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Case No.:	ER-2026-0143

SURREBUTTAL TESTIMONY

OF

RON NELSON

Submitted on Behalf of the Office of the Public Counsel

EVERGY METRO, INC. D/B/A EVERGY MISSOURI METRO

CASE NO. ER-2026-0143

** ____ **
Denotes Confidential Information that has been redacted.

September 10, 2026

PUBLIC

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EVERGY MISSOURI METRO, INC., D/B/A EVERGY MISSOURI METRO

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I. Introduction

Q. Please state your name, business address and current position.

A. My name is Ron Nelson. I am a Founding Partner of Current Energy Group ("CEG"). My business address is 4764 E Sunrise Drive Unit #508, Tucson, AZ 85718.

Q. On whose behalf are you submitting testimony?

A. I am filing testimony on behalf of Missouri Office of Public Council ("OPC").

Q. Did you file Direct testimony on July 14, 2026?

A. Yes.

Q. What is the purpose of your Surrebuttal Testimony?

A. In my Surrebuttal testimony I respond to a limited number of issues raised by Evergy Missouri Metro ("EMM") and other parties in rebuttal testimony.

II. Large Load Revenues

Q. What is the purpose of this portion of your testimony?

A. In this section, I respond to the rebuttal testimony of Midwest Energy Consumers Group witness Greg Meyer, Google LLC witness Dr. Carolyn Berry, and EMM witness Kevin Gunn, all of whom address the treatment of projected Schedule Large Load Power Service ("LLPS") revenues in this proceeding. I explain why the recommendations in my direct testimony remain the most reasonable approach, why other proposals are not well suited to resolve concerns with large load growth, and why the Company's rebuttal does not adequately respond to the underlying problem.

Q. Please summarize the portions of your initial testimony that you would like to highlight.

A. As I explain in my Direct testimony, the Company's proposed COSS decreases its revenue requirement by $25 million to reflect anticipated revenue from its Schedule LLPS customer, **____________ **.[1] However, the projected revenues from Schedule LLPS customers are well beyond this adjustment and without further action will result in a windfall profit for EMM. I recommended that the Commission increase the adjustment made by the Company regarding Schedule LLPS revenues from $25 million per year to $117 million per year. My secondary recommendation, if the Commission would prefer not to make a large pro forma adjustment to the Company's revenues, would be to establish a mechanism similar to the Earnings Review Surveillance (ERS), under which the Company would annually calculate revenues from Schedule LLPS customers, and any revenues that exceed the pro-forma adjustment of $25 million included in the Company's COSS model would be refunded to all other rate classes in the following year.

Q. Were there responses to your recommendations in any rebuttal testimony?

A. Not directly, no.

[1] Gunn Direct at p. 10

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Q. Please summarize the relevant recommendations made by Witness Meyer in direct testimony.

A. Witness Meyer's recommendations were framed in response to the concern that rapid LLPS revenue growth between rate cases can produce a windfall absent Commission action, the same concern I raised in developing my recommendations.

MECG witness Meyer generally supports the Company's $25 million adjustment but would require annual reporting of actual LLPS revenues starting in 2027. If actual net revenue to serve LLPS load above what is already embedded in current base rates exceed $25 million, the excess is booked as a regulatory liability and is resolved in the Company's next rate case.[2]

Q. Do you agree with the recommendations made by Witness Meyer?

A. I support Mr. Meyer's efforts to track the Company's incremental costs to serve LLPS customers and resolve excess costs beyond what is embedded in current base rates, but this is the wrong approach for several reasons.

Q. What concerns do you have with Mr. Meyer's proposal?

A. First, the proposal would require determining what specific incremental costs to serve LLPS load are not already recovered through current base rates. This determination is inherently more difficult to litigate on an annual basis than through the comprehensive cost-of-service review that occurs in a general rate case, where all costs and revenues from all classes are examined together. The complexity of such an analysis would be easy to

[2] Meyer Direct at 9-11.

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game by the utility given the information asymmetry and the challenges with identifying the specific incremental costs incurred to serve one customer.

Second, although this calculation would be done annually, any excess revenues would not be returned to ratepayers until EMM's next general rate case. In the meantime, other customer classes would bear the cost of serving LLPS load while the corresponding revenue growth accrues to the Company, an affordability concern for other classes. Given that **____ _____** this mismatch could persist across multiple rate cases before the excess revenues are returned to customers.

Ultimately, Mr. Meyer's proposed mechanism wouldn't be resolved until a future rate case, providing less protection to ratepayers than either my primary recommendation to increase the revenue adjustment proposed by the Company or my secondary recommendation to create a true-up mechanism that operates annually and outside the rate case cycle.

