BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company	)	
d/b/a Ameren Missouri's Tariffs to	)	**File No. ER-2021-0240**
Increase Its Annual Revenues for	)	
Electric Service.	)	

INITIAL POSTHEARING BRIEF

OF

MIDWEST ENERGY CONSUMERS GROUP

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A. OVERVIEW

In its recent Order Approving Stipulations and Agreement, the Commission established the revenue requirement for this case. The issues addressed in this Brief address the manner in which the revenue increase should be allocated to the various customer classes as well as the process by which rates will be established for the industrial classes in order to recover that rate increase.

The failure to reach a settlement addressing the method for allocating the revenue allocation in this case is directly tied to Staff and OPC's absolute unwillingness to address the lingering residential subsidy. This unwillingness flies in the face of repeated Commission action in Ameren rate cases. In at least the last ***SEVEN*** Ameren rate cases the Commission has taken affirmative steps to reduce the residential subsidy. Now, despite the obvious Commission concern for elimination of the residential subsidy and movement towards cost-based rates, the Staff and OPC instead choose to bury their heads in the sand and simply ignore the residential subsidy. In fact, Staff is audacious enough to suggest that, despite these previous Commission decisions, a residential subsidy does not even exist. Despite Staff's refusal to see the obvious, Ameren and MIEC have both conducted class cost of service studies which demonstrate a residential subsidy of approximately $95 million. In the revenue allocation portion of this brief, MECG suggests a proposal to eliminate 41% of this remaining subsidy. As an alternative, MECG suggests a procedure to eliminate either 27% or 21% of the subsidy.

In the industrial rate design portion of this brief, MECG recommends that the LGS / SP revenue requirement be recovered through an increase in the class demand charges. Specifically, MECG suggests that the LGS / SP demand charges should be increased by 3 times the class revenue increase. So, if the LGS / SP rate classes receive a 6.7% rate increase as recommended by MECG, then the demand charge should be increased by 20% with the remaining revenue requirement increase being recovered through an equal percent increase on the class energy charges. Again, such a proposal is consistent with decisions issued by the Commission in recent Ameren rate cases.

Finally, in order to address the complicated nature of the LGS / SP rate structure, MECG urges the Commission to order Ameren to simply propose a more straightforward rate design in the next rate case. In addition, MECG urges the Commission to reject Staff's "punitive" proposal to "suspend" the Rider B credits for Small Primary / Large Primary customers that have constructed, operate and maintain their own substations.

B. ALLOCATION OF FIXED PRODUCTION COSTS

Issue: How should production costs be allocated among customer classes within a Class Cost of Service Study?

General Position: As reflected by the Commission's decision in recent Ameren rate cases, the Staff class cost of service methodology is "unreliable."[1] First, Staff relies upon the Peak and Average methodology for the allocation of nuclear and fossil investment that the Commission has found to be "inherently flawed". The Commission has previously rejected the Peak and Average approach as it "double counts the average system usage" to the detriment of high load factor industrial customers.[2] Next, Staff relies exclusively on the energy allocator for the allocation of renewable investment. By relying entirely on class energy and failing to recognize class demand to any degree, Staff fails to recognize the capacity value of these generating units. This is directly contrary to the Commission's IRP rules as well as those of MISO which expressly recognize the capacity value of such renewable generation. Recognizing that Staff's approach is "inherently flawed", the Commission should rely on the Average & Excess ("A&E") fixed production cost allocator, as recommended by Ameren, MIEC and MECG.

1. OVERVIEW

During the 2021 legislative session, the General Assembly enacted Section 393.1620. That statute, enacted primarily in response to Staff's ever-changing method for allocating fixed production costs, mandates that the Commission only consider class cost of service studies that "allocate the electrical corporation's production plant costs from nuclear and fossil generating units using the average and excess method ["A&E"] or one of the methods of assignment or allocation contained

[1] Tr. 315.

[2] *Report and Order*, Case No. ER-2010-0036, issued May 28, 2010, at page 84.

within the National Association of Regulatory Commissioners 1992 manual or subsequent manual."[3]

There were several class cost of service studies presented in this case. Each of those studies largely complies with Section 393.1620.[4] Specifically, MECG, MIEC and Ameren each presented studies that rely on the A&E methodology not only for the allocation of the "nuclear and fossil generating units" required by the statute, but also for the allocation of renewable resources.

In contrast, Staff relied upon an amalgam of allocation methodologies. Specifically, Staff presented 3 studies. Consistent with Section 393.1620, Staff utilized a NARUC-recognized methodology for the allocation of nuclear and fossil generating units, but then relied exclusively on an energy allocator for the allocation of all renewable generation investment.

2. STAFF'S FLAWED APPROACH

In its Class Cost of Service Report the Staff presented three different approaches. While Staff utilized a NARUC-recognized methodology in each of the three studies for the allocation of investment in nuclear and fossil units, as required by Section 393.1620, Staff then relied exclusively on the energy allocator for all renewable generation investment in all three studies.

> Staff segregated the various Ameren Missouri generating facilities into 10 categories: Nuclear; coal; combustion turbine; Taum Sauk; Osage; Keokuk; Wind; Landfill; General Solar; and Community Solar. Staff then calculated the revenue requirement

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[3] Section 393.1620.2.

[4] MECG suggests that each of the class cost of service studies "largely" complies with Section 393.1620 because, while Ameren utilizes the Average and Excess methodology expressly recognized by the statute, in that Ameren does not use each class' coincident peak for those months in which Ameren experienced its system peaks. Instead, Ameren used non-coincident peaks. "Upon examination of the calculation of Ameren's proposed allocator, it appears that allocator differs slightly from that specified in Section 393.1620.1(1) RSMo, in that the months used for the 4NCP in the A&E 4NCP are "determined…for the four months with the highest system peak loads." As shown in Exhibit SWC-4 row (9), the four months with the highest system peak loads are February, June, July, and August, but in rows (10) through (14) the class NCPs used for the calculation of the allocator are, depending on the class, from January, March, April, May, June, July, August, and September." Exhibit 750, Chriss Direct, page 18. As reflected in MECG's testimony, this shortcoming is not result in the calculation of class A&E allocators that are meaningfully different. Instead, MECG simply raised this issue out of an abundance of caution and to avoid the possibility that parties would seek to reject the A&E analyses in this case on the basis that the studies did not comply with the newly enacted statute.

> associated with the fixed costs of each of these categories of generating units (see Staff Report, pages 37-39). Staff then considered a range of allocation methodologies, including variants of single peak; multiple peak; Average & Excess; and Peak & Average methodologies for the nuclear; coal; combustion turbine; Taum Sauk and Osage generation categories. For the other generation categories (Keokuk; Wind; Landfill; and General Solar), Staff relied only on the energy allocator under the misplaced premise that these generation facilities exist simply to provide Renewable Energy Certificates ("RECs") and energy and do not provide any capacity benefit (see Staff Report, page 42). Finally, Staff allocated the fixed costs associated with the Community Solar category entirely to the Community Solar customers.[5]

The evidence shows that Staff's fragmented approach is "inherently flawed" for two primary reasons. ***First***, to the extent that Staff relied upon the Peak and Average approach for the allocation of nuclear and fossil investment, the Commission has already rejected that approach as "unreliable". ***Second***, the overreliance on the energy allocator for the allocation of investment in renewable generation fails to recognize the capacity value of renewable generation, assigns an excess amount of costs to high load factor customers, and is contradictory to the Commission's IRP rules and MISO revenue adequacy procedure.

In 2010 the Commission considered facts virtually identical to those presented here. In that case Staff proposed to allocate fixed production costs using the Peak and Average approach. In contrast, Ameren and MIEC both recommended that the Commission rely upon the A&E approach. There the Commission branded Staff's approach as "unreliable" because it "double counts" each classes' average demand (energy).

> Staff asserts that its Peak and Average Demand allocation method is superior to the Average and Excess method because it considers each class' contribution to the system's total peak rather than each class' excess demand at peak. However, what Staff describes as its method's strength is actually its downfall because ***the Peak and Average demand method double counts the average demand of the customer classes***. The Peak and Average method, in contrast, initially allocates average costs to each

[5] Exhibit 501, Brubaker Rebuttal, pages 3-4.

> class, but then, instead of allocating just the excess of the peak usage period to the various classes to the cost causing classes, the method reallocates the entire peak usage to the classes that contribute to the peak. Thus, the classes that contribute a large amount to the average usage of the system but add little to the peak, have their average usage allocated to them a second time. ***Thus, the Peak and Average method double counts the average system usage, and for that reason is unreliable***.[6]

This was not the first time that the Commission rejected the Peak and Average approach and noted that the approach was punitive to high load factor industrial customers. "Indeed, the Peak and Average Demand allocation method used by Staff is inherently flawed as it double counts the average demand of customer classes, resulting in customers with higher load factor, in other words industrials, being allocated an inequitable share of production plant investment. . . . ***The class cost of service study offered by Staff is inherently flawed and unreliable***."[7]

Here Ameren agrees that Staff's Peak & Average approach is "inherently flawed."

