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# Exhibit No. 502

MECG – Exhibit 502  
Kavita Maini  
Direct  
File No. ER-2024-0189

Exhibit No.:  
Issue: Class Cost of Study, Revenue Allocation, Rate Design  
Witness: Kavita Maini  
Type of Exhibit: Direct Testimony  
Sponsoring Parties: MECC  
Case No.: ER-2024-0189  
Date Testimony Prepared: July 12, 2024

**BEFORE THE PUBLIC SERVICE  
COMMISSION OF THE STATE OF MISSOURI**

\_\_\_\_\_)  
**In the Matter of Evergy Missouri West, )  
Inc. d/b/a Every Missouri West’s Request ) File No. ER-2024-0189  
for Authority to Implement A General )  
Rate Case Increase for Electric Service )**  
\_\_\_\_\_)

Direct Testimony and Schedules of

**Kavita Maini**

On behalf of

**MIDWEST ENERGY CONSUMERS GROUP**

July 12, 2024



*Protecting Your Bottom Line*

**KM ENERGY CONSULTING, LLC**

**BEFORE THE PUBLIC SERVICE COMMISSION  
OF THE STATE OF MISSOURI**

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In the Matter of Evergy Missouri West, Inc. d/b/a )  
Every Missouri West’s Request for )  
Authority to Implement A General Rate ) Case No. ER-2024-0189  
Case Increase for Electric Service )

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STATE OF WISCONSIN )  
 ) SS  
COUNTY OF WAUKESHA )

**AFFIDAVIT OF KAVITA MAINI**

Kavita Maini, being first duly sworn, on her oath states:

1. My name is Kavita Maini. I am a consultant with KM Energy Consulting, LLC. having its principal place of business at 961 North Lost Woods Road, Oconomowoc, WI 53066. I have been retained by the Midwest Energy Consumers Group (“MECG”) in this proceeding on its 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-2024-0189.
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.

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Kavita Maini

**BEFORE THE PUBLIC SERVICE  
COMMISSION OF THE STATE OF MISSOURI**

**In the Matter of Evergy Missouri West, )  
Inc. d/b/a Every Missouri West’s Request )  
for Authority to Implement A General )  
Rate Case Increase for Electric Service )  
)**

**File No. ER-2024-0189**

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**ATTACHMENT A: DATA RESPONSE TO MECG 2.4**

**BEFORE THE PUBLIC SERVICE  
COMMISSION OF THE STATE OF MISSOURI**

In the Matter of Evergy Missouri West, )  
Inc. d/b/a Every Missouri West’s Request )  
for Authority to Implement A General ) **File No. ER-2024-0189**  
Rate Case Increase for Electric Service )  
)

**Direct Testimony of Kavita Maini**

1 **I. INTRODUCTION**

2 **Q. Please state your name and occupation.**

3 A. My name is Kavita Maini. I am the principal and sole owner of KM Energy Consulting,  
4 LLC.

5 **Q. Please state your business address.**

6 A. My office is located at 961 North Lost Woods Road, Oconomowoc, WI 53066.

7 **Q. Please state your educational and professional background.**

8 A. I am an economist with over 32 years of experience in the energy industry. I graduated  
9 from Marquette University, Milwaukee, Wisconsin with a Master’s degree in Business  
10 Administration and a Master’s degree in Applied Economics. From 1991 to 1997, I  
11 worked for Wisconsin Power & Light Company (“WP&L”) as a Market Research  
12 Analyst and Senior Market Research Analyst. In this capacity, I conducted process and  
13 impact evaluations for WP&L’s Demand Side Management (“DSM”) programs. I also  
14 conducted forward price curve and asset valuation analysis. From 1997 to 1998, I  
15 worked as Senior Analyst at Regional Economic Research, Inc. in San Diego,  
16 California. From 1998 to 2002, I worked as a Senior Economist at Alliant Energy

1 Integrated Services' Energy Consulting Division. In this role, I was responsible for  
2 providing energy consulting services to commercial and industrial customers in the area  
3 of electric and natural gas procurement, contract negotiations, forward price curve  
4 analysis, rate design and on-site generation feasibility analysis. I was also involved in  
5 strategic planning and due diligence on acquisitions.

6 Since 2002, I have been an independent consultant. In this role, I have provided  
7 consulting services in the areas of class cost of service studies, rate design, revenue  
8 allocation, resource planning and revenue requirement related issues, Midcontinent  
9 Independent System Operator ("MISO") related matters and various policy matters. I  
10 also represent industrial trade associations at MISO's various task forces and  
11 committees and am the End Use Sector representative at MISO's Advisory and Planning  
12 Advisory Committees.

13 **Q. Have you participated in utility related proceedings?**

14 A. Yes, I have testified before a number of state regulatory commissions, including in  
15 Wisconsin, Minnesota, Missouri, Iowa, North Dakota and South Dakota. I have  
16 testified on a variety of issues related to revenue requirements, resource planning and  
17 generation resource acquisition, cost of service, revenue allocations and rate design. I  
18 have also provided technical comments in Federal Energy Regulatory Commission  
19 ("FERC") proceedings, several of which have involved MISO-related activities.

20 **Q. On whose behalf are you testifying in this proceeding?**

21 A. I am testifying as an expert witness on behalf of the Midwest Energy Consumers Group  
22 ("MECG"). The MECG is an incorporated entity representing the interests of large  
23 commercial and industrial customers including those taking service from Evergy

1 Missouri West, Inc. (“EMW” or “Company”) on its Large General Service (“LGS”) and  
2 Large Power Service (“LPS”) rate schedules.

3 **Q. How are the companies represented by MECG impacted by this proceeding?**

4 A. I am advised that many of companies whose interest MECG represents operate energy  
5 intensive facilities and compete in a regional and national environment. Therefore,  
6 energy costs are typically among the primary costs of doing business for these  
7 companies. Thus, energy affordability affects the competitiveness, output and potential  
8 employment levels for these companies.

9 In this rate case proceeding, EMW proposes an approximately \$109 million  
10 increase in revenue requirement or 14% increase on a systemwide basis. For this  
11 increase, EMW proposes a 14.3% increase to the LPS class and 11.5% increase to the  
12 LGS class respectively while the Company’s own cost of service study supports much  
13 lower increases at 6% for the LPS class or no increase for the LGS class. The large  
14 commercial and industrial customers members served by EMW will therefore be  
15 significantly impacted by the outcome of this proceeding.

16 **Q. What is the purpose of your testimony?**

17 A. The purpose of my testimony is to discuss and provide recommendations regarding the  
18 Company’s: (a) class cost of service study (“COSS”); (b) an appropriate allocation  
19 approach for any rate change; and (c) rate design for the LPS and LGS rate schedules.

20 The rest of my testimony is organized as follows:

21 Section II: Summary

22 Section III: Class Cost of Service Study

23 Section IV: Revenue Requirement Allocation

2 **II. SUMMARY**

3 **Q. Please summarize your testimony and recommendations.**

4 A. The following is a summary of my testimony and recommendations:

5 **Section III: Class Cost of Service Study (“COSS”)**

6 a) A COSS study is critical in establishing fair and reasonable rates because it: (i) guides how  
7 the revenue requirement should be allocated to classes and (ii) informs rate design. Thus,  
8 it is important that the COSS approach reflect cost causation.

9 b) Either the Peak Demand or the Average & Excess (A&E) method are reasonable allocation  
10 methods for fixed production plant-related costs; the Company uses the A&E method and I  
11 support this method in this case.

12 c) The A&E approach considers the load profile of customer classes by incorporating the  
13 class’s maximum demands, load factor and average energy use. Therefore, the A&E  
14 approach is a reasonable method to use in this case. In fact, the A&E method is used by  
15 Ameren, Liberty-Empire and Evergy respectively.

16 d) While the Company uses class coincident peak contribution to the four summer peaks in  
17 calculating the excess demand portion, I recommend the class average of the four highest  
18 non-coincident peaks, which is consistent with the method described in the NARUC Manual  
19 and Section 393.1620.1 (1) of the Missouri Statute.

20 e) I recommend that the Commission adopt MECG’s COSS. Given the substantial similarity  
21 in results, however, MECG would not be opposed to the Commission adopting EMW’s  
22 COSS.