Q. Please summarize the relevant recommendations made by Witness Berry in direct testimony.

A. Google witness Berry proposes an Earnings Sharing Mechanism (ESM) that is triggered by the Company's overall earned return-on-equity relative to its authorized return-on-equity in this case. The ESM is not specific to large load growth or large load customers, although the justification for proposing it is due to LLPS-driven revenue growth. Under the ESM proposal, the Company would retain 100% of earnings up to 25 basis points above its authorized return on equity ("ROE"). Earnings beyond that limit are shared, with customers receiving 75% of the benefits and 25% retained by the Company. The proposal is based on a previously settled Ameren Missouri case, which used a customer/Company earnings split.[3]

Q. How do you respond to the proposal made by Witness Berry?

A. While I maintain my recommendations to address this issue, Dr. Berry's proposal to create an ESM could be a reasonable alternative, with some modifications. First, while not totally clear, it appears that Dr. Berry's ESM design addresses company-wide revenues, not those specifically generated by the LLPS class. Dr. Berry explains that post-test-year LLPS growth is likely to push EMM's earned ROE above its authorized level before that growth is reflected in a future rate case.[4] Given that the problem motivating this mechanism is LLPS-specific, the ESM should focus exclusively on LLPS revenues. Dr. Berry proposes tracking the company-wide ROE, which could potentially hide an LLPS-driven windfall in a year where other elements of the Company's business underperform or trigger action based on factors that have nothing to do with LLPS growth at all, such as weather. If the Commission determines that an ESM is an appropriate tool to address this concern, it should be scoped specifically to Schedule LLPS revenues, consistent with the true-up mechanism I proposed as my secondary recommendation in Direct testimony.

Q. Do you have any additional proposed modifications to Dr. Berry's ESM proposal?

A. Yes. I would also recommend that excess revenues from Schedule LLPS customers returned through an ESM are returned exclusively to other rate classes and not to the Schedule LLPS customers themselves. If the Commission adopts the modification I propose above to look exclusively at earnings from Schedule LLPS, it would not also be

[3] Berry Direct (Revenue Requirement) at 12-14.
[4] Berry Direct (Revenue Requirement) at 12

appropriate to return those excess earnings to Schedule LLPS customers. The rate for Schedule LLPS customers was agreed to in the previous proceeding and if the Company earns over its authorized rate of return from those customers, excess revenues should be returned to other customer classes.

Additionally, I recommend the Commission reduce the deadband from the 25 basis points Dr. Berry proposes to 10 basis points. Given the size of the potential mismatch in revenues I identified in Direct, a wide deadband risks leaving a substantial share of those revenues in the pockets of shareholders.

Q. Please summarize, in your own words, how the Company has responded in Rebuttal testimony to the proposals made by Witness Meyer and Berry.

A. Company Witness Gunn responded to Witness Meyer's proposal by stating that EMM has already voluntarily reduced its revenue requirement by approximately $25 million to reflect projected LLPS revenues, and that the figure is expected to grow to $43 million at true-up, therefore the Company has appropriately assumed the risk that actual revenues could fall short of what was forecasted. He argues that Witness Meyer's mechanism improperly isolates a single customer class from the Company's overall earned return, which reflects the combined effect of revenues, expenses, depreciation, taxes, and other factors across all classes. He argues that the reporting and stakeholder-review provisions established in the EO-2025-0154 settlement as an adequate alternative. Finally, he states that the proposed mechanism is an unbalanced one-way tracking mechanism that would fail to return revenues to the Company if revenues fall short of projections.

Mr. Gunn responds to Witness Berry's proposal by stating that the Company is not opposed to an earnings-sharing mechanism in principle, stating that Evergy Kansas Central uses an Earnings Review and Sharing Plan in Kansas. He does, however, object to the scope of the mechanism proposed by Dr. Berry. He argues that if the Commission adopts an ESM, it should evaluate the Company's overall earned return rather than revenues tied to Schedule LLPS specifically, given that EMM's earned return depends on many factors beyond any single customer class. Mr. Gunn also notes that the specific sharing percentages and the deadband in Dr. Berry's proposal differ from those that the Commission approved in a previous Ameren Missouri settlement. Additionally, Mr. Gunn explains that large load users under Schedule LLPS have important advantages for electric utilities and their customers that should be considered, and that Mr. Gunn's proposal would effectively reopen the LLPS framework at an inappropriate time.[5]

Q. Do you agree that adopting an earnings-sharing mechanism of any kind in this case would improperly reopen the EO-2025-0154 settlement?

A. No. The EO-2025-0154 settlement addresses the terms of serving large loads themselves, including the tariff structure, initial pricing, and the timing of a future comprehensive cost allocation and rate design review once a qualifying customer is reflected in a test year. The settlement does not address how a large load customer's revenue should affect other customers or how utilities should handle the revenue requirement in a general rate case when a large load customer generates revenue that will occur before a future test year. Addressing that question does not reopen Schedule LLPS's terms. Additionally, large load

[5] Gunn Rebuttal at 10-13.

issues are unprecedented and necessitate the Commission to take action as ratepayer protections are needed.

Q. How do you respond to the assertion of the Company that they have already assumed the risk of a revenue shortfall by including a $25 million revenue adjustment that will grow to $43 million?

A. This framing does not accurately capture the potential windfall revenues for the Company from Schedule LLPS. As discussed in my Direct, if Schedule LLPS revenues substantially exceed the amount reflected in rates, the resulting mismatch in customer cost allocation and company windfall would not be captured until the next rate case at the earliest, and is a product of a known and foreseeable load ramp that the Company references elsewhere in this case. I quantify this potential windfall in Direct as approximately **__________ __________** which was unrebutted by the Company. Mr. Gunn's own rebuttal testimony acknowledges that if actual LLPS revenues exceed the forecast, "those results will become part of the Company's actual operating results and will be reflected in the Company's future earnings", meaning that excess revenues would flow entirely to the Company under the status quo.[6] The potential windfall for EMM from ramping large loads falls on the backs of ratepayers. This risk is further mitigated by contract terms approved by the Commission in EO-2025-0154. Through those terms the Company is guaranteed significant revenues through the minimum billing and other provisions. These terms significantly mitigate the risk to the Company of underrecovery and guarantee significant revenues for the Company.

