,964,023	$168,827
396.000	Gen-Power Operated Equip-Elec	7-Admin & Overhead	$19,947,157	$9,267,061	$355,059
397.000	Gen-Communication Equip-Elec	7-Admin & Overhead	$0	$0	$0
397.001	Gen-Communication Equip-Elec - Wolf Creek	4-Nuclear	$0	$0	$0
397.002	Gen-Communication Equip- WC -MO Gross Up AFDC	4-Nuclear	$0	$0	$0
397.010	Gen-Computer Hardware FERC 898 39102	7-Admin & Overhead	$55,897,059	$37,063,155	$6,987,132
397.010	Gen-Computer Hardware FERC 898 39700	7-Admin & Overhead	$10,882,376	$5,969,598	$1,360,297
397.021	Gen-Computer Software 3yrs Customer Related FERC 898 30316	7-Admin & Overhead	$10,287,005	$6,419,432	$0
397.021	Gen-Computer Software 3yrs Demand Related FERC 898 30316	7-Admin & Overhead	$8,504,650	$2,697,169	$0
397.021	Gen-Computer Software 3yrs Corporate Software FERC 898 30316	7-Admin & Overhead	$20,543,782	$8,678,614	$0
397.022	Gen-Computer Software 5yrs Customer Related FERC 898 30302	7-Admin & Overhead	$84,832,887	$28,357,374	$0
397.022	Gen-Computer Software 5yrs Energy Related FERC 898 30302	7-Admin & Overhead	$10,181,599	$1,233,157	$0
397.022	Gen-Computer Software 5yrs Demand Related FERC 898 30302	7-Admin & Overhead	$48,057,739	$16,452,122	$0
397.022	Gen-Computer Software 5yrs Corporate Software FERC 898 30302	7-Admin & Overhead	$131,154,743	$33,709,990	$0
397.022	Gen-Computer Software 5yrs Transmission Related FERC 898 30302	5-Transmission	$1,848,360	$137,705	$0
397.022	Gen-Computer Software 5yrs MEEIA Uplight - 100% MO FERC 898 30302	7-Admin & Overhead	$0	$0	$0
397.023	Gen-Computer Software 10yrs Customer Related FERC 898 30303	7-Admin & Overhead	$68,987,401	$8,469,934	$0
397.023	Gen-Computer Software 10yrs Energy Related FERC 898 30303	7-Admin & Overhead	$37,125,871	$6,448,624	$0
397.023	Gen-Computer Software 10yrs Demand Related FERC 898 30303	7-Admin & Overhead	$22,524,548	$3,287,892	$0
397.023	Gen-Computer Software 10yrs Corporate Software FERC 898 30303	7-Admin & Overhead	$35,278,603	$7,781,592	$0
397.024	Gen-Computer Software 15yrs FERC 898 30315	7-Admin & Overhead	$167,745,864	$99,061,924	$0
397.030	Gen-Communication Equipment FERC 898 39700	7-Admin & Overhead	$107,997,990	$75,386,170	$3,088,743
398.000	Gen-Misc Equip	7-Admin & Overhead	$1,392,903	$1,095,220	$46,384
399.000	Gen-Other Tangible Property	7-Admin & Overhead	$0	$0	$0
	Gen Plant-Slvg & removal/retirements not classified	7-Admin & Overhead	$0	$1,403,948	$0
	TOTAL GENERAL PLANT		$1,006,458,738	$449,825,052	$15,865,970
	CAPITALIZED ST FINANCIAL AWARDS				
	Capitalized ST Incentive Compensation Awards	7-Admin & Overhead	-$6,317,132	-$5,902,177	-$181,302
	TOTAL CAPITALIZED ST FINANCIAL AWARDS		-$6,317,132	-$5,902,177	-$181,302

Account Number	Account Description	Functional Allocator	Gross Plant	Net Plant	Depreciation Expense
	CAPITALIZED LT INCENTIVE STOCK AWARDS				
	Capitalized LT Incentive Stock Awards PLANT	7-Admin & Overhead	-$5,561,671	-$5,283,587	-$278,084
	TOTAL CAPITALIZED LT INCENTIVE STOCK AWARDS		-$5,561,671	-$5,283,587	-$278,084
			$7,472,819,039	$4,319,579,528	$199,927,302

Account Number	Description	Allocation Number	MO Adjusted Jurisdictional Non Labor	MO Adjusted Jurisdictional Labor
	RETAIL RATE REVENUE			
400.000	Missouri (excluding GRT)	3-Revenue Related	$898,658,443	See note(1)
400.000	Kansas Retail Revenues		$0	See note(1)
	TOTAL RETAIL RATE REVENUE		$898,658,443	
	OTHER OPERATING REVENUES			
450.000	Forfeited Discounts - MO	7-Admin & Overhead	$925,708	See note(1)
450.000	Forfeited Discounts - KS		$0	See note(1)
451.000	Miscellaneous Services - MO	7-Admin & Overhead	$187,170	See note(1)
451.000	Miscellaneous Services - KS		$0	See note(1)
451.000	Miscellaneous Services - Allocated - Dist	6-Distribution	$14	See note(1)
454.000	Rent from Electric Property - MO	7-Admin & Overhead	$3,626,867	See note(1)
454.000	Rent from Electric Property - KS		$0	See note(1)
454.000	Rent from Electric Property - Allocated - Prod	1-Production 1	$12,124	See note(1)
454.000	Rent from Electric Property - Allocated - Trans	5-Transmission	$185,533	See note(1)
454.000	Rent from Electric Property - Allocated - Dist	6-Distribution	-$16	See note(1)
456.000	Transmission for Others	5-Transmission	$13,291,255	See note(1)
456.000	Other Elec Revenues - MO	18-Net Energy	$2,503,765	See note(1)
456.000	Other Elec Revenues - KS		$0	See note(1)
456.000	Other Elec Revenues - Allocated	18-Net Energy	$11,216	See note(1)
	TOTAL OTHER OPERATING REVENUES		$20,743,636	
	BULK POWER SALES (BPS)			
447.000	Firm Bulk Sales (Capacity & Fixed)		$0	See note(1)
447.000	Firm Bulk Sales (Energy)	18-Net Energy	-$26,334	See note(1)
447.016	Sales for Lot Term Cap Pre - Allocated	51-GROSS PRODUCTION PLANT	$9,359,719	See note(1)
447.000	Non-Firm Off System Sales Energy	18-Net Energy	$52,268,541	See note(1)
447.000	Misc. Charges and Revenues	7-Admin & Overhead	$6,555,031	See note(1)
	TOTAL BULK POWER SALES (BPS)		$68,156,957	
	SALES FOR RESALE (FERC JURIS CUST)			
447.100	FERC JURIS WHOLESALE FIRM POWER		$0	See note(1)
447.100	TRANSMISSION FOR FERC WHSLE FIRM POWER		$0	See note(1)
	TOTAL SALES FOR RESALE (FERC JURIS CUST)		$0	
	PROVISION FOR RATE REFUNDS			
449.100	Provision for Rate Refunds - MO		$0	See note(1)
449.100	Provision for Rate Refunds - KS		$0	See note(1)
	TOTAL PROVISION FOR RATE REFUNDS		$0	
	TOTAL OPERATING REVENUES		$987,559,036	$0
	POWER PRODUCTION EXPENSES			
	STEAM POWER GENERATION			
	OPERATION & MAINTENANCE EXPENSE			
500.000	Prod Steam Operation- Suprv & Engineering	1-Production 1	$2,450,386	$2,191,834
501.000	Fuel Expense - Labor	1-Production 1	$4,200,469	$4,630,698
501.000	Fuel Handling (non-labor)	1-Production 1	$674,650	$0
501.000	Fuel Expense-Coal & Freight	1-Production 1	$83,636,924	$0
501.000	Fuel Expense-Oil	1-Production 1	$4,305,697	$0

| Account Number | Description | Allocation Number | MO Adjusted Jurisdictional Non Labor | MO Adjusted Jurisdictional Labor |