23 f) The Company needs to further refine the classification of its primary distribution system  
24 into single and three-phase circuits in order to properly direct costs to primary and  
25 secondary voltage customers. Failure to do so results in allocating single phase circuit  
26 related costs to primary customers who are not served by single-phase configuration. I  
27 recommend that in rebuttal testimony, the Company should identify the steps and effort  
28 needed to get access to the data needed and the associated timeline to delineate between  
29 single phase and three phase distribution configurations to properly allocate costs to  
30 secondary and primary customers.

31 g) The Company’s fuel cost allocation can more closely follow cost causation by following an  
32 allocation method that recognizes the class load and fuel cost hourly variations. In rebuttal



1 testimony, the Company should explain if it has the class data necessary to calculate the  
2 E8760 allocator and associated timeline to get this allocator incorporated in its COSS.

#### 3 4 **Section IV: Revenue Requirement Allocation**

5 a) While the Company's and MECG's COSS could be refined further, the current  
6 methodology is reasonable and the COSS results can be relied upon, as guidance for revenue  
7 apportionment to classes.

8 b) The COSS should be used as the primary guiding principle in allocating revenue  
9 requirement to classes and informing rate design. Such an approach will foster equity  
10 amongst classes, send appropriate price signals and encourage economic efficiency. While  
11 other factors such as gradualism and rate continuity may also be considered, these factors  
12 should not be the dominating elements such that there is little to no movement towards class  
13 cost responsibility.

14 c) Both the Company and my COSS results show that at present rates and equal rates of return,  
15 the residential and EV classes are paying rates that are substantially below cost  
16 responsibility. All other classes are paying rates above their class cost responsibility.

17 d) While a much larger revenue neutral adjustment is justifiable based on the COSS results,  
18 given the double digit proposed increase of approximately 14%, I employed substantial  
19 moderation while also making a concerted effort to make revenue neutral shifts in my  
20 revenue allocation recommendation. I recommend that if the systemwide rate increase is  
21 lower than 10%, the multipliers should change to accommodate additional revenue neutral  
22 shifts and make further movement towards cost responsibility. The lower the Company's  
23 jurisdictional rate increase, the more it is reasonable to focus on larger revenue neutral shifts  
24 to get class revenue responsibility closer to cost responsibility.

#### **Section V: LPS/LGS Rate Design**

25 a) LPS and LGS Rates: The Company proposes to align the facility and customer charges  
26 based on its COSS results. With regards to changes in other charges, the remaining revenue  
27 requirement is proposed to be collected via demand and energy charges with extra  
28 weighting given to demand charges in recognition of the historical fixed/variable cost  
29 disparity between energy and demand charges.

30  
31 Given the limitations of the Company's COSS regarding the classification of certain  
32 distribution plant, which may not be properly allocating costs to the LPS and LGS classes  
33 and sub classes respectively, I recommend lower increases to the facility charges compared  
34 to the Company's proposal. In addition, I recommend retaining the existing customer  
35 charge, retaining the same percentage increase to energy charges as proposed by the  
36 Company and increasing the billed demand charge to recover the remaining revenue  
37 requirement.

1 b) With regards to changes in future cases, I support the Company's view that we need to  
2 consider rate impacts and transition towards time variant rates by addressing the annual  
3 base demand element as a first step as it relates to the LGS and LPS rates. In this regard, I  
4 recommend that the Company work collaboratively with MECG to develop and refine its  
5 proposed approaches before introducing these proposals in a future case.

### 6 III. COST OF SERVICE

#### 7 *A. Importance of A Utility's Cost of Service Study*

8 **Q. What is the importance of a utility's cost of service study?**

9 A. A utility's cost of service study is the fundamental basis for establishing just and  
10 reasonable rates in the ratemaking process. The cost of service study helps determine a  
11 utility's revenue requirement, guides revenue allocation to classes and informs rate  
12 design.

13 **Revenue Requirement:** A utility's cost of service is used in the determination of the  
14 revenue requirement of the utility and whether an increase, decrease or no change is  
15 necessary. Efforts are made to align total company rate revenues with the utility's cost  
16 of service.

17 **Revenue Allocation to Classes:** Given a certain revenue requirement, a utility's cost  
18 of service study guides the way in which a given revenue requirement should be  
19 allocated to classes. The level of the revenue requirement for each class should be based  
20 primarily on aligning each class's revenues with its cost of service providing the same  
21 or equal rates of return.

22 **Setting Rates:** For a certain revenue allocation to each class, a utility's cost of service  
23 also informs the design of class rates by setting rates with the goal of providing  
24 appropriate pricing signals.

1 **Q. For a given revenue requirement, what is the impact of closely aligning rates with**  
2 **the costs to serve each class?**

3 A. Provided that the class cost of service study is properly developed to reflect cost  
4 causation, closely aligning rates with each class's cost of service fulfills the important  
5 goals of promoting equity among classes and encouraging economic efficiency.

6 **Q. Please explain how equity is promoted among classes.**

7 A. If rates are aligned with the cost of service, then equity is promoted because each class  
8 pays its fair share of costs. Given this, a class that has rates that are not recovering its  
9 cost of service should receive an above system average increase while a class paying  
10 rates above cost of service should receive a below average increase. In cases where the  
11 class revenues are significantly misaligned with cost responsibility, larger corrections  
12 or adjustments may be warranted in order to restore equity among classes.

**Q. How is economic efficiency achieved?**

13 A. If retail rates align with the cost of service, then they provide accurate pricing signals  
14 that drive consumer behavior, which in turn results in more efficient use of the system  
15 and minimizes system costs. For example, in instances where the class rates are set  
16 above cost, say for the industrial class, the resulting rates would incent customers in this  
17 class to reduce production or shift production elsewhere. Such a consequence results in  
18 higher costs for all customers since the utility's fixed costs would need to be recovered  
19 from a lesser number of billing determinants. As mentioned, the Commission expressly  
20 recognized this fact in 2014 when it found that "if businesses leave Empire's service  
21 area, Empire's remaining customers bear the burden of covering the utility's fixed costs

1 with a smaller amount of billing determinants.”<sup>1</sup> On the other hand, for classes where  
2 rates are set at artificially low levels, then the rates are not sending the price signal that  
3 those customers should engage in energy efficiency measures.

4 Economic efficiency is not only affected by the misallocation of the revenue  
5 requirement among the rate classes, but also impacted by the class rate design. In  
6 instances where the class revenue responsibility is at the cost of service, but rates are  
7 designed such that there is recovery of fixed costs through volumetric charges, then the  
8 pricing signals are distorted and have the potential once again of sending inappropriate  
9 cost signals. For example, if fixed generation costs are recovered through variable  
10 charges, then the demand charge is kept artificially low, thus sending the improper price  
11 signal that generation capacity is cheaper than is actually the case. Similarly, if the  
12 energy charge is artificially high then there is an implication that energy costs are more  
13 expensive than is actually the case. Such a signal could then result in customers  
14 choosing to use less energy but contributing more to peak conditions. This has the effect  
15 of increasing the need for capacity, thereby increasing system costs, which once again,  
16 must be recovered from customers through higher rates.

17 ***B. COSS Steps***

18 **Q. What are the different steps involved in the cost of service process?**

19 A. A cost of service study generally follows three basic steps. First, the various costs are  
20 identified as production, transmission, and distribution (functionalization step). Next,  
21 these functionalized costs are classified as demand-related; energy-related; or customer-

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<sup>1</sup> See the Commission’s decision in ER-2014-0351.

1 related (classification step). Finally, these classified costs are allocated among the  
2 various rate classes based upon factors which attempt to measure each customer class's  
3 contribution to that total classified cost (allocation step).

4 **Functionalization:** Various costs are separated according to function such as  
5 generation, transmission, distribution, customer service and administration. To a large  
6 extent, this is done in accordance with the Federal Energy Regulatory Commission's  
7 ("FERC") Uniform System of Accounts.

8 **Classification:** The functionalized costs are classified based on the components of the  
9 utility service being provided and the underlying cost causative factors. As described  
10 by the NARUC Manual, the three principal cost classifications are: (1) demand-related  
11 costs (costs that vary with the kW demand imposed by the customer), (2) energy-related  
12 costs (costs that vary with energy or kWh that the utility provides), and (3) customer-  
13 related costs (costs that are directly related to the number of customers served). See  
14 NARUC Manual page 20.

15 **Allocation:** Once the costs are classified as demand-related, energy-related or  
16 customer-related, they are then allocated to classes using the relevant demand, energy  
17 or customer allocators. Each of these allocators measures each class's contribution to  
18 the total system cost.

19 Each of the three steps – functionalization, classification, and allocation, is very  
20 important because it sets the foundation for developing rates and sending accurate  
21 pricing signals. If costs are improperly functionalized, classified or allocated, they  
22 result in cross subsidies and economically inefficient pricing signals in rate design.

1 **C. COSS: Fixed Production Plant Cost Allocation**

2 **Q. What are fixed production plant-related costs?**

3 A. Fixed production plant-related costs are costs that are functionalized as production  
4 related and incurred in acquiring or procuring generation resources. Utilities are  
5 required to build or acquire sufficient generation capacity to ensure that they can reliably  
6 meet system peak demands. Primarily, these costs consist of the fixed investment in  
7 power plants, but do not include the variable cost (e.g., fuel) of generation. These costs  
8 include return on and of investment and fixed operations and maintenance costs. Once  
9 the generation investment is made, the costs are sunk costs, fixed in nature and do not  
10 vary with energy usage.

11 **Q. What should be considered in determining the appropriate allocator for fixed**  
12 **production plant-related costs?**

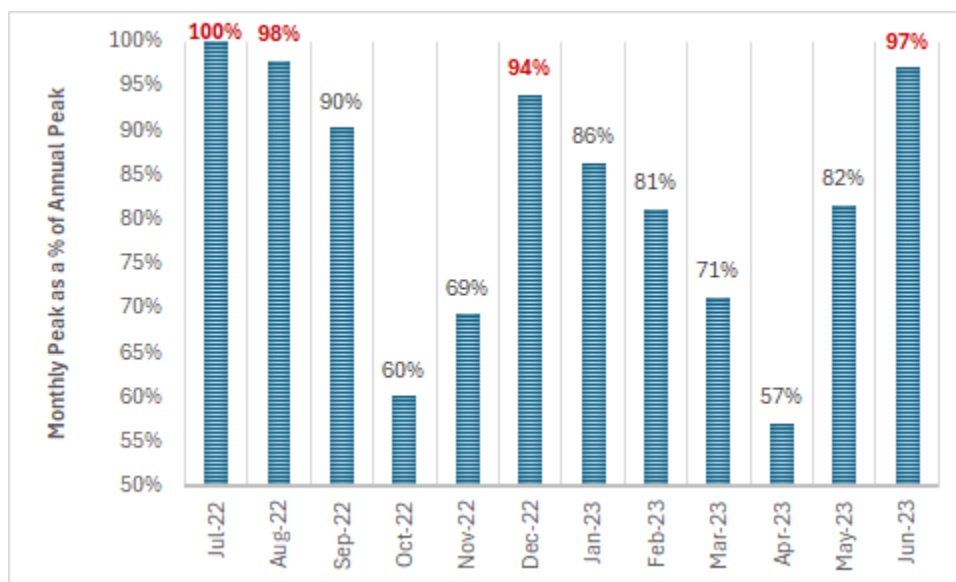
13 A. Since a utility needs to ensure that it has sufficient generation capacity to reliably meet  
14 its peak load requirements, the most important factor is the annual load pattern of the  
15 utility and the annual system peak. Further, since production plant must be sized to  
16 meet the maximum load or demand imposed on these facilities, the appropriate  
17 allocation method should reflect the load characteristics (system peaks) of the utility.

18 **Q. Did you analyze EMW's system load?**

19 A. Yes, I did. Figure 1 shows the system monthly peak demands as a percentage of overall  
20 annual peak for the test year. This chart shows that EMW's system maximum demand  
21 occurs in the summer with the highest peak occurring in July, followed by the second  
22 and third highest peaks also occurring in the summer in June and August respectively.  
23 The fourth highest peak occurred in December. Since generation capacity is sized to

1 reliably meet the highest peak demands, it would be appropriate to consider class  
2 contributions to monthly demands for these four months. Further, as I discuss later in  
3 this section, utilizing the non-coincident peaks for the four months with the highest  
4 system peak load in calculating the average and excess production cost allocator, is also  
5 consistent with the Section 393.1620.1 of the Missouri Statutes.

6 **Figure 1: Test Year EMW’s Monthly Peaks**  
7 **As a Percent of Annual Peak**  
8



9  
10 **Q. What allocation methods are reasonable in allocating fixed production plant-**  
11 **related costs?**

12 A. Either the Peak Demand method or the Average and Excess (“A&E”) Demand method  
13 are reasonable methods for allocating fixed production costs.

14 In the Peak Demand method, the fixed production plant-related costs are  
15 allocated to rate classes on demand factors that measure the class contribution to system  
16 peak or peaks. As demonstrated above, in EMW’s current case, class contributions

1 coincident with the four highest demands of June through August and December would  
2 be appropriate to use in calculating the production cost allocator.

3 While the Peak Demand method relies solely on class contribution coincident to  
4 the relevant monthly peak demands, the A&E methodology considers demand as well  
5 as class energy usage. As the name implies, the A&E Demand method consists of an  
6 average demand component and an excess demand component. The average demand  
7 component, which considers the class energy, is calculated by dividing the energy usage  
8 of each class by the number of hours in a year (8,760 for a non-leap year). The excess  
9 component, which considers the class peak demand, is calculated as the difference  
10 between the customer class's maximum non-coincident peak or peaks and the average  
11 demand. The average demand component for each class is then weighted by the system  
12 load factor and the excess component for each class is weighted by 1-load factor.<sup>2</sup> The  
13 composite allocator is simply the sum of the weighted average and excess components.

14 The A&E approach considers the load profile of customer classes by  
15 incorporating the maximum demands, load factor and average energy use. While the  
16 average demand measures the duration, the excess portion measures the variability of  
17 the load profile of a class. For example, as noted in the Commission decision in its  
18 Report and Order in Docket ER-2010-0036 (pages 84-85),

19 Some customer classes, such as large industrials, may run factories at a  
20 constant rate, 24 hours a day, 7 days a week. Therefore, their usage of  
21 electricity does not vary significantly by hour or by season. Thus, while  
22 they use a lot of electricity, that usage does not cause demand on the  
23 system to hit peaks for which the utility must build or acquire additional  
24 capacity. Another customer class, for example, the residential class,  
25 will contribute to the average amount of electricity used on the system,  
26 but it will also contribute a great deal to the peaks on system usage, as

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<sup>2</sup> See NARUC Manual, page 49,81-82



1 residential usage will tend to vary a great deal from season to season,  
2 day to day, and hour to hour.

3 **Q. Are you familiar with Section 393.1620 enacted in 2021?**

4 A. It is my understanding, from talking to counsel, that Section 393.1620 limits the  
5 Commission to considering class cost of service studies that utilize a method reflected  
6 in the NARUC manual for the allocation of fixed production plant costs associated with  
7 nuclear and fossil generating units. Specifically, Section 393.1620 provides:

8 In determining the allocation of an electrical corporation's total revenue  
9 requirement in a general rate case, the commission shall only consider class  
10 cost of service study results that allocate the electrical corporation's  
11 production plant costs from nuclear and fossil generating units using the  
12 average and excess method or one of the methods of assignment or  
13 allocation contained within the National Association of Regulatory Utility  
14 Commissioners 1992 manual or subsequent manual.

15 **Q. How is the average and excess method defined in Section 393.1620?**

16  
17 A. Section 393.1620.1 (1) defines the average and excess method as:

18  
19 A method for allocation of production plant costs using factors that consider  
20 the classes' average demands and excess demands, determined by  
21 subtracting the average demands from the noncoincident peak demands, for  
22 the four months with the highest system peak loads. The production plant  
23 costs are allocated using the class average and excess demands  
24 proportionally based on the system load factor, where the system load factor  
25 determines the percentage of production plant costs allocated using the  
26 average demands, and the remainder of production plant costs are allocated  
27 using the excess demands.

28 **Q. Are the peak demand and A&E methods included in the NARUC Manual?**

29 A. Yes, the Peak Demand and A&E methods are included in the NARUC manual. While  
30 the general approach is included in the NARUC manual, the manual appears to leave  
31 some discretion to the analyst regarding the specifics of application. For instance, the  
32 peak demand approach or the A&E approach could consider a single monthly peak or

1 multiple month peaks. In terms of developing the allocator for EMW, utilizing the class  
2 contribution to the Company's four highest system demands using the Peak Demand  
3 method or the A&E method are valid and reasonable approaches.

