BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service.	**))))**	**File No. ER-2018-0145**
In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement a General Rate Increase for Electric Service.	**))))**	**Case No. ER-2018-0146**

<u>MECG / MIEC STATEMENT OF POSITION</u>

I. Rate Design/Class Cost of Service

a. CCOS: What revenue neutral changes to class revenue responsibility, if any, should the Commission order for each utility?

It is well established that the electric industry is very capital intensive. The evidence indicates that KCPL has invested almost $10.1 billion in its production, transmission and distribution facilities.[1] Of this, almost 63% is associated with KCPL's investment in its various generating units.[2] Given the magnitude of KCPL's production plant investment, the single most significant issue underlying any class cost of service study is the method by which these production fixed costs are allocated to the customer classes.

While there are different methods utilized for allocating generation fixed costs, the difference in these methodologies generally concerns the extent to which production plant is deemed to be an <u>energy-related</u> cost (focused on meeting system energy usage) or a <u>demand-related</u> cost (focused on meeting system peak demand). The evidence indicates, however, that all production plant investments are <u>both</u> energy and demand

[1] Staff Accounting Schedules, Accounting Schedