Exhibit No. 13

Evergy Missouri Metro – Exhibit 13
Craig E. Brown
Surrebuttal Testimony
File Nos. ER-2022-0129 & ER-2022-0130

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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2022-0129 / 0130

SURREBUTTAL TESTIMONY

OF

CRAIG E. BROWN

ON BEHALF OF

EVERGY MISSOURI METRO and EVERGY MISSOURI WEST

Kansas City, Missouri
August 2022

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SURREBUTTAL TESTIMONY

OF

CRAIG E. BROWN

Case No. ER-2022-0129 / 0130

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Craig E. Brown. My business address is 9400 Ward Parkway, Kansas City, Missouri 64114.

Q: Are you the same Craig E. Brown who submitted surrebuttal testimony in these dockets on July 13, 2022?

A: Yes.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Evergy Metro, Inc. d/b/a Evergy Missouri Metro ("EMM") and Evergy Missouri West, Inc. d/b/a Evergy Missouri West ("EMW") (collectively, the "Company").

Q: What is the purpose of your surrebuttal testimony?

A: The purpose of my surrebuttal testimony is to respond to topics related to the Company's Class Cost of Service ("CCOS") studies and issues raised by Staff witness Lange in her rebuttal testimony. In particular, I (1) review Staff's CCOS studies, and (2) respond to Staff's CCOS rebuttal testimony.

Q: Why weren't issues with Staff's CCOS Studies covered in your rebuttal testimony?

A: The Company requested I only address a few specific topics with my rebuttal testimony. Given the continued testimony about the appropriateness of CCOS studies and allocation methodologies used, the Company has requested I offer my review of Staff rebuttal testimony and its CCOS Study as an expert witness in this area and offer my experience with studies of these types in the ratemaking process.

Q: What qualifies you as an expert witness in the area of electric cost of service and rate design?

A: I have spent the past 18 years of my career providing rate and regulatory consulting services to my clients, which are predominantly electric utilities. I have had the privilege of being employed by two of the top engineering and consulting firms serving the electric utility industry; the past three years with 1898 & Co., the consulting division of Burns & McDonnell Engineering Company and the prior fifteen years at Black & Veatch. I learned and developed my skills and experience under the guidance of four expert witnesses that have conducted cost of service and rate design studies and provided expert witness testimony across the United States and in Canada, including many proceedings before the Missouri Public Service Commission. I spent years conducting the studies they filed and supporting their testimony. I now lead a team of consultants conducting cost of service and rate design studies across the United States and serve investor-owned, municipal, and cooperative electric utilities. I am further supported by having direct access to Burns & McDonnell's over 10,000 engineers and consultants. Burns & McDonnell is ranked #1 in transmission and distribution engineering by Engineering New Record ("ENR").

Q: Please summarize your surrebuttal testimony.

A: 1. Staff's CCOS studies are incomplete and include arbitrary allocations and adjustments not based on cost causation principles. Staff's CCOS results should be rejected.

2. The Company CCOS studies are complete, based in industry standard methods and data, are confirmed as such by intervening witness.

3. The Company's A&E 4CP method is more appropriate based on cost causation principles than the A&E 4NCP proposed by Staff and MECG.

4. Staff's CCOS rebuttal testimony demonstrates a misunderstanding of cost causation principles.

II. REVIEW OF STAFF CCOS STUDIES AND STAFF TESTIMONY

Q: Have you reviewed Staff's CCOS studies used in these cases?

A: I have reviewed the workpapers provided and attempted to make a thorough review of the CCOS models, but as noted in Staff's direct testimony[1], Staff did not prepare a full CCOS study. Rather it adjusted certain classifiers and allocators and used its own gross cost of service and revenue requirements. Furthermore, Staff did not provide a functional working CCOS model to validate its adjustments and the results they show are generally hard coded numbers in the files they provided.

Q: Does this limit the validity of Staff's CCOS studies?

A: It certainly limited my ability to validate Staff's CCOS results and the claims made in rebuttal testimony by not having the ability to trace calculations through the entire model. With the lack of transparency, one must accept the results at face value, in my mind limiting the value.

Q: How does this differ from the CCOS models provided by the Company?