Account Number	Description	Allocation Number	MO Adjusted Jurisdictional Non Labor	MO Adjusted Jurisdictional Labor
501.000	Fuel Expense- Gas	1-Production 1	$2,291,561	$0
501.000	Fuel Expense-Residual - Labor	1-Production 1	$184,223	$0
501.000	Fuel Expense-Residual - Non-Labor	1-Production 1	$3,444,039	$0
501.000	Fuel Expense - Additives, incl NH4, Limestone & Oth	1-Production 1	$5,234,982	$0
501.000	Fuel Expense - Unit Train Depreciation		$0	$0
501.000	Fuel Expense - Residual Non FAC	1-Production 1	$793,691	$0
501.600	Fuel Expense Rider Underrecov - MO FAC		$0	$0
501.600	Fuel Expense Rider Underrecov - KS ECA		$0	$0
501.610	Fuel Exp Recovery - CY RECA - MO FAC		$0	$0
501.610	Fuel Exp Recovery - CY RECA - KS ECA		$0	$0
502.000	Steam Operating Expense	1-Production 1	$6,246,111	$3,868,597
505.000	Electric Operating Electric Expense	1-Production 1	$1,773,711	$1,254,796
506.000	Misc Other Power Expenses	1-Production 1	$2,499,145	$921,203
507.000	Steam Operating Exp - Rents	1-Production 1	$45,061	$0
509.000	NOX/Other Allowances-Allocated	1-Production 1	$9,578	$0
509.000	Amort of SO2 Allowances-MO	1-Production 1	-$2,302,166	$0
509.000	Amort of SO2 Allowances-KS		$0	$0
509.000	Emission Allowance -REC Exp.		$0	$0
411.115	Gain from Disp of Envr Credits - MO	1-Production 1	-$1,051,847	$0
411.115	Gain from Disp of Envr Credits - KS		$0	$0
411.115	Gain from Disp of Envr Credits - Allo	1-Production 1	$7,803	$0
411.125	Loss from Disp of Envr Credits - MO		$0	$0
411.125	Loss from Disp of Envr Credits - KS		$0	$0
411.125	Loss from Disp of Envr Credits - Alloc		$0	$0
411.800	Gain On Disposition - Emission Allow - MO	1-Production 1	-$507,278	$0
411.800	Gain On Disposition - Emission Allow - KS		$0	$0
411.800	Gain On Disposition - Emission Allow - Alloc	1-Production 1	$3,668	$0
411.800	Loss On Disposition - Emission Allow - KS		$0	$0
	TOTAL OPERATION & MAINTENANCE EXPENSE		$113,940,408	$12,867,128
	TOTAL STEAM POWER GENERATION		$113,940,408	$12,867,128
	ELECTRIC MAINTENANCE EXPENSE			
510.000	Steam Maintenance Suprv & Engineering	1-Production 1	$3,155,103	$2,039,330
511.000	Maintenance of Structures	1-Production 1	$2,634,935	$383,608
512.000	Maintenance of Boiler Plant	1-Production 1	$10,226,975	$2,708,499
513.000	Maintenance Elec Plt Other	1-Production 1	$1,671,709	$560,950
513.010	Steam Maintenance Computer Hardware	1-Production 1	$215,587	$0
513.020	Steam Maintenance Computer Software	1-Production 1	$9,297	$0
513.030	Steam Maintenance Communication Equipment	1-Production 1	$917	$0
514.000	Maintenance of Miscellaneous Steam Plant	1-Production 1	$345,851	$19,522
	TOTAL ELECTRIC MAINTENANCE EXPENSE		$18,260,374	$5,711,909
	NUCLEAR POWER GENERATION			
	OPERATION - NUCLEAR			
517.000	Prod Nuclear Operation- Superv & Engineer	4-Nuclear	$3,419,438	$2,579,297
518.000	Nuclear Fuel Expense - Net Amortizarion	4-Nuclear	$14,029,936	$0
518.000	Nuclear Fuel Expense - Prod Nuclear-Disposal Costs	4-Nuclear	$0	$0
518.000	Nuclear Fuel Expense - Cost of Oil	4-Nuclear	$73,124	$0
518.000	Nuclear Fuel Expense - Labor		$0	$0
519.000	Coolants and Water	4-Nuclear	$1,780,472	$979,261
520.000	Steam Expense	4-Nuclear	$4,101,676	$3,923,141
520.000	Steam Expense-MidCycle Outage-100% MO		$0	$0

Account Number	Description	Allocation Number	MO Adjusted Jurisdictional Non Labor	MO Adjusted Jurisdictional Labor
523.000	Electric Expense	4-Nuclear	$572,085	$554,469
524.000	Misc. Nuclear Power Expenses-100% KS		$0	$0
524.000	Decommissioning-Missouri	4-Nuclear	$1,281,264	$0
524.000	Decommissioning-Kansas		$0	$0
524.000	Decommissioning-FERC		$0	$0
524.000	Refueling Outage Amortization	4-Nuclear	$7,347	$0
524.000	Refueling Outage Amortization - MO only		$0	$0
524.000	Misc. Nucl Power Exp-Other-Alloc	4-Nuclear	$11,035,162	$4,881,403
	TOTAL OPERATION - NUCLEAR		$36,300,504	$12,917,571
	MAINTENANCE - NP			
528.000	Prod Nuclear Maint- Suprv & Engineer	4-Nuclear	$2,208,849	$1,768,465
529.000	Prod Nuclear Maint- Maint of Structures	4-Nuclear	$1,130,840	$883,948
530.000	Prod Nuclear Maint- Maint Reactor Plant - Refueling Outage Amortization	4-Nuclear	$2,997,452	$0
530.000	Prod Nuclear Maint- Maint Reactor Plant - Refueling Outage Amortization - MO only		$0	$0
530.000	Prod Nuclear Maint- Maint Reactor Plant - Maint Reactor Plant - Other	4-Nuclear	$3,448,279	$1,676,852
531.000	Prod Nuclear Maint - Electric Plant	4-Nuclear	$1,719,316	$884,811
531.010	Nuclear Maint - Computer Hardware	4-Nuclear	$3,681	$0
531.020	Nuclear Maint - Computer Software	4-Nuclear	$126,244	$0
531.030	Nuclear Maint - Communication Equipment	4-Nuclear	$87	$0
532.000	Prod Nuclear Maint- Maint of Miscl Plant	4-Nuclear	$940,399	$546,401
	TOTAL MAINTENANCE - NP		$12,575,147	$5,760,477
	TOTAL NUCLEAR POWER GENERATION		$48,875,651	$18,678,048
	HYDRAULIC POWER GENERATION			
	OPERATION - HP			
	TOTAL OPERATION - HP		$0	$0
	MAINTANENCE - HP			
	TOTAL MAINTANENCE - HP		$0	$0
	TOTAL HYDRAULIC POWER GENERATION		$0	$0
	OTHER POWER GENERATION			
	OPERATION - OP			
546.000	Prod Turbine Oper-Supr & Engineering	1-Production 1	$86,973	$76,651
547.000	Other PowerOperation- Fuel Expense - Labor	1-Production 1	$21,961	$21,802
547.000	Fuel Handling (non-labor) - Other Power	1-Production 1	$7,705	$0
547.000	Other Fuel Expense - Oil - Other Power	1-Production 1	$0	$0
547.000	Other Fuel Expense - Gas - Other Power	1-Production 1	$12,311,897	$0
547.000	Other Fuel Expense - Gas Transport Reservation	1-Production 1	$2,858,953	$0
547.000	Other Fuel Expense - Additives	1-Production 1	$112,809	$0
548.000	Other Power Generation Expense	1-Production 1	$627,751	$535,594
549.000	Misc Other Power Generation Expense	1-Production 1	$531,953	$304,036
550.000	Other Generation Rents	1-Production 1	$82	$79
558.130	WIND Oper Superv & Engineering	2-Production 2	$7,229	$0
558.140	WIND Oper Expense	2-Production 2	$281,302	$0
558.160	WIND Oper Rents	2-Production 2	$58,804	$0
	TOTAL OPERATION - OP		$16,907,419	$938,162