> ***[T]he use of the P&A method is inherently flawed as it double counts the average demand of customer classes***. This double counting results from the previously described use of class average demand for a portion of production plant altercation (i.e., the 55 percent system load factor weighting piece) and the use of class peak or non-coincident peak demands, which include an average demand component for the remaining allocation of production plant (i.e., 45 percent). This double counting results in customers with higher load factors being allocated an inequitable share of production plant investment. This result is driven by the high load factor customers demonstrating a better correlation between average demands and peak demands than do lower load factor customers; therefore, higher load factor customers receive a disproportionate share of the non-average demand (i.e., 45 percent) portion of production plant investment.[8]

Not only is Staff's approach "unreliable" as a result of its utilization of the "inherently flawed" Peak and Average approach for allocating nuclear and fossil investment, its approach is also flawed for its reliance on the energy allocator for the allocation of investment in renewable

[6] *Report and Order*, Case No. ER-2010-0036, issued May 28, 2010, at pages 84 and 85 (emphasis added).
[7] *Report and Order*, Case No. ER-2008-0318, issued January 27, 2009, at pages 125 and 126 (emphasis added).
[8] Tr. 315-316 (emphasis added).

generation.[9] As Mr. Brubaker points out, the reliance on the energy allocator fails to recognize that renewable generation provides not only energy, but also the capacity needed to meet Ameren's system peak demand.

> To effectively and cost-efficiently serve the power requirements of its customers, electric utilities invest in and/or procure through purchased power agreements a variety of generation resources that have different characteristics. A generation resource portfolio typically includes baseload facilities that are designed to operate most of the time, and which have (in a relative sense) higher fixed costs, and lower variable cost. At the other end of the spectrum of characteristics are peaking plants (whose use is expected to be needed only infrequently for unexpected needs and for peaking capacity) that have (in a relative sense) relatively higher variable costs and relatively lower fixed costs. . . Recognizing that all of these facilities are part of an overall generation resource portfolio designed to serve the overall power requirements of a utility's customers at the lowest overall reasonable cost, and that all provide capacity, the generally accepted method is to allocate the fixed costs associated with all of these facilities on the basis of an appropriate measure of customer demand, and to allocate all of the variable costs to customer classes on the basis of relative class kWh requirements.[10]

The failure to recognize that all generating units, including renewable generation, provides some measure of capacity value is recognized by the MISO resource adequacy process.

> Q. Anyway, is it your understanding that MISO to some degree assures that each utility meets certain resource adequacy requirements?
>
> A. MISO specifies a requirement, and it's up to the utility to actually make that happen.
>
> Q. And under the MISO resource adequacy guidelines, are renewable generation assets provided a capacity value?
>
> A. They are, yes.
>
> Q. So MISO recognizes that there's a capacity component with renewable energy; is that true?

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[9] Interestingly, while Section 393.1620 does not require that the allocation of investment in renewable generation be done utilizing a NARUC-recognized allocator, Staff chose to utilize an energy allocator that is not recognized by NARUC. (Tr. 353).

[10] *Id.* at page 8.

A. Correct.[11]

Similarly, the fact that renewable generation provides a measure of capacity value is also reflected in the Commission's Integrated Resource Planning rules.

> Q. Okay. Is it fair to say that the Missouri Commission's IRP rule basically in very general terms provides for a 20-year load forecast, looks at the current generation assets, determines if there's any shortfall between the load forecast and current capacity and then seeks to meet that difference with future supply-side additions or demand-side management?
>
> A. Generally, yeah, that's part of the analysis and part of the reason for having the IRP process.
>
> Q. Can you tell me under the Commission's IRP rule whether the Commission provides for a capacity value for renewable energy?
>
> A. Yes, I think that would be accurate.
>
> Q. So the Commission's IRP implicitly finds that there's capacity value for renewable energy and that renewable resources are not there solely for energy generation?
>
> A. I think that's the way it's looked at, although I don't think that the Commission itself specifies what that attribution of capacity value is. I think that's really driven by MISO, but the Commission is part of MISO. So when the Commission looks at adequacy, it looks at it through the lens of the MISO requirements.
>
> Q. But the Commission's IRP rule specifically states to look at the capacity for "all" generating resources?
>
> A. Yes, I believe that's correct.[12]

Recognizing that all generation, including renewable generation, is recognized to provide a measure of value to meeting the utility's capacity needs, it is inappropriate to simply ignore this fact and allocate the investment in renewable generation solely as if it only provides value towards

[11] Tr. 352.
[12] Tr. 353-354.

meeting system energy requirements.

Ameren agrees. "A cost allocation methodology that gives weight to <u>both</u> class peak demands and class energy consumption (average demands) is required to properly address both of the above considerations associated with capacity planning. The A&E methodology gives weight to both of these considerations by its inclusion of both average class demands, which are kilowatt hours divided by total hours in the year (8,760 hours), and the excess NCP demands of each class."[13]

The motivation underlying Staff's exclusive reliance on the energy allocator is apparent – it shifts costs away from low load factor / less efficient customer classes that use less energy per kW of demand (i.e., residential class) to high load factor / more efficient customer classes that use more energy per kW of demand (i.e., large general service, small primary and large primary classes). As was recognized, Staff's approach "results in customers with higher load factors being allocated an inequitable share of production plant investment."[14]

The Commission should recognize that all generating units provide a measure of capacity value and reject Staff's misplaced attempt to allocate the costs of renewable generation entirely on class energy usage.[15]

In addition to its reliance on the "inherently flawed" Peak and Average allocator, as well as its dependence on the energy allocator for allocation of renewable generation investment, Staff's methodology is defective for other reasons. Specifically Staff double-downed on its over-reliance on

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[13] Exhibit 30, Hickman Direct, page 19 (emphasis added).

[14] Tr. 315. The Staff's utilization of a methodology that is punitive to high load factor customers undoubtedly explains the reason that Public Counsel, the representative of the class with the lowest load factor, and the entity most benefitted from Staff's "inherently flawed" approach, no longer sees the need to conduct its own class cost of service study.

[15] There are numerous other problems underlying Staff's class cost of service study. As detailed in Mr. Brubaker's rebuttal testimony (Exhibit 501), Staff used inappropriate allocators for the allocation of general overhead costs (pages 9-11) and plant in service account (PISA) costs (pages 11-12). These problems inherent in Staff's methodology provide additional justification, in addition to Staff's overreliance on the energy allocator, for the rejection of Staff's study.

the energy allocator by depending on that same methodology for the allocation of general overhead, plant in service accounting costs; and socialized program costs.

While Staff claimed that general overheads are too general to be reasonably allocated, MIEC pointed out that "[t]he fact that they may not be precisely assignable does not justify a failure to make reasonable assignments and allocations, and instead lump everything into one bucket and arbitrarily allocate those costs to customer classes on the basis of class energy requirements."[16] A more reasonable approach would be to again reject Staff's reliance on the energy allocator and, instead, allocate these costs "across functions (generation, transmission and distribution) and between demand-related, energy-related, and customer-related costs on the basis of the relationship between these costs and the costs in the specific functional categories."[17]

Given the numerous flaws inherent in Staff's approach, Ameren, MIEC and MECG all agree that the Staff's methodology should be rejected.

3. <u>AMEREN / MIEC / MECG A&E APPROACH</u>

In contrast to Staff's "unreliable" approach which relies upon the "inherently flawed" Peak and Average methodology for allocating nuclear and fossil investment and the energy allocator for all renewable investment, Ameren, MIEC and MECG each relied upon the A&E methodology for the allocation of <u>all</u> generation investment.[18] This methodology has previously been accepted by this Commission.[19]

> Since the class cost of service studies offered by Staff and Public Counsel are unreliable, the Commission must choose between the Average and Excess method studies submitted by AmerenUE and MIEC. After carefully considering all the

[16] Exhibit 501, Brubaker Rebuttal, page 10.
[17] *Id.*
[18] Tr. 314.
[19] *Report and Order*, Case No. ER-2010-0036, issued May 28, 2010, at pages 86 and 87.