4 **Q. What allocation method does the Company use for allocating fixed production**  
5 **plant related costs?**

6 A. The Company uses the A&E method for allocating fixed production costs.<sup>3</sup> Ms.

7 Marisol Miller testifies that after considerable efforts to determine the most

8 appropriate production allocation methodology in prior rate cases, the Company

9 intends to continue to utilize the A&E method. EMW has been utilizing the A&E

10 method since the 2018 rate case (docket ER-2018-0146). In the 2018 case, the

11 Company evaluated a number of methodologies and chose the A&E method in large

12 part to acknowledge and appropriately recognize that industrial facilities with

13 relatively high load factors efficiently use the system and to develop industrial rates

14 that are competitive with neighboring utilities.<sup>4</sup>

15 I support the Company's decision to continue to use the A&E method in this  
16 case.

17 **Q. Has the A&E methodology seen widespread adoption by Missouri utilities?**

18 A. Yes, as the Commission is aware from the recent rate cases, the A&E methodology has  
19 been adopted by Ameren, Empire and Evergy respectively.

20 **Q. What class peaks does EMW use to calculate the excess demand portion?**

---

<sup>3</sup> The A&E allocator is also used to allocate transmission costs, which is appropriate for all of the same cost causative reasons as identified in my testimony for fixed production plant.

<sup>4</sup> See Mr. Thomas Sullivan's direct testimony in docket ER-2018-0145.

1 A The Company’s A&E approach relies on class contribution coincident to the four  
 2 summer peak demands to calculate the excess demand. The method prescribed in the  
 3 NARUC manual for the A&E method, however, appears to encourage the use of non-  
 4 coincident peak demands (NCP) and is also a more common approach used by other  
 5 Missouri utilities. Further, the Test Year system peak data shows that the four highest  
 6 demands are in June, July, August and December and therefore, not all four summer  
 7 months.

8 **Q. Have you calculated the A&E allocator using non-coincident peak demands for the**  
 9 **four highest system peak loads?**

10  
 11 A. Yes. I did. I used class non-coincident peak demands for the four highest system peak  
 12 load months of June, July, August and December receptively (or 4NCP) to make this  
 13 calculation.

14 **Q. Please explain in detail the derivation of the A&E 4NCP allocator.**

15 A. Figure 2 shows the derivation of the A&E 4NCP allocator.

16 **Figure 2: Derivation of the A&E 4NCP Allocator**

Column	1	2	3	4	5	6	7
	Peak Demand	Energy Sales	Average Demand	Excess Demand	Average Demand	Excess Demand	Total Allocator
	4NCP (MW)	with Losses (MWh)	(MW)	(MW)	(%)	(%)	(%)
Residential	1,149.86	4,011,929	457.98	691.88	45.23%	69.608%	57.09%
Small General Service	290.30	1,391,822	158.88	131.41	15.69%	13.221%	14.49%
Large General Service	240.09	1,315,137	150.13	89.96	14.83%	9.050%	12.02%
Large Power Service	315.58	2,107,294	240.56	75.02	23.76%	7.548%	15.87%
Lighting	10.34	43,778	5.00	5.34	0.49%	0.537%	0.51%
EV	0.41	509	0.06	0.35	0.01%	0.035%	0.02%
Total	2,006.58	8,870,469	1,013	994	100.00%	100.000%	100.000%

17  
 18 Column 1 shows the average of the four non-coincident peaks (“NCP”) for the  
 19 four peaking months by class. Column 2 shows the annual energy (MWh) by class and  
 20 Column 3 converts this annual energy (MWh) to average demand (MW) by dividing the  
 21 annual energy usage by 8,760 (number of hours in the test year). The excess demand

1 shown in Column 4 is calculated by subtracting the average demand in Column 3 from  
2 the NCP average demand for the four peaking months as reflected in Column 1. Column  
3 5 shows each class's average demand share as a percentage of EMW's system average  
4 demand. So, for instance the residential average demand percentage share is 457.98  
5 MW divided by the total of 1013 MW or 45.23%. Column 6 then shows each class's  
6 excess demand share as a percentage of the total excess demand for all classes. So,  
7 continuing to use the residential class as an example, this component would be 691.88  
8 MW divided by 994 MW or 69.61%. Column 7 represents that sum of (a) weighting  
9 class average demand as a proportion to the system average demand (Column 5) by the  
10 system load factor (51.36%) and (b) weighting the class excess as a proportion to the  
11 total excess demand (Column 6) by 1 minus the system load factor (48.64%). This  
12 method is consistent with the NARUC manual.

13 The total allocator calculated in Column 7 of Figure 3 is used to allocate fixed  
14 production plant-related costs to the classes. For example, based upon this  
15 methodology, the residential class should be allocated 57.09% of the total fixed  
16 production plant-related costs, while the LPS and LGS classes should be allocated  
17 15.87% and 12.02% of these costs respectively.

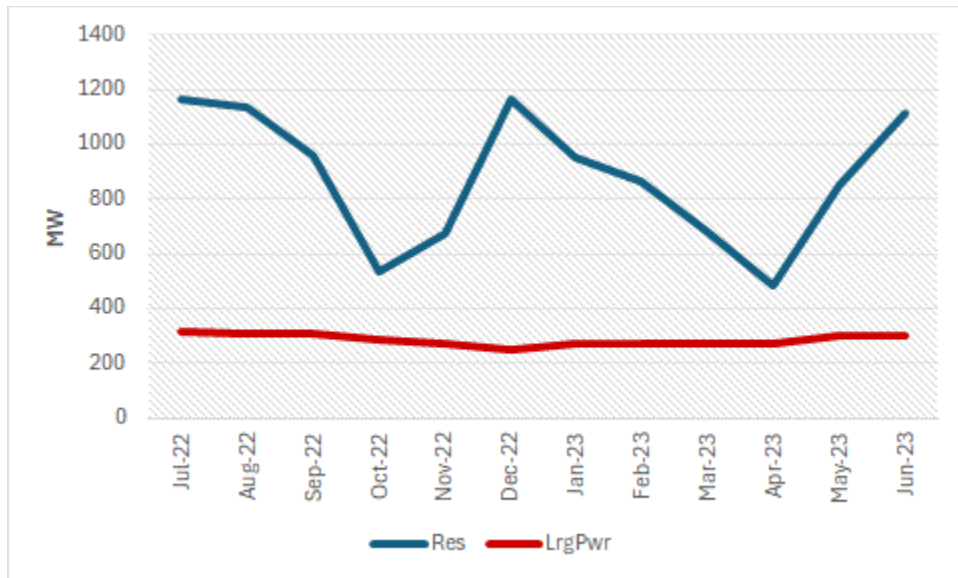
18 **Q. What insights can be gained from Figure 2 above?**

19 A. As the Commission recognized in its 2010 Ameren decision, the class average and  
20 excess demand calculations provide important insights regarding the relative variability  
21 in each class's load profile. Classes with higher variability use the system less  
22 efficiently, are generally weather sensitive and cause demand on the system to hit peaks.  
23 From a relative standpoint, classes with excess demand percentage shares (Column 6 in

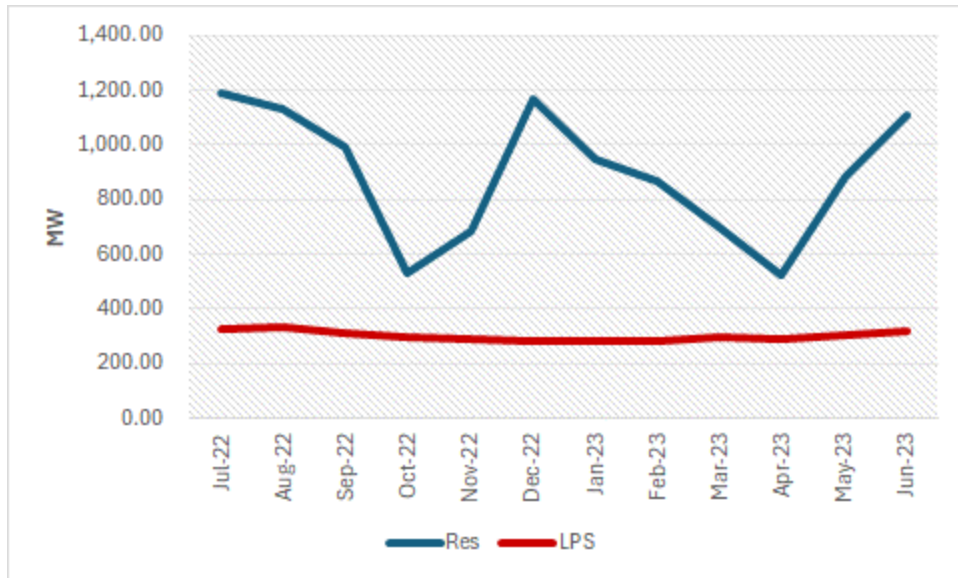
1 Figure 2) that exceed their respective average demand percentage shares (Column 5 in  
2 Figure 2) have higher variability in their load profile such as the residential class.  
3 Conversely, classes with average demand percentage shares higher than their excess  
4 demand shares have lesser variability and utilize the system more efficiently such as the  
5 Large General Service and Large Power Service classes.

6 Figures 3(a) and 3(b) demonstrate the difference in variability in both monthly  
7 coincident and non-coincident peak demand for two classes, namely, residential and  
8 LPS classes respectively. The graphs show the higher variability or “peakiness” in  
9 residential peak demands compared to the LPS class, which is relatively flatter.

10 **Figure 3 (a): Residential and LPS Class Monthly CP Demands**



11  
12 **Figure 3 (b): Residential and LPS Class Monthly NCP Demands**



1

2 **Q. Did you use the Company’s COSS model to calculate the results using the A&E**  
 3 **4NCP allocator?**

4 A. Yes, I did. I changed the Company’s A&E allocator in the Company’s COSS model  
 5 from the A&E 4CP to MECG’s A&E 4NCP allocator.

6 **Q. Please explain how the COSS results are shown.**

7 A. Upon completion of the class cost of service study, the net income for each class  
 8 (revenues less expenses) is divided by the rate base dedicated to serving that class to  
 9 calculate the rate of return earned at present rates. To the extent that a class rate of return  
 10 is greater than the system return, then the revenues recovered from the class are more  
 11 than the costs to serve that class. Similarly, to the extent that a class rate of return is  
 12 lower than the system return, then the revenues recovered from the class are less than  
 13 the costs to serve this class. For instance, as reflected in Figure 4, EMW’s overall earned  
 14 return under the class cost of service study is 4.64% at present rates. As can be observed  
 15 from MECG’s COSS results (which are substantially similar to the Company’s results),

1 EMW earned a below system average return from the residential class (2.74%) and  
 2 above system average return from the small general service (9.01%), lighting (8.93%),  
 3 large general service (7.44%) and large power classes (5.94%) respectively. The  
 4 Company earned a negative return from the EV class, meaning that this class’s revenue  
 5 was not enough to cover its expenses.

6 **Q. Are the COSS results using EMW’s A&E 4CP method and your A&E 4NCP**  
 7 **method generally consistent?**

8 A. Yes, they are. I compared the earned rate of return (“ROR”) and the relative ROR<sup>5</sup> and  
 9 found that the results are substantially similar. Classes with the relative rate of return  
 10 below 1 are currently paying rates that are below the cost to serve those classes such as  
 11 the residential class. Conversely, Classes with the relative ROR above 1 are currently  
 12 paying rates that are above the cost to serve those classes such as small general service,  
 13 lighting LGS and LPS respectively. Figure 5 shows a summary of the COSS results  
 14 utilizing MECG’s A&E 4NCP method at present rates.

**Figure 4: MECG v. EMW’s CCOSS Earned Rate of Return (“ROR”) and  
 Relative ROR by Class at Present Rates**

Class	EMW COSS RESULTS (A&E 4CP)		MECG COSS RESULTS (A&E 4NCP)	
	Earned ROR	Relative ROR	Earned ROR	Relative ROR
Residential	2.64%	0.57	2.74%	0.59
Small General Service	9.29%	2.00	9.01%	1.94
Large General Service	7.58%	1.63	7.44%	1.60
Large Power Service	5.94%	1.28	5.94%	1.28
Lighting	10.46%	2.26	8.93%	1.93
EV	-59.93%	-12.93	-52.08%	-11.23
EMW	4.64%	1.00	4.64%	1.00

15 **Q. Which fixed production cost allocation method should be used in this case?**

<sup>5</sup> Relative ROR is an index calculated as class ROR divided by system ROR.

1 A. I recommend that the Commission adopt the A&E 4NCP allocator (and the related  
2 MECG COSS results), since this method is more consistent with the A&E methodology  
3 described in the NARUC manual and Section 393.1620.1 (1). That said, should the  
4 Commission decide to adopt the Company's production cost allocation in this case,  
5 MECG does not oppose, given the substantial similarity in results.

6 ***D. COSS: Fuel Production Costs***

7 **Q. How were the fuel costs associated with the production plant allocated in EMW's**  
8 **COSS study?**

9 A. Ms. Miller indicates on page 17 of her direct testimony that fuel costs were allocated  
10 using a monthly kWh allocator.

11 **Q. What are your observations about the use of a flat energy allocator?**

12 A. This allocator does not recognize hourly energy cost and load variations. Fuel costs vary  
13 by the hour and are typically higher in the week daytime hours compared to night-time  
14 and weekend hours. Other utilities utilize an E8760 allocator to allocate fuel costs to  
15 appropriately recognize the hourly customer class and fuel cost variations. I recommend  
16 that in rebuttal testimony, the Company identify if it has the class and fuel cost data  
17 necessary to calculate the E8760 allocator and associated timeline to get this allocator  
18 incorporated in its COSS.

19 ***E. COSS: Fixed Distribution Plant Related Costs***

20 **Q. What are fixed distribution plant related costs?**

21 A. Fixed distribution plant related costs are associated with infrastructure that connects  
22 customers with the transmission grid and is built to provide access to electricity that has  
23 been generated and transmitted.



1 **Q. What method has the Company used to classify certain fixed distribution plant**  
2 **related costs booked in FERC accounts 364 through 368, into customer and**  
3 **demand related components?**

4 A. Costs booked in FERC accounts 364 through 368 are associated with certain distribution  
5 plant related fixed costs as follows:

- 6 • Account 364 – Poles, Towers and Fixtures
- 7 • Account 365 – Overhead Conductors and Devices
- 8 • Account 366, 367 – Underground Conduits, Conductors and Devices
- 9 • Account 368 – Line Transformers

10 Similar to past cases, the Company has utilized the minimum size or system  
11 method to classify distribution plant related costs in the above mentioned FERC  
12 accounts as customer and demand related.

13 In this case, the Company has introduced a new primary-secondary allocator that  
14 further splits the costs classified as demand-related into primary and secondary voltage.  
15 As noted in Ms. Miller’s testimony on page 18, this allocator is based on dollar-weighted  
16 line miles for both overhead and underground conductor.

17 **Q. What are your observations about the Company’s methodology to classify and**  
18 **allocate the distribution costs booked in FERC accounts 364 through 368?**

19 A. The minimum distribution approach is a long established approach, widely used by  
20 utilities and recognized in the NARUC manual. I support this approach as it recognizes  
21 the basic premise that that the distribution system exists to serve a dual purpose: 1) being  
22 capable of delivering service to customers’ residences or businesses (customer costs),  
23 and 2) ensuring that the distribution system is large enough to provide reliable service  
24 (demand costs).

1           As it relates to the Company's specific assumptions used to ascertain the  
2           minimum system costs, I am in the process of evaluating and have issued discovery  
3           questions. I may have additional feedback in rebuttal testimony.

4           While the Company has made efforts to further split the demand related costs  
5           into primary and secondary voltage, further refinements are necessary to ensure that  
6           customers served under primary voltage are not allocated a disproportionate share of  
7           the costs by failing to recognize the single phase and three phase delineation associated  
8           with the primary distribution system. I discuss this issue further below.

