Exhibit No.: 302
Issues: Cost of Service/Revenue Allocation/Rate Design
Witness: Jessica A. York
Type of Exhibit: Direct Testimony
Sponsoring Party: Midwest Energy Consumers Group
Case No.: ER-2026-0143
Date Testimony Prepared: July 14, 2026

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**

Direct Testimony and Schedules of

Jessica A. York

On behalf of

Midwest Energy Consumers Group

July 14, 2026

BRUBAKER & ASSOCIATES, INC.

Project 12018

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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STATE OF MISSOURI)
) **SS**
COUNTY OF ST. LOUIS)

Affidavit of Jessica A. York

Jessica A. York, being first duly sworn, on her oath states:

1. My name is Jessica A. York. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by Midwest Energy Consumers Group in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes are my direct testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2026-0143.

3. I hereby swear and affirm that the testimony and schedules are true and correct and that they show the matters and things that they purport to show.

Jessica A. York

Subscribed and sworn to before me this 14th day of July, 2026.

SHELBY HUGHES
Notary Public - Notary Seal
STATE OF MISSOURI
Franklin County
My Commission Expires: May 21, 2030
Commission # 26560408

Notary Public

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Direct Testimony of Jessica A. York

I. INTRODUCTION

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jessica A. York. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of Midwest Energy Consumers Group ("MECG"). MECG represents the interests of large commercial and industrial customers taking service from Evergy Missouri Metro primarily on its Large General Service ("LGS") and Large Power Service ("LPS") rate schedules. These customers are energy-intensive,

compete in regional and national markets, and are very sensitive to electric rate levels and structures.

Q WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A The purpose of my Direct Testimony is to evaluate Evergy Missouri Metro's ("Evergy" or the "Company") Class Cost of Service Study ("CCOSS"), to offer recommendations regarding customer class revenue apportionment, and to address rate design issues affecting the Large General Service ("LGS") and Large Power Service ("LPS") customer classes. Specifically, my testimony addresses: (1) the Company's production and distribution cost allocation methodologies, including the single-phase and three-phase split of distribution costs; (2) the movement of class revenues toward cost of service rather than an equal percent increase approach; (3) rate design changes proposed by the Company, including the optional Time-of-Use ("TOU") rate, demand threshold changes, billing demand measurement changes, elimination of the Hours Use rate structure, and the elimination of the Time Related Pricing ("TRP") rate; and (4) appropriate demand charge levels for the LGS and LPS classes consistent with cost of service guidance.

II. SUMMARY

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A My conclusions and recommendations are as follows:

1. I support the Company's embedded cost of service methodology, including its use of the Average and Excess Demand ("A&E") method, incorporating a Four Coincident Peak ("4CP") component, for production plant costs and its newly implemented single-phase and three-phase split of primary distribution costs.

2. The Company's CCOSS results demonstrate that, at present rates, the LGS and LPS classes produce rates of return of 10.08% and 14.73%, respectively,

against a system average of 4.90% under the Current Class Structure CCOSS, and 9.85% and 15.89%, respectively, under the Proposed Class Structure CCOSS. The results clearly indicate that the LGS and LPS classes are paying rates materially over the utility's costs to provide their service, while the utility is significantly under-collecting from Residential and Clean Charge Network ("CCN" or "Electric Vehicle") classes. The Company has proposed an equal percent increase across all classes. I disagree with the Company's approach and recommend class-specific multipliers relative to the system average increase, which result in greater movement toward cost of service for all classes than proposed by the Company. The specific recommendation is presented in Section IV of my testimony.

3. Regarding Rate Design:

   a. I do not oppose the Company's proposed demand thresholds.

   b. I do not oppose the Company's proposed transition from 30-minute to 15-minute billing demand measurement.

   c. I oppose the elimination of the Hours Use rate structure at this point in time.

   d. I support the Company's Optional TOU rate for C&I classes, but the voltage- differentiated rates should appropriately reflect that higher voltage customers are less costly to serve. In addition, demand and energy charges should recover appropriate levels of fixed and variable costs, respectively.

   e. I recommend that the Commission address the mitigation needed for customers currently on rate schedules being eliminated, particularly TRP customers, and I express MECG's willingness to work with the Company and other parties on appropriate mitigation approaches.

III. CLASS COST OF SERVICE STUDY

III.A. Overview and Methodology

Q WHAT IS THE PURPOSE OF THE CLASS COST OF SERVICE STUDY IN THIS PROCEEDING?

A The CCOSS is the foundational analytical tool for establishing just and reasonable rates. It serves three related functions: (1) it allocates the Company's total revenue requirement among customer classes based on each class's cost responsibility; (2) it identifies the degree to which each class is currently over- or under-recovering its costs at present rates; and (3) it informs rate design by indicating appropriate levels for

demand, energy, and customer charges. A well-constructed CCOSS promotes economic efficiency by aligning rates with cost-causation, ensuring that no class subsidizes another and that price signals encourage efficient use of the electric system.

Q DOES THE COMPANY'S CCOSS FOLLOW SOUND COST-CAUSATION PRINCIPLES?

A Yes. The Company's CCOSS uses the embedded cost of service framework, which is the widely accepted approach in Missouri and in utility ratemaking generally. The Company uses the 4CP A&E demand allocation method for production plant costs, and it has incorporated a new single-phase and three-phase split of primary distribution costs. Both of these choices are consistent with cost-causation and represent improvements or continuations of prior methodology. I support these approaches.

III.B. Production Cost Allocation

Q PLEASE DESCRIBE THE 4CP A&E METHOD AND WHY YOU SUPPORT IT FOR PRODUCTION COST ALLOCATION.

A The A&E method is one of two predominant methods of production capacity cost allocation in the industry. The other is the coincident peak method, which utilizes the demands of customer classes occurring at the time of the system peak or peaks selected for allocation. In the case of Evergy, this would be one or more peaks occurring during the summer.

Unlike the coincident peak method which relies strictly on a class' relative contribution to one or more utility peaks, the A&E method is one of a family of methods that incorporates a consideration of both the maximum rate of use (demand) and the duration of use (energy). A&E makes a conceptual split of the system into an "average"

component and an "excess" component. The "average" demand is simply the total kWh usage divided by the total number of hours in the year. This is the amount of capacity that would be required to produce the energy if it were taken at the same demand rate each hour. The system "excess" demand is the difference between the system peak demand and the system average demand.

Under the A&E method, the average demand is allocated to classes in proportion to their average demand (energy usage). The difference between the system average demand and the system peak(s) is then allocated to customer classes on the basis of a measure that represents their "peaking" or variability in usage.[1]

Q IS THE A&E METHOD CONSISTENT WITH ESTABLISHED UTILITY RATEMAKING PRACTICE IN MISSOURI?

A Yes. The A&E method is used by Ameren Missouri and has been used by Evergy in prior Missouri rate cases. It has been recognized as a reasonable and appropriate production cost allocation methodology by the Missouri Public Service Commission. However, the method identified in the National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual ("NARUC Manual") appears to encourage the use of Non-Coincident Peak ("NCP") demands,[2] rather than CP demands as used by Evergy. In addition, other Missouri utilities such as Ameren use a 4NCP measure of demand rather than 4CP in the development of the A&E allocator as Evergy has done.

[1] NARUC Electric Utility Cost Allocation Manual, 1992, at 81.
[2] January 1992 NARUC Manual at 49-52.

Q HAVE YOU COMPARED THE 4CP A&E ALLOCATOR AND ASSOCIATED CCOSS RESULTS TO A 4NCP A&E APPROACH?

A Yes. I recalculated the A&E allocator using class NCP demands for the four highest system peak load months of June through September and compared that to Evergy's 4CP A&E allocator. The comparison is shown in Table JAY-1.

TABLE JAY-1

4CP A&E vs. 4NCP A&E Allocator

Line	Description	Current Class Structure 4CP A&E[1]	Current Class Structure 4NCP A&E[2]	Proposed Class Structure 4CP A&E[3]	Proposed Class Structure 4NCP A&E[4]
		(1)	(2)	(3)	(4)
1	Residential	46.26%	44.81%	46.26%	44.81%
2	Small General Service	8.31%	7.89%	5.32%	5.03%
3	Medium General Service	13.52%	13.33%	14.03%	13.71%
4	Large General Service	18.60%	19.04%	18.76%	19.15%
5	Large Power Service	12.92%	13.76%	15.25%	16.11%
6	Lighting	0.32%	1.11%	0.32%	1.11%
7	CCN	0.06%	0.07%	0.06%	0.07%
8	Total	100.00%	100.00%	100.00%	100.00%

Sources:

[1] From Evergy's confidential external allocation factor workpaper, current class structure.

[2] Calculated using Evergy's confidential external allocation factor workpaper, with the current class structure.

[3] From Evergy's confidential external allocation factor workpaper, proposed class structure.

[4] Calculated using Evergy's confidential external allocation factor workpaper, with the proposed class structure.

As shown in Table JAY-1, the allocation factors resulting from both methods are similar for the major rate classes. The CCOSS results by class are also similar under both approaches as shown in Table JAY-2. Additional details are included in Schedule JAY-1 (current class structure) and Schedule JAY-2 (proposed class structure).

TABLE JAY-2

Class Rate of Return at Present Rates

Line	Description	Current Class Structure 4CP A&E[1]	Current Class Structure 4NCP A&E[2]	Proposed Class Structure 4CP A&E[3]	Proposed Class Structure 4NCP A&E[4]
		(1)	(2)	(3)	(4)
1	Residential	0.51%	0.78%	0.51%	0.77%
2	Small General Service	7.92%	8.62%	5.96%	6.58%
3	Medium General Service	8.43%	8.67%	7.57%	7.94%
4	Large General Service	10.08%	9.66%	9.85%	9.48%
5	Large Power Service	14.73%	13.21%	15.89%	14.52%
6	Lighting	3.73%	-2.65%	3.73%	-2.66%
7	CCN	-39.30%	-38.18%	-39.27%	-38.14%
8	Total	4.90%	4.90%	4.90%	4.90%

Sources:

[1] Graham Jaynes' Direct Testimony, Table 8.

[2] Calculated using Evergy's confidential CCOSS model, with the current class structure.

[3] Graham Jaynes' Direct Testimony, Table 9.

[4] Calculated using Evergy's confidential CCOSS model, with the proposed class structure.

Q WHY IS IT REASONABLE TO CALCULATE THE EXCESS DEMAND COMPONENT OF THE A&E ALLOCATOR ON A 4CP BASIS?

A Utility system load characteristics are an important factor in determining the specific method which should be employed to allocate fixed or demand-related costs on a utility system. The most important characteristic is the annual load pattern of the utility.

The annual load pattern of Evergy shows that summer peaks dominate the system in the test year.[3] Specifically, the four highest peaks occurred in June through September, with the highest in July. The June and August peaks were within 10% of

[3]Evergy's confidential external allocation factor workpapers.

the July peak, while the September peak was within 15% of the annual peak.[4] The monthly peaks occurring in the other months were substantially lower.

The specific production capacity cost allocation method should be consistent with the principle of cost causation. As such, a 4CP A&E approach is an appropriate method to reflect these characteristics.

III.C Transmission Cost Allocation

Q HOW DOES THE COMPANY ALLOCATE TRANSMISSION COSTS IN ITS CCOSS?

A The Company's method for allocating transmission plant is consistent with that of production plant.[5] I do not oppose the Company's proposal for the allocation of transmission plant to follow production plant.

III.D. Distribution Cost Allocation

Q PLEASE DESCRIBE THE COMPANY'S NEW SINGLE-PHASE AND THREE-PHASE DISTRIBUTION COST ALLOCATION.

A In this case, the Company has disaggregated its primary distribution system costs between single-phase and three-phase configurations.[6] This represents a methodological refinement that the Company has committed to as part of its ongoing CCOSS development.[7] The foundation for this refinement is the factual observation, confirmed in the prior Evergy Missouri West case through a discovery response,[8] that single-phase primary circuits are used almost exclusively to serve secondary voltage

[4] *Id.*
[5] Graham Jaynes' Direct Testimony at 37, lines 17-20.
[6] *Id.* at 45, lines 5-8.
[7] *Id.* at 43, lines 15-17.
[8] Case No. ER-2024-0189. Direct Testimony of Kavita Maini, Attachment 1.

customers, while primary voltage customers are served through three-phase circuit configurations. As a result, allocating single-phase circuit costs to primary voltage customers, which is what happens under an undifferentiated primary distribution allocation, over-allocates costs to primary voltage customers who do not receive service over single-phase infrastructure.

Q DO YOU SUPPORT THE COMPANY'S SINGLE-PHASE AND THREE-PHASE SPLIT?

A Yes. It directly addresses a cost-causation deficiency that MECG identified in the prior Evergy Missouri West rate case (Case No. ER-2024-0189). In that case, MECG recommended that the Company take steps to delineate between single-phase and three-phase distribution configurations in order to properly allocate costs to secondary and primary voltage customers, noting that failure to do so results in allocating single-phase circuit costs to primary customers who are not served by single-phase infrastructure. The Company has now done what MECG recommended. This is a meaningful improvement to the CCOSS methodology that more accurately reflects cost causation.

Q DOES THIS CHANGE AFFECT THE CCOSS RESULTS FOR THE LGS AND LPS CLASSES?

A Yes. The Company's testimony confirms that incorporating the single-phase and three-phase allocator reduces the cost responsibility of primary voltage customers in the LGS and LPS classes, which more appropriately aligns their cost responsibility with the facilities used to serve them. While the LGS and LPS classes still show a materially above-system average rate of return at present rates even after this refinement, the

directional effect of this change is appropriate and further demonstrates that previous CCOSS models have overstated the cost responsibility of primary voltage LGS and LPS customers.

IV. REVENUE APPORTIONMENT

Q WHAT DOES THE COMPANY'S CCOSS SHOW REGARDING CLASS RATES OF RETURN AT CURRENT RATES?

A The Company's CCOSS results at current rates are summarized in Table JAY-3 and are striking.

TABLE JAY-3

Class Rate of Return at Present Rates

Line	Description	Current Class Structure[1]	Proposed Class Structure[2]
		(1)	(2)
1	Residential	0.51%	0.51%
2	Small General Service	7.92%	5.96%
3	Medium General Service	8.43%	7.57%
4	Large General Service	10.08%	9.85%
5	Large Power Service	14.73%	15.89%
6	Lighting	3.73%	3.73%
7	CCN	-39.30%	-39.27%
8	Total	4.90%	4.90%

Sources:

[1] Graham Jaynes' Direct Testimony, Table 8.

[2] Graham Jaynes' Direct Testimony, Table 9.

Under the Current Class Structure CCOSS, with an overall jurisdictional rate of return of 4.90%, the individual class rates of return vary dramatically. The LPS class produces a rate of return of 14.73%, or three times the system average. The LGS class

produces 10.08%, which is more than twice the system average. The MGS class produces 8.43% and the SGS class produces 7.92%. Meanwhile, the Residential class contributes only 0.51%, a fraction of the system average, and the CCN class produces a deeply subsidized negative rate of return of 39.30%. Under the Proposed Class Structure CCOSS, the LPS rate of return at current rates rises further to 15.89%, while the LGS rate of return at current rates is 9.85%.

Q WHAT DOES THE COMPANY'S CCOSS SHOW REGARDING THE INCREASES NEEDED FOR EACH CLASS TO REACH COST OF SERVICE AT ITS PROPOSED REVENUE REQUIREMENT?

A The Company's CCOSS results at its claimed revenue requirement are summarized in Table JAY-4.

TABLE JAY-4

Change Required to Achieve Equalized Rate of Return by Class

Line	Description	Current Class Structure[1]	Proposed Class Structure[2]
		(1)	(2)
1	Residential	52.30%	52.30%
2	Small General Service	-1.30%	9.20%
3	Medium General Service	-3.70%	0.40%
4	Large General Service	-10.40%	-9.50%
5	Large Power Service	-23.40%	-26.90%
6	Lighting	25.10%	25.20%
7	CCN	369.70%	369.00%
8	Total	15.19%	15.19%

Sources:

[1] Graham Jaynes' Direct Testimony, Table 8.

[2] Graham Jaynes' Direct Testimony, Table 9.

As shown in the table, to achieve equalized rates of return, the LPS class (as currently structured) would need a revenue requirement decrease of 23.4%, and the LGS class would need a decrease of 10.4%. The Residential class would require an increase of 52.3% or about 3.4 times the system average increase to reach cost of service.

Q IF THE ILLUSTRATIVE LLPS CUSTOMER IS EXCLUDED FROM THE LPS GROUP IN TABLES JAY-3 AND JAY-4 WOULD THE LPS CLASS STILL REQUIRE A DECREASE TO REACH COST OF SERVICE AT THE COMPANY'S PROPOSED REVENUE REQUIREMENT?

A Yes. Evergy's confidential CCOSS workpapers confirm that LPS is well-above cost of service at current rates, and would still need a significant reduction to reach cost of service at the Company's claimed revenue requirement.[9] Specifically, the LPS class, exclusive of Large Load Power Service ("LLPS"), has a rate of return of 9.7% at present rates under the current class structure, and 11.7% under the proposed class structure. Thus, even after removing any distortion caused by LLPS, the LPS class return is still approximately double the system average return at present rates under the current class structure, and nearly 2.5 times the system average return under the proposed class structure.

[9]Confidential 26 MO Metro CCOS Proposed Class Structure workpaper, tab labeled COS Summary_Subclass, line 20; Confidential 26 MO Metro CCOS Current Class Structure, tab labeled COS Summary_Subclass, line 20.

Q WHAT IS THE COMPANY'S REVENUE APPORTIONMENT PROPOSAL?

A The Company proposes to apply an equal percentage increase of 15.19% across all customer classes.[10] The Company acknowledges that the CCOSS results indicate significant cross-subsidization between classes, but argues that equal percent treatment is appropriate in this case due to four factors: (1) uncertainty regarding LLPS revenues and costs; (2) incomplete cost allocation for LLPS in the CCOSS; (3) the LLPS revenue credit already incorporated into the CCOSS; and (4) simultaneous rate design changes affecting class composition.[11] The Company offers a hypothetical "traditional" scenario in Table 10 of Mr. Jaynes' testimony that would have applied approximately 93% of the system average increase to LPS and LGS under a more typical gradual approach.

Q DO YOU SUPPORT THE COMPANY'S EQUAL PERCENT APPROACH?

A No, I do not. While I acknowledge that the Company has articulated legitimate concerns about LLPS uncertainty and the complexity of simultaneous rate design changes, these concerns do not justify ignoring CCOSS results that indicate such a large divergence between class cost responsibility and current revenue recovery. As shown above, even after removing the distortion caused by the LLPS customer, the LPS and LGS classes are producing at least two times the system average rate of return at present rates. Applying an equal percent increase to all classes in this circumstance does nothing to reduce that cross-subsidization, and instead, locks it in at a higher revenue level. In addition, the revenue requirement increase in conjunction with all of the simultaneous rate design changes proposed for the C&I classes will result

[10]Graham Jaynes' Direct Testimony at 48, line 2.
[11]*Id.* at 48, line 4 through page 50, line 2.

in bill impacts greatly in excess of the 15.19% system average increase for multiple individual C&I customers, as discussed in greater detail later in my testimony. Thus, the Commission should require greater movement toward cost of service, even if full equalization is not achievable in a single case.

Q WHAT IS YOUR REVENUE APPORTIONMENT RECOMMENDATION?

A I recommend class-specific multipliers relative to the system average increase, based on the results of the Company's CCOSS models. My recommended revenue apportionment is shown in Table JAY-5 and uses an $85 million revenue requirement increase (9.2%) based on Staff's revenue requirement testimony.

TABLE JAY-5

MECG Proposed Revenue Allocation
at Staff's Revenue Requirement Increase

Line	Description	Current Revenues[1]	Proposed Increase Amount	Proposed Increase Percent	Ratio to System Average
		(1)	(2)	(3)	(4)
1	Residential	$371,537,659	$51,245,180	13.79%	1.50
2	Small General Service	55,946,113	5,658,763	10.11%	1.10
3	Medium General Service	125,759,290	11,563,758	9.20%	1.00
4	Large General Service	186,389,020	11,052,913	5.93%	0.64
5	Large Power Service	176,428,823	4,509,144	2.56%	0.28
6	Lighting	7,828,745	899,831	11.49%	1.25
7	Electric Vehicle	510,495	70,411	13.79%	1.50
8	Total	$924,400,145	$85,000,000	9.20%	1.00

Sources:
[1] Schedule GAJ-10.

As shown in the table, the Residential and Electric Vehicle classes would see increases of 1.5 times the system average because they are furthest below cost of

service. Based on the revenue requirement testimony of other parties in this case, I anticipate that the authorized revenue requirement will be less than the Company proposed. This provides an opportunity for the Residential class (and others) to make greater movement toward cost of service without exceeding the Company's proposed 15.19% increase. The LGS and LPS classes would need decreases to reach cost of service based on the Company's CCOSS models, and as such they should receive the smallest increases relative to the system average. In addition, a below-system average increase is appropriate for these classes in light of the bill impacts that will result for customers within these classes due to multiple simultaneous rate design changes being proposed. Increases for the remaining classes were also determined taking into consideration the Company's CCOSS results.

My revenue apportionment moves classes toward cost of service while still recognizing the need for gradualism. To the extent the Commission authorizes a system average increase that differs from the example in Table JAY-5, my recommended class-specific multipliers would still be applicable.

V. RATE DESIGN

V.A. Demand Threshold Changes

Q PLEASE DESCRIBE THE COMPANY'S DEMAND THRESHOLD PROPOSAL.

A The Company proposes to establish class-specific maximum demand thresholds for C&I customer classes based on NCP demand.[12] These thresholds, combined with the existing minimum billing demand criteria, create upper and lower bounds that more clearly define customer class eligibility.[13] Specifically, the Company proposes the

[12] *Id.* at 10, lines 7–12.
[13] *Id.*

upper thresholds of: Small General Service ("SGS") at 31 kW; Medium General Service ("MGS") at 250 kW; and Large General Service ("LGS") at 3,000 kW.[14] Customers whose demands consistently exceed these thresholds would be assigned to the next higher class. The proposal is designed to prevent opportunistic rate switching, improve class homogeneity, and facilitate future jurisdictional alignment between Evergy Missouri Metro and Evergy Missouri West.[15]

Q DID EVERGY PROVIDE INFORMATION ABOUT THE BILL IMPACTS THAT WOULD RESULT FOR CUSTOMERS THAT WOULD BE MIGRATED TO A DIFFERENT RATE AS A RESULT OF THE PROPOSED DEMAND THRESHOLDS?

A Yes. As explained by Mr. Jaynes, an estimated 4,224 C&I customers would be migrated.[16] Of these, an estimated 663 customers would see an impact of greater than 10% of their annual bill at the current rate (prior to the application of the Company's proposed revenue requirement increase), with 406 of these customers having 12 full months of usage.[17] Further, Evergy's workpapers show that the range of bill impacts resulting from the proposed demand thresholds is 10% to 469%, prior to the application of the Company's proposed 15.19% revenue requirement increase in this case. Table JAY-6 summarizes certain bill impact information for the Company's "high-impact" customers, which appear to be defined as customers with bill impacts at current rates that exceed 10%.

[14] *Id.* at 13, lines 21-23.
[15] *Id.* at 10, lines 14-18.
[16] *Id.* at 14, lines 18-19.
[17] *Id.* at 15, lines 2-4.

TABLE JAY-6

C&I Bill Impacts Resulting from Proposed Demand Thresholds

Line	Description	Minimum Bill Impact	Maximum Bill Impact	No. of Impacts > 10.0%	No. of Impacts > 15.19%
		(1)	(2)	(3)	(4)
1	Customers with full 12-months of data	10.1%	333.4%	404	317
2	Customers with less than 12-months of data	10.2%	468.5%	258	232
3	All High-Impact Customers	10.1%	468.5%	662	549

Source: Evergy's C&I Demand Threshold Bill and Revenue Impact workpaper.

Q DO YOU SUPPORT THE COMPANY'S DEMAND THRESHOLD PROPOSAL?

A I do not oppose the demand threshold proposal. Demand thresholds serve an important role in maintaining the integrity of class assignments and preventing customers from taking service under a rate schedule that is not designed to reflect their cost causation characteristics. The Company's analysis demonstrates that outlier customers exist within each class whose demand characteristics are more consistent with the next higher class, and the proposed thresholds address this misalignment in a reasonable and administratively clear manner.

V.B. 15-Minute Billing Demand Measurement

Q PLEASE DESCRIBE THE COMPANY'S PROPOSAL TO CHANGE THE BILLING DEMAND MEASUREMENT INTERVAL FROM 30 MINUTES TO 15 MINUTES.

A Currently, Evergy Missouri Metro uses 30-minute demand intervals to establish billing demand for C&I customers.[18] The Company proposes to transition to a 15-minute demand interval, consistent with the measurement approach already used by Evergy Missouri West, Ameren Missouri, and Empire District Electric Company.[19] Under the 15-minute interval, billing demand is set based on the customer's highest 15-minute integrated demand during the billing period.

Q DO YOU SUPPORT THE TRANSITION TO 15-MINUTE BILLING DEMAND MEASUREMENT?

A I do not oppose the Company's proposal to revise the measurement of billing demand. The 15-minute demand interval is a more accurate measurement of the actual capacity a customer requires from the electric system. Because capacity costs are driven by peak demand, a billing demand measure that more precisely captures the customer's actual peak consumption provides a better cost signal and more accurately reflects cost causation. This change also improves consistency with other Missouri jurisdictions, facilitating future tariff alignment.

[18] *Id.* at 16, lines 6-13.
[19] *Id.* at 16, lines 15-18.

V.C. Hours Use Rate Design Elimination

Q WHAT IS THE COMPANY'S PROPOSAL REGARDING THE HOURS USE RATE DESIGN?

A The Company proposes to eliminate the Hours Use rate structure for LGS and LPS customers and replace it with a TOU energy charge combined with an on-peak demand charge.[20] The Hours Use structure currently provides declining per-kWh energy rates as consumption increases and was designed to promote efficient utilization of Evergy's energy infrastructure.[21]

Q WHAT IS YOUR RECOMMENDATION ON THE PROPOSED ELIMINATION OF THE HOURS USE RATE DESIGN?

A I recommend that the Commission not adopt the elimination of the Hours Use rate structure in this proceeding. Instead, I recommend that the Commission either defer this structural change or, if it elects to move forward, direct the Company to implement it through a phased transition with appropriate mitigation. My recommendation is not based on disagreement with the direction of the proposed structure. It is based on the absence of information necessary to determine whether the proposed change produces just and reasonable results for individual LGS and LPS customers.

[20] Jaynes' Direct Testimony at 20, lines 10-15.
[21] *Id.* at 18, lines 13-14.

Q WHY DOES THE RECORD NOT SUPPORT ELIMINATION OF THE HOURS USE RATE STRUCTURE AT THIS TIME?

A The Brattle Group analysis in Schedule GAJ-04 evaluates the Hours Use replacement in isolation, on a class-level, revenue-neutral basis.[22] It does not quantify the combined bill impact that any individual customer will actually experience. In this case, the Hours Use replacement is one of four changes the Company proposes to impose on LGS and LPS customers at the same time, and as shown in the bill impact analysis provided in response to MECG Data Request 2.55, several C&I customers would experience bill impacts ranging from 20% to 63% from this rate design change alone, prior to the application of the Company's proposed increase in this case. In addition, each of the other three changes independently alters a customer's bill, and Evergy has not provided an account-level analysis showing what happens when all three rate design changes and the proposed revenue requirement increase are applied together.

Q WHAT ARE THE FOUR CHANGES AND WHY MUST THEY BE EVALUATED TOGETHER?

A The four changes are the class demand threshold revisions, the transition from a 30-minute to a 15-minute billing demand interval, the Hours Use replacement, and the proposed revenue requirement itself. These changes interact rather than simply being added together. The demand threshold revisions migrate customers between classes, so a migrating customer is billed under a different rate structure entirely. The 15-minute interval increases measured billing demand, which is why the Company applies a conversion factor of 1.03042 to maintain revenue neutrality. That factor is calibrated to

[22] *Id.* at 24, lines 6-7.

hold the class whole on average; it does not hold any individual account whole. The Hours Use replacement then shifts recovery from declining-block energy onto seasonal energy and a partial on-peak demand charge, and each customer's outcome under that shift depends on its load factor and load shape. The revenue requirement scales all of it. A customer could be approximately neutral under any single change and materially affected once all four are combined. Schedule GAJ-04 cannot reveal that result because it holds the other three changes constant.

Q THE COMPANY DESCRIBES THE HOURS USE REPLACEMENT RATE DESIGN AS REVENUE NEUTRAL AT THE CLASS LEVEL. DOES THAT ADDRESS YOUR CONCERN?

A No. Revenue neutrality confirms only that the Company collects the same revenue before and after the rate changes at current rates. A revenue-neutral redesign produces winners and losers within the classes. It provides no assurance that any particular LGS or LPS customer is treated reasonably (particularly when all four changes are combined), and it is the individual account impacts, not the class average impacts, that are not clear from the Company's filing.

Q DO YOU OPPOSE MOVING TOWARD A MORE COST-BASED RATE STRUCTURE FOR THESE CLASSES?

A No. MECG supports rate designs that recover fixed costs through demand-related charges consistent with cost causation, and a structure that places greater weight on a demand charge and a defined peak signal is generally favorable to the higher-load factor customers MECG represents. My recommendation should not be read as a criticism of cost-based rate design or of the Company's long-term direction. It is a

recommendation about the sufficiency of the evidence and the pace of change. The Company has not demonstrated, on an account-specific basis, that eliminating the Hours Use rate simultaneously with three other significant changes produces reasonable outcomes, and MECG cannot verify that it does on the information provided.

Q IS YOUR RECOMMENDATION CONSISTENT WITH THE COMPANY'S OWN POSITION IN THIS CASE?

A Yes. The Company cites the uncertainty created by simultaneous rate design changes, along with the pending large load issues, to support mitigating the revenue spread. That reasoning reflects a sound principle: when multiple significant changes are proposed at once, a gradual approach is warranted.

MECG does not agree that this concern justifies restraining the movement toward cost of service in the revenue allocation, where the LGS and LPS rates of return remain well above the 4.90% system average. But the Company's underlying point applies squarely to its own rate design proposals (e.g., the revised demand thresholds, the 30-to-15-minute billing demand conversion, and the Hours Use elimination) each proposed to take effect at once and none supported by an account-level analysis of their combined bill impact. If that volume of simultaneous change is enough to temper the revenue spread, it is more than enough to warrant deferral or a phased transition of the Hours Use elimination.

Q DO YOU HAVE ANY OTHER CONCERNS WITH THE PROPOSED REPLACEMENT RATE DESIGN FOR THE LPS CLASS?

A Yes. Under current rates, LGS and LPS demand and energy rates are differentiated by voltage subclass between secondary and primary (for LGS) and secondary, primary, substation, and transmission level (for LPS). Currently, secondary voltage demand and energy rates are the highest, and transmission voltage demand and energy rates are the lowest. Conceptually, this makes sense as customers served at different voltage levels utilize system infrastructure differently and also impose different levels of line losses on the system. In addition for both LGS and LPS, current demand and energy rates are higher in the summer season than in the winter season. However, the proposed LGS and LPS replacement rates are not fully consistent with these expected patterns. For the LGS class, the proposed demand rates are higher for primary voltage customers than for secondary, and winter energy charges are higher than summer. For the LPS class, the proposed rate structure reflects transmission voltage demand and energy rates that are more expensive than the substation voltage rates, and primary voltage demand rates that are more expensive than secondary voltage rates.[23] In addition, this pattern is inconsistent with the unit costs of service by voltage level resulting from the Company's CCOSS.[24] The unit costs of service from the Company's CCOSS models for the LGS and LPS voltage subclasses are summarized in Table JAY-7, and confirm that higher voltage classes should generally have lower rates than lower voltage classes.