Account Number	Description	Allocation Number	MO Adjusted Jurisdictional Non Labor	MO Adjusted Jurisdictional Labor
	MAINTANENCE - OP			
551.000	Other Maint-Supr Eng. Struct Gen & Misc.	1-Production 1	$25,448	$24,482
552.000	Other General Maintenance of Structures	1-Production 1	$147,884	$38,944
553.000	Other General Maint of General Plant	1-Production 1	$1,422,680	$647,023
553.010	Other Pwr Gen Maint - Computer Hardware	1-Production 1	$32,274	$0
553.020	Other Pwr Gen Maint - Computer Software	1-Production 1	$6,321	$0
554.000	Other Gen Maint Miscl. Other General Plant	1-Production 1	$39,628	$1,085
558.070	SOLAR Maintenance Structure	2-Production 2	$12,985	$0
558.110	SOLAR Maintenance Misc	2-Production 2	$2,049	$0
558.180	WIND Maintenance Superv & Engineering	2-Production 2	$4,109	$0
558.190	WIND Maintenance Structure	2-Production 2	$618,506	$245,472
558.200	WIND Maintenance Computer Hardware	2-Production 2	$39,596	$0
558.220	WIND Maintenance Communication Equipment	2-Production 2	$214	$0
558.230	WIND Maintenance Misc	2-Production 2	$81,455	$0
	TOTAL MAINTANENCE - OP		$2,433,149	$957,006
	TOTAL OTHER POWER GENERATION		$19,340,568	$1,895,168
	OTHER POWER SUPPLY EXPENSES			
555.000	Purchased Power-Energy	18-Net Energy	$99,945,663	$0
555.000	Purchased Power-Capacity (Demand)		$0	$0
555.000	Purch Pwr Energy Solar Contrct (100% MO)		$0	$0
555.000	Solar Renew Energy Credits (100% KS)		$0	$0
555.002	Purchased Power FCE - KS		$0	$0
555.070	Purchased Power-Admin Fees	5-Transmission	$2,153,639	$0
556.000	System Control and Load Dispatch	5-Transmission	$487,561	$408,829
557.000	Other Expenses	18-Net Energy	$1,357,939	$808,177
557.050	Other Power Supply-Common Use	18-Net Energy	$840,491	$0
	TOTAL OTHER POWER SUPPLY EXPENSES		$104,785,293	$1,217,006
	TOTAL POWER PRODUCTION EXPENSES		$305,202,294	$40,369,259
	TRANSMISSION EXPENSES			
	OPERATION - TRANSMISSION EXP.			
560.000	Transmission Operation Suprv and Engrg	53-GROSS TRANSMISSION PLANT	$464,351	$290,594
561.000	Transmission Operation- Load Dispatch	53-GROSS TRANSMISSION PLANT	$5,055,491	$314,729
562.000	Transmission Operation- Station Expenses	53-GROSS TRANSMISSION PLANT	$217,088	$830
563.000	Transmission Operation-Overhead Line Expense	53-GROSS TRANSMISSION PLANT	$28,031	$1,028
564.000	Trans Oper-Underground Line Expense		$0	$0
565.000	Transmission of Electricity by Others	5-Transmission	$33,038,242	$0
565.000	Transmission of Electricity by Others (100% MO)	5-Transmission	$2,757,468	$0
565.100	Trans Op Trans Rider all KS 11200		$0	$0
566.000	Miscl. Transmission Expense	5-Transmission	$1,118,945	$443,803
567.000	Transmission Operation Rents	5-Transmission	$206,531	$0
575.000	Regional Transmission Operation		$0	$0
	TOTAL OPERATION - TRANSMISSION EXP.		$42,886,147	$1,050,984
	MAINTENANCE - TRANSMISSION EXP.			
568.000	Transmission Maint-Suprv and Engrg	53-GROSS TRANSMISSION PLANT	$132,422	$114,438
569.000	Transmission Maintenance of Structures	53-GROSS TRANSMISSION PLANT	$289,612	$229,952
569.010	Transmission Maint Computer Hardware	53-GROSS TRANSMISSION PLANT	$153	$0
569.020	Transmission Maint Computer Software	53-GROSS TRANSMISSION PLANT	$6,206	$0