> studies, the Commission finds that AmerenUE's class cost of service study, modified to allocate revenues from off-system sales on the basis of class energy requirements, is the most reliable of the submitted studies.[20]

The A&E approach has not only previously been adopted by the Missouri Commission, it has also been accepted by the state utility commissions of virtually every vertically integrated state.[21]

► Louisiana: "***In light of all the relevant evidence, the commission deems it appropriate to allocate the rate increase under the average and excess method proposed by Gulf States***. This method reflects the theoretical justifications for a rate design that reflects an allocation of embedded costs but tends somewhat to spread the impact of the cost allocation. This approach furthers the overall interests historically considered by the commission in designing rates and is consistent with the purposes of PURPA. ***In addition, it reflects the concern of the commission that the rates assigned to industrial customers in Louisiana not reach a level at which these firms would be placed in an untenable competitive position***."[22]

► Oklahoma: "***The allocation of production demand-related costs to the various retail customer classes in the class COSS is based on a 4CP Average & Excess (4CP A&E) methodology***. The peak demands for the summer months of June through September for the years of 2006 to 2009 are consistently the highest monthly peak demands incurred on the system. By using the 4CP A&E method, PSO ensured that all customers who benefit from the use of the Company's generation system will be allocated a reasonable share of the cost of developing and operating that system."[23]

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[20] *Report and Order*, Case No. ER-2010-0036, issued May 28, 2010, at pages 86-87.

[21] Since deregulated states generally are characterized by competition in the generation portion of the electric industry, the utility commission in these deregulated states are not faced with issues concerning the allocation of generation investment.

[22] Re: Gulf States Utilities Company, Louisiana Public Service Commission, Docket No. U-14495, issued November 17, 1980 (emphasis added). *See also*, Re: Gulf States Utilities Company, Louisiana Public Service Commission, Docket No. U-17282, issued March 1, 1991. ("The company has proposed to redesign its rates for the residential, commercial and industrial classes. Any design of rates must begin with the development of a cost of service study. Consistent with the Commission's past practice, the company utilized the Average and Excess Demand Method to allocate costs.").

[23] Re Public Service Company of Oklahoma, Oklahoma Corporation Commission, Cause No. PUD 201000050, issued January 5, 2011 (emphasis added). *See also*, Re: Oklahoma Gas & Electric Company, Oklahoma Corporation Commission, Cause No. PUD 201100087, issued July 9, 2012 ("A 4CP Average and Excess allocation method using the above adjustments will be used for allocation of costs between Oklahoma jurisdiction customer classes."); Re: Public Service Company of Oklahoma, Oklahoma Corporation Commission, Cause No. PUD 200800144, issued January 14, 2009 ("The allocation of production demand-related costs to the various retail customer classes in the class cost-of-service was based on a 4CP A&E methodology."); Re: Oklahoma Gas & Electric Company, Oklahoma Corporation Commission, Case No. PUD 201000037, issued July 29, 2010; Re: Oklahoma Gas & Electric Company, Oklahoma Corporation Commission, Case No. PUD 900000898, issued February 25, 1994.

► Texas: "The ALJs begin by examining the final decision in the ETI case in Docket No. 39896. In that document, the utility proposed to allocate capacity-related production and transmission costs to the retail classes based on A&E/4CP. The utility had used the same method in its last contested rate proceeding. In the Final Order approving ETI's previous application, the Commission found that the continued use of the A&E/4CP method was reasonable for allocating transmission costs and that the A&E/4CP method was "devoid of any double counting problem." The "double counting problem" is a reference to an error in the A&P calculation method by which a part of the demand data is counted twice. The Commission has been aware of the flaw since at least 1988, when an examiner's report rejected the use of another method for the same reason. Accordingly, because of the A&P method's flaws, we narrow the scope of our analysis by rejecting Mr. Johnson's recommendation that SWEPCO use the A&P method.

The continued use of the A&E 4CP allocator is the most reasonable methodology for allocating production and transmission plant among classes. The A&E 4CP allocator sufficiently recognizes customer demand and energy requirements and assigns cost responsibility to peak and off-peak users. It best recognizes the contribution of both peak demand and the pattern of capacity use throughout the year."[24]

►Arkansas: Recently the General Assembly passed Act 725. Codified at 23-4-422(b)(2), that legislation mandates the utilization of the Average & Excess method for the allocation of fixed production costs.

> (A) For the retail jurisdiction rate classes, ensure that all electric utility production plant, production related costs, all nonfuel production-related costs, purchased

[24] Re: Southwestern Electric Power Company, Texas Public Utility Commission, PUC Docket No. 40443, issued May 20, 2013 (citations omitted, emphasis added); *See also*, Re: Southwestern Electric Power Company, Texas Public Utility Commission, PUC Docket No. 40443, issued October 10, 2013 ("SWEPCO proposed the use of the Texas retail load factor in its A&E / 4CP methodology for allocating capacity-related production costs. Because SWEPCO's generation is built to meet system needs based on analysis of the system loads, it is reasonable to allocate costs using the system load factor. The appropriate load factor for use in the A&E / 4CP methodology is the system load factor."); Re: Homeowner's United, Texas Public Utility Commission, PUC Docket No. 40627, issued April 29, 2013 ("Austin Energy's use of the modified A&E 4CP for production cost allocation under the terms of the agreement is reasonable."); Re: Entergy Texas, Inc. Texas Public Utility Commission, PUC Docket No 39896, issued September 14, 2012 ("The Average and Excess (A&E) 4 CP method for allocating capacity-related production costs, including reserve equalization payments, to the retail classes is a standard methodology and the most reasonable methodology."); Re: Reliant Energy, Incorporation, Texas Public Utility Commission, PUC Docket No. 21665, issued May 31, 2000 ("In Docket No. 12065, the most recent docket addressing Applicant's rate design, the Commission approved the use of the Average & Excess 4 CP (A&E 4CP) to allocate Applicant's costs. Development of demand allocations using the generation-related base revenues by class resulting from the A&E 4CP is reasonable and appropriate and should be approved."); Re: Entergy Texas, Inc. Texas Public Utility Commission, PUC Docket No 16705, issued October 14, 1998; Re: Southwestern Electric Power Company, Texas Public Utility Commission, PUC Docket No. 36961, issued November 17, 2009; Re: Entergy Gulf States, Inc., Texas Public Utility Commission, PUC Docket No. 31315, issued February 9, 2006.

capacity costs, and any energy costs incurred resulting from the electric utility's environmental compliance are classified as production demand costs.

(B) ***Ensure that production demand costs are allocated to each customer class pursuant to the average and excess method*** shown in Table 4-10B on page 51 of the 1992 National Association of Regulatory Utility Commissioners Manual, as it existed on January 1, 2015, using the average of the four (4) monthly coincident peaks for the months of June, July, August, and September for each class for the coincident peak referenced in Table 4-10B of the manual, as it existed on January 1, 2015, or any subsequent version of the manual to the extent it produces an equivalent result.

► Colorado: "Public Service proposed continued use of the AED allocation method for the allocation of Production, Transmission, and Distribution Substation fixed capacity costs among the various rate classes. . . . ***We agree with Public Service that the AED method should be used to allocate Production, Transmission, and Distribution Substation costs. This method has a long precedent of acceptance by this Commission***. The testimony regarding this issue has convinced us that the method proposed by the OCC is not an accepted methodology and may cause problems by mixing two methods. Their hybrid method could result in a double counting of costs because the average demand is inherently a part of any measure of system peak."[25]

► District of Columbia: "Contrary to claims by WMATA and the District, the Commission is not required to "reinvent the wheel" or turn every rate case into an endless morass by requiring *de novo* justification of well-settled policies like AED (NCP) in every case. In short, we are simply not persuaded that WMATA and the District have carried their heavy burden to justify overthrowing the traditional AED(NCP) method. ***The old AED(NCP) method has value as a tried-and-true benchmark, against which the Commission can measure its progress towards marginal cost based rates. We adhere to that method***."[26]

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[25] Re: Public Service Company of Colorado, Colorado Public Utilities Commission, Docket No. 04S-164E, issued April 11, 2005 (emphasis added); *See also*, Re: Aquila, Inc. dba Aquila Networks – WPC, Colorado Public Utilities Commission, Docket No. 03S-539E, issued December 30, 2004 ("We adopted the use of AED allocation method using non-coincident peak to calculate the excess portion of transmission and generation plant and associated expenses."); Re: Black Hills / Colorado Electric Utility Company, L.P., Colorado Public Utilities Commission, Docket No. 12AL-1052E, issued May 14, 2013 ("It is also noted that the Commission approved a 4CP-AED allocator for the allocation of Public Service's production plant costs in Decision No. C10-0286 in Docket No. 09AL-299E issued March 29, 2010. While no policy directives are provided in that Decision, nonetheless, this approach is the Commission's most recent consideration of the issue."); Public Service Company of Colorado, Colorado Public Utilities Commission, Docket No. 09AL-2993, issued March 29, 2010.