[6] Gunn Rebuttal at 6.

Q. How would you respond to the assertion of the Company that the existing framework established by EO-2025-0154 is adequate in place of a true-up mechanism?

A. The reporting and stakeholder review processes established under EO-2025-0154 require the Company to report on an annual basis the number of new or expanded customers that have enrolled in LLPS and the total estimated load enrolled under Schedule LLPS.[7] This is not sufficient information to address how EMM's revenue requirement in a general rate case should account for anticipated LLPS revenue growth in the interim between rate cases, only providing information to address transparency around Schedule LLPS's implementation. As I discuss in Direct, the Commission considered a similar mechanism to what I propose in EO-2025-0514 and expressly deferred a decision on its merits to a future case, when the relevant revenues would be known and measurable, as they are now.

Q. Given all of the testimony discussed above, what is your recommendation?

A. I maintain the same recommendation as in Direct. The Commission should increase the Company's LLPS revenue adjustment from $25 million to $117 million, **________ ____ **

[7] See Non-Unanimous Global Stipulation & Agreement at ¶ 35, No. EO-2025-0154 (Sept. 25, 2025).

Q. What is your secondary recommendation?

A. My secondary recommendation is to establish a mechanism similar to the Earnings Review Surveillance (ERS), under which the Company would annually calculate revenues from Schedule LLPS customers, and any revenues that exceed the pro-forma adjustment of $25 million included in the Company's COSS model would be refunded to all other rate classes in the following year. Should the Commission prefer an ESM similar to what Dr. Berry proposes, the design principles should include an LLPS-specific scope, with benefits flowing to other customer classes in the year following adjustment, no refund exposure for Schedule LLPS customers, and a smaller deadband of 10 basis points.

III. The Minimum System Method

Q. You testified on the Company's use of the Minimum System Method to classify distribution plant costs as customer-related in direct testimony. Would you summarize your findings?

A. Yes. I reviewed the underlying logic of the Minimum System Method, which the Company uses to functionalize certain distribution system costs between the customer and demand functions. The Minimum System Method assumes that there is some portion of the distribution system whose costs are unrelated to actual customer demand and vary, instead, by the number of customers. I expressed concern over the use of this method, noting that it is based on an unrealistic concept of a hypothetical utility and the impact is that a higher proportion of costs are allocated to customer classes with larger numbers of customers, primarily the residential customer class. At the time, I did not take a position on the Company using another established method, but I will propose a change in this Surrebuttal testimony.

Q. Would you summarize, in your own words, the rebuttal response on the Minimum System Method of Company Witness Jaynes?

A. Mr. Jaynes does not dispute that the Minimum System Method requires constructing a hypothetical zero-demand system, nor does he dispute that the Company does not remove a pole or transformer when a customer disconnects from its system. Rather, he argues that my criticism "misses the purpose of the methodology," that the method is commonly used and Commission-recognized, and that I have not provided a Company-specific alternative study.[8]

Q. Mr. Jaynes responds to your point that a system without customer demand would never be built by arguing that "if there were no customers there would be no system at all." How do you respond?

A. As I discuss in my Direct testimony, according to the NARUC Electric Utility Cost Allocation Manual states customer costs are those that are "directly related to the number of customers served." A cost meets that test only if it varies with the number of customers connected to the system, not with the level of demand those customers place on it. Mr. Jaynes does not dispute the fact that answers this question: the Company does not remove a pole, conductor, or transformer when an individual customer disconnects. That fact demonstrates that the sizing and installation of this resource is driven by the level of demand to be served on a line, not by the number of customers attached to it, and those costs should not be functionalized to customers.

[8] Jaynes Rebuttal at 20-21

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In a 2020 paper on electric cost allocation, the Regulatory Assistance Project (RAP) wrote that it is unrealistic to suppose that the mileage of the shared distribution system and the number of physical units are customer-related for eight reasons.[9] While I will not repeat each of the reasons in this testimony, it is worth expanding upon two of the arguments identified in the paper:

1. There is a weak correlation between the area, or mileage, of a distribution system and the number of customers it serves.
2. Adding customers without adding peak demand or serving new areas does not require any additional poles or conductors.

Q. Why is there a weak correlation between the mileage of the distribution system and the number of customers it serves?

A. The size of the electric distribution system does not account for the density of customers on the system. The electric utility must build its system to connect its entire geographic area. The costs of that system are the same regardless of the number of customers connected, and changes to those costs are (for the most part) driven by changes in demand. Because the Minimum System Method does not account for the density factor, James C. Bonbright, in his 1961 book Principles of Public Utility Rates, dismissed including the costs of a minimum-sized distribution system as customer-related costs as "clearly indefensible."[10]

[9] Lazar, J. et al. "Electric Cost Allocation for a New Era, A Manual" Regulatory Assistance Project, 2020. P. 145.
[10] James C. Bonbright, *Principles of Public Utility Rates* p. 348 (1st ed. 1961)

Q. Please explain the relevance of adding customers with and without contributions to peak demand for assigning distribution costs.

A. Unless there is a change in peak demand, adding a customer onto the distribution system, should not trigger additional costs to the distribution system. For example, imagine a one-mile distribution line running from Point A to Point B with 10 customers. If two additional customers connect to the system along the 1-mile line but demand does not increase, the utility would not need to invest in additional poles or conductors. Likewise, if two customers departed the system the utility would not remove poles or conductors from the one-mile segment. A utility may have to make upgrades to the system, however, if the additional customers' contribution to the peak demand on the segment triggers the need for additional investments.