A: The Company was required to submit fully functional and unlocked CCOS studies with full supporting workpapers. Staff and any interveners that present alternative CCOS results

[1] Lange Direct, p. 3.

based on their own internal studies should be held to the same standard and provide fully functional models and well documented workpapers.

Q: What is the overarching theme in Staff's testimony as to why it could not provide a full CCOS study?

A: On page 27 of Ms. Lange's rebuttal, starting on line 5 Staff states, "In short, due to its use of an unreasonable A&E 4CP allocator and selection of a net energy allocator which ignore the existence of the SPP integrated energy market, the EMM study also fails to properly classify distribution assets, substation assets, and transmission assets that would not have been installed but-for facilitation of service to unique customers served at primary, substation, and transmission voltage. they were given limited data therefore the entire study is unreliable. Staff further states, "…due to lack of information about the use of the distribution system, lack of information about distribution expenses, lack of detail of energy consumption by rate schedule, and reliance on antiquated production allocation methods…"[2]

Q: Are Staff's concerns valid?

A: No, they are not. As I will describe in more detail throughout my surrebuttal testimony, the Company has provided a comprehensive cost of service study using industry standard methods and appropriate detail by rate class. Further, distribution expenses are properly recorded using the FERC Uniform System of Accounts ("USoA") and provides all the detail necessary to functionalize and classify test year expenses. Normalized energy consumptions by rate class, including all subclasses, were provided by the Company, and are embedded in the Company's CCOS studies. Further, the intervening parties in this case

[2] Lange Direct, p. 25.

have confirmed that the CCOS study prepared by the Company is based on an appropriate level of detail, follows accepted industry standards and methodologies, and produces results appropriate for making decision of rate class revenue recovery.

Q: What is your response to the level of detail requested by Staff and its assertion that the Company is not being responsive to data requests by not providing the level of detail requested?

A: The level of detail requested by Staff is in a level of detail I have not seen applied in a cost of service study. It appears to me that Staff is attempting to directly assign costs to customers where it is not appropriate. For example, data request question 0212 requests the following:

> *Please identify, by retirement unit and account, the transmission or distribution plant associated with providing service to isolated customers. Please identify, by rate schedule and voltage and phase at which service is taken, the retirement unit and account associated with transmission or distribution plant associated with providing service to isolated customers. For example, if a customer is served at 34kV but is adjacent to a 69kV, please identify the transformation equipment, conductor, switchgear, etc, used to facilitate service to that customer; or the line transformer and conductor combination used as a service drop for a given size of secondary customer.*

First and foremost, I can think of no reason the Company would keep track of how many "isolated customers" it has or even what the definition of isolated is in this context. It is unclear how this level of detail would be applied, but it appears Staff desires to directly assign the majority distribution plant to rate subclasses. While direct assignment of costs is appropriate in certain cases, such as dedicated feeders and related distribution facilities not owned by the customer, it is inappropriate and an ineffective use of resources to track the level of resources requested by Staff.

Q: Can you expand on why an over-reliance on direct assignment is inappropriate and not even feasible?

A: The reality of a distribution system is that it's an extremely complex network of assets consisting of millions of individual components including poles, conductor, circuit breakers, switches, communication devices, and transformers. Most of these components are shared among different numbers and types of customers and customer classes, and many of them impact service at a variety of voltage levels and phases. The key point being the distribution grid is designed to and operates as a *network*, and not as a series linear spurs serving individual customers. So even though a customer may have a small segment of conductor that serves only them or are the only customer connected to a line transformer, that does not mean the power they use does not travel through a significant portion of the shared network before it gets to the point where Staff considers them "isolated." The distribution network is designed to provide both reliability and redundancy for all customers. Staff seems focused on directly assigning individual poles and conductor to individual customers, which undermines the purpose of conducting a cost allocation study in the first place.

Q: Why is it not appropriate or feasible to directly assign individual distribution system assets?