569.030	Transmission Maint Communication Equip	53-GROSS TRANSMISSION PLANT	$743	$0
570.000	Transmission Maintenance of Station Equipment	53-GROSS TRANSMISSION PLANT	$418,883	$351,060
571.000	Transmission Maintenance of Overhead Lines	53-GROSS TRANSMISSION PLANT	$1,314,797	$70,228
572.000	Transmission Maint Underground Lines	53-GROSS TRANSMISSION PLANT	$154,816	$0
573.000	Trans Maintenance of Miscl. Trans Plant	53-GROSS TRANSMISSION PLANT	$7,543	$0
573.050	Transmission - Common Use	53-GROSS TRANSMISSION PLANT	-$2,820,173	$0
	TOTAL MAINTENANCE - TRANSMISSION EXP.		-$494,998	$765,678
	TOTAL TRANSMISSION EXPENSES		$42,391,149	$1,816,662
	DISTRIBUTION EXPENSES			
	OPERATION - DIST. EXPENSES			
580.000	Distribution Operation - Supr & Engineering	52-GROSS DISTRIBUTION PLANT	$926,252	$823,049
581.000	Distribution Operation - Load Dispatching	52-GROSS DISTRIBUTION PLANT	$594,308	$586,405
582.000	Distribution Operation - Station Expense	52-GROSS DISTRIBUTION PLANT	$104,554	$1,162
583.000	Dist Operation Overhead Line Expense	52-GROSS DISTRIBUTION PLANT	-$119,465	$376,050
584.000	Dist Operation Underground Line Expense	52-GROSS DISTRIBUTION PLANT	$580,839	$19,294
585.000	Distrb Oper Street Light & Signal Expense	52-GROSS DISTRIBUTION PLANT	$120,535	$0
586.000	Distribution Operation Meter Expense	52-GROSS DISTRIBUTION PLANT	$634,361	$729,806
587.000	Distrb Operation Customer Install Expense	17-Specific Cust	$2,845	$517
588.000	Dist Operation Miscl Distribution Expense	52-GROSS DISTRIBUTION PLANT	$4,700,402	$766,539
589.000	Distribution Operations Rents	6-Distribution	$219,016	$2,342
	TOTAL OPERATION - DIST. EXPENSES		$7,763,647	$3,305,164
	MAINTENANCE - DISTRIB. EXPENSES			
590.000	Distribution Maint-Suprv & Engineering	52-GROSS DISTRIBUTION PLANT	$51,992	$46,487
591.000	Distribution Maintenance-Structures	52-GROSS DISTRIBUTION PLANT	$312	$0
592.000	Distribution Maintenance-Station Equipment	52-GROSS DISTRIBUTION PLANT	$326,591	$187,431
592.020	Distribution Maint Computer Hardware	52-GROSS DISTRIBUTION PLANT	$2,569	$0
592.030	Distribution Maint Computer Software	52-GROSS DISTRIBUTION PLANT	$130,164	$0
592.040	Distribution Maint Communication Equip	52-GROSS DISTRIBUTION PLANT	$350	$0
593.000	Distribution Maintenance-Overhead lines	52-GROSS DISTRIBUTION PLANT	$19,475,129	$3,951,237
594.000	Distrib Maint-Maintenance Underground Lines	52-GROSS DISTRIBUTION PLANT	$570,071	$296,250
595.000	Distrib Maint-Maintenance Line Transformer	6-Distribution	$804,540	$449,776
596.000	Distrib Maint- Maintenance St Lights/Signal	17-Specific Cust	$92,702	$17,915
597.000	Distrib Maint-Maintenance of Meters	6-Distribution	$365,943	$292,321
598.000	Distrib Maint-Maint Miscl Distribution Plant.	6-Distribution	$1,086,358	$170,076
598.050	Distrib Maint-Common Use	6-Distribution	$2,042,666	$0
	TOTAL MAINTENANCE - DISTRIB. EXPENSES		$24,949,387	$5,411,493
	TOTAL DISTRIBUTION EXPENSES		$32,713,034	$8,716,657
	CUSTOMER ACCOUNTS EXPENSE			
901.000	Cust Acct-Suprv Meter Read Collection Miscl	6-Distribution	$825,541	$653,061
902.000	Cust Accts Meter Reading Expense	6-Distribution	$2,101,388	$130,434
903.000	Customer Accts Records and Collection	7-Admin & Overhead	$7,433,048	$3,870,834
903.000	Cust Accts-Interest on Deposits - MO	7-Admin & Overhead	$49,684	$0
903.000	Cust Accts-Interest on Deposits - KS		$0	$0
903.050	Customer Accts - Common Use	7-Admin & Overhead	-$22,323,914	$0
Account Number	**Description**	**Allocation Number**	**MO Adjusted Jurisdictional Non Labor**	**MO Adjusted Jurisdictional Labor**
903.050	Customer Accts - Common Use - 100% MO		$0	$0
904.000	Uncollectible Accounts-MO 100%	7-Admin & Overhead	$5,226,492	$0
904.000	Uncollectible Accts-KS 100%		$0	$0
905.000	Miscellaneous Customer Accts Expense	7-Admin & Overhead	$3,796,458	$1,756

Account Number	Description	Allocation Number	MO Adjusted Jurisdictional Non Labor	MO Adjusted Jurisdictional Labor
	TOTAL CUSTOMER ACCOUNTS EXPENSE		-$2,891,303	$4,656,085
	CUSTOMER SERVICE & INFO. EXP.			
907.000	Customer Service Suprv	7-Admin & Overhead	$150,521	$147,585
908.000	Customer Assistance Exp-100% MO	7-Admin & Overhead	$2,169,720	$1,189,844
908.000	Customer Assistance Exp-100% KS		$0	$0
908.000	Customer Assistance Expense-Allocated	7-Admin & Overhead	$289,143	$0
908.100	Cust Assist Exp - Exp Rider 343 MEIAA4		$0	$0
908.500	Customer Assistance Exp-MEEIA 100% MO	7-Admin & Overhead	$1,644,290	$0
908.500	Customer Assistance Exp - 100% KS		$0	$0
909.000	Information and Instruction Advertising - Alloc	7-Admin & Overhead	$312,607	$0
909.000	Inform & Instructional Advertising-MO	7-Admin & Overhead	$14,638	$0
909.000	Inform & Instructional Advertising-KS		$0	$0
910.000	Misc Cust Accts & Info Exp-Allocated	7-Admin & Overhead	$1,033,598	$539,244
910.000	Misc Cust Accts & Info Exp-100% MO	7-Admin & Overhead	$154,308	$0
910.000	Misc Cust Accts & Info Exp-100% KS		$0	$0
	TOTAL CUSTOMER SERVICE & INFO. EXP.		$5,768,825	$1,876,673
	SALES EXPENSES			
911.000	Sales Supervision	7-Admin & Overhead	$30,979	$29,481
912.000	Sales Demonstration and Selling	7-Admin & Overhead	$139,623	$125,288
913.000	Sales Advertising Expense		$0	$0
916.000	Miscellaneous Sales Expense	7-Admin & Overhead	$23,134	$21,962
	TOTAL SALES EXPENSES		$193,736	$176,731
	ADMIN. & GENERAL EXPENSES			
	OPERATION- ADMIN. & GENERAL EXP.			
920.000	Admin & Gen-Administrative Salaries	7-Admin & Overhead	$18,906,100	$15,370,738
921.000	Admin & General Off Supply	7-Admin & Overhead	$282,510	$4,377
922.000	Admin Expense Transfer Credit	7-Admin & Overhead	-$3,001,767	-$2,317,064
922.050	Admin Expense Transfer Credit - 100% MO		$0	$0
923.000	Outside Services Employed	7-Admin & Overhead	$6,423,404	$0
924.000	Property Insurance	56-GROSS PLANT LESS INCENTIVE COMP. CAPITALIZATION	$1,637,068	$635
925.000	Injuries and Damages	7-Admin & Overhead	$5,103,467	$568
926.000	Employee Pensions	64-PAYROLL - INC. STATEMENT	$1,555,263	$0
926.000	Employee OPEB		$0	$0
926.000	Other Miscellaneous Employee Benefits	64-PAYROLL - INC. STATEMENT	$16,422,468	$0
926.000	Employee Pensions - NSC		$0	$0
928.000	Reg Comm Exp - FERC Assment	7-Admin & Overhead	$1,042,339	$65,509
928.000	Reg Comm Exp - MPSC Assment - 100% MO	7-Admin & Overhead	$2,496,855	$0
928.000	Reg Comm Exp - KCC Assment - 100% KS		$0	$0
928.000	Reg Comm Exp - MO Proceeding 100% MO	7-Admin & Overhead	$180,335	$0
928.000	Reg Comm Exp - KS Proceeding 100% KS		$0	$0
928.000	Reg Comm Exp - FERC Proceeding - Alloc	7-Admin & Overhead	$101,067	$0
928.000	Reg Comm Exp - FERC Proceeding 100% to FERC		$0	$0
928.000	Miscellaneous Regulatory Expense - MO	7-Admin & Overhead	$58,272	$0
928.000	Miscellaneous Regulatory Expense - KS		$0	$0
928.000	Miscellaneous Regulatory Expense - Alloc	7-Admin & Overhead	$306,135	$0
929.000	Duplicate Charges-Credit	7-Admin & Overhead	-$1,374,980	$0
930.100	General Advertising Expense		$0	$0
930.200	Miscellaneous General Expense	7-Admin & Overhead	$2,077,093	-$58,324
931.000	Admin & General Expense-Rents-Allocated	7-Admin & Overhead	$726,758	$0
931.000	Asset Finance Lease - Multifunctional Printing Devices	7-Admin & Overhead	$140,062	$0