[26] Re: Potomac Electric Power Company, District of Columbia Public Service Commission, Case No. 912, issued June 26, 1992, 13 DC PSC 512 (citations omitted). *See also*, Re: Potomac Electric Power Company, District of Columbia Public Service Commission, Case No. 541, issued April 15, 1970, 83 P.U.R.4th 113; Re: Potomac Electric Power Company, District of Columbia Public Service Commission, Case No. 596, issued November 16, 1973, 3 P.U.R.4th 65; Re: Potomac Electric Power Company, District of Columbia Public Service Commission, Case No. 905, issued October

► FERC: "The average and excess demand method was clearly delineated in Re Wisconsin Michigan Power Co., as follows: "Under the average-excess demand method, capacity costs (C) are divided into two parts in accordance with the system load factor (L). The portion equal to LC is allocated to customer classes on an energy use or average demand basis, and the balance (1 L)C is allocated on the basis of excess demands (the maximum demand of a load less its average demand). The effect of the average-excess method is to emphasize the extent of use of capacity, resulting in allocation of an increasing proportion of capacity costs to a customer as his load factor increases. . . . ***The average and excess demand method accomplishes this result and is accordingly adopted in this proceeding***."[27]

► Hawaii: "The AED method allocated production demand costs on the basis of each class' average demand weighted by system load factor and the peak demand in excess of weighted average demand. In our opinion, this method distinguishes between the cost to serve the average demand and the cost to serve the excess demand. The AED method recognizes such cost-related factors as class and system load factors, diversity of demand, and peak class demand whereas the PR and NCD method are based solely on a single load characteristic which can lead to unstable results. We believe that no single method of allocating demand costs can be claimed to be correct or best for all utilities, but ***the AED method is reasonable*** and an equivalent form of this method has been used and approved by this commission for all Hawaiian Electric Company, Inc., HELCO, and MECO rates cases"[28]

Other state utility commissions that have adopted the Average & Excess method for allocating fixed production plant-related costs include the Pennsylvania Public Utilities

23, 1991; Re: Potomac Electric Power Company, District of Columbia Public Service Commission, Case No. 929, issued March 4, 1994, 150 P.U.R.4th 528; Re: Potomac Electric Power Company, District of Columbia Public Service Commission, Case No. 1087, issued September 27, 2012, 300 P.U.R.4th 166; Re: Potomac Electric Power Company, District of Columbia Public Service Commission, Case No. 1103, issued March 26, 2014, 313 P.U.R.4th 340 (emphasis added).

[27] Re: Public Service Company of Oklahoma, Federal Power Commission, Docket No. E-8242, issued February 17, 1977, 19 P.U.R.4th 190 (emphasis added).

[28] Re: Hawaiian Electric Company, Inc., Hawaii Public Utilities Commission, Docket No. 3705, issued June 26, 1981, 44 P.U.R.4th 234. *See also*, Re: Hawaiian Electric Company, Inc., Hawaii Public Utilities Commission, Docket No. 4536, issued September 16, 1983, 56 P.U.R.4th 398 (""We agree with HECO that although there is no single best method of allocating demand costs for all utilities, the AE method is reasonable for HECO. . . . The AE method takes into consideration class and system load factors, diversity of demand, and class peak demand."); *See also*, Re: Maui Electric Company Ltd., Hawaii Public Utilities Commission, Docket No. 1739, issued March 28, 1968 ("In the average and excess demand method used by the applicant, both the maximum loads and the extent of use of equipment are taken into account in the allocation process. In other words, in the average excess demand method, the allocation takes into consideration the average use of capacity and the responsibility for the capacity required to meet system loads. Used capacity costs are assigned to the various classes of service in proportion to their respective use and the remaining capacity costs, representing the portion of demand costs associated with the unused portion of capacity, is apportioned to the various classes of service in the ratio that the individual group demands, in excess of used demands, bear to total demand.").

Commission,[29] Maryland Public Service Commission,[30] and Connecticut Department of Public Utility Control.[31]

Unlike the Staff's "inherently flawed" Peak and Average approach, Ameren, MIEC and MECG each has recommended the A&E methodology that has been adopted by this Commission and numerous other state utility commission. The results of the Ameren, MIEC, and MECG A&E studies are all closely aligned. The amount of fixed production plant costs allocated under each of these studies is:

	Ameren	**MIEC**	**MECG**
Residential	52.53%	52.5%	52.76%
SGS	10.93%	10.9%	10.89%
LGS / SP	28.71%	28.7%	28.77%
LP	7.50%	7.5%	7.24%
Company – Owned Lighting	0.34%	0.2%	0.33%
Customer – Owned Lighting	0.34%	0.1%	0.33%

Source: Exhibit 750, Chriss Direct, page 21; Exhibit 500, Brubaker Direct, Schedule MEB-COS-3A.

The reasonableness of the A&E methodology is best exemplified by comparing the A&E results to allocations produced by several of the other methodologies recognized in the NARUC manual.

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[29] Pa. Publ. Util. Comm'n v. PPL Gas Utilities Corporation, Docket No. R-00061398, issued February 9, 2007.

[30] Re: Potomac Electric Power Company, Maryland Public Service Commission, Case No. 9286, issued July 20, 2012; Re: Potomac Electric Power Company, Maryland Public Service Commission, Case No. 9336, issued July 2, 2014.

[31] Re: The Connecticut Light and Power Company, Connecticut Department of Public Utility Control, Docket No. 03-07-02RE09, issued December 8, 2006; Re: The United Illuminating Company, Connecticut Department of Public Utility Control, Docket No. 05-06-04RE02, issued December 19, 2006.

	Residential	SGS	LGS / SP	LP	Company-Owned Lighting	Customer-Owned Lighting
A&E 4 NCP	52.5%	10.9%	28.7%	7.5%	0.2%	0.1%
A&E 2 NCP	52.5%	11.1%	28.7%	7.4%	0.2%	0.1%
A&E 1 NCP	52.6%	11.1%	28.6%	7.4%	0.2%	0.1%
4 CP	52.9%	10.5%	29.0%	7.5%	0.0%	0.0%
2 CP	53.4%	10.9%	28.4%	7.4%	0.0%	0.0%
1 CP	53.3%	10.9%	28.6%	7.2%	0.0%	0.0%
4 NCP	52.3%	10.9%	28.7%	7.5%	0.4%	0.2%
2 NCP	52.7%	11.2%	28.4%	7.2%	0.3%	0.2%
1 NCP	52.9%	11.1%	28.2%	7.2%	0.3%	0.2%

Source: Exhibit 500, Brubaker Direct, Schedule MEB-COS-3A

Given the reasonableness of the A&E methodology, as well as the fact that Staff's methodology is "unreliable" and "inherently flawed", the Commission should adopt either of the A&E studies presented in this case.

C. ALLOCATION OF PRODUCTION NON-FUEL / NON-LABOR COSTS

Issue: How should the non-fuel, non-labor components of production, operation and maintenance expense be classified and allocated among customer classes?

In its cost of service study, Ameren recommends that $69 million of non-fuel, non-labor costs of production and O&M expense be treated as a variable cost and allocated on the basis of class energy usage. In its rebuttal testimony, however, MIEC pointed out that these costs are fixed and are incurred regardless of the amount of electricity generated at the generating units.

> It is my position that the vast majority of these costs do not vary in any appreciable way with the number of kWh generated, but occur primarily as a function of the existence of the plants, the hours of operation and the passage of time. In fact, Ameren Missouri schedules the maintenance on its coal and nuclear generation units on a "passage of time" basis, not on a "kWh generated" basis. I believe the most appropriate approach is to classify all of the generation O&M expense other than fuel and purchased power as a fixed cost. This is sometimes referred as the "expenses follow plant" basis.[32]

Noticeably, despite the opportunity to rebut this assertion in its surrebuttal testimony, Ameren never responded. Given the unrebutted assertion that these costs are incurred on the basis of time and not the amount of electricity generated, the Commission should allocate these costs on the basis basis as the underlying units ("expenses follow plant").

[32] Exhibit 500, Brubaker Direct, page 34.

D. REVENUE ALLOCATION

Issue: How should any rate increase be allocated to the several customer classes?

General Position: The Commission should allocate the authorized rate increase in this case based upon the measured approach suggested in the testimony of MECG witness Chriss (Exhibit 750, Chriss Direct, pages 27-28). Specifically, Mr. Chriss suggests that the Commission should utilize one-half of the difference between the revenue increase sought by Ameren in this case ($298 million) and the amount actually authorized ($220 million)[33] to address the long-standing residential subsidy. In this way, all classes are guaranteed to see some benefit from the reduced revenue requirement in this case while also continuing the Commission's efforts from the last 14 years to mitigate the residential subsidy. Such an approach reflects gradualism while also taking definitive steps towards cost-based rates by eliminating 41% of the residential subsidy inherent in Ameren rates. In response to questions from the bench, Mr. Chriss acknowledged that there was nothing "magical" about the proposal to eliminate 41% of the residential subsidy.[34] Therefore, as an alternative, the Commission could utilize either 33% or 25% of the reduced revenue requirement in this case, instead of the 50% reflected in testimony. These alternatives would eliminate 27% or 21% of the residential subsidy respectively.