Q. Is there another method that you recommend for classifying distribution system costs?

A. Yes. I recommend that the Commission adopt the Basic Customer method for allocation distribution system costs, which only classifies only customer-specific costs as customer-related, and the rest of the distribution system as energy- or demand-related. The Basic Customer method recognizes that the system is built for meeting customer demand and does not vary significantly based on the number of customers. Classifying distribution costs as energy- or demand-related, as opposed to customer-related, better conforms to cost causation and fairness than the Minimum System Method for the reasons I just discussed. Namely, customer-related costs are "costs that are directly related to the number of

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customers served"[11] and the costs of the distribution system, for the most part, do not change with the addition or subtraction of customers.

Q. What would the impact of using the Basic Customer method rather than the Minimum System Method?

A. The Basic Customer method classifies FERC accounts 364 – 368 as 100 percent demand-related.

Q. Are there other public utility commissions that use the Basic Customer method or a similarly situated demand-related method?

A. Yes, I know of several commissions, including Connecticut,[12] Illinois,[13] Iowa,[14] California,[15] Rhode Island,[16] Maryland,[17] Washington state,[18] and Arkansas.[19]

Specifically, the Arkansas Public Service Commission wrote, "The Commission agrees with EAI, Staff and AG that accounts 364-368 should be allocated to the customer classes using a 100% demand methodology and find that AEEC and HHEG do not provide sufficient evidence to warrant a determination that these accounts reflect a customer

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[11] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, January 20, 1992. P. 20.
[12] See https://law.justia.com/codes/connecticut/2015/title-16/chapter-283/section-16-243bb/
[13] Final Order, Commonwealth Edison Company Proposed General Increase in Electric Rates (Tariffs filed October 17, 2007), at 208 (Sep. 10, 2008), Docket No. 07-0566 (Illinois Commerce Commission)
[14] Iowa Admin. Code 199-20.10(2)(e).
[15] Interim Opinion, Re San Diego Gas and Electric Company, (Dec. 19, 1988), Decision 88-12-085 (California Public Utilities Commission), (1988 WL 1663871), at 15.
[16] Decision and Order, In Re: The Application of the Narragansett Electric Company d/b/a National Grid for Approval of a Change in Electic[sic] Base Distribution Rates, at 142 (April 29, 2010), Docket No. 4065 (State of Rhode Island and Providence Plantations Public Utilities Commission).
[17] Order No. 83907, In the Matter of the Application of Baltimore Gas and Electric Company for Revisions in its Electric and Gas Base Rates, at 81–82 (March 9, 2011) Case No. 9230 (Public Service Commission of Maryland).
[18] Ninth Supplemental Order on Rate Design Issues, Petition of Puget Sound Power & Light Company for an Order Regarding the Accounting Treatment of Residential Exchange Benefits, (Aug. 16, 1993) Docket No. UE-920433 (Washington Utilities and Transportation Commission) (1993 WL 13812140), at 5–6.
[19] Order, In the Matter of the Application of Entergy Arkansas, Inc., for Approval of Changes in Rates for Retail Electric Service, at 124–26 (Dec. 30, 2013) Docket No. 13-028-U (Arkansas Public Service Commission).

component necessary for allocation purposes."[20] Indeed, Washington state went so far as to specify in rule the electric cost of service approved classification and allocation methodologies, and specifically requires distribution substations, distribution line transformers, and distribution poles and wires as demand related.[21]

Q. Have you done the analysis to show the impacts of switching to the Basic Customer method rather than the Minimum System Method on the COSS?

A. Yes. Reclassifying Accounts 364 through 368 as 100% demand-related, and allocating the reclassified amount using the same non-coincident peak methodology the Company already applies to the demand-related share of these accounts, results in a decrease in the annual residential revenue requirement of approximately $17.3 million, a 4.3% decrease. These classes have a greater non-coincident peak demand relative to their customer count. This result confirms that the Minimum System Method's customer-related classification results in higher costs allocated to the residential class that is not supported by the class's actual demand on Company facilities.

IV. Generation and Transmission Cost Allocation

Q. Please summarize the rebuttal testimony of Witnesses York and Jaynes as it relates to your proposal to use the POD method for production and transmission cost allocation.

A. Company Witness Jaynes and MECG Witness York both disagree with my proposal to implement the POD method for production and transmission cost allocation. Witness

[20] Order, In the Matter of the Application of Entergy Arkansas, Inc., for Approval of Changes in Rates for Retail Electric Service, at 124–26 (Dec. 30, 2013) Docket No. 13-028-U (Arkansas Public Service Commission)
[21] See Washington administrative Code 480-85-060. Available at: https://app.leg.wa.gov/WAC/default.aspx?cite=480-85-060

Jaynes argues that the POD is functionally an energy allocator, making it inappropriate for allocating capacity costs.[22] Both witnesses take issue with the fact that the method has not been widely adopted, and point out that the time-variant methods that have been adopted in other jurisdictions vary from the methodology I have proposed in this case.[23] Witness York presents several other arguments against adopting the POD in this proceeding: that the analysis I provided in my direct testimony is preliminary; that adopting a new allocation method represents too significant a change in the Company's CCOSS to implement at this stage of the proceeding; that the POD method itself is data-intensive and relies on too many modeling assumptions; that the shifts in revenue responsibility that would result from adopting the POD allocation would produce significant bill increases for "established customers" despite no change in their usage patterns.[24]

Q. Before addressing the substantive arguments against your POD proposal, MECG Witness York argues the POD method should be rejected because the results you presented in direct testimony are "preliminary." Have you prepared an updated set of POD results?