Account Number	Description	Allocation Number	MO Adjusted Jurisdictional Non Labor	MO Adjusted Jurisdictional Labor
933.000	Transportation Expense	7-Admin & Overhead	-$746,524	$0
	TOTAL OPERATION- ADMIN. & GENERAL EXP.		$52,335,925	$13,066,439
	MAINT., ADMIN. & GENERAL EXP.			
935.000	Maintenance Of General Plant	7-Admin & Overhead	$198,672	$6,528
935.010	General Maintenance Computer Hardware	7-Admin & Overhead	$549,903	$0
935.020	General Maintenance Computer Software	7-Admin & Overhead	$5,044,473	$0
935.030	General Maintenance Communication Equip	7-Admin & Overhead	$30,313	$0
935.050	General Maint-Common Use	7-Admin & Overhead	-$22,397,070	$0
	TOTAL MAINT., ADMIN. & GENERAL EXP.		-$16,573,709	$6,528
	TOTAL ADMIN. & GENERAL EXPENSES		$35,762,216	$13,072,967
	DEPRECIATION EXPENSE			
403.000	Depreciation Expense, Dep. Exp.	Class % from Depreciation Schedule	$199,927,302	See note(1)
403.010	Depreciation Exp Software Amrt	7-Admin & Overhead	$66,339,597	See note(1)
403.021	Depreciation Exp - KCC AFUDC - KS		$0	See note(1)
403.330	Other Depreciation - ARO		$0	See note(1)
	TOTAL DEPRECIATION EXPENSE		$266,266,899	$0
	AMORTIZATION EXPENSE			
404.000	Amortization of Limited Term Plant-Allocated	7-Admin & Overhead	$935,786	$0
405.001	Amort-lat & LC Reg Asset & Oth Non-Plant-MO	1-Production 1	$334,114	$0
405.001	Amort-lat & LC Reg Asset & Oth Non-Plant-KS	1-Production 1	$0	$0
405.010	Amortization of Other Plant-Allocated	7-Admin & Overhead	$3,446,522	$0
405.010	Amortization of Other Plant - MO	7-Admin & Overhead	$873,201	$0
405.010	Amortiz of Unrecov Dist Meters-KS		$0	$0
405.935	Amortization of Cloud Dev Cost	7-Admin & Overhead	$76,034	$0
	TOTAL AMORTIZATION EXPENSE		$5,665,657	$0
	REGULATORY DEBITS & CREDITS			
407.300	Regulatory Debits		$0	$0
407.300	Regulatory Debits - MO	7-Admin & Overhead	$2,196,469	$0
407.300	Regulatory Debits - KS		$0	$0
407.301	Pension & OPEB Exp Tracker - NSC RD - MO	64-PAYROLL - INC. STATEMENT	-$4,721,920	$0
407.301	Pension & OPEB Exp Tracker - NSC RD - KS		$0	$0
407.310	Regulatory Debit - Pension & OPEB - MO	64-PAYROLL - INC. STATEMENT	$9,266,051	$0
407.310	Regulatory Debit - Pension & OPEB - KS		$0	$0
407.320	TOTIT Rider Amortization - MO	56-GROSS PLANT LESS INCENTIVE COMP. CAPITALIZATION	$5,581,021	$0
407.320	TOTIT Rider Amortization - KS		$0	$0
407.358	Reg Asset Depreciation Related - PISA Amort - MO	10-PISA	$9,656,718	$0
407.358	Reg Asset Depreciation Related - PISA Amort - KS		$0	$0
407.400	Regulatory Credits - ARO		$0	$0
407.401	Regulatory Credits - MO	7-Admin & Overhead	-$4,437,789	$0
407.401	Regulatory Credits - KS		$0	$0
407.402	Pension & OPEB Exp Tracker - NSC RD - MO 2	64-PAYROLL - INC. STATEMENT	-$906,863	$0
407.402	Pension & OPEB Exp Tracker - NSC RD - KS 2		$0	$0
407.410	Regulatory Debit - Pension & OPEB - MO 2	64-PAYROLL - INC. STATEMENT	$495,569	$0
407.410	Regulatory Debit - Pension & OPEB - KS 2		$0	$0
407.420	TOTIT Rider Deferral - MO		$0	$0
407.420	TOTIT Rider Deferral - KS		$0	$0
407.426	Contra PISA Depr and Amort Exp - MO		$0	$0
407.427	Contra PISA Depr and Amort Exp - KS		$0	$0
407.491	Reg Credits Residential	7-Admin & Overhead	-$87,079	$0

407.492	Reg Credits Commercial	7-Admin & Overhead	-$61,535	$0
407.493	Reg Credits Industrial	7-Admin & Overhead	-$18,130	$0
407.494	Reg Credits Other	7-Admin & Overhead	-$1,752	$0
411.109	Accretion Exp-Asset Retirement Obligation		$0	$0
	TOTAL REGULATORY DEBITS & CREDITS		$16,960,760	$0
	OTHER OPERATING EXPENSES			
408.100	KS Property Tax RIDER		$0	$0
408.110	KCMO City Earnings Tax-100% MO	64-PAYROLL - INC. STATEMENT	$876,942	$0
408.112	TOTIT Misc Taxes	56-GROSS PLANT LESS INCENTIVE COMP. CAPITALIZATION	$23,013	$0
408.120	Property Tax	56-GROSS PLANT LESS INCENTIVE COMP. CAPITALIZATION	$76,279,901	$0
408.130	Gross Receipts Tax		$0	$0
408.140	Payroll Tax, incl Unemployment	64-PAYROLL - INC. STATEMENT	$5,521,306	$0
	TOTAL OTHER OPERATING EXPENSES		$82,701,162	$0
	TOTAL OPERATING & MAINT. EXPENSE		$790,734,429	$70,685,034
	NET INCOME BEFORE TAXES		$196,824,607	$70,685,034
	INCOME TAXES			
409.100	Current Income Taxes	50-NET RATE BASE	-$2,110,989	See note(1)
	TOTAL INCOME TAXES		-$2,110,989	$0
	DEFERRED INCOME TAXES			
0.000	Deferred Income Taxes - Def. Inc. Tax.	11-Deferred Tax	-$9,075,879	
0.000	Amortization of Deferred ITC	11-Deferred Tax	-$1,548,360	
0.000	Additional DIT	11-Deferred Tax	$2,105,590	See note(1)
0.000	Amortization COR Stip ER-2007-0291	55-GROSS P,T,D PLANT	$354,438	See note(1)
0.000	Amortization of Protected EDIT	11-Deferred Tax	-$6,581,374	See note(1)
0.000	Amortization of Unprotected EDIT	11-Deferred Tax	-$2,581,777	See note(1)
0.000	Amortization of IRA Tracker	11-Deferred Tax	-$7,077,279	See note(1)
	TOTAL DEFERRED INCOME TAXES		-$24,404,641	$0
	NET OPERATING INCOME		$223,340,237	$70,685,034