1. BACKGROUND

In recent cases the Commission has expressly recognized the importance of cost-based rates for industrial customers. For instance, in a 2014 Empire rate case, the Commission found the following:

[33] On December 22, 2021, the Commission approved a stipulation providing for an overall $220 million revenue increase for Ameren. See, *Order Approving Stipulation and Agreements*, Case No. ER-2021-0240, issued December 22, 2021.
[34] Tr. 393.

> Competitive industrial rates are important for the retention and expansion of industries within Empire's service area. If businesses leave Empire's service area, Empire's remaining customers bear the burden of covering the utility's fixed costs with a smaller amount of billing determinants. This may result in increased rates for all of Empire's remaining customers.[35]

Still again, in the 2011 Ameren case, the Commission stated:

> In general, it is important that each customer class carry its own weight by paying rates sufficient to cover the cost to serve that class. That is a matter of simple fairness in that one customer class should not be required to subsidize another. Requiring each customer class to cover its actual cost of service also encourages cost effective utilization of electricity by customers by sending correct price signals to those customers.[36]

Such a finding mirrors a finding from the 2010 Ameren rate case.[37]

Based upon its desire to have "each customer class cover its actual cost of service", the Commission has taken affirmative steps in the last ***SEVEN*** Ameren rate cases to address the lingering residential subsidy. For instance, in the last case (ER-2019-0335), Staff acknowledges that the industrial classes received a larger reduction than the residential class.[38] The steps to address the residential subsidy were not limited to the last case. In fact, in the previous case (ER-2016-0179) the Commission also took steps to address the sizeable and lingering residential subsidy.[39] Still again, in the previous case (ER-2014-0258), the Commission also took steps to address the residential subsidy. "The small general service, large general service and small primary service rate classes have received negative rate adjustments in past Ameren Missouri rate cases, meaning the Commission has acted to

[35] Report and Order, Case No. ER-2014-0351, issued June 24, 2015, page 18.
[36] *Report and Order*, Case No. ER-2011-0028, issued July 13, 2011, at pages 115-116.
[37] *Report and Order*, Case No. ER-2010-0036, issued May 28, 2010, at page 87.
[38] Tr. 369-370. See also, *Report and Order*, Case No. ER-2019-0335, issued March 18, 2020, at Corrected Stipulation and Agreement, Exhibit J.
[39] See, *Order Approving Unanimous Stipulation and Agreement*, Case No. ER-2016-0179, issued March 8, 2017, page 2.

move those classes closer to their cost of service."[40] In the same fashion, in the previous case (ER-2012-0166), the Commission approved a stipulation which gave a lower rate increase to the LGS / SP rate class.[41] Once again, in Case No. ER-2011-0028, the Commission also approved a stipulation which gave a lower increase to the industrial classes in order to address the enduring residential subsidy.[42] Again, in Case No. ER-2010-0036, the Commission issued its Report and Order which imposed a significant increase on the residential class in order to address the lingering residential subsidy.

> Specifically, for an overall rate increase of $225 million, which is approximately the rate increase that will result from this order, the addendum to the stipulation and agreement would impose a roughly 1.5 percent revenue-neutral increase on the residential and small general service classes. That amounts to a revenue neutral increase of $14.5 million for the residential class and $3.8 million for the small general service class.[43]

Finally, in Case No. ER-2008-0318, the Commission assigned a larger portion of the revenue requirement increase to the residential class to reflect the existence of a residential subsidy.[44]

Now, after 14 years and 6 cases of taking steps to address the residential subsidy, Staff and OPC ask the Commission to simply ignore the subsidy. In this case the Commission can once again demonstrate its concern for establishing cost based rates by ignoring the advice of Staff and OPC.

The class cost of service studies in this case all show the existence of a significant residential subsidy. For instance, under Ameren's class cost of service study, the residential class is currently

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[40] See, *Report and Order*, Case No. ER-2014-0258, issued April 29, 2015, at page 73.
[41] See, *Order Approving Revised Stipulation and Agreement Regarding Rate Design Issues*, issued October 18, 2012, attached Revised Non-Unanimous Stipulation and Agreement, page 1.
[42] See, *Report and Order*, Case No. ER-2011-0028, issued July 13, 2011, at pages 111-120.
[43] See, *Report and Order*, Case No. ER-2010-0036, issued May 28, 2010, at page 89.
[44] See, *Report and Order*, Case No. ER-2008-0318, issued January 27, 2009, at pages 119-126.

paying rates that are $93.2 million below cost of service.[45] The MIEC study quantifies this amount at $99.3 million.[46] The existence of this residential subsidy necessarily means that the industrial classes are paying rates that are significantly above cost of service. Specifically almost 10% of every dollar spent by an industrial customer is used to subsidize residential rates.

In recent years the General Assembly and utilities have sought to take steps to put a band-aid on the gunshot wound that is the above-cost industrial rates. For instance, in 2007, Ameren sought to implement an Economic Development and Retention Rider which "would offer a discounted rate to new or expanding industrial customers who can show they have an option to move out of AmerenUE's service territory to <u>an area with lower electric rates</u>."[47] In 2017, the General Assembly passed legislation (Section 393.355) for steel mills and aluminum smelters unable to compete given Missouri's inflated industrial rates. The next year, the General Assembly passed SB564, which provided discounted rates to rates to industrial customers willing to expand or relocate to Missouri.[48] Finally, just recently, Evergy filed for a special rate mechanism for data centers willing to locate in Missouri.[49] The need for each of these steps would certainly be minimized if industrial rates were cost-based and not being used to subsidize residential rates.

2. <u>MECG MEASURED APPROACH</u>

As previously indicated, MECG encourages the Commission to reject Staff's class cost of service study in this case and utilize either the Ameren or MIEC studies that rely upon the A&E

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[45] Exhibit 750, Chriss Direct, page 24; Exhibit 700, Brubaker Direct, Schedule MEB-COS-5.
[46] Exhibit 700, Brubaker Direct, Schedule MEB-COS-5.
[47] *Report and Order*, Case No. ER-2007-0002, issued May 22, 2007, at page 98 (emphasis added).
[48] See, Section 393.1640.
[49] See, Case No. EO-2022-0061.

methodology.[50] The results of the Ameren and MIEC studies are consistent.

	Ameren		MIEC	
	Earned Return	Rate of Return Index	Earned Return	Rate of Return Index
Residential	3.10%	0.65	3.44%	0.72
SGS	5.15%	1.08	5.01%	1.05
LGS / SP	7.35%	1.54	6.83%	1.43
LP	7.70%	1.62	7.27%	1.53
Company-Owned Lighting	9.02%	1.89	7.94%	1.67
Customer-Owned Lighting	-4.57%	(0.96)	-2.05%	-43
Total Company	4.76%	1.00	4.77%	1.00

Source: Exhibit 750, Chriss Direct, Schedule SWC-7; Exhibit 500, Schedule MEB-COS-5.

The results of these studies demonstrate two undeniable facts. ***First***, under both studies, the residential class revenues are producing a rate of return (3.10-3.44%) that is well below Ameren's system rate of return (4.76%). ***Second***, each of the general service classes (SGS, LGS / SP, and LP) are providing revenues that produce a rate of return well above the Ameren system rate of return. Specifically, the LGS / SP class is providing a rate of return of 6.83% - 7.35% at a time when Ameren is earning a total return of 4.76%. Thus, it is apparent that these general service classes are all paying rates above cost of service while the residential class is paying rates below cost of service. Clearly then, a residential subsidy is inherent in Ameren's rates.

The existence of a residential subsidy is not new. As Mr. Chriss details, "LGS and SP rates have provided a rate of return above their cost of service levels in every rate case back to and including the Company's 2007 rate case. . . This has resulted in LGS and SP customers paying rates well in excess of the Company's cost to serve them since 2007. As such, rate relief is long overdue."

[50] While MECG witness Chriss provided the results of his A&E methodology, he did not carry those results through to a complete class cost of service study. As such, there are no independent results to show the quantification of the residential subsidy. Instead, his A&E calculation supports the reasonableness of Ameren's class cost of service study and Ameren's quantification of the residential subsidy.

As the following table indicates, Ameren has consistently earned much more from the LGS / SP rate class than it has on a total company basis over the past 15 years. So, under current rates, Ameren is earning 7.35% return on equity at a time when it is only earning a total return of 4.76%.

Case	LGS / SP Rate of Return (%)	Total Missouri Rate of Return (%)	Rate of Return Index Value
ER-2007-0002 (LGS)	5.86%	2.74%	2.14
ER-2007-0002 (SP)	4.47%	2.74%	1.63
ER-2008-0318	7.01%	4.06%	1.73
ER-2010-0036	6.12%	1.89%	3.24
ER-2011-0028	8.26%	4.59%	1.80
ER-2012-0166	6.32%	2.89%	2.19
ER-2014-0258	7.57%	4.44%	1.71
ER-2016-0179	9.73%	5.41%	1.80
ER-2019-0335	11.35%	7.37%	1.54
Present Case	7.35%	4.76%	1.54

Source Exhibit 750, Chriss Direct, page 23. (Prior to 2007 Ameren had not had a rate case for over 20 years. Therefore, the residential subsidy is likely to have existed prior to the 2007 rate case).