A. Yes. I called my original POD results preliminary because there was a discrepancy between the annual class kWh consumption totals I calculated from the Company's hourly load profiles and the class kWh values used for the energy allocators in the Company's CCOSS. This is important because if there is underlying disagreement between my allocation method and the Company's regarding annual class kWh consumption, the allocation results

[22] Jaynes at 12:9-13
[23] Jaynes at 14:6-10, York at 5:14 through 6:7
[24] York at 4:15 through 7:2

cannot be compared directly. To remedy the discrepancy, I applied two levels of adjustments to the hourly metered load profiles in my original analysis: the first level of adjustments applied the monthly weather normalization and annualization adjustment factors used by the Company to generate its Energy 2 allocator, and the second layer applied the loss factor adjustments the Company used to generate the Energy 1 allocator. After applying these adjustments to the hourly metered class load profiles, I was able to use the same POD allocation method described in my direct testimony to generate a direct comparison of allocation results using hourly class load profiles that summed up to the same annual class kWh consumption totals the Company used as the basis for its allocation results. Table 1 below presents my updated POD results, as compared to the Company's AED-4CP allocator.[25]

Table 1. Updated POD Results Comparison

	EMM Proposed A&E Allocators	**MO Proposed POD Allocators**	**Difference**
Residential	46.3%	34.5%	-11.8%
SGS	8.3%	8.1%	-0.2%
MGS	13.5%	13.6%	0.1%
LGS	18.6%	23.9%	5.3%
LPS	12.9%	19.3%	6.4%
Lighting	0.3%	0.6%	0.2%
CCN	0.1%	0.0%	0.0%
LLPS	0.0%	0.0%	0.0%
Total	**100.0%**	**100.0%**	

As I predicted in my direct testimony, the updated results are directionally similar to my original analysis, though with a slightly less significant difference from the Company's

[25] The Company's allocators are taken from the "Current Class Structure" Cost of Service Study.

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AED-4CP allocator. For example, the difference between the POD Allocator and the AED-4CP allocator was 13.4% in my direct testimony compared with 11.8% now.

Q. How do you respond to witnesses Jaynes and York's arguments that POD isn't an established method, and therefore should not be used in this rate case?

A. The relative lack of adoption of POD cost allocation has no bearing on the question of whether it is an accurate reflection of class cost-causation, nor does it mean POD allocation is not an "established method." Utility economists have recognized the importance of time-variant cost-causation since the 1980s, and the POD method itself is included in the 1992 publication of the NARUC Electric Cost Allocation Manual.[26] The historical obstacle to implementing POD allocation has been the granular hourly data the method requires; prior to the widespread adoption of advance metering infrastructure ("AMI"), or "smart meters," which allow electric utilities to collect hourly consumption data for individual customers, this data was not available for cost allocation. However, the last decade has seen rapid deployment of AMI across U.S. utilities, including by the Company. AMI deployment for Every, with approximately 321,000 residential AMI meters, was completed over the last couple of years.[27] The rarity of POD-related allocation methods does not make it a new concept, it is rather a consequence of the relatively new development of this enabling technology.

[26] *See* Edward Kahn, *Electric Utility Planning and Regulation* (ACEEE, 1988), 120; NARUC CAM at 62.
[27] See https://www.efis.psc.mo.gov/Document/Display/777694

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Q. Please respond to Company Witness Jaynes' objection to the POD method's proximity to an energy allocator.

A. Witness Jaynes argues that by allocating production costs based on all 8,760 hours of class consumption, the POD method ignores the capacity component of generation fleet investment. He states that production plant is constructed "first and foremost, to serve the system's peak reliably," and that "[u]nder cost-causation, those demand-related costs should be allocated on the basis of the classes' contribution to the peak conditions that drive the investment."[28] Mr. Jaynes gives the example of a base-load plant having its costs spread out over nearly every hour of the year, which he characterizes as a "perverse result."[29] This characterization of production cost-causation ignores well-established differences in cost structures of different generation technologies, which each feature particular trade-offs between capacity and energy costs and therefore follow different patterns of cost-causation.

Q. Please explain the trade-off between capacity and energy costs you mentioned.

A. Every generation technology features a combination of fixed and variable costs of production. For instance, nuclear and coal facilities tend to be expensive to build, thus featuring high fixed capital costs, but are very cost-efficient to run with relatively lower variable costs, so are typically built to serve base-load and intermediate load periods efficiently. Gas turbine and combined-cycle facilities, on the other hand, are relatively inexpensive to build, but feature higher fuel costs, thus are typically built to serve peak load periods. This theoretical difference in how these plants are dispatched are evident in

[28] Jaynes Rebuttal at 11:18-23.
[29] Jaynes Rebuttal at 13:7-11.