Description	MO Adjusted Jurisdictional	Allocation Number	Further Research	Large Load	Production 1	Production 2	Nuclear	Net Energy	Transmission	Distribution	Assign to Customers	Admin & Overhead	PISA	Deferred Tax	Retail Revs
Plant In Service	$7,472,819,039	from Plant	$0	$0	$2,417,307,451	$165,853,795	$1,159,939,571	$0	$492,692,778	$2,190,944,048	$49,337,971	$996,743,425	$0	$0	$0
Less Accumulated Depreciation Reserve	$3,153,239,511	from Reserve	$0	$0	$1,058,731,948	$127,152,908	$657,722,648	$0	$135,627,183	$598,785,328	$21,039,469	$554,180,027	$0	$0	$0
Net Plant In Service	$4,319,579,528	from Net Plant	$0	$0	$1,358,575,503	$38,700,887	$502,216,922	$0	$357,065,594	$1,592,158,721	$28,298,502	$442,563,398	$0	$0	$0
ADD TO NET PLANT IN SERVICE															
Gross Payroll - from CWC	$2,047,743	64-PAYROLL - INC. STATEMENT	$0	$0	$720,791	$9,353	$665,387	$28,726	$75,120	$331,136	$6,598	$210,631	$0	$0	$0
Accrued Vacation - from CWC	-$2,675,334	64-PAYROLL - INC. STATEMENT	$0	$0	-$941,699	-$12,220	-$869,314	-$37,529	-$98,143	-$432,623	-$8,621	-$275,186	$0	$0	$0
Employee Benefits - from CWC	$477,828	64-PAYROLL - INC. STATEMENT	$0	$0	$168,192	$2,183	$155,264	$6,703	$17,529	$77,269	$1,540	$49,150	$0	$0	$0
Purchased Coal & Freight - from CWC	$2,442,438	1-Production 1	$0	$0	$2,442,438	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Purchased Gas - from CWC	-$674,101	1-Production 1	$0	$0	-$674,101	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Purchased Oil - from CWC	$138,962	1-Production 1	$0	$0	$138,962	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Purchased Power - from CWC	-$3,787,476	18-Net Energy	$0	$0	$0	$0	$0	-$3,787,476	$0	$0	$0	$0	$0	$0	$0
Pension Expense - from CWC	-$79,000	64-PAYROLL - INC. STATEMENT	$0	$0	-$27,807	-$361	-$25,670	-$1,108	-$2,898	-$12,775	-$255	-$8,126	$0	$0	$0
Incentive Compensation - from CWC	-$2,808,750	64-PAYROLL - INC. STATEMENT	$0	$0	-$988,660	-$12,829	-$912,666	-$39,401	-$103,037	-$454,197	-$9,051	-$288,909	$0	$0	$0
Bad Debt Expense - from CWC	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PSC Assessment - from CWC	$372,201	7-Admin & Overhead	$0	$0	$0	$0	$0	$0	$0	$0	$0	$372,201	$0	$0	$0
Cash Vouchers - from CWC	-$4,059,950	7-Admin & Overhead	$0	$0	$0	$0	$0	$0	$0	$0	$0	-$4,059,950	$0	$0	$0
FICA - Employer Portion - from CWC	$161,857	64-PAYROLL - INC. STATEMENT	$0	$0	$56,973	$739	$52,593	$2,271	$5,938	$26,174	$522	$16,649	$0	$0	$0
Federal & State Unemployment Taxes - from CWC	-$3,223	64-PAYROLL - INC. STATEMENT	$0	$0	-$1,134	-$15	-$1,047	-$45	-$118	-$521	-$10	-$332	$0	$0	$0
MO Gross Receipts Taxes - 6%, 4%, and Other Cities - from CWC	-$7,702,720	7-Admin & Overhead	$0	$0	$0	$0	$0	$0	$0	$0	$0	-$7,702,720	$0	$0	$0
Property Tax - from CWC	-$42,731,676	56-GROSS PLANT LESS INCENTIVE COMP. CAPITALIZATION	$0	$0	-$13,822,842	-$948,399	-$6,632,860	$0	-$2,817,356	-$12,528,433	-$282,128	-$5,699,659	$0	$0	$0
Sales & Use Taxes - from CWC	$55,683	7-Admin & Overhead	$0	$0	$0	$0	$0	$0	$0	$0	$0	$55,683	$0	$0	$0
Contributions in Aid of Construction Amortization	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Materials and Supplies	$114,180,956	7-Admin & Overhead	$0	$0	$0	$0	$0	$0	$0	$0	$0	$114,180,956	$0	$0	$0
Prepayments	$12,004,271	7-Admin & Overhead	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,004,271	$0	$0	$0
Fuel Inventory-Oil	$7,964,558	1-Production 1	$0	$0	$7,964,558	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Fuel Inventory-Coal	$20,439,393	1-Production 1	$0	$0	$20,439,393	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Fuel Inventory-Nuclear	$48,494,153	4-Nuclear	$0	$0	$0	$0	$48,494,153	$0	$0	$0	$0	$0	$0	$0	$0
Fuel Inventory-Lime and Limestone	$236,222	1-Production 1	$0	$0	$236,222	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Fuel Inventory-Amonia	$73,368	1-Production 1	$0	$0	$73,368	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Fuel Inventory-Powder Activated Carbon	$47,864	1-Production 1	$0	$0	$47,864	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PAYS	$353,571	7-Admin & Overhead	$0	$0	$0	$0	$0	$0	$0	$0	$0	$353,571	$0	$0	$0
PISA Deferrals	$183,471,055	10-PISA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$183,471,055	$0	$0
Property Tax Tracker Regulatory Asset	$26,107,960	56-GROSS PLANT LESS INCENTIVE COMP. CAPITALIZATION	$0	$0	$8,445,403	$579,447	$4,052,508	$0	$1,721,332	$7,654,552	$172,373	$3,482,345	$0	$0	$0
Iatan II Regulatory Asset	$11,040,710	1-Production 1	$0	$0	$11,040,710	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL ADD TO NET PLANT IN SERVICE	$365,588,563		$0	$0	$35,318,631	-$382,102	$44,978,348	-$3,827,859	-$1,201,633	-$5,339,418	-$119,032	$112,690,575	$183,471,055	$0	$0