A: Electric utility assets are organized and categorized according to the standards set forth in the FERC USoA. Distribution assets are considered mass property, which means they are relatively homogeneous property units that tend to be retired individually but tracked as a group. FERC prescribes the level of detail that should be maintained in financial records related to mass property as follows:

B. For each category of mass property:

(1) A general description of the property and quantity;

(2) The quantity placed in service by vintage year;

(3) The average cost as set forth in Plant Instructions 2 and 3 of this part; and

(4) The plant control account to which the costs are charged.[3]

Note that the FERC definition refers to "general description" and "average cost" for the quantities of assets in a given vintage year, which implies aggregate as opposed to individual tracking of assets. The level of detail Staff has requested does not exist in the financial records of the Company or most other utilities that follow the FERC USoA.

Even if the Company could identify and inventory the individual assets that serve each isolated customer through physical inspection of hundreds, if not thousands, of site visits, those assets could not be tracked to the individual plant records to accurately identify the original cost and accumulated depreciation for the specific assets due to the nature of mass property accounting as defined by the FERC. It's difficult to even contemplate how this could be considered a reasonable approach to conducting a cost of service study.

Q: What is the impact of Staff's claim that EMM and EMW were unable to provide the data necessary to do a robust study of the proper classification, assignment, and allocation of the distribution system?

A: The impact is minimal for how the CCOS results are applied in this rate case; that is, to make direction changes in rate class revenue requirement responsibility. Staff states that data was not available to determine proper classification of the distribution system. This is patently false. A proper embedded cost of service analysis consists of three parts:

3 18 CFR Part 101, Definitions, Subsection 8.

functionalization, classification, and allocation. Functionalization refers to whether costs or plant are for the purpose of generation, transmission, distribution, or customer functions. These are generally well defined by the FERC USoA. Costs are classified based on the operational characteristics of the system - demand, energy, and customer. Guidance on how costs should be classified are well defined in the NARUC Cost Allocation Manual ("Manual") and are based on cost causation principles. In other words, costs that vary with the kW demand imposed by the customer are demand related; energy costs are those that vary with kWh that the utility provides; and customer costs are those that vary with the number of customers. The final step is allocation, where the functionalized and classified costs are allocated to rate classes using various methods based on cost causation principles.

Distribution system costs are classified as either demand or customer related. Further, the NARUC Manual defines methods used to identify the appropriate split between demand and customer costs within the distribution function. The Company applied the Minimum-Size Method in its CCOS studies to classify distribution costs.

Q: Do you believe that the NARUC methods to classify distribution costs are appropriate?

A: Yes, I do. I also believe that the current CCOS study better reflects the classification of distribution costs relative to prior Company studies because it follows the NARUC prescribed and industry accepted Minimum Size method to classify distribution costs between demand and customer.

Q: Would any of the minutiae of detail requested by Staff change the classification of costs in the CCOS study?

A: No, it would not.

Q: Would any of the additional detail requested by Staff change the allocation of costs to the Company's principal rate classes?

A: No, it would not, but it could change the allocation of costs *within* the rate classes, down to the subclass level. Examples of subclasses in this context would be standard residential services versus residential with electric heating or Large General Service at primary voltage versus Large General Service at secondary voltage.

Q: Please elaborate.

A: The allocation step often involves the most discussion or disagreement in methods of how to allocate the functionalized and classified costs to rate classes. Not only for the method selected for allocation, such as Average and Excess Demand versus Base-Intermediate-Peak, but also for the level of detail in if rate subclasses have individual cost of service analyses. The standard approach is to conduct CCOS analyses at the principal rate class level (residential, SGS, LGS, etc.). Staff's approach seems to imply an individual cost of service study for each rate code.

Q: Why is this unnecessary?

A: Rate classes are designed to be generally homogeneous groups of customers that generally have similar load characteristics. As load profiles within the classes become more unique or heterogeneous, that would indicate the need for a separate rate class.

Q: How would the allocation of energy costs by rate subclass be different than the class as a whole?

A: It would not be different. The Company's CCOS studies already use normalized kWh billing determinants by rate code. Therefore, allocations of costs that vary with energy have already been adjusted for voltage differences between primary and secondary customers, for example.

Q: How would the allocation of customer costs by rate subclass be different than the class as a whole?