9   **Q.   Why should the single phases costs be separated out from the three-phase circuit**  
10 **configuration within the primary distribution system?**

11 A.   To properly assign costs to those customer classes and voltages that utilize the specific  
12 configurations. Feeders originate from substation in three-phase configuration and is  
13 distributed via separate conductors for each phase. The Company's primary  
14 distribution system consists of single-phase and three-phase circuit configurations.  
15 While the costs of these configurations are included in FERC accounts 364 through  
16 367, the Company does not currently differentiate the system costs based on single  
17 and three-phased configurations as shown in response to MECG 2.4 (see Attachment  
18 A). As a result the COSS allocates costs related to single phase primary distribution  
19 circuits to both primary voltage and secondary voltage customers, which does not  
20 follow cost causation. Failure to separate out costs associated with single versus three  
21 phase distribution circuits results in over allocating the costs to primary voltage  
22 customers due to the following:

1 1. The Company has identified that through its Mapping System that 61.4% of the  
2 Company total miles of circuits are single phase and 38.6% are three-phase (including  
3 the two-phase configuration which is used to provide a form of three-phase service).  
4 As noted by the Company, the single phase circuits are not utilized to provide service  
5 to primary customers.<sup>6</sup> Therefore, the single phase circuit related costs associated  
6 with 61.4% of the Company's total miles of circuits should only be allocated to  
7 secondary voltage customers. None of these costs should be allocated to primary  
8 voltage customers.

9 2. As it relates to the three-phase related configuration, the costs associated with this  
10 configuration should be allocated to secondary and primary voltage customers because  
11 as noted by the Company, the secondary voltage customers are also served by three-  
12 phased circuit configuration.<sup>7</sup>

13 I am particularly concerned regarding the over allocation to primary customers (and  
14 therefore, related classes such as LPS) in this case because the Company has requested  
15 \$56 million in revenue requirement associated with new infrastructure related  
16 primarily to distribution equipment, which includes overhead and underground  
17 conductors and associated infrastructure that incorporates the single phase and three-  
18 phase circuits.

19 **Q. Do you know of other utilities that have delineated between single phase and**  
20 **three phase circuits related costs within their primary distribution system?**

21 A. Yes, I know of at least two examples of major utilities that have separated out the  
22 single phase versus three phase costs and allocated them appropriately:

---

<sup>6</sup> See response to MECG 2.4 b.

<sup>7</sup> See response to MECG 2.4 d.

- 1       • Xcel Energy in Minnesota introduced this delineation in 2013 in docket E002/GR-13-  
2       868 and has been including it since that time.
- 3       • We Energies in Wisconsin introduced this delineation in 2014 in docket 05-UR-107  
4       and has incorporated it in their COSS since that time.

5   **Q.   Based on the above observations, what is your recommended approach to the**  
6   **Company to address this issue?**

7   A.   Instead of identifying a primary and secondary allocator for costs classified as demand  
8       related to be split into primary and secondary voltage service levels, I recommend three  
9       subcategories:

- 10   1. Single-phase primary costs: These costs should be allocated to only secondary voltage  
11       customers since single-phase circuits are only used to provide service to secondary  
12       customers and not used to provide service to primary voltage customers.
- 13   2. Three-phase primary costs: These costs should be allocated to primary and secondary  
14       voltage customers to follow cost causation as discussed above.
- 15   3. Secondary costs. These costs should be allocated to secondary voltage customers only.

16               Based on the Company's discovery response to MEEG 2.4 (Attachment 1), the  
17       Company's systems do not currently differentiate between single and multi-phase  
18       configuration. I recommend that the Company explain in rebuttal testimony the steps  
19       and effort needed to get access to the data needed to conduct the separation of costs  
20       and the associated timeline.

21   **Q.   Please summarize your recommendations regarding COSS.**

22   A.   The summary of my recommendations is as follows:

1           **Fixed Production Cost Allocator:** I recommend that the Commission adopt the A&E  
2           4NCP allocator (and the related MECG COSS results), since this method is more  
3           consistent with the A&E methodology described in the NARUC manual and Section  
4           393.1620.1 (1). That said, should the Commission decide to adopt the Company’s  
5           production cost allocation in this case, MECG does not oppose, given the substantial  
6           similarity in results.

7           **Fuel Cost Allocation:** In rebuttal testimony, the Company should identify if it has the  
8           class data necessary to calculate the E8760 allocator and associated timeline to get this  
9           allocator incorporated in its COSS.

10          **Fixed Distribution Plant related to FERC Accounts 364-367:** I recommend that in  
11          rebuttal testimony, the Company should identify the steps and effort needed to get  
12          access to the data needed and the associated timeline to delineate between single phase  
13          and three phase distribution configurations to properly allocate costs to secondary and  
14          primary customers

#### 15          **IV. REVENUE REQUIREMENT ALLOCATION**

16          **Q.       What should be the primary guiding principle in establishing fair and reasonable**  
17          **rates?**

18          A.       A properly developed COSS is important to establishing fair and reasonable rates. It is  
19          used to determine revenue requirement for the Company and should be used as the  
20          primary guiding principle in allocating revenue requirement to classes and informing  
21          rate design. Also as discussed earlier in my testimony, such an approach fulfills the  
22          important goals of promoting equity among classes and encouraging economic  
23          efficiency. If revenues are allocated to classes and align closely with the class cost

1 responsibility, equity is maintained because each class pays its fair share of costs.  
2 Further, if retail rates align with cost of service, they reflect accurate pricing signals that  
3 drive consumer behavior, which in turn results in more efficient use of the system and  
4 minimizes system costs.

5 **Q. Can other factors be also considered?**

6 A. Yes. Other factors such as gradualism and rate continuity may also be considered. At  
7 the same time, however, these factors should not be the dominating elements such that  
8 there is little to no movement towards cost responsibility. We must also weigh in the  
9 fairness consideration and not ignore the important aspect that when one class is not  
10 paying their full share, one or more classes are being asked to pay more than their cost  
11 responsibility.

12 **Q. Do you rely on MECG's COSS results to make recommendations regarding**  
13 **revenue apportionment to classes?**

14 A. Yes. I do. While both the Company's and MECG's COSS could be refined further to  
15 address the issues explained in Section III, the current methodology is reasonable and  
16 the COSS results can be relied upon, as guidance for revenue apportionment.

17 As noted earlier, MECG's COSS results are substantially similar to the  
18 Company's COSS results and I draw the same conclusions from a policy perspective  
19 from both the COSS results. For instance, given that the residential and EV classes have  
20 ROR below EMW's system ROR at present rates, these classes should receive above  
21 system average increases. All other classes such as the small general service, large  
22 general service, large power service and lighting classes have RORs above the system

1 ROR at present rates. Therefore, these classes should receive increases that are below  
2 the system average increase.

3 **Q. What are the total revenue neutral adjustments needed by class to completely**  
4 **eliminate the cross subsidization at present rates in this case?**

5 A. Figure 5 shows the derivation of the MECG COSS revenue neutral adjustments  
6 needed to align revenue responsibility with cost responsibility at present rates. Lines 1  
7 through 5 show the results for each class at present rates and the related ROR and  
8 relative ROR. Line 8 shows the income required to achieve equal ROR and Line 9  
9 shows the difference between the income required to achieve equal ROR (Line 8) and  
10 income that produces the current ROR (Line 3). Lines 10 and 11 show the revenue  
11 neutral changes (in both nominal dollars and %) needed to class revenues in order to  
12 completely eliminate cross subsidization. That is, it shows the amount of increase or  
13 decrease required to have every class yield the same rate of return, before considering  
14 any overall change in revenues for the utility. Line 12 (a) and 12 (b) shows 25% and  
15 50% revenue neutral shifts to yield the same ROR at present rates.

16 As can be observed, in order to eliminate any cross subsidization under present  
17 rates, significant revenue neutral changes would be necessary. For example, under  
18 present rates, the Residential would need a revenue neutral increase of 10.4% to base  
19 rate revenues in order to achieve cost based responsibility. The SGS, LGS and LP  
20 classes would need a 17.8%, 11.4% and 4.9% decrease respectively.