[23] Schedule GAJ-11.

[24] Unit COS tab of Evergy's Confidential 26 MO Metro CCOS Current Class Structure workpaper, and Unit COS tab of Evergy's Confidential 26 MO Metro CCOS Proposed Class Structure.

TABLE JAY-7

LGS and LPS Unit Cost of Service by Voltage

Line	Description	Voltage Level Secondary	Primary	Subtransm.	Transm.
		(1)	(2)	(3)	(4)
	Current Class Structure[1]				
	LGS				
1	Customer ($/month)	$ 50.08	$ 50.08		
2	Demand ($/kW)	$ 24.86	$ 22.41		
3	Energy ($/kWh)	$ 0.0231	$ 0.0225		
	LPS				
4	Customer ($/month)	$ 249.03	$ 249.03	$ 356.01	$ 356.01
5	Demand ($/kW)	$ 32.99	$ 27.42	$ 26.70	$ 21.47
6	Energy ($/kWh)	$ 0.0234	$ 0.0226	$ 0.0222	$ 0.0224
	Proposed Class Structure[2]				
	LGS				
7	Customer ($/month)	$ 49.47	$ 49.47		
8	Demand ($/kW)	$ 26.31	$ 25.44		
9	Energy ($/kWh)	$ 0.0231	$ 0.0224		
	LPS				
10	Customer ($/month)	$ 232.78	$ 232.78	$ 339.70	$ 339.70
11	Demand ($/kW)	$ 54.13	$ 32.09	$ 27.07	$ 21.79
12	Energy ($/kWh)	$ 0.0233	$ 0.0226	$ 0.0222	$ 0.0224

Sources:

[1] Confidential 26 MO Metro CCOS Current Class Structure workpaper. Tab labeled "Unit COS."

[2] Confidential 26 MO Metro CCOS Proposed Class Structure workpaper. Tab labeled "Unit COS."

Q PLEASE SUMMARIZE YOUR RECOMMENDATION REGARDING THE HOURS USE RATE STRUCTURE.

A I recommend the following. First, the Commission should decline to eliminate the Hours Use rate in this proceeding absent an account-level analysis of the combined bill impact of all four changes at the proposed revenue requirement. Second, the Commission should direct the Company to produce that combined analysis, presented for each LGS and LPS account and identifying each account's class before and after any threshold migration, so that the reasonableness of the stacked result can be evaluated on the

record. I would also note that maintaining the Hours Use rate structure is consistent with the Evergy Missouri West jurisdiction.

V.D. Optional TOU Rate

Q PLEASE DESCRIBE THE COMPANY'S OPTIONAL TOU RATE PROPOSAL.

A The Company proposes an optional TOU rate available to SGS, MGS, LGS, and LPS customers.[25] The optional TOU rate features a facilities charge to recover distribution costs, a demand charge for generation cost recovery, and a TOU energy charge that varies by on-peak, off-peak, and super off-peak periods.[26] The rate is designed to provide customers with the opportunity to reduce their bills by shifting usage away from on-peak hours, while also providing more granular price signals that reflect the time-varying cost of electric service.

Q DO YOU SUPPORT THE OPTIONAL TOU RATE PROPOSAL?

A Yes, I support the Company's proposal to offer an optional TOU rate for C&I customers. It mirrors the Optional TOU rate structure designed with input from stakeholders in Evergy Kansas Central's service territory. In addition, TOU pricing is more consistent with the time-varying nature of generation costs than flat energy charges, and it provides customers with an opportunity to both benefit the system and manage their bills by shifting load away from high cost periods. Making the TOU rate optional is appropriate because it allows customers who can benefit from load shifting to choose the rate that rewards that flexibility, while customers who cannot easily shift their load are not compelled to adopt a pricing structure that may not suit their operational

[25] Jaynes' Direct Testimony at 25, lines 3-14.
[26] *Id.*

constraints. The optional structure respects customer diversity and avoids mandating bill increases on customers whose load profiles cannot respond to time-differentiated pricing.

Q DO YOU HAVE ANY CONCERNS REGARDING THE OPTIONAL TOU RATE DESIGN?

A Yes. My concern regarding the proposed voltage differentiated demand and energy charges described in relation to the Hours Use replacement rate design also applies here. As shown on Schedule GAJ-04, page 34, for LPS transmission voltage demand and energy rates are higher than substation voltage rates, and primary voltage demand rates are higher than secondary voltage demand rates. For LGS the primary voltage demand rates are higher than the secondary voltage rates. This is inconsistent with cost of service by voltage as previously described. In addition, proposed LGS and LPS winter energy rates are higher than the summer rates in certain periods. The Company should explain this outcome in its rebuttal.

V.E. TRP Rate Elimination and Customer Mitigation

Q WHAT IS THE COMPANY'S PROPOSAL REGARDING THE TRP RATE?

A The Company proposes to eliminate the TRP rate schedule, which has been available to LGS and LPS customers[27] since it was approved in the 2022 rate case, with rates effective in early 2023.[28] TRP customers receive energy charges that vary by time period, reflecting a form of time-differentiated pricing similar in concept to TOU, but with a different rate structure. The Company proposes the optional TOU rate as the

[27]Jaynes' Direct Testimony at 29, lines 1-5, and 8.
[28]Case No. ER-2022-0129.

presumed successor to TRP.[29] The Company's analysis indicates that, when TRP customers are migrated to the standard rate structure with revenue neutralization adjustments and the 15-minute demand conversion applied, the median customer impact is approximately 15.74%.[30]

Q WHAT IS MECG'S CONCERN ABOUT THE ELIMINATION OF THE TRP RATE?

A MECG is concerned about the potential impact on individual TRP customers whose bills would increase materially as a result of the TRP elimination. A median impact of 15.74% is significant on its own, and the Company's workpapers show that some customers would experience impacts above the median at about 20%, prior to the application of the Company's proposed revenue requirement increase in this case.[31] These customers chose the TRP rate because it suited their load profiles and allowed them to manage their electric costs by operating more intensively during off-peak hours. Eliminating TRP removes that tool. While the optional TOU rate may serve as a functional replacement for some customers, the TOU structure differs from TRP in material ways, and not all TRP customers may find the optional TOU rate to be an adequate or equivalent substitute.