A: There is a chance that small differences could be identified within a subclass, but it is unlikely to be impactful. This would only be an issue if the Company proposed customer charges for each rate subclass that were directly using the unit costs resulting from the CCOS Study. Since the Company's customer charge proposals are only generally guided by the CCOS Study, there is no concern.

Q: How would the allocation of demand costs by rate subclass be different than the class as a whole?

A: Demand costs are generally allocated on coincident peaks ("CP") or non-coincident peaks ("NCP"). As such, the allocation is based on system demand at a specific point in time. Depending on the diversity of customers within the class, there may be variance in the CP and NCPs for the subclasses, so the cost of service analyst must evaluate how the study results will be used. If the study will be used to justify directional class revenue adjustments, like in the Company's rate proposal, demand allocations at the rate class level are appropriate.

Q: What is the key takeaway from the discussion of rate class versus rate subclass cost of service studies?

A: If the goal of a cost of service study is to identify inter-class imbalances in cost recovery and make incremental changes in class revenue targets and provide general guidance on the cost of service basis for rate design components, then the CCOS studies presented by the Company are appropriate for use in this rate case. If the Commission wishes to evaluate whether new rate classes should be created or if CCOS results will be more directly applied to rate design, some additional detail may be warranted in future rate cases.

Q: What other issues have you identified with Staff's approach to its CCOS studies?

A: Staff purports to use A&E 4NCP for allocation of production costs, but in reality, Staff is proposing a method that only allocates dispatchable resources (i.e., non-renewable resources) using A&E 4NCP and allocates non-dispatchable renewable resources on energy. Staff is taking an allocation method that is already an energy weighted method per the NARUC Manual and allocating additional costs on energy only. This is inappropriate and not based on cost causation principles. Staff is ignoring the fact that renewable resources, while non-dispatchable, do have a capacity value, just like every other generation resource. Staff's blended allocator of A&E 4NCP and Energy should be rejected.

Q: What is your response to Staff referring to the Company's production allocation method as unreasonable and antiquated[4]?

A: It is difficult at best to understand how one of the standard methods in the NARUC Manual can be considered unreasonable and antiquated. In using the term "antiquated", Staff implies that the method is obsolete or no longer used, and not a mainstream, industry-accepted method for allocating production demand costs. Staff is the only party in this case that does not recommend use of the average and excess demand ("A&E") method for allocation of production costs. Three different subject matter experts support utilizing the methodology. The reality is that more regional utilities, including Missouri utilities

[4] Lange rebuttal, p. 27.

regulated by the Commission[5], are moving to the A&E method because it is the most justified method based on cost causation principles. The method cannot be considered antiquated and is a current industry accepted standard prescribed by NARUC.

Q: What method should be used for production and transmission expenses?

As noted in my rebuttal testimony, I continue to support average and excess demand using a 4 summer months CP factor ("A&E 4CP") is the appropriate allocation method for allocating production and transmission costs in this rate case. As I outlined in my testimony, using 4CP to determine the allocation of excess demand costs is consistent with the Company's planning process in how it sizes generation and transmission investment decisions. The only support that has been provided by any witness in this proceeding to use A&E 4NCP is that the NARUC Manual says to use NCP because if CP is used with the A&E method, the results will be identical to using a direct CP method. This was demonstrated to be false in my rebuttal testimony, therefore there is no support for NCP being superior to CP based on cost causation principles in the Manual.

Q: What is your recommendation?

A: The Commission should rely on a CCOS study that uses the A&E 4CP method for allocating production and transmission costs because it is the only method that has been supported by cost causation principles in this rate case.

[5] Evergy (Case No. ER-2018-0145 and ER-2018-0146), Ameren Missouri (ER-2021-0240), Empire District Electric Company (ER-2021-0312), Westar Energy (Kansas) (Docket No. 18-WSEE-328-RTS), Kansas City Board of Public Utilities (Kansas) (2016).

Q: What is your response to Staff's focus on the Company ignoring the existence of the SPP integrated marketplace.