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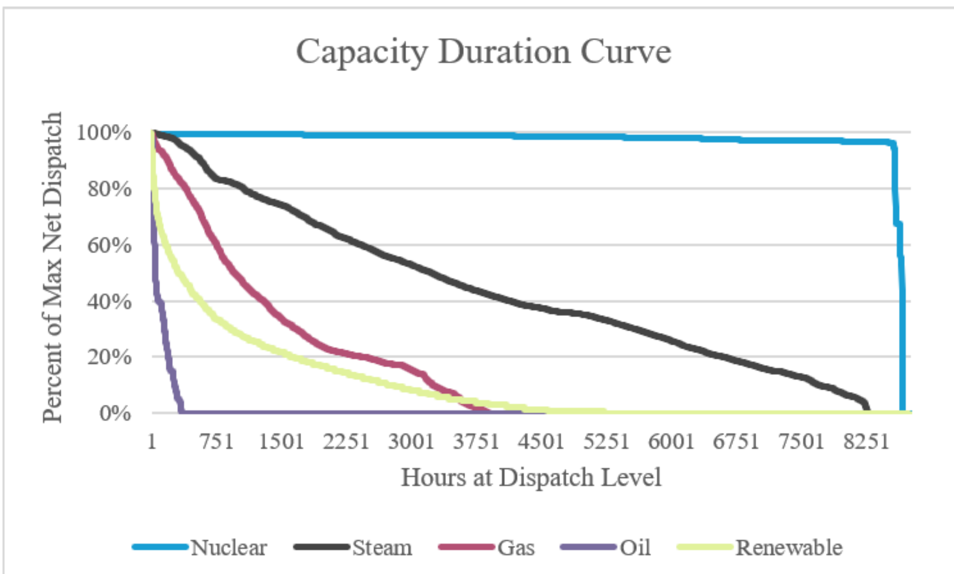
the hourly generation data the Company reports to the Commission. Figure 1 below shows the capacity duration of each generation technology in the Company's fleet during the base-year period; it shows that the Company's nuclear assets functioned at or near their maximum output for nearly every hour of the year, while its steam assets show a linear decrease in output across the year, and its gas and oil operations are highly concentrated in relatively few hours of the year.

Figure 1. Capacity Duration Curve



This demonstrates that while the Company's gas and oil investments are largely driven by peak demand requirements, its steam investments are driven by a combination of peak demand and yearly energy consumption, while its nuclear investments are almost entirely driven by yearly energy requirements. The need to recognize energy cost-causation as well as demand in capacity investment has been acknowledged for decades; in fact, it is one of the original reasons the A&E method used by the Company was developed.[30] Distributing

[30] Kahn, 1980, pg. 127.

the cost of base-load plants across all hours of the year is not a "perverse" result, it is an accurate measure of how the costs of those plants are actually caused.

Q. Does the Company's A&E 4-CP allocation method adequately incorporate class energy requirements into its calculation?

A. No. The results of the Company's A&E method are functionally identical to a strictly coincident-peak based allocator. Table 2 below compares the A&E 4-CP and 1-CP demand allocators in the Company's CCOSS.[31]

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The Company's proposed A&E allocator would result in nearly the exact same production allocation as would assigning costs by class load during the single coincident peak hour of the base year, which shows that this method does not adequately reflect cost-causation as it does not adequately consider energy usage in addition to 1 CP demand.

[31] Jaynes Workpaper "CONFIDENTIAL 26 MO Metro Current Class Structure.xlsm"

Q. How do you respond to the comparison between your POD results and the Company's energy allocators in Table 1 of Witness Jaynes' rebuttal testimony?

A. While my original POD results are close to an energy allocation, the comparison Mr. Jaynes makes in Table 1 is not a direct comparison. As I explained in my direct testimony, my original POD results were based on annual class load totals that were not yet reconciled to the Company's energy allocators, thus the comparison in Table 1 is not valid.[32] As discussed above, I have finalized my analysis above.

Q. How do your finalized POD results compare to the Company's energy allocators?

A. The updated results, which are based on reconciled annual class load data, are very similar to the Company's Energy 1 allocator; however, while the comparison in Mr. Jaynes' Table 1 showed a reduction in the residential allocator in the POD results compared to energy allocation, there is actually a slight decrease. This relationship is similar to the results of my original analysis.

Table 3. Comparison between POD and Energy Allocators

	EMM COSS Energy w/ Losses	MO Proposed POD Allocators	Difference
Residential	34.0%	34.5%	0.44%
SGS	8.1%	8.1%	0.02%
MGS	13.6%	13.6%	0.00%
LGS	24.1%	23.9%	-0.16%
LPS	19.6%	19.3%	-0.27%
Lighting	0.6%	0.6%	-0.03%
CCN	0.0%	0.0%	0.00%
LLPS	0.0%	0.0%	0.00%
Total	**100.0%**	**100.0%**	

[32] Nelson Direct at 43:13.

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Q. Should the proximity between your POD results and the Energy 1 allocator disqualify the POD method in this case?

A. No. The high correlation between the POD allocation results and EMM's energy allocators is rather an indication that the energy-related cost-causation embedded in the Company's generation capacity is significantly higher than the proposed A&E allocators would indicate. The Company's nuclear and steam assets contribute a high proportion of the Company's net generation compared to more demand-driven generation technologies, and the POD method simply reflects this difference.

Moreover, my updated POD results exhibit greater variation from the Company's energy allocators than the proposed A&E allocators do from the strictly peak-based allocators. Table 4 below compares the range in class allocation variance between the POD and Energy 1 allocators to the variance between the A&E-4CP and 1 CP allocators.