21

22

**Figure 5: MECCG COSS: Revenue Neutral Adjustments Needed  
for Equal ROR at Present Rates**

LINE NO:		MO West Retail	Residential	Small General Service	Large General Service	Large Power Service	Electric Vehicle	Lighting
<b>REVENUE REQUIREMENT SUMMARY</b>								
1	Test Year Revenue	\$778,520,014	\$411,065,976	\$127,764,174	\$94,688,002	\$122,364,301	\$83,305	\$13,661,095
<b>RETURN AT PRESENT RATES</b>								
2	Rate Base	\$ 2,830,914,746	\$ 1,713,682,941	\$394,681,313	\$294,026,969	\$347,890,345	\$ 1,595,232	\$61,134,518
3	Net Operating Income at Present Rates	\$131,252,484	\$ 46,894,762	\$ 35,574,262	\$ 21,867,850	\$ 20,679,172	\$ (830,727)	\$ 5,456,551
4	Rate of Return at Present Rates	4.64%	2.74%	9.01%	7.44%	5.94%	-52.08%	8.93%
5	Relative Rate of Return	1.00	0.59	1.94	1.60	1.28	(11.23)	1.93
<b>EQUALIZED RATE OF RETURN AT PRESENT RATES</b>								
6	Rate Base	\$ 2,830,914,746	\$ 1,713,682,941	\$ 394,681,313	\$ 294,026,969	\$ 347,890,345	\$ 1,595,232	\$ 61,134,518
6	Equalized Rate of Return	4.64%	4.64%	4.64%	4.64%	4.64%	4.64%	4.64%
7	Relative Rate of Return	1.00	1.00	1.00	1.00	1.00	1.00	1.00
8	Return Required @ Equalized Rate of Return at Present Rates	\$131,252,484	\$79,453,167	\$18,298,998	\$13,632,261	\$16,129,582	\$73,961	\$2,834,440
9	Difference in Income at Equal ROR at Present Rates	\$0	\$32,558,405	(\$17,275,264)	(\$8,235,588)	(\$4,549,589)	\$904,689	(\$2,622,111)
10	Revenue Neutral Change to attain Equal ROR at Present Rates	\$0	\$42,752,116	(\$22,683,977)	(\$10,814,069)	(\$5,974,020)	\$1,187,938	(\$3,443,068)
11	Revenue Neutral % Change to attain Equal ROR at Present Rates	0.0%	10.4%	-17.8%	-11.4%	-4.9%	1426.0%	-25.2%
12 (a)	25% Revenue Neutral Change @ Equal ROR at Present Rates	0.0%	2.6%	-4.4%	-2.9%	-1.2%	356.5%	-6.3%
12 (b)	50% Revenue Neutral Change @ Equal ROR at Present Rates	0.0%	5.2%	-8.9%	-5.7%	-2.4%	713.0%	-12.6%

**Q. What is the Company’s revenue allocation proposal?**

A. The Company proposes to apply certain multipliers to the average system increase in order to move classes closer to cost. Specifically, the Company proposes the following increases for each class for a system average increase of 13.99% (excluding special contracts):

- Apply a 16.59% increase to the residential and EV classes, which uses approximately 116% of the jurisdictional rate increase as the multiplier.
- Apply 15.05% to the LPS class which uses approximately 100% of the jurisdictional rate increase as the multiplier.
- Apply a 13.03% to the LPS class which uses approximately 80% of the jurisdictional rate increase as the multiplier.
- Apply 8.84% to the SGS class which uses approximately 60% of the jurisdictional rate increase as the multiplier. and Apply 8.65% to the lighting class which uses approximately 60% of the jurisdictional rate increase as the multiplier.

**Q. Please comments on the Company’s proposed approach.**

A. Given an average double digit jurisdictional increase of 13.99%, I am generally supportive of the Company’s method to gradually moving class revenue responsibility



towards cost responsibility. With a proposed double digit increase, it is not unreasonable to moderate the impact to certain classes and gradually move towards cost responsibility. However, I have an alternative recommendation for revenue apportionment to classes which amongst other factors, considers that the LPS class should not end up receiving an above average increase because this class earned an above average return under present rates.<sup>8</sup>

**Q. What is your recommendation to the Commission?**

A. My recommendation is provided in Figure 6 below. In this Figure, I show the COSS multipliers for the Company and MECG (last two columns). As can be observed in comparing with COSS based multipliers, both the Company and MECG applied significant rate moderation in recommending the revenue apportionment to classes.

**Figure 6: EMW and MECG Multiplier Comparisons**

	COSS Multipliers (Class Increase/ System Increase)		Multiplier Percent of Jurisdictional Increase	
	EMW	MECG	EMW	MECG
Residential	194%	189%	116%	117%
Small General Service	-49%	-42%	60%	70%
Large General Service	0%	4%	80%	77%
Large Power Service	43%	43%	100%	87%
EV	10111%	10721%	116%	117%
Lighting	-114%	-57%	60%	70%

Aside from moderating the impacts, my recommendation is similar to the Company’s proposal in the following ways:

- First, out of all the classes, the residential and EV classes are subject to the highest and same multipliers because the COSS results show that at present rates, these two classes have relative RORs which are less than 1 or negative (see Figure 5, line 5).

<sup>8</sup> It should also be noted that the LGS and LPS are the two classes that includes primary customers which are over allocated certain distribution costs as discussed in Section III.

- Second, out of all the classes, the SGS and lighting classes are subject to the lowest and same multiplier because the relative RORs are the highest and close to one another at 1.93 and 1.94 respectively.

My recommendation departs from the Company’s proposal with regards to the LPS class. I prescribe a lower than 100% multiplier to the LPS to recognize the above average return (or higher than 1 ROR) at present rates. I would also note that my revenue allocation recommendation is generally close to a 25% revenue neutral shift for most classes as shown in Figure 7 while remaining consistent with the application of the same class multiplier between certain classes based on relative ROR considerations at present rates.

**Figure 7: MECG’s COSS 25% Revenue Neutral Shift under Present Rates versus Revenue Neutral Shift Included in MECG Revenue Allocation Recommendation**

	25% Revenue Neutral Shift from MECG COSS	Revenue Neutral Shift included in MECG Revenue Allocation
Residential	2.6%	2.7%
Small General Service	-4.4%	-4.1%
Large General Service	-2.9%	-2.9%
Large Power Service	-1.2%	-1.6%
EV	356.5%	2.6%
Lighting	-6.3%	-4.1%

With regards to the revenue requirement increase, the MECG multiplier recommendations shown in the last column in Figure 6 would be reasonable to apply for system wide increases of 10% and above. If the systemwide rate increase is lower than 10%, the multipliers should change to accommodate additional revenue neutral shifts and make further movement towards cost responsibility. The lower the

jurisdictional rate increase, the more it is reasonable to focus on larger revenue neutral shifts to get class revenue responsibility closer to cost responsibility.

**V. RATE DESIGN**

**Q. What are the main unit charge components of the LPS Rate?**

A The main unit charges consist of facilities charge, customer charge, demand and energy charges. The demand and energy charges are seasonally differentiated. Further, the demand charge includes base billing demand charges for the summer and winter and seasonal demand charges for the summer only. The energy charges reflect Hours Use structure and consist of three blocks for seasonal and energy charges respectively. As more energy is consumed, the rates are lower, which is implicitly accounting for higher use of energy in the off-peak hours. Figure 8 shows the existing charges for the LPS at the secondary voltage service level. The rate schedule also includes service at the primary, sub transmission and transmission voltage service level.

**Figure 8: LPS Rate at Secondary Voltage Service Level**

Demand Charge	Summer	Winter
Base Billing Demand	\$10.788	\$5.618
Seasonal Billing Demand	\$10.788	
Base Energy Charges		
First 180 Hours of Use per month	\$0.05445	\$0.05083
Next 180 Hours of Use per month	\$0.04287	\$0.03999
Over 360 Hours of Use per month	\$0.03759	\$0.03507
Seasonal Energy Charges		
First 180 Hours of Use per month	\$0.05445	\$0.03274
Next 180 Hours of Use per month	\$0.04287	\$0.03274
Over 360 Hours of Use per month	\$0.03759	\$0.03274
Customer Charge per Month	\$675.46	
Facilities Charge (\$/KW-Month)	\$3.223	

1 **Q. What is the Company’s revenue allocation to the LPS class?**

2 A. The Company proposes a revenue increase of 15.05% for a systemwide increase of  
3 13.99%. As discussed earlier, I do not support this increase for the LPS class. In the  
4 rate design discussion, however, I assume the same revenue requirement as the  
5 Company in order to demonstrate an apples-to-apples comparison.