A: Staff seems to imply that the Company would change its generation dispatch patterns to meet environmental goals or achieve profits in the SPP integrated marketplace.[6] As environmental goals are generally met through the operation of renewable sources, the Company is not making decisions on when these non-dispatchable resource are run. As for a situation where the Company would operate to achieve some perceived profit, if Evergy were in a situation to run its generating resources in excess of its native load requirements because of high SPP market prices related to an extreme weather or generation unplanned outages, those revenues would be credited to all classes through Bulk Power Sales. Because both the fuel expense and the sales revenue would be allocated on energy, and it is a safe assumption that the bulk power sales would comfortably exceed fuel costs, all customer classes would benefit from this situation.

Q: What is your overall impression of Staff's CCOS testimony?

A: 1. Staff did not prepare a full COS study, so any CCOS results presented should be viewed with skepticism.

2. Staff is hyper-focused on a level of detail that does not reasonably exist and does not improve the rate class cost of service results.

3. Staff has adjusted Company revenue requirements and allocators in ways that are not based on cost causation or industry accepted cost allocation principles.

4. Staff's CCOS recommendations should be rejected.

[6] Lange rebuttal, p. 27

III. REVIEW OF STAFF REBUTTAL TESTIMONY ON CLASS COST OF SERVICE AND RATE DESIGN

Q: Have you reviewed Staff witness Lange's rebuttal testimony?

A: Yes, I have. My surrebuttal testimony will respond to cost of service topics and certain rate design issues related to cost of service studies.

Q: What is your response to Staff's assertion that the Company's CCOS studies are unreliable?

A: The Company has presented CCOS studies that follow industry standard methodologies, and this has been confirmed by other intervening parties in this case. MIEC witness Mr. Brubaker has over 50 years of regulatory experience and MECG witness Ms. Maini with over 30 years of regulatory experience have both confirmed the Company study is both reasonable and reliable for use in this proceeding. Staff's hyper-focus on direct assigning costs beyond a reasonable level and its desire to see an individual cost of service study for every rate code does not invalidate the CCOS studies prepared by the Company. The Company has appropriately allocated costs at the rate class level. Therefore, Staff is incorrect in stating the studies are not reliable for purposes of recommending interclass revenue responsibility. I do agree with Staff that there are limitations on how they can be applied to intraclass rate design, since the CCOS was not prepared at the rate code level. However, if the Commission's goal is to guide interclass revenue adjustments and provide high level guidance to rate design, the Company's studies are reliable and appropriate for use.

Q: What response do you have to Staff's rebuttal testimony on Distribution Classification and Allocation.

A: I think it shows a misunderstanding in how distribution costs are classified and how distribution systems are planned and how distribution system expenses are incurred by the Company.

Q: Can you provide an example?

A: Yes, on page 17 of the rebuttal testimony, Ms. Lange asks,

> "*Would you expect the customer-specific distribution facilities (including a meter, a service drop, and a line transformer) associated with delivering an average of 7 million to 12 million kWh of energy on an annual basis to be more expensive or less expensive than the customer-specific distribution facilities associated with delivering an average of 10 thousand to 30 thousand kWh on an annual basis?*

It concerns me that the question is framed as the amount of kWh of energy as it relates to distribution customer costs. Distribution costs are either caused by demand or customer requirements – not based on energy requirements[7]. The volume of energy delivered is not a consideration in sizing of distribution assets. Further, customer costs were identified appropriately in the Company's CCOS studies. Metering costs were weighted by the relative cost of the typical meter used to serve each class, the customer component of line transformers was appropriately identified using the Minimum Size method, and services were allocated based on the best information the Company could provide. While it would have been preferential to have services weighted in the same manner as meters, the data was not available.

[7] NARUC Electric Utility Cost Allocation Manual, Table 6-1 - Classification of Distribution Plant and Table 6-2 - Classification of Distribution Expenses.

Q: Does the lack of weighting factors for larger services impact the overall results of the studies?

A: No, it does not. Costs allocated using the Services allocator represent about a ***half of a percent*** of total operating expenses. To allocate a few thousand dollars more to Large General Service would not change the overall directional results of the study. To demonstrate this, I ran a very unrealistic scenario where I replaced the EMM allocator for 369-Services with one that allocated all Services costs to the LGS and LPS rate classes (50% to each) to see the impact on overall rate of return ("ROR") at present rates. The ROR for Residential increased from 2.04% to 2.40% and even after allocating all Services related costs to LGS and LPS, their respective ROR at present rates were still 3.5 – 4 times larger than the Residential class (9.36% and 8.24%, respectively). The relative relationship of Residential under-recovering its cost of service and LGS and LPS over-recovering its cost of service remains the same. I point this out to further demonstrate that Staff's focus on lack of detail in certain allocator factors is not materially impactful to the overall cost of service results.