Table 4. Allocation Variance Comparison

	1 CP	AED 4CP	Difference	Energy w/ Losses	POD Allocators	Difference
Residential	46.5%	46.3%	-0.25%	34.0%	34.5%	0.44%
SGS	8.3%	8.3%	0.0%	8.1%	8.1%	0.02%
MGS	13.6%	13.5%	-0.1%	13.6%	13.6%	0.00%
LGS	18.7%	18.6%	-0.1%	24.1%	23.9%	-0.16%
LPS	12.8%	12.9%	0.1%	19.6%	19.3%	-0.27%
Lighting	0.0%	0.3%	0.3%	0.6%	0.6%	-0.03%
CCN	0.1%	0.1%	0.0%	0.0%	0.0%	0.00%
LLPS	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%
Diffence Range			**0.56%**			**0.72%**

The A&E method and the POD method are both meant to combine class demand and energy characteristics into a single calculation; this comparison shows that my POD results

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are more influenced by demand characteristics than the Company's A&E method is by energy characteristics.

Q. Does EMM have any critiques of the justification you use for the POD analysis?

A. Yes, EMM witnesses Jaynes and York both point out that the two versions of time-variant allocation techniques that I cite as examples in my direct testimony vary significantly from the POD method I recommend.

Q. How do you respond to this critique?

A. In my Direct testimony I cite to the MidAmerican Hourly Costing Model ("HCM") and the POD-PH methodology Xcel Energy uses as examples of similar methods in use by utilities for allocating generation costs. While the mechanics of MidAmerican's HCM and the 1,000-hour version of the POD method that Xcel Energy uses are different from my model, they rely on a similar fundamental theory that production cost allocation should be based on class consumption characteristics well beyond the one-to-twelve hours utilities typically use for CP demand-based allocation. Moreover, in my experience the HCM reliably produces similar allocation results to my 8,760-hour POD method. To demonstrate this, I have prepared a set of HCM results using the same load profiles as my updated POD results.

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Table 5. A&E, HCM, and POD Comparison

	A&E	HCM	POD
Residential	46.3%	37.4%	34.7%
SGS	8.3%	8.1%	8.1%
MGS	13.5%	13.5%	13.6%
LGS	18.6%	22.7%	23.8%
LPS	12.9%	17.7%	19.2%
Lighting	0.3%	0.4%	0.5%
CCN	0.1%	0.3%	0.0%
LLPS	0.0%	0.0%	0.0%
Total	**100.0%**	**100.0%**	**100.0%**

The similarity between HCM and POD results demonstrates that while this method is mechanically different from the POD, its results show a similar undue reliance on peak demand inherent to the A&E method.

Q. How do you respond to Witness York's objection that switching to POD allocation at this stage would create undue impacts on existing large customers?

A. Over the course of a rate case, the questions of cost allocation, revenue apportionment, and rate design need to be considered separately and in the proper order. While I would recommend increasing the proportion of final revenue recovery from large customers , the rate design concept of gradualism is always a consideration. What is more important at the cost allocation stage is fair recognition of cost-causation, which the A&E method plainly does not accomplish. What my POD results show is that not only are residential customers being allocated an excessive amount of production and transmission costs, but that they have essentially been unfairly subsidizing the annual energy requirements of large commercial and industrial customers for many years.

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Q. What is your recommendation regarding production cost allocation?

A. I maintain my original recommendation from Direct testimony, that the Commission should direct EMM to use the POD methodology for production cost allocation in its CCOSS.

Residential Customer Charge

Q. What was your recommendation in Direct testimony regarding the Company's proposal to increase its residential customer charge from $12.00 to $13.82?

A. I recommended that the Commission reject the Company's proposal for a number of reasons. First, the Company did not show that its customer charge calculations reflect cost causation, because its customer-related unit cost calculations appear to be inflated. Second, cost causation must be balanced against state policy goals and equity considerations, and the Company's proposal does not do so. Increases to the customer charge can undermine the progress achieved through energy efficiency programs established by Missouri legislature under the Missouri Energy Efficiency Investment Act.

Q. Witness Jaynes was largely responsible for the Company's rebuttal on the residential customer charge. Can you summarize Witness Jaynes' rebuttal on this topic in your own words?

A. Jaynes states that the CCOSS shows a purely cost-based customer charge would be $18.33, so the Company's $13.82 proposal is less than the level supported by the cost of service model. Additionally, Jaynes states that a $1.82 monthly increase doesn't meaningfully diminish any customer's efficiency incentive, and the Company's energy efficiency programs administered under MEEIA provide efficiency incentives independent of rate design. Lastly, Jaynes disputes that a higher fixed charge would cause harm to low-income customers, as we did not provide evidence that low usage customers are the same as low-income customers, and that shifting more recovery to volumetric rates would actually cause risk for low-income customers when hot weather arises and they may be reliant on A/C to keep cool.[33]

Q. How do you respond to the Company's claim that "the CCOSS shows that a purely cost-based residential customer charge would be $18.33 per month", and by not moving all the way to that cost-based level, it is embracing gradualism to maintain existing cost recovery proportions between fixed and volumetric charges?

A. While the Company appropriately applies the three-step framework consistent with National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual, the classification of customer-related costs appears to be overinflated as discussed in my Direct. I maintain that the Minimum System Method is grounded in an unrealistic concept of a hypothetical utility that has no basis in reality. The impact of using this method is that a higher proportion of costs are functionalized as customer-related. The Company does not address this reasoning in its Rebuttal testimony.