6 **Q. What is the Company’s rate design proposal for the LPS class?**

7 A The Company proposes to align the facility and customer charges based on its COSS  
8 results. With regards to changes in other charges, the remaining revenue requirement is  
9 collected via demand and energy charges with extra weighting given to demand charges  
10 “in recognition of the historical fixed/variable cost disparity between energy and  
11 demand charges.”<sup>9</sup>

12 **Q. What elements do you support regarding the Company’s proposal?**

13 A I support the Company’s proposal to allocate higher cost increases to demand charges  
14 versus energy charges. The higher cost recovery from fixed charges makes sense since  
15 over 95% of the revenue requirement increase is associated with increases in fixed costs.

16 **Q. What concerns do you have regarding the Company’s rate design proposal?**

17 A. The Company proposes to increase the facility charges by 69%, 63% and 129% for the  
18 LPS secondary, primary and substation classes respectively. Aside from the concern  
19 about the large percentage increases impacting gradualism principles, I also do not feel  
20 comfortable in completely relying on the COSS results to increase the facility charges  
21 this significantly due to the issues regarding the classification and allocation of certain

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<sup>9</sup> See Ms. Miller’s direct testimony at page 30.

1 distribution plant related costs which may not be properly allocating costs to the LPS  
2 class and sub classes.

3 **Q. What do you recommend?**

4 A. Assuming the same revenue requirement allocation as proposed by the Company, my  
5 recommendation is as follows:

- 6 1. Increase facility charges by no more than 1.49 times the existing rate for secondary and  
7 primary voltage service levels.<sup>10</sup>
- 8 2. Retain the existing customer charge.
- 9 3. Retain the same percentage increase to energy charges as proposed by the Company.
- 10 4. Increase the billed demand charge to recover the remaining revenue requirement.

11 **Q. What are the main unit charge components of the LGS Rate?**

12 A The main unit charges consist of facilities charge, customer charge, demand and energy  
13 charges. The LGS rate design is similar to the LPS rate design and consists of the same  
14 components as described earlier for the LPS rate. Figure 9 shows the current charges.  
15 The difference is in the charges. The demand charges for the LGS class are lower than  
16 \$1/KW-month which means substantial under-recovery of fixed costs through demand  
17 charges and over-recovery through energy charges. Figure 9 shows the existing charges  
18 for the LGS at the secondary voltage service level. The rate schedule also includes  
19 service at the primary voltage service level.

20

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<sup>10</sup> For the substation level, the facility charge should be no more than half the proposed rate. At present, there is no facility charge.

1

**Figure 9: LGS Rate at Secondary Voltage Service Level**

Demand Charge	Summer	Winter
Base Billing Demand	\$0.906	\$0.61
Seasonal Billing Demand	\$0.906	
<b>Base Energy Charges</b>		
First 180 Hours of Use per month	\$0.08973	\$0.06836
Next 180 Hours of Use per month	\$0.06790	\$0.06266
Over 360 Hours of Use per month	\$0.04751	\$0.04291
<b>Seasonal Energy Charges</b>		
First 180 Hours of Use per month	\$0.08973	\$0.03753
Next 180 Hours of Use per month	\$0.06790	\$0.03753
Over 360 Hours of Use per month	\$0.04751	\$0.03753
Customer Charge per Month	\$74.84	
Facilities Charge (\$/KW-Month)	\$2.290	

2

3 **Q. What is the Company’s revenue allocation to the LGS class?**

4 A. The Company proposes a revenue increase of 13.03% for a systemwide increase of  
5 13.99%. While my revenue allocation recommendation differs from the Company for  
6 the same systemwide increase, I assume the same revenue requirement as the Company  
7 in order to demonstrate an apples-to-apples comparison.

8 **Q. What is the Company’s rate design proposal for the LGS class?**

9 A. Similar to the proposal for LPS, the Company proposes to align the customer charges  
10 and facility charges with its COSS results. With regards to changes in other charges, the  
11 remaining revenue requirement is collected via demand and energy charges with extra  
12 weighting given to demand charges as was done for the LPS rate. The higher cost  
13 recovery from fixed charges makes sense since over 95% of the revenue requirement  
14 increase is associated with increases in fixed costs.

15

1 **Q. What concerns do you have regarding the Company's rate design proposal?**

2 A. The Company proposes to increase the facility charges by 89% and 104% for the LGS  
3 secondary and primary classes respectively. I also do not feel comfortable in completely  
4 relying on the COSS results to increase the facility charges this significantly due to the  
5 issues regarding the classification and allocation of certain distribution plant related  
6 costs which may not be properly allocating costs to the LGS class and sub classes.  
7 Further, I am concerned that the LGS billing demand charges are very low and not  
8 consistent with cost of service guidance.<sup>11</sup>

9 **Q. What do you recommend?**

10 A. Assuming the same revenue requirement allocation as proposed by the Company to  
11 allow for an apples-to-apples comparison, my recommendation is as follows:

- 12 1. Increase facility charges no more than 1.75 times the existing rate for the two voltage  
13 service levels.
- 14 2. Retain the existing customer charge.
- 15 3. Retain the same percentage increase to energy charges as proposed by the Company.
- 16 4. Increase the billed demand charge to recover the remaining revenue requirement.

17 **Q. Do you have any other comments regarding rate design?**

18 A. Yes, I do. Company witness Mr. Brad Lutz has described the Company's proposed  
19 approach to phase out of the hours use rate design to a time variant rate design in a  
20 future rate case. He also identified that Evergy Missouri Metro's non-residential rates  
21 would transition towards a time variant rate sooner than EMW due to the presence of

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<sup>11</sup> The Company's and MECG's COSS shows cost of service guidance for demand charges is above \$15/KW-month.

1 the Annual Base Demand (or ABD) element in EMW's LGS and LPS rate design. He  
2 indicated that the ABD element would need to be addressed first before transitioning  
3 to a time variant rate due to bill impact considerations.<sup>12</sup>

4 **Q. Do you support Mr. Lutz's view with regards to the transition to time variant**  
5 **rates?**

6 A. Yes, I support Mr.Lutz's view that we need to consider rate impacts and transition  
7 towards time variant rates by addressing the ABD element as a first step as it relates to  
8 EMW LGS and LPS rates. In this regard, I recommend that the Company work  
9 collaboratively with MECG to develop and refine its proposed approaches before  
10 introducing these proposals in a future case.

11 **Q. Does this conclude your direct testimony?**

12 A Yes.

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<sup>12</sup> See Mr. Brad Lutz's direct testimony on page 21.





## Attachment 1

Evergy Missouri West  
Case Name: 2024 Evergy MO West Rate Case  
Case Number: ER-2024-0189

Requestor Opitz Timothy -  
Response Provided July 09, 2024

### Question:2.4

Please answer the following questions regarding Evergy Missouri West's three-phase and single-phase primary distribution circuits:

a. What portion of the cost of the Company's primary distribution system is associated with three-phase circuits? What portion is associated with single-phase circuits?

Please provide the information in terms of both percentage of overall primary distribution system and, if available, as a percentage of net plant cost for the primary distribution system.

b. Are single-phase circuits used to provide service to primary voltage customers? If so, how many primary voltage customers does Evergy Missouri West serve and how many primary voltage customers receive their electric service via single-phase primary circuits?

c. What portion of the primary voltage customers' class load is served by single-phase circuits?

d. Are single-phase circuits primarily used to provide service to secondary voltage customers?

**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:**

- a. Company accounting systems do not differentiate system costs based on single phase or three phase configurations. Separately, the Company Mapping system does identify configuration. Based on that source, 61.4% of the Company total miles of circuits are single phase and 38.6% are three phase (including the two-phase configuration which is used to provide a form of three-phase service).



- b. Company systems do not link the metering voltage to the circuit configuration, but anecdotally, it is rare that single-phase circuits are used to provide service to primary voltage customers. For the purpose of this data request, the Company would accept that there are no occurrences where single-phase circuits used to provide service to primary voltage customers.
- c. Company systems do not differentiate load by single phase or three phase configurations. Please see the response to part “b” of this question.
- d. Yes, where energy is distributed via single phase circuits, the customers on those circuits are primarily served via secondary voltages. It should be noted that the Company serves a considerable majority of customers via secondary voltages. As a result, customers on three phase circuits are also primarily served via secondary voltages.

**Information provided by:** Brad Lutz

**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