The magnitude of the residential rate increase necessary to eliminate the residential subsidy and get residential rates to cost of service is material. Specifically, both MIEC and Ameren have asserted that the residential class would require a revenue neutral **increase** of 7.8% or 7.32% respectively, prior to the 8.81% increase envisioned by the Unanimous Stipulation.[51] In contrast, the Large General Service / Small Primary class would require a revenue neutral **reduction** of 9.7% or 9.14% respectively prior to the increase reflected in the stipulation.

[51] "Revenue neutral refers to the changes necessary to bring each class to cost of service assuming no overall change in the utility's revenues." Exhibit 750, Chriss Direct, page 24.

	MIEC		Ameren	
	$$ (millions)	**%**	**$$ (millions)**	**%**
Residential	$99,254	7.8%	$93,202	7.32%
Small General Service	($3,565)	-1.3%	($4,258)	-1.55%
Large General Service / Small Primary	($70,674)	-9.7%	($66,501)	-9.14%
Large Primary	($20,385)	-10.8%	($17,855)	-9.47%
Company-Owned Lighting	($6,160)	-17.3%	($6,183)	-17.35%
Customer-Owned Lighting	$1,530	53.7%	$1,594	55.96%

Source: Exhibit 750, Chriss Direct, page 24; Exhibit 700, Brubaker Direct, Schedule MEB-COS-5.

Given the magnitude of the increase that would be required to completely eliminate the residential subsidy, MECG has instead proposed a gradual elimination of the subsidy. "If the Commission awards a revenue requirement increase lower than that proposed by the Company, MECG recommends the Commission take significant steps to bring the rates paid by SGS, LGS, SP, and LPS closer to their cost of service-based levels."[52] Specifically, MECG proposes a two-step revenue allocation methodology which would: (1) apply one-half of the difference between the revenue increase initially requested by Ameren and the amount actually authorized by the Commission towards the elimination of the residential subsidy and then (2) apply any authorized increase on an equal percentage basis.[53] Such an approach would lead to an approximate "41 percent" elimination of the residential subsidy.[54]

In response to questions from the bench Mr. Chriss pointed out that there is nothing magical about his recommendation to apply one-half of the reduction in the authorized revenue requirement towards the residential subsidy. While using one-half of the reduction would lead to a 41 percent movement towards cost-based rates, the Commission could use a different amount and still show its commitment to cost-based rates. For instance, using one third (33%) or one quarter (25%) of the

[52] Exhibit 750, Chriss Direct, page 26.
[53] *Id.* at pages 27-28.
[54] *Id.* at page 28.

reduction in the authorized revenue requirement would result in the elimination of 27% or 21% of the residential subsidy respectively.

	50% of Revenue Requirement Change used for Subsidy Elimination		**33% of Revenue Requirement Change used for Subsidy Elimination**		**25% of Revenue Requirement Change used for Subsidy Elimination**	
Customer Class	**Class Increase**	**Subsidy Reduction (%)**	**Class Increase**	**Subsidy Reduction (%)**	**Class Increase**	**Subsidy Reduction (%)**
Residential	10.4%		9.8%		9.5%	
Small General Service	9.8%	41%	9.4%	27%	9.3%	21%
Large General Service	6.7%	41%	7.4%	27%	7.7%	21%
Small Primary Service	6.7%	41%	7.4%	27%	7.3%	21%
Large Primary Service	6.6%	41%	7.4%	27%	7.7%	21%
Customer-Owned Lighting	12.8%	41%	12.3%	27%	12.0%	21%
Company-Owned Lighting	3.2%	41%	4.9%	27%	5.9%	21%

Source: Exhibit 750, Chriss Direct, page 28.

Thus, recognizing that Ameren initially sought an 11.97% increase, under any of MECG's proposals the residential class would still see a benefit in the form of a reduced rate increase while still allowing the Commission to signal its intent to continue to move towards cost-based rates.

Given the long standing nature of the residential subsidy, as well as the economic implications of the large commercial / industrial customers continuing to pay rates that are 10-11% above cost of service, MECG recommends that the Commission adopt its proposal.

3. <u>OTHER PROPOSALS</u>

While MECG recommends steps which would help to address the long-standing residential subsidy, Ameren and Staff[55] choose to bury their heads in the sand and ignore this problem.[56]

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[55] Once again OPC blindly accepts Staff's revenue allocation proposal. (Exhibit 402, Marke Rebuttal, page 26 – "In my opinion, the Commission should rely on Staff's study for an objective perspective in this case."). Where it once deemed

For instance, while Ameren quantifies the residential subsidy at $99.3 million (7.8% below cost of service),[57] Ameren actually proposes a revenue allocation which would give the residential class an increase that is below the overall increase in this case. Thus, Ameren's proposal would not only preserve the existing residential subsidy, it would actually increase the residential subsidy. Similarly, while acknowledging that the LGS / SP are already paying rates that are well above cost of service, Ameren actually proposes to give these classes an increase that is above the system average increase. On cross-examination Ameren acknowledge the illogical nature of its revenue allocation proposal in that its revenue allocation proposals are not "directionally consistent" with its class cost of service study.[58]

Similarly, Staff ignores the residential subsidy by vaguely recommending that based, upon "its expert judgement considering the precision of such studies in general and known shortcomings of these studies in particular. . . Staff recommends that the increase be allocated to the classes as an equal percentage increase."[59] Interestingly, during the hearing Staff justified its position by suggesting two self-serving criteria which should be applied by the Commission in considering the allocation of any revenue increase. For instance, without recitation to any statute, rule, or Commission order, Staff suggests that no recognition should be given to any subsidy unless that

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it necessary to conduct its own class cost of service study, OPC no longer finds it necessary as it realizes that Staff's position will inevitably be beneficial to the residential customers represented by OPC. Instead, OPC simply suggests that it would be inappropriate for the Commission to take any steps to recognize the residential subsidy due to vague concerns with difficulties securing cost allocation data. (Id. at page 26). OPC's excuse for ignoring the residential subsidy is the latest in a litany of excuses designed to perpetuate the subsidy on behalf of the residential customers that it represents. For instance, in recent cases, OPC has urged the Commission to maintain the residential subsidy due to concerns with billing determinants, number of estimated bills, magnitude of rate increases, economic factors, the Covid pandemic, unemployment, etc.

[56] MIEC submitted a revenue allocation proposal which would eliminate 50% of the residential subsidy. (Exhibit 500, Brubaker Direct, page 41). Thus it is largely consistent with the position advanced by MECG.

[57] Exhibit 750, Chriss Direct, page 24

[58] Tr. 333-335.

[59] Exhibit 205, Staff Class Cost of Service Study, page 3.

subsidy is greater than 5%.[60] Such a suggestion is a self-serving criterion which is designed to permanently maintain a residential subsidy of at least 5%. In any event, only the "inherently flawed" and "unreliable" Staff study results in quantifications of a residential subsidy of less than 5%. Under either the Ameren or MIEC class cost of service studies, the residential subsidy is well in excess of Staff's arbitrary criteria.[61]

Similar to its arbitrary 5% rule, Staff attempts to excuse the significant residential subsidy by suggesting that all classes are currently paying rates "that exceed allocated expenses and are contributing toward rate of return." Again, Staff's criterion is designed to perpetuate the residential subsidy permanently by suggesting that each class is not required to pay its fully allocated rate of return, but must simply make a "contribution toward rate of return." The nonsensical nature of Staff's suggestion is premised on the erroneous notion that rate of return is not an actual cost. Such a ludicrous suggestion is rebutted by the United States Supreme Court which held that like all other operating expenses, return on equity is an expense which the utility is entitled to recover.[62] Mr. Brubaker agrees.

> Q. Do you believe that return on equity is a cost to the utility?
>
> A. Yeah, I was a little confused by his statement. Certainly return on equity along with the associated income taxes and debt is part of the overall return requirement. So to say that your rate of return is below average doesn't mean that you're covering your cost. It means the opposite, you're not.[63]

Noticeably, given the holding of the United States Supreme Court, the Staff failed to provide any citation to a statute, rule or Commission order which supports its faulty suggestion.

[60] Tr. 207.
[61] Exhibit 750, Chriss Direct, page 23.
[62] *Bluefield Water Works and Improvement Company v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923)
[63] Tr. 354.