Perhaps more importantly, considering that the Company is not proposing to ground the customer charge in the results of their COSS, the Company is implying that policy considerations outweigh the need to stick to any specific COSS outcome. The Company puts forth a value that it claims to be the most purely cost driven, but their proposal falls back on an arbitrary customer charge of $13.82 in the name of gradualism. Since policy

[33] Jaynes Rebuttal at 17-23.

considerations appear to be more important to the Company than reaching a purely cost based number, the potential harm to low-income customers and reduction in incentive to pursue energy efficiency should drive the Commission to maintain the current customer charge of $12.00. The American Council for an Energy-Efficient Economy's Rate Design Matters study quantifies this relationship. They model 14 efficiency measures across 20 rate scenarios, finding that an adjustment to the fixed charge, even a moderate one, produces a corresponding decline in the volumetric rate, which their modeling translates into measurably longer payback periods for efficiency investments and standard elasticity-based increases in consumption.[34]

Q. How do you respond to the Company's claim that "a $1.82 monthly increase does not meaningfully diminish any customer's incentive to pursue efficiency"?

A. Witness Jaynes' claim lies on an assumption that a $1.82 increase is small enough to fall below some threshold where rate design stops mattering for energy efficiency behavior. That assumption doesn't hold up.

The mechanism by which a higher fixed charge weakens efficiency incentives operates continuously, not as a threshold effect. Any dollar shifted from the volumetric rate into the fixed charge is a dollar a customer can no longer avoid by using less electricity, meaning every kWh a customer conserves is worth slightly less to them than it was before the shift. The Regulatory Assistance Project's Smart Rate Design for a Smart Future report addresses this directly, recommending that residential fixed charges be limited to costs that

[34] American Council for an Energy-Efficient Economy, *Rate Design Matters: The Intersection of Residential Rate Design and Energy Efficiency and Distributed Generation*.

are genuinely and unavoidably tied to the customer's connection (estimated at $4 per month for service drop, billing, and collection), precisely because any amount recovered above that level comes at the expense of the price signal that drives conservation, regardless of how small or large that amount is.[35]

Q. Has the Commission previously ruled on maintaining fixed charges for the sake of preserving energy efficiency?

A. Yes. The Commission has decided to weigh public policy considerations over the findings of a specific cost of service study in past rate cases. Specifically, in Docket ER-2014-0258 regarding an Ameren Missouri rate case, the Commission's final order stated that "because no party is arguing that the customer charge should be based on the results of a particular class cost of service report, the Commission will not address the details of those reports... [and] is not bound to set the customer charges based solely on the details of the cost of service studies. ... residential customers should have as much control over the amount of their bills as possible so that they can reduce their monthly expenses by using less power, either for economic reasons or because of general desire to conserve energy. Leaving the monthly charge where it is gives the customer more control."[36] The Commission further states that, since Ameren Missouri has not shown a strong reason to increase the customer charge and is seeking only a small, largely token increase, there is no reason to increase the customer charge. The same logic holds here.

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[35] Regulatory Assistance Project, *Smart Rate Design for a Glowing Grid* (Lazar & Gonzalez, July 2015).

[36] Docket ER-2014-0258, Commission Report and Order, April 29, 2015, pp. 76-77

Q. How do you respond to Witness Jaynes' assertion that "low usage is not the same as low income... and Mr. Nelson provides no evidence to correlate the two concepts"?

A. As I discussed in my Direct testimony, raising the customer charge reduces customers' ability to control their own bills through energy efficiency and conservation. This impact is more acute for low-usage customers who have relatively smaller bills and are more influenced by the size of the customer charge.

Low income residents of Missouri use less electricity on average than high income residents, and there is data to support this. According to the Energy Information Administration's Residential Energy Consumption Survey (RECS), households in Missouri making below $60,000 annually consume an average of 10,844 kWh per year, and those making at least $60,000 consume 13,445 kWh, a 19% difference on average with a relative standard error of 5.2%.[37]

Q. How do you respond to the assertion from Witness Jaynes that "volumetric rates mean that whenever it is hotter than normal, then bills will increase by more as customers cool their homes"?

A. Witness Jaynes is stating that increasing the proportion of costs to volumetric rates increases risk to low-income customers because they are unable to safely avoid higher bills in circumstances of hot weather and high air conditioning usage. This argument is flawed for several reasons. First, Mr. Jaynes has not provided evidence to confirm that low-income customers tend to spend any more than an average customer on cooling, meaning the impact of increasing cooling demand in any given day does not necessarily

[37] Energy Information Administration, Residential Energy Consumption Survey Microdata

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disproportionately affect low-income customers. Additionally, as discussed above, low-income customers tend to consume less electricity on average compared to non-low-income residential customers. The risks associated with a change in electric rates should not only be considered in the context of the hottest days of the year, but rather the full year of electricity consumption. For customers who consume less on average, as is the case with low-income customers in Missouri, there is a risk of harmful bill impacts when the proportion of costs is increased to fixed customer charges than if the Company were to recover more through volumetric rates. Finally, investing in energy efficiency measures for low-income customers can help reduce the risk of unaffordable bills during hot weather by improving the efficiency of an HVAC system or improving the insulation of a home. These efficiency measures are being implemented successfully by the utility, as mentioned by Mr. Jaynes, but the signal to invest in these measures and reduce the associated payback time should be supported by maintaining the current fixed charge and therefore not reducing the proportion of costs recovered through volumetric rates.

Q. Given your review of EMM's Rebuttal testimony do you maintain your initial recommendation regarding the residential customer charge?

A. Yes, I do. I maintain that, given the policy considerations laid out above, the Commission should maintain a customer charge of $12 per month.

V. Conclusion

Q. Does this conclude your testimony?

A. Yes.

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