Q: Are there other examples that demonstrate a misunderstanding in how utility costs are incurred?

A: Yes, on pages 18 and 19 of her rebuttal testimony, Staff witness Lange discusses facilities charges by voltage levels and the development of discounts by voltage level. Staff's response includes:

> "*Note the 17%, 13%, and 70% premiums as the voltage level decreases. This pricing indicates an assumption that the revenue requirement associated with the facilities to serve secondary customers exceeds that associated with the facilities to serve primary customers, on a per kW basis; and that the revenue requirement associated with the facilities to serve*

primary customers exceeds that associated with the facilities to serve substations customers, on a per kW basis, etc."

Staff fails to recognize that, on a per kW basis, the cost to serve a secondary customer actually does exceed that of a primary or transmission service customer. This is due to economies of scale in the cost of distribution facilities such as transformers. In fact, this data was available to Staff as it was part of the Company's Minimum Size System study used to identify distribution customer costs. An example is shown in Table 1, below.

Table 1: Transformer Cost per KVA

Transformer Size	Cost per kVa	% less per kva
kva	2021$	from 25 kva
25	$154.16	
50	$101.24	-34%
150	$88.42	-43%
500	$58.63	-62%
1,000	$45.30	-71%

The table shows the average cost per kVa for line transformers of various sizes ranging from 25 kVa to 1,000 kVa. This is based on EMMs actual line transformer inventory, adjusted to 2021 dollars. A 25 kVa transformer would be the size typically used to serve a residential customer and is the "minimum size" standard in the Minimum Size study for line transformers. As the table demonstrates, as the size of transformer increases, the unit cost decreases, which is why Staff is incorrect in stating there was no evidence to support this analysis.

While the table does calculate a percentage cost difference relative to a 25 kVa transformer, this is simply an example to demonstrate the relative nature of distribution costs and not to support the Company's specific rate proposals.

Q: Are there any other concerns with Staff's understanding of distribution system costs?

A: Yes, on page 20 of her rebuttal testimony, Staff witness Lange states,

> "*It is my understanding that the transformer that drops from the applicable network voltage to the applicable secondary voltage is recorded into account 368, "line transformers," while, for example, if a customer served at a primary voltage is situated next to a network conductor that is operating at a higher primary voltage, that transformers would be recorded as "station equipment," in account 362.*"

This is simply not true. First, only a transformer that is inside the fence of a substation would be recorded in account 362 – Station Equipment. Second, it implies that a customer taking service at a primary voltage is not part of a distribution network that has step down transformers that drop voltage from one primary voltage (35 kV) to a lower primary voltage (4 kV) before it reaches the customer's facility. Table 2 below shows the wide range of line transformer sizes in the EMM system.

Table 2: EMM Line Transformer Inventory

Transformer Capacity (kVA)	Quantity
Under 20	17,625
25-50	103,643
75-200	26,826
225-333	2,417
500-833	2,638
>=1000	1,443
Total	154,592

Again, this information was sourced from the Company's line transformer data included in the workpapers for the Minimum Size Study. As the table shows, over 100,000 of EMMs line transformers are in the 25-50 kVa range, which is typical of a small secondary customer. Of note is the fact that there are over 1,400 line transformers rated at

1,000 kVa a (1 MVA) or higher. Within that value are 31 line transformers rated at 5,000 kVa (5 MVA).

Staff dedicates numerous Q&As in the Lange rebuttal testimony to the alleged lack of detail in the Company's allocation for 369 – Services, but at the same time demonstrates a lack of understanding of cost causation for distribution assets as a whole. While Staff is hyper-focused on account 369 and the associated allocation of customer costs to LGS and LPS, it fails to recognize the Company's improvement in classification of customer costs to all customers through the Minimum Size study. In prior Company rate cases, costs related to accounts 364 – 368 (generally lines, poles, and line transformers) were 100% classified as demand with no classification to customer. The Company's current CCOS study is an overall improvement in the classification and allocation of distribution customer costs to all rate classes.