Description	MO Adjusted Jurisdictional	Allocation Number	Further Research	Large Load	Production 1	Production 2	Nuclear	Net Energy	Transmission	Distribution	Assign to Customers	Admin & Overhead	PISA	Deferred Tax	Retail Revs
SUBTRACT FROM NET PLANT															
Federal Tax Offset	$117,621	50-NET RATE BASE	$0	$0	$42,677	$1,173	$16,585	-$145	$11,130	$49,573	$879	$15,749	$5,823	-$25,823	$0
State Tax Offset	$320,723	50-NET RATE BASE	$0	$0	$116,371	$3,198	$45,223	-$394	$30,347	$135,173	$2,396	$42,945	$15,879	-$70,413	$0
City Tax Offset	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Interest Expense Offset	$15,201,261	7-Admin & Overhead	$0	$0	$0	$0	$0	$0	$0	$0	$0	$15,201,261	$0	$0	$0
Contributions in Aid of Construction	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Retired Plant in Service	$43,865,171	55-GROSS P,T,D PLANT	$0	$0	$16,429,789	$1,128,294	$7,765,807	$0	$3,306,747	$14,904,870	$329,664	$0	$0	$0	$0
Customer Deposits	$641,086	6-Distribution	$0	$0	$0	$0	$0	$0	$0	$641,086	$0	$0	$0	$0	$0
Customer Advances for Construction	$1,009,453	6-Distribution	$0	$0	$0	$0	$0	$0	$0	$1,009,453	$0	$0	$0	$0	$0
DSM Programs	$2,864,388	7-Admin & Overhead	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,864,388	$0	$0	$0
Income Eligible Weatherization Program	$248,016	7-Admin & Overhead	$0	$0	$0	$0	$0	$0	$0	$0	$0	$248,016	$0	$0	$0
IRA Tracker	$35,386,396	7-Admin & Overhead	$0	$0	$0	$0	$0	$0	$0	$0	$0	$35,386,396	$0	$0	$0
Deferred Taxes	$643,914,500	11-Deferred Tax	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$643,914,500	$0
Protected EADIT	$140,434,213	11-Deferred Tax	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$140,434,213	$0
Unprotected EADIT	$29,244,785	11-Deferred Tax	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$29,244,785	$0
Other regulatory liability (SO2 Emission Allowances) 21 year May 2010 to April 2031	$14,553,224	1-Production 1	$0	$0	$14,553,224	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FAS 87 Pension Tracker	$49,585,117	64-PAYROLL - INC. STATEMENT	$0	$0	$17,453,610	$226,486	$16,112,019	$695,576	$1,819,002	$8,018,307	$159,778	$5,100,340	$0	$0	$0
FAS 106 OPEB Tracker	$2,419,402	64-PAYROLL - INC. STATEMENT	$0	$0	$851,612	$11,051	$786,152	$33,939	$88,754	$391,237	$7,796	$248,860	$0	$0	$0
TOTAL SUBTRACT FROM NET PLANT	$979,805,356		$0	$0	$49,447,283	$1,370,202	$24,725,786	$728,976	$5,255,980	$25,149,699	$500,513	$59,107,955	$21,702	$813,497,262	$0
NET RATE BASE ADJUSTMENT	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Description	MO Adjusted Jurisdictional	Allocation Number	Further Research	Large Load	Production 1	Production 2	Nuclear	Net Energy	Transmission	Distribution	Assign to Customers	Admin & Overhead	PISA	Deferred Tax	Retail Revs
TOTAL RATE BASE	$3,705,362,735		$0	$0	$1,344,446,851	$36,948,583	$522,469,484	-$4,556,835	$350,607,981	$1,561,669,604	$27,678,957	$496,146,018	$183,449,353	-$813,497,262	$0
TOTAL RETURN ON RATE BASE	$267,749,511	Rate of Return used is 0.07226	$0	$0	$97,149,729	$2,669,905	$37,753,645	-$329,277	$25,334,933	$112,846,246	$2,000,081	$35,851,511	$13,256,050	-$58,783,312	$0
TOTAL OPERATING & MAINT. EXPENSE	$790,734,429	from Income Statement	$0	$0	$269,224,077	$6,600,637	$99,961,687	$102,544,012	$63,619,470	$120,264,708	$3,991,180	$114,871,945	$9,656,718	$0	$0
TOTAL INCOME TAXES	-$2,110,989	from Income Statement	$0	$0	-$765,947	-$21,050	-$297,657	$2,596	-$199,746	-$889,702	-$15,769	-$282,660	-$104,513	$463,459	$0
TOTAL DEFERRED INCOME TAXES	-$24,404,641	from Income Statement	$0	$0	$132,755	$9,117	$62,749	$0	$26,719	$120,434	$2,664	$0	$0	-$24,759,079	$0
ADDITIONAL CURRENT TAX REQUIRED	$13,466,164	50-NET RATE BASE	$0	$0	$4,886,038	$134,280	$1,898,778	-$16,561	$1,274,192	$5,675,476	$100,592	$1,803,112	$666,698	-$2,956,441	$0
NET EXPENSE ADJUSTMENT	-$23,026,843	8-Large Load	$0	-$51,026,843	$0	$0	$0	$0	$0	$0	$0	$28,000,000	$0	$0	$0
TOTAL EXPENSES	$754,658,120		$0	-$51,026,843	$273,476,923	$6,722,984	$101,625,557	$102,530,047	$64,720,635	$125,170,916	$4,078,667	$144,392,397	$10,218,903	-$27,252,061	$0
TOTAL REVENUE (RATE REVENUE + OTHER REVENUE)	$987,559,036		$0	$0	$6,105,530	$404,478	$2,861,835	$54,757,188	$13,476,788	-$2	$0	$11,294,776	$0	$0	$898,658,443
CLASS COST OF SERVICE	$1,022,407,631		$0	-$51,026,843	$370,626,652	$9,392,889	$139,379,202	$102,200,770	$90,055,568	$238,017,162	$6,078,748	$180,243,908	$23,474,953	-$86,035,373	$0
OTHER REVENUE	$20,743,636		$0	$0	$12,124	$0	$0	$2,514,981	$13,476,788	-$2	$0	$4,739,745	$0	$0	$0
CLASS COST OF SERVICE LI	$1,001,663,995		$0	-$51,026,843	$370,614,528	$9,392,889	$139,379,202	$99,685,789	$76,578,780	$238,017,164	$6,078,748	$175,504,163	$23,474,953	-$86,035,373	$0
RATE REVENUE	$898,658,443		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$898,658,443
CURRENT RATE OF RETURN	6.2855%		0.0000%	0.0000%	-19.8871%	-17.1008%	-18.9033%	1048.3781%	-14.6157%	-8.0152%	-14.7356%	-26.8263%	-5.5704%	-3.3500%	0.0000%
CURRENT RATE OF RETURN	3.8863%		0.0000%	0.0000%	-20.3412%	-18.1955%	-19.4510%	2250.0276%	-18.4595%	-8.0152%	-14.7356%	-29.1028%	-5.5704%	-3.3500%	0.0000%
CLASS TOTAL REVENUE ABOVE OR BELOW TOTAL COST OF SERVICE	-$34,848,595		$0	$51,026,843	-$364,521,122	-$8,988,411	-$136,517,367	-$47,443,582	-$76,578,780	-$238,017,164	-$6,078,748	-$168,949,132	-$23,474,953	$86,035,373	$898,658,443
% CHANGE NEEDED TO BRING CLASS RATE REVENUE EQUAL TO CLASS COST OF SERVICE	3.8778%		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	-100.0000%

% UNDER OR OVER-RECOVERY	-3.4791%		0.0000%	-100.0000%	-98.3559%	-95.6938%	-97.9467%	-47.5931%	-100.0000%	-100.0000%	-100.0000%	-96.2650%	-100.0000%	-100.0000%	0.0000%

Summer	12:00 AM	1:00 AM	2:00 AM	3:00 AM	4:00 AM	5:00 AM	6:00 AM	7:00 AM	8:00 AM	9:00 AM	10:00 AM	11:00 AM	12:00 PM	1:00 PM	2:00 PM	3:00 PM	4:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	9:00 PM	10:00 PM	11:00 PM
Demand Period	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Energy Price Period	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	2	2	2	2	2	2	1	1	1
Peak																8	4	4						
System Load	75%	71%	67%	63%	61%	61%	62%	64%	67%	71%	76%	81%	85%	90%	94%	97%	99%	100%	100%	98%	95%	91%	87%	81%
Energy Prices	28%	25%	21%	19%	19%	21%	25%	29%	35%	45%	50%	55%	63%	71%	80%	87%	96%	100%	93%	83%	69%	57%	47%	37%

Non Summer	12:00 AM	1:00 AM	2:00 AM	3:00 AM	4:00 AM	5:00 AM	6:00 AM	7:00 AM	8:00 AM	9:00 AM	10:00 AM	11:00 AM	12:00 PM	1:00 PM	2:00 PM	3:00 PM	4:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	9:00 PM	10:00 PM	11:00 PM
Demand Period	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Energy Price Period	0	0	0	0	0	0	1	2	2	2	2	2	1	1	1	2	2	2	2	2	2	1	1	1
Non Summer Peak								11	3	1	1					1	6	4	4	-	1			
Winter Peak								9	1	1	1					-	-	1	3	-	-			
Non Summer Load	84%	82%	81%	80%	80%	81%	83%	87%	89%	90%	90%	91%	90%	91%	91%	91%	91%	92%	93%	94%	93%	92%	90%	87%
N.S. Energy Price	32%	39%	36%	37%	38%	42%	53%	65%	70%	74%	81%	75%	69%	66%	64%	63%	64%	69%	78%	76%	70%	64%	55%	46%
Winter Load	93%	92%	91%	91%	91%	92%	94%	98%	100%	100%	99%	98%	95%	97%	96%	96%	96%	96%	98%	99%	99%	98%	97%	95%
Winter Energy Price	43%	59%	56%	59%	59%	63%	76%	91%	95%	96%	100%	94%	84%	79%	74%	69%	69%	74%	88%	88%	83%	79%	70%	61%