[29] Jaynes' Direct Testimony at 29, lines 21-22.
[30] *Id.* at line 18.
[31] Jaynes' public TRP Bill Impacts workpaper.

Q WHAT DOES MECG RECOMMEND REGARDING MITIGATION FOR TRP CUSTOMERS AND OTHER CUSTOMERS AFFECTED BY RATE SCHEDULE ELIMINATIONS?

A MECG recommends that the Commission require the Company to develop and implement an appropriate mitigation strategy for customers currently taking service under rate schedules being eliminated in this case, with particular attention to TRP customers. The Company should work collaboratively with MECG and other affected intervenors to identify the most appropriate mitigation approach, which could include: (1) a transition period during which affected customers are allowed to remain on their existing rate schedule while they evaluate alternatives; (2) bill caps or phase-in mechanisms limiting the rate of increase for affected customers during an initial period following migration to a new schedule; and/or (3) targeted outreach and rate analysis assistance to help TRP customers identify whether the optional TOU rate or another available schedule would mitigate their bill impact. MECG expresses its willingness and desire to work with the Company to develop appropriate mitigation approaches that protect customers from abrupt and potentially severe bill increases resulting from rate schedule eliminations they did not choose.

Q DOES THE NEED FOR MITIGATION AFFECT YOUR OVERALL POSITION ON THE RATE DESIGN PROPOSALS?

A Yes. The simultaneous implementation of multiple significant changes, demand thresholds that may shift some customers to higher-cost rate schedules, the 15-minute demand measurement transition, hours use structure elimination, TRP elimination, and the overall rate increase, creates a risk of compounded, unanticipated bill impacts for individual customers. The Commission should be mindful that the aggregate effect of

these changes on particular customers may significantly exceed the class average impact, and that customers whose rate schedules are being eliminated have no choice but to migrate to alternative schedules. Mitigation is not merely a matter of customer relations; it is a matter of rate continuity and the Commission's obligation to ensure that rate changes do not impose unreasonable and abrupt hardships on customers who have made business and operational decisions based on their existing rates.

V.F. LGS and LPS Demand and Energy Charges

Q DO YOU HAVE ANY COMMENTS ON LGS AND LPS RATE DESIGN GENERALLY, ASIDE FROM THE RATE DESIGN CHANGES AND VOLTAGE DIFFERENTIATION ISSUES YOU HAVE ALREADY ADDRESSED?

A Yes. As a general matter, rate design should follow cost causation, which in turn depends on how the underlying costs behave. A large majority of Evergy's revenue requirement is fixed, principally capital-related costs of generation, transmission, and distribution plant and associated fixed operating costs, that the Company incurs regardless of any individual customer's energy usage. Only a comparatively small portion, largely fuel and variable operating expense, varies with energy consumption. That cost structure generally supports recovering fixed, capacity-related costs through demand and customer charges, rather than through volumetric energy charges.

For example, the Company's CCOSS with the proposed class structure, shows that energy costs represent around 30% of the total cost of service for the LPS class, yet the Company's proposed LPS energy rates recover about 65% of the revenue requirement allocated to the LPS class. Thus, the energy rates are recovering a significant portion of fixed demand-related costs. The LGS class has a similar issue, as about 60% of the allocated revenue requirement is recovered through energy

charges, despite only about 25% of the cost of service being energy-related. To improve alignment between the rate structure and cost structure, demand charges should be increased by a larger percentage than the energy charges. I recommend increasing demand charges by 1.5 times the class average increase assigned to LPS, and the energy charges by 0.5 times the class average increase, with the remainder of revenue requirement collected from the remaining rate elements.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Jessica A. York

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jessica A. York. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE IDENTIFY THE JURISDICTIONS IN WHICH YOU HAVE PREVIOUSLY SPONSORED TESTIMONY.

A I have sponsored expert testimony in front of the Regulatory Commission of Alaska, Arizona Corporation Commission, Idaho Public Utilities Commission, the Illinois Commerce Commission, Indiana Utility Regulatory Commission, the Iowa Utilities Commission, the Kansas Corporation Commission, the Kentucky Public Service Commission, the Michigan Public Service Commission, the Minnesota Public Utilities Commission, the Missouri Public Service Commission, the Public Utilities Commission of Nevada, the Oklahoma Corporation Commission, the Virginia State Corporation Commission, and the Public Service Commission of Wisconsin.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A I graduated from Truman State University in 2008 where I received my Bachelor of Science Degree in Mathematics with minors in Statistics and Actuarial Science.

I earned my Master of Business Administration Degree with a concentration in Finance from the University of Missouri-St. Louis in 2014.

I joined BAI in 2011 as an analyst. Then, in March 2015, I joined the consulting team of BAI.

I have worked in various electric, natural gas, and water and wastewater regulatory proceedings addressing cost of capital, sales revenue forecasts, revenue requirement assessments, class cost of service studies, rate design, and various policy issues. I have also conducted competitive power and natural gas solicitations on behalf of large electric and natural gas users, have assisted those large power and natural gas users in developing procurement plans and strategies, assisted in competitive contract negotiations, and power and natural gas contract supply administration. In the regulated arena, I have evaluated cost of service studies and rate designs proffered by other parties in cases for various utilities, including in Idaho, Illinois, Indiana, Kansas, Wisconsin, and others. I have conducted bill audits, rate forecasts, and tariff rate optimization studies.

I have also provided support to clients with facilities in deregulated markets, including drafting supply Requests for Proposals ("RFP"), evaluating supply bids, and auditing competitive supply bills. I have also prepared and presented to clients reports that monitor the electric market and recommend strategic hedging transactions.

BAI was formed in April 1995. BAI and its predecessor firm have participated in more than 700 regulatory proceedings in forty states and Canada.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on

occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys, and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation.