Q: Staff's rebuttal testimony continues to focus on the Company's use of A&E 4CP and even calls it a "mistake".[8] What is your response?

A: I have supported my decision to use 4CP with A&E based on cost causation principles – that is the Company's investment decisions for generation capacity are based on serving summer CP load, not NCP load. As such, the allocation of excess demand should follow. Further, the only support the NARUC Manual provides for not using CP has been proven incorrect. No witness in this proceeding has provided evidence or even commentary on how A&E 4NCP is superior based on cost causation principles. Mr. Brubaker in his rebuttal testimony opined that "Both of these versions of A&E are time-tested, main-stream allocation methods which produce reasonable results."

[8] Lange Rebuttal, p. 25.

Q: Are there any significant differences in rate class allocations between A&E 4CP and A&E 4NCP?

A: As presented in my rebuttal testimony and repeated below, the differences are very small for the principal rate classes. Once exception is the allocation to the Lighting class.

Table 3: Comparison of Production Allocation Factors

Allocation	Res	SGS	MGS	LGS	LPS	SL	CCN	Total
A&E 4CP	45.98%	7.14%	14.17%	19.59%	12.59%	0.52%	0.01%	100.00%
A&E 4NCP	44.92%	6.89%	14.24%	20.00%	12.74%	1.21%	0.01%	100.00%
4CP	44.94%	7.13%	14.26%	20.19%	13.48%	0.00%	0.01%	100.00%

As shown in Table 3, the demand allocator for Lighting is 57% lower using A&E 4CP (from 1.21% to 0.52%).

Q: Does this concern you?

A: No, it does not. In fact, this is supported by cost causation and further demonstrates that A&E 4CP is the superior allocation method based on cost causation.

Q: How does this reflect cost causation?

A: The Lighting class is predominantly an off-peak load that operates at night. More importantly, Lighting load is rarely coincident with the Company's system peaks and is not coincident at all in the four summer months June through September, as shown in Table 4.

Table 4: Lighting Coincident Peak Load

Date	Lighting Coincident Peak Load (MW)	
	MO Metro	MO West
Jul-20	0.0	0.0
Aug-20	0.0	0.0
Sep-20	0.0	0.0
Oct-20	0.0	0.0
Nov-20	0.0	16.2
Dec-20	14.4	0.0
Jan-21	0.0	12.4
Feb-21	0.0	12.4
Mar-21	0.0	0.0
Apr-21	0.0	0.0
May-21	0.0	0.0
Jun-21	0.0	0.0

As stated previously, the Company makes its investment decisions for production and transmission to serve coincident peak load more than non-coincident peak load. Therefore, Lighting load is less of a consideration in these decisions. It is still appropriate for the Lighting class to contribute to the production and transmission functions, and this is accomplished through the average demand portion of the A&E 4CP allocator.

IV. USE OF CCOS RESULTS IN RATE DESIGN

Q: On page 27 and 34 of her rebuttal testimony, Ms. Lange offers that the CCOS study completed is not reliable to be used in rate design. How is a Class Cost of Service Study useful in developing rate design?

A: First and foremost, a CCOS Study is useful for identifying interclass imbalances in cost recovery through rates. If one class is significantly under-recovering its cost of service (i.e., rate of return at present rates well below authorized rate of return) relative to the other rate classes, it should bear a greater proportion of any rate increases relative to the system average. There is rarely an attempt to exactly match class revenue targets with cost of service results (all classes at equalized rate of return). The more common practice is to make direction changes, gradually over time depending on the extent of the imbalance, to move class rate revenues closer to cost of service. Another useful tool resulting from a CCOS study is using the unit costs of service as a guide for setting rate design components.

Q: What do you mean by unit costs of service?