During cross-examination,[64] Staff sought to perpetuate the residential subsidy by pointing out, based upon MECG's evidence, that industrial rates are now producing a rate of return index of 1.54 – the lowest in 15 years. Specifically, LGS / SP rates are producing a rate of return of 7.35% - 54% higher than the system average of 4.76%.[65] Thus, Staff implies that the residential subsidy has decreased in recent years. Given this, Staff feels justified in suggesting that the Commission ignore the residential subsidy in this case and instead adopt Staff's recommended equal percent approach.

What Staff fails to recognize is that, while the residential subsidy has decreased in recent, the reduction is a result of revenue allocation steps in recent cases. As detailed at pages 21-22, the Commission has taken steps to reduce the residential subsidy in at least Ameren's last seven rate cases. Therefore, it shouldn't be surprising that the residential subsidy is at the lowest point in the last 14 years. Nevertheless, the residential subsidy is still significant and deserving of attention. Despite the Commission's demonstrated effort to reduce the residential subsidy and move to cost-based rates, the Staff instead chooses to ignore the subsidy and instead recommends the utilization of an equal percentage approach to the allocation of the revenue requirement increase in this case. MECG suggests that, after twelve years of concerted effort to reduce the residential subsidy, now is not the time to accept Staff's misguided advice and simply turn a blind eye towards the disparities in Ameren's rates.

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[64] Tr. 394-395.
[65] Exhibit 750, Chriss Direct, page 23.

E. LGS / SP RATE DESIGN PROPOSALS

Issue: Should the Commission approve MECG's proposed shift to increase the demand component for Large General Service and Small Primary Service and decrease energy charges?

Position: The Commission should increase the summer and winter demand charges for LGS and SP by three times the percent class increase.

In order to avoid intra-class subsidies it is important that the Commission establish rates which collect costs in the manner in which they are incurred. Thus, fixed costs should never be collected on a per kwh. Instead these costs should be collected through a demand charge on a per kW basis. Collecting such fixed costs through energy charges on a per kWh basis would lead to high load factor customers in a particular class subsidizing low load factor customers in that class. Under such a rate design, energy costs, which are incurred on a variable basis depending on the amount of electricity generated, would then be the only costs that are collected through energy charges on a per kWh basis.[66] By collecting costs through charges that reflect the manner in which costs are incurred sends proper price signals regarding the actual cost of building generation as well as the variable cost of generating the electricity.

Ameren's LGS / SP rate schedules include both demand charges and energy charges. So while the mechanisms exist to collect costs in the manner in which they are incurred (i.e., fixed costs collected on a per kW basis and variable costs collected on a per kWh basis), the "LGS and SP rates do not currently reflect the underlying cost of serving those classes. That is to say that demand charges do not collect all demand-related costs. Instead a significant portion of these demand-related costs are collected on a variable basis through the energy charges."[67] This fact is best demonstrated

[66] Exhibit 750, Chriss Direct, pages 35-36.
[67] *Id.* at page 32.

by the fact that, while 77% of costs are demand-related, only 14% of LGS revenues and 9.6% of SP revenues are collected through demand costs."[68] "Clearly then LGS and SP rate components are sending incorrect price signals."[69]

Component	**COSS Results**		**LGS Revenue Requirement**		**SP Revenue Requirement**	
	($000)	**(% of Total)**	**($000)**	**(% of Total)**	**($000)**	**(% of Total)**
Demand	$565,531	76.7	$79,558	14.0	$23,625	9.6
Energy	$153,373	20.8	$474,667	83.6	$220,289	89.3
Customer	$18,762	2.5	$13,563	2.4	$2,903	1.2
Total	**$737,666**	**100**	**$562,180**	**100**	**$243,913**	**100**

Source: Exhibit 750, Chriss Direct, page 34.

Recognizing that 76.7% of the LGS / SP costs are demand-related, 76.7% of revenues should be collected through the demand charge. This would require a significant increase in the demand charges and a commensurate decrease in the energy charges. "Assuming the demand charge recovers 76.7 percent of base rate revenues, consistent with the Company's cost of service study results, the estimated cost of service-based $/kW demand charge for LGS for the summer period would be $27.42/kW and for the winter period would be $15.22/kW. Additionally, the cost of service-based energy charge for the summer period is $0.02228/kWh and for the winter period is $0.01316/kWh."[70]

The practical implication of such a rate design shortcomings is to subject Ameren "to under and overcollection of its revenue requirement due to fluctuations in customer usage. As such, issues such as weather and the economy will have a greater impact on the utility versus a rate design in which an appropriate amount of revenue requirement is collected through the demand charge.[71]"

Given the obvious problems in the LGS / SP rate design, MECG recommends that the

[68] *Id.* at page 34.
[69] *Id.*
[70] *Id.* at 38.
[71] *Id.* at 37.

Commission "increase the demand and winter demand charges for the LGS and SP by three times the percent class increases."[72] Thus, if the LGS / SP rate class receives an overall increase of 6.7% (see page 7), then the demand charges should be increased by 20% with the remainder of the class increase being collected through the customer and energy charges. The practical implication of this proposal is that, since demand charges do not currently capture a sufficient level of fixed costs, the demand charge resulting from this case should be maximized and the energy charges minimized.

Ameren witness Wills agrees with the thrust of MECG's position. "Mr. Chriss' proposal for this case – to increase the demand charge more than the energy charge – is directionally consistent with cost of service principles to the extent that the distribution demand-related costs are not currently fully reflected in the demand charge."[73] Ameren witness Harding reiterated Ameren's acceptance of the direction of Mr. Chriss' proposal on behalf of MECG.

> Q. Okay. So it is directionally correct to move more cost into demand and take costs out of energy charges; is that correct?
>
> A. Yes. You could do that. There's still room there. You could do that before those costs exceed what we're showing in our class cost of service.[74]

MECG's rate design proposal is not novel. In fact, reflecting the gradualism inherent in its proposal, MECG has made the same proposal in previous Ameren cases. In both of the last two Ameren cases, the Commission has sought to move more fixed costs to the LGS / SP demand charges and minimize the energy charges. For instance, in 2019, the Commission reflected the entirety of the

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[72] *Id.* at page 46. Ameren acknowledges that Mr. Chriss' recommendation is "directionally consistent with cost of service principles to the extent that the distribution demand-related costs are not currently fully reflected in the demand charge." Exhibit 18, Wills Rebuttal, page 53.
[73] Exhibit 18, Wills Rebuttal, page 53.
[74] Tr. 344.

LGS / SP revenue reduction by decreasing energy charges.[75] Similarly, in ER-2016-0179 the Commission, as MECG recommends here, recovered more of the rate increase in the LGS / SP demand charges.[76]

[75] See, *Report and Order*, Case No. ER-2019-0335, issued March 18, 2020, at Corrected Stipulation and Agreement, Exhibit J.
[76] *Report and Order,* Case No. ER-2016-0179, issued March 8, 2017, approving Unanimous Stipulation and Agreement at page 13.

F. ALTERNATIVE INDUSTRIAL RATE DESIGN PROPOSALS

Issue: Should the Commission approve MECG's recommendation to require the Company to present analyses of alternatives to the hours-use rate design by 2025?

The LGS / SP rate schedules are built upon a concept known as hours-use rate design. Specifically, these rate schedules include three declining block seasonal energy charges. Customers move through the declining energy charges based upon its load factor. Specifically, the rate in the first energy block is applicable for all usage less than 150 kWh / kW of billing demand. The second energy block rate is applicable for all usage between 150 – 350 kWh / kW, with the third energy block rate being applicable to all additional usage.[77] Mr. Chriss points out that this "hours-use structure is not the simplest manner as it requires the analyst to have more than a surface level understanding of the rate structure in order to understand the interplay of the energy rates and load factor, which is needed to perform bill analyses."[78]

In fact, when asked to describe the hours-use rate design structure in the "most simplified fashion", the Ameren witness spoke in terms of block thresholds and customer demand:

> It's a block rate like we have block rates in other classes except for the size of the energy blocks that are applied to pricing are a function of that customer's demand. So if you have a higher demand, you have a higher block threshold. And if you have a lower demand, you have a lower block threshold. As you use energy, it proceeds through those prices more quickly if you have a higher demand level.[79]

Recognizing his description in the "most simplified fashion", it is not surprising that the Ameren witness admits that a "significant number" of customers do not understand the rate design structure. As a result, customers do not understand their bills and are, therefore, incapable of responding to any price signals inherent in this convoluted rate design.

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[77] *Id.* at page 29.
[78] *Id.* at page 41.
[79] Tr. 301-302.

> Q. Do you believe that most customers in the LGS and SP classes understand the hours use rate design?
>
> A. I can't speak for all customers. I think that there's probably a significant number that don't understand fully that rate design.[80]

Given the complexity of the rate design and that most customers lack the sophistication to: (1) calculate their rates; (2) respond to price signals; and (3) take steps to reduce their electric bills, MECG suggests that the Commission order Ameren to begin to simplify its LGS / SP rates. Specifically, MECG recommends that the Commission "require Ameren to redesign LGS and SP as three part rates with unbundled demand charges and time varying energy charges and for all LGS and SP customers to be transitioned to those rates by 2025, which is my understanding of when the Company anticipates AMI will be fully deployed."[81]

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[80] Tr. 302.
[81] *Id.* at page 45.