NSI	12:00 AM	1:00 AM	2:00 AM	3:00 AM	4:00 AM	5:00 AM	6:00 AM	7:00 AM	8:00 AM	9:00 AM	10:00 AM	11:00 AM	12:00 PM	1:00 PM	2:00 PM	3:00 PM	4:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	9:00 PM	10:00 PM	11:00 PM
NonSummer	395,048	386,938	380,506	376,622	375,718	379,690	390,791	407,873	420,390	424,211	425,082	426,486	421,709	427,686	427,980	428,048	429,922	432,751	439,526	439,726	436,114	432,244	423,781	409,582
True Winter	217,762	216,194	214,643	213,902	214,397	216,846	222,128	229,929	235,003	235,071	233,206	231,334	224,380	227,954	226,440	224,990	224,720	226,433	230,994	232,804	232,101	230,732	227,400	222,498
Summer	228,922	214,975	202,522	193,161	187,150	185,221	189,211	196,010	205,530	217,382	230,783	245,925	260,347	273,857	285,787	294,736	302,105	303,921	304,541	298,606	287,872	277,248	265,953	248,118

Hourly Avg NSI	12:00 AM	1:00 AM	2:00 AM	3:00 AM	4:00 AM	5:00 AM	6:00 AM	7:00 AM	8:00 AM	9:00 AM	10:00 AM	11:00 AM	12:00 PM	1:00 PM	2:00 PM	3:00 PM	4:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	9:00 PM	10:00 PM	11:00 PM
NonSummer	49,381	48,367	47,563	47,078	46,965	47,461	48,849	50,984	52,549	53,026	53,135	53,311	52,714	53,461	53,498	53,506	53,740	54,094	54,941	54,966	54,514	54,030	52,973	51,198
True Winter	54,440	54,048	53,661	53,476	53,599	54,212	55,532	57,482	58,751	58,768	58,301	57,833	56,095	56,988	56,610	56,248	56,180	56,608	57,749	58,201	58,025	57,683	56,850	55,624
Summer	57,231	53,744	50,630	48,290	46,788	46,305	47,303	49,003	51,382	54,346	57,696	61,481	65,087	68,464	71,447	73,684	75,526	75,980	76,135	74,651	71,968	69,312	66,488	62,030

SPP Peak Counts	12:00 AM	1:00 AM	2:00 AM	3:00 AM	4:00 AM	5:00 AM	6:00 AM	7:00 AM	8:00 AM	9:00 AM	10:00 AM	11:00 AM	12:00 PM	1:00 PM	2:00 PM	3:00 PM	4:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	9:00 PM	10:00 PM	11:00 PM
NonSummer	-	-	-	-	-	-	-	11	3	1	1	-	-	-	-	1	6	4	4	-	1	-	-	-
True Winter	-	-	-	-	-	-	-	9	1	1	1	-	-	-	-	-	-	1	3	-	-	-	-	-
Summer	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	4	4	-	-	-	-	-	-

LMP	12:00 AM	1:00 AM	2:00 AM	3:00 AM	4:00 AM	5:00 AM	6:00 AM	7:00 AM	8:00 AM	9:00 AM	10:00 AM	11:00 AM	12:00 PM	1:00 PM	2:00 PM	3:00 PM	4:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	9:00 PM	10:00 PM	11:00 PM
NonSummer	$ 20.97	$ 25.93	$ 23.89	$ 24.16	$ 24.77	$ 27.48	$ 34.59	$ 42.82	$ 46.14	$ 48.90	$ 52.96	$ 49.57	$ 45.22	$ 43.52	$ 42.33	$ 41.16	$ 41.76	$ 45.28	$ 51.03	$ 49.64	$ 46.03	$ 42.19	$ 35.88	$ 30.02
True Winter	$ 28.30	$ 38.92	$ 37.10	$ 38.54	$ 38.99	$ 41.68	$ 50.23	$ 59.53	$ 62.52	$ 62.80	$ 65.71	$ 62.05	$ 55.50	$ 51.95	$ 48.50	$ 45.58	$ 45.15	$ 48.95	$ 57.84	$ 57.88	$ 54.66	$ 51.73	$ 46.14	$ 40.24
Summer	$ 19.73	$ 17.71	$ 15.14	$ 13.89	$ 13.68	$ 14.99	$ 17.87	$ 20.42	$ 24.92	$ 31.90	$ 35.94	$ 39.51	$ 44.88	$ 50.70	$ 57.15	$ 62.36	$ 68.26	$ 71.34	$ 66.45	$ 58.99	$ 49.07	$ 40.36	$ 33.36	$ 26.16

Evergy Missouri Metro
Case Name: 2026 Evergy MO Metro Rate Case
Case Number: ER-2026-0143

Requestor Mastrogiannis Brooke -
Response Provided July 08, 2026

Question:0447

Please explain if future Conditional High Impact Large Load Service ("CHILLS") customers will be responsible for the charges under SPP Schedules 8 and 11. If future CHILLS customers will not be responsible for the charges under SPP Schedules 8 and 11, how does EMM plan to recover those charges? Data request submitted by Brooke Mastrogiannis (Brooke.Mastrogiannis@psc.mo.gov

RESPONSE: (do not edit or delete this line or anything above this)

Confidentiality: PUBLIC
Statement: This response is Public. No Confidential Statement is needed.

Response:

Conditional High Impact Large Load Service ("CHILLS") is addressed under the Southwest Power Pool ("SPP") Open Access Transmission Tariff as a distinct non-firm, conditional transmission service. CHILLS is not standard firm Network Integration Transmission Service and is not itself traditional Schedule 8 service. Rather, SPP established a separate Schedule 15 specifically applicable to CHILLS service.

Under the CHILLS framework, customers are billed under Schedule 15 using a zonal rate based on the hourly rate applicable to non-firm point-to-point transmission service for the applicable hour of CHILLS usage and the zone in which the load is located. In addition, CHILLS customers are responsible for applicable Schedule 11 base plan zonal and region-wide charges, as well as applicable ancillary service costs, wholesale distribution charges, and real power losses.

Further, if a CHILLS customer exceeds its reserved CHILLS capacity at a point of delivery, the SPP tariff provides for a penalty charge equal to 100 percent of the non-firm point-to-point transmission service charges under Schedules 8 and 11 for the period during which the excess service was used and for the amount in excess of the reserved capacity.

Accordingly, future CHILLS customers, or the applicable Transmission Customer or Network Customer serving such load, would be responsible for transmission-related charges under the SPP Open Access Transmission Tariff through the Schedule 15 rate structure, including associated Schedule 11 charges, and would also be subject to Schedule 8 and Schedule 11-based charges in the event of usage exceeding the reserved CHILLS capacity.

Because CHILLS is a new SPP transmission service and is not currently reflected as a specific service construct in Evergy Missouri Metro's retail tariffs, Evergy's retail billing treatment for any future Missouri retail customer taking service supported by CHILLS would need to be consistent with the applicable SPP OATT requirements, Evergy Missouri Metro's Commission-approved retail tariffs, and any applicable Commission-approved service agreement or other regulatory approval required at the time.

Information provided by: Derek Brown, Large Customer Strategy and Planning Director

Attachment(s):

Missouri Verification:
I have read the Information Request and answer thereto and find answer to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request(s).

Signature /s/ *Brad Lutz*
Director Regulatory Affairs