A: Once a cost study has been fully functionalized, classified, and allocated, or fully unbundled, costs can be viewed in various ways by class. I find it particularly useful to calculate the unit costs of service by classification. I calculate unit costs of service by taking each rate class's costs that are energy related and dividing by the test year kWh. Demand unit costs divide all rate class costs classified as demand and divides by the class test year demand billing units[9] and customer unit costs take all customer related costs and divides by the number of bills in the test year. Because the classification categories of energy, demand, and customer are also the building blocks of rate design through energy charges, demand charges, and customer charges, the unit costs of service provide insight into what a true, cost-based rate design would be.

Q: Why aren't the unit costs of service used directly in rate design to set appropriate cost-based rates?

A: Using the classification of EMM residential costs as an example, 60% of costs are demand related, 21% are customer related, and only 19% are energy related. So, a pure cost-based rate design would have 60% of costs recovered in a residential demand charge. This contrasts to EMM's current rate design that is approximately 10% recovered through a fixed customer charge and 90% with a dollars per kWh energy charge.

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[9] Some classes without demand charges will not have test year demand billing determinants, but they could be estimated with AMI data.

Traditional rate design structure, such as a customer charge and dollars per kWh energy charge for residential classes, or a customer charge, demand charger per kW-month and energy charge per kWh for larger customers, date to the 19th century. These rate structures have endured over time because rate classes have been mostly homogeneous and nearly all customers were full requirements customers.[10] Over time rate design has improved with the addition of time-of-use rate structures and facilities demand charges for recovery of distribution costs, but these traditional rate designs do a poor job of aligning with the fixed and variable nature of an electric utility's costs.

Q: Which utility costs are fixed, and which are variable?

A: As a general rule, only costs that vary with kWh usage are considered variable. All other costs are considered fixed. Therefore, using the classification of costs, customer and demand costs are fixed and energy costs are variable.

Q: How does this imbalance impact rate design and cost recovery?

A: By having the majority of fixed costs recovered in variable ($/kWh) charges, a utility is at risk of not recovering its costs if the way customers use the utility changes. By this I mean, if a customer stops purchasing a portion of its energy from the utility, those fixed costs that were intended to be recovered in a variable energy charge are not recovered. The classic example of this is a net metering customer with an onsite solar array. The net amount of energy purchased from the utility at full retail rates can be reduced dramatically, with the result being fixed costs are not recovered.

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[10] A full requirements customer is any customer that receives 100% of their power direct from the utility. A customer that self-supplies a portion of their load (such as a customer with a PV solar array installed on their home) would be considered a partial requirements customer.

Q: Please summarize the conclusions you reach in your surrebuttal testimony.

A: 1. Staff's CCOS studies are incomplete and include arbitrary allocations and adjustments not based on cost causation principles. Staff's CCOS results should be rejected.

2. The Company CCOS studies are complete, based in industry standard methods and data, are confirmed as such by intervening witness.

3. The Company's A&E 4CP method is more appropriate based on cost causation principles than the A&E 4NCP proposed by Staff and MECG.

4. Staff's CCOS rebuttal testimony demonstrates a misunderstanding of cost causation principles.

5. The Company's CCOS studies are appropriate for use in Rate Design.

Q: Does that conclude your surrebuttal testimony?

A: Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Evergy Metro, Inc. d/b/a Evergy Missouri Metro's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2022-0129
In the Matter of Evergy Missouri West, Inc. d/b/a Evergy Missouri West's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2022-0130

AFFIDAVIT OF CRAIG E. BROWN

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

Craig E. Brown, being first duly sworn on his oath, states:

1. My name is Craig E. Brown. I work in Kansas City, Missouri, and I am employed by 1898 & Co., a division of Burns & McDonnell Engineering Company as Project Manager in the Financial Analysis and Rate Design department.

2. Attached hereto and made a part hereof for all purposes is my Surrebuttal Testimony on behalf of Evergy Missouri Metro and Evergy Missouri West consisting of twenty-four (24) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

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

Craig E. Brown

Craig E. Brown

Subscribed and sworn before me this 16th day of August 2022.

Linda R. Olvera

Notary Public

My commission expires: 10/11/2024

Linda R. Olvera
Notary Public-Notary Seal
STATE OF MISSOURI
Commissioned for Jackson County
My Commission Expires: 10/11/2024
ID. #12403570