G. ALLOCATION OF DISTRIBUTION COSTS

Issue: How should distribution costs be allocated or assigned among customer classes within a Class Cost of Service Study?

In its Class Cost of Service Report Staff spends an inordinate amount of time criticizing Ameren's recordkeeping related to distribution facilities and costs. The thrust of Staff's criticism appears to be premised on its desire to "assign" instead of "allocate" distribution costs to specific customers and classes. Staff's approach represents a radical change from its approach in recent cases, as well as a repudiation of the concept of mass property accounting.

In his testimony, Mr. Brubaker rebutted Staff's criticism.

> While any set of records probably could be made more precise, the question is whether or not the added degree of precision would add useful or meaningful information and improve the accuracy of cost allocation studies. Knowing the exact cost (and depreciated value) of a specific 34 kV line running from Point A to Point B as compared to the average cost per mile of all 34 kV lines is not particularly meaningful when rates are set on the basis of general categories of customers and voltage level. Customers taking service at 34 kV are allocated a share of the costs of 34 kV and higher voltage equipment. Rates are designed to serve all 34 kV customers as a class, without regard to their specific geographic location, or the age of the facilities specifically providing service. In other words, unless rates were to be set separately for each individual customer, the added information would be of no value.[82]

Ultimately, Mr. Brubaker concludes, based upon his 50 years of experience reviewing class cost of service studies in 34 different regulatory jurisdictions, that the detail underlying Ameren's class cost of service study, including its accounting for distribution costs is "generally consistent with the level of detail and the practices of other electric utilities."[83]

[82] Exhibit 501, Brubaker Rebuttal, page 13.
[83] *Id.*

H. RIDER B CREDITS

Issue: What is the appropriate level of Rider B credits to be applied to the bills of customers providing their own substation equipment?

Ameren currently has two rate schedules, Small Primary (Schedule 4M) and Large Primary (Schedule 11M), that require customers to take service at primary voltage levels or higher. The customers taking service at primary voltage level therefore rely on Ameren to provide all substations in order to step down the voltage to that level. There are, however, certain customers that "own, operate and maintain" their own substations and, therefore, can take service at a higher voltage level (34 kV or higher).[84] Since these customers provide their own substations, Ameren does not incur the costs for such substations.[85] Recognizing that the Small Primary and Large Primary rates assume that all customers take service at primary voltage and require Ameren to incur the costs for these step-down substations, it is necessary to back out the substation costs that are otherwise included in these rates.[86] The mechanism to back out these substation costs is reflected in Rider B.

> Where a customer served under rate schedules 4(M) or 11(M) takes delivery of power and energy at a delivery voltage of 34kV or higher, Company will allow discounts from its applicable rate schedule as follows:
>
> 1. A monthly credit of $1.14 / kW of billing demand for customers taking service at 34.5 or 69 kV.
> 2. A monthly credit of $1.35 / kW of billing demand for customers taking service at 115 kV or higher.[87]

As Ameren correctly points out, "without the credit provided for by Rider B, that difference in the

[84] Exhibit 18, Wills Rebuttal, page 22.
[85] *Id.* at page 23.
[86] Unlike other utilities (i.e., Evergy) that distinguish industrial rates based upon the voltage level of service (i.e., primary, secondary, substation, or transmission level), Ameren's rates assume that all customers take service at primary voltage and then provide a credit to those that provide their own substations to reflect the fact that these customers do not rely on Ameren to provide the substation to step down the voltage.
[87] Exhibit 501, Brubaker Rebuttal, Schedule MEB-COS-R-4.

cost of serving these customers would be completely ignored. This punitive change would be unfair to customers that made such significant investment decisions based on an understanding that they would receive these bill credits as a result of their efforts."[88]

In its Class Cost of Service Report, however, Staff recommends that the Commission "suspend" the applicability of the Rider B credits.

> Staff recommends that unless the costs of substation equipment that is dedicated to primary customer is specifically assigned to the bills of primary customers, that the discounts provided to primary customers under Rider B be ***suspended*** until Ameren Missouri provides the information necessary to include the cost of primary customer substations in the bills of primary customers (and such costs are so included).[89]

In his rebuttal testimony, Mr. Brubaker points out that Staff's recommendation "does not make sense"[90] and "defies logic."[91] Ameren's assessment of Staff's proposal was even more pointed. Specifically, Ameren describes Staff's recommendation as "stunning"; "punitive"; "objectively incorrect"; "reflects a fundamental misunderstanding of cost allocation"; based on Staff's "hyper-focus on direct assignment"; and premised on a "convoluted analysis."[92]

Ameren's witness Wills clearly explains why Staff's recommendation to "suspend" the Rider B credit is "objectively incorrect."

> Customers who elect to install their own substations initially have to invest hundreds of thousands, or millions, of dollars that displace similar investments that the Company otherwise would have to make. They also bear the on-going cost to operate and maintain those substations. There should be no doubt that the cost of serving these customers is meaningfully lower than the cost of serving similarly situated customers in the same rate class who have not made these initial and on-going investments on their own behalf and instead relied on the Company to make them. But without the credit provided for by Rider B, that difference in the cost of serving

[88] Exhibit 18, Wills Rebuttal, page 23.
[89] Exhibit 205, Staff Class Cost of Service Report, page 54 (emphasis added).
[90] Exhibit 501, Brubaker Rebuttal, page 15.
[91] *Id.* at page 16.
[92] Exhibit 18, Wills Rebuttal, pages 1 and 22-27.

> these customers would be completely ignored. This punitive change would be unfair to customers that made such significant investment decisions based on an understanding that they would receive these bill credits as a result of their efforts.[93]

Mr. Wills continues on to point out why Staff's recommendation is "punitive" and the impact that suspending the Rider B credits will have on these customers that provide and maintain their own substations. "The removal of these discounts would increase the SPS customers' and LPS customers' bills on average by an estimated 4.4% and 3.3% respectively, before consideration of any other rate increase granted in this case."[94]

During the hearing the Staff witness finally appeared to recognize the "illogical nature" of her half-baked proposal[95] and began to immediately backtrack. After three rounds of testimony it now appears that Staff's proposal is simply a threat to suspend these Rider B credits if the Commission accepts MECG's proposal to adopt a revenue allocation that addresses the lingering residential subsidy.

> Q. So bottom line. In order for me to educate my clients, is it Staff's position that these clients that have these customers that have installed their own substation, Staff wants to take that credit away from them?
>
> A. No, because Staff's recommendation does not require that under Staff's recommendation. If you get your rate shift recommendation and for the clarity of the record you being MECG, then because that would reduce class revenues below the level that is assumed in the Staff's study, then we would either need to suspend those credits or frankly I do like your suggestion you threw out and I don't have a management approval to say this but I'll say it anyway, you know, just to lock them in at the current level of discount and not grow that discount proportionate with the demand charge increase which would otherwise be the way they're grown.[96]

It is clear, however, that Staff's position was not tied in any way to the ultimate resolution of

[93] *Id.* at page 23.
[94] *Id.* at page 23.
[95] Half-baked is defined as "not fully thought through; lacking a sound basis."
[96] Tr. 382.

the revenue allocation issue. First, in its Class Cost of Service Report, Staff used the definitive phrase "suspend" without any caveats. There was no condition included that the credit would need to be suspended if an alternative revenue allocation was adopted. Second, it is important to recognize that Staff made this proposal in its direct testimony. Therefore, Staff was not yet aware of MECG's revenue allocation proposal[97] to address the residential subsidy. If the Rider B proposal was reflective of Staff's response to the MECG revenue allocation proposal then it would have been contained in Staff's rebuttal testimony filed after Staff learned of MECG's "rate shift recommendation", not in Staff's direct testimony. In all honesty, the Staff's proposal to "suspend" the Rider B credits was a stand-alone recommendation that was independent of any revenue allocation proposals. Only now that it realizes the punitive nature of its uninformed proposal does Staff seek to justify it by tying to other issues – specifically the residential subsidy that it is so desperate to defend.

Recognizing that Staff's recommendation "defies logic" and is "objectively incorrect", the Commission should reject Staff's "punitive" recommendation to suspend the Rider B credits and refuse to be held hostage by Staff's attempt to prevent the Commission from addressing the residential subsidy.

[97] Staff witness referred to it as a "rate shift recommendation".

Respectfully submitted,

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing pleading by email, facsimile or First Class United States Mail to all parties by their attorneys of record as provided by the Secretary of the Commission.

David L. Woodsmall

Dated: December 28, 2021