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

Line No.	Description	System Total	Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Lighting	CCN
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	REVENUE REQUIREMENT SUMMARY								
1	Retail Sales Revenue	$ 920,123,208	$ 371,316,551	$ 87,213,295	$ 125,528,420	$ 185,903,096	$ 141,828,327	$ 7,824,086	$ 509,432
2	LLPS Credit	3,834,861	1,584,371	372,131	535,617	793,230	513,954	33,385	2,174
3	Test Year Revenue	$ 923,958,069	$ 372,900,922	$87,585,426	$126,064,038	$186,696,326	$ 142,342,281	$7,857,471	$511,605
3	Gross Revenue Requirements	$ 831,585,418	$ 392,885,340	$ 67,693,186	$ 99,609,606	$ 149,369,621	$ 110,361,704	$ 9,884,239	$ 1,781,721
4	Less Other Revenue	$ (97,684,917)	$ (35,878,712)	$ (7,969,460)	$ (13,185,911)	$ (22,330,187)	$ (17,730,226)	$ (553,583)	$ (36,838)
5	Net Revenue Requirements	$ 733,900,501	$ 357,006,628	$59,723,727	$86,423,695	$127,039,434	$ 92,631,478	$9,330,656	$1,744,883
6	**Net Operating Income**	$ 190,057,567	$ 15,894,294	$ 27,861,699	$ 39,640,342	$ 59,656,892	$ 49,710,803	$ (1,473,186)	$ (1,233,278)
	RETURN AT PRESENT RATES								
7	Rate Base	$ 3,879,303,485	$ 2,046,240,761	$ 323,186,779	$ 457,368,212	$ 617,350,085	$ 376,426,205	$ 55,500,916	$ 3,230,527
8	Net Operating Income at Present Rates	$ 190,057,567	$ 15,894,294	$ 27,861,699	$ 39,640,342	$ 59,656,892	$ 49,710,803	($1,473,186)	$ (1,233,278)
9	Return at Current Rates	4.90%	0.78%	8.62%	8.67%	9.66%	13.21%	-2.65%	-38.18%
10	Relative Rate of Return	1.00	0.16	1.76	1.77	1.97	2.70	(0.54)	(7.79)
	EQUALIZED RATE OF RETURN								
11	Rate Base	$ 3,879,303,485	$ 2,046,240,761	$ 323,186,779	$ 457,368,212	$ 617,350,085	$ 376,426,205	$ 55,500,916	$ 3,230,527
12	Equalized Rate of Return	7.6546%	7.6546%	7.6546%	7.6546%	7.6546%	7.6546%	7.6546%	7.6546%
13	Return Required @ Equalized Rate of Return	$296,945,165	$156,631,545	$24,738,655	$35,009,707	$47,255,680	$28,813,920	$4,248,373	$247,284
14	Operating Income Deficiency/(Surplus)	$106,887,597	$140,737,252	($3,123,044)	($4,630,635)	($12,401,213)	($20,896,883)	$5,721,559	$1,480,562
15	Additional Current Tax Required	$33,465,438	$44,063,426	($977,794)	($1,449,806)	($3,882,696)	($6,542,605)	$1,791,363	$463,549
16	Revenue Deficiency/ (Surplus)	$140,353,035	$184,800,678	($4,100,838)	($6,080,441)	($16,283,908)	($27,439,488)	$7,512,922	$1,944,111
17	Percent Revenue Change - Equal Rates of Return	15.19%	49.6%	-4.7%	-4.8%	-8.7%	-19.3%	95.6%	380.0%

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

Line No.	Description	System Total	Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Lighting	CCN
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	REVENUE REQUIREMENT SUMMARY								
1	Retail Sales Revenue	$ 920,123,208	$ 371,316,244	$ 55,926,068	$ 125,729,536	$ 186,328,310	$ 172,488,779	$ 7,824,080	$ 510,191
2	LLPS Credit	3,834,861	1,584,370	238,631	536,476	795,044	644,779	33,385	2,177
3	Test Year Revenue	$ 923,958,069	$ 372,900,614	$56,164,699	$126,266,011	$187,123,355	$ 173,133,557	$7,857,464	$512,368
3	Gross Revenue Requirements	$ 831,585,418	$ 392,934,996	$ 46,362,303	$ 102,241,714	$ 149,928,054	$ 128,451,155	$ 9,885,375	$ 1,781,820
4	Less Other Revenue	$ (97,684,917)	$ (35,879,298)	$ (5,061,619)	$ (13,464,775)	$ (22,192,792)	$ (20,495,998)	$ (553,596)	$ (36,840)
5	Net Revenue Requirements	$ 733,900,501	$ 357,055,698	$41,300,684	$88,776,939	$127,735,262	$ 107,955,157	$9,331,779	$1,744,981
6	**Net Operating Income**	$ 190,057,567	$ 15,844,916	$ 14,864,015	$ 37,489,072	$ 59,388,093	$ 65,178,400	$ (1,474,315)	$ (1,232,613)
	RETURN AT PRESENT RATES								
7	Rate Base	$ 3,879,303,485	$ 2,046,784,441	$ 225,986,604	$ 472,411,064	$ 626,638,704	$ 448,738,118	$ 55,512,983	$ 3,231,571
8	Net Operating Income at Present Rates	$ 190,057,567	$ 15,844,916	$ 14,864,015	$ 37,489,072	$ 59,388,093	$ 65,178,400	($1,474,315)	$ (1,232,613)
9	Return at Current Rates	4.90%	0.77%	6.58%	7.94%	9.48%	14.52%	-2.66%	-38.14%
10	Relative Rate of Return	1.00	0.16	1.34	1.62	1.93	2.96	(0.54)	(7.79)
	EQUALIZED RATE OF RETURN								
11	Rate Base	$ 3,879,303,485	$ 2,046,784,441	$ 225,986,604	$ 472,411,064	$ 626,638,704	$ 448,738,118	$ 55,512,983	$ 3,231,571
12	Equalized Rate of Return	7.6546%	7.6546%	7.6546%	7.6546%	7.6546%	7.6546%	7.6546%	7.6546%
13	Return Required @ Equalized Rate of Return	$296,945,165	$156,673,162	$17,298,371	$36,161,177	$47,966,686	$34,349,108	$4,249,297	$247,364
14	Operating Income Deficiency/(Surplus)	$106,887,597	$140,828,246	$2,434,356	($1,327,895)	($11,421,406)	($30,829,292)	$5,723,612	$1,479,977
15	Additional Current Tax Required	$33,465,438	$44,091,916	$762,172	($415,751)	($3,575,928)	($9,652,343)	$1,792,006	$463,366
16	Revenue Deficiency/ (Surplus)	$140,353,035	$184,920,162	$3,196,528	($1,743,645)	($14,997,335)	($40,481,635)	$7,515,617	$1,943,343
17	Percent Revenue Change - Equal Rates of Return	15.19%	49.6%	5.7%	-1.4%	-8.0%	-23.4%	95.6%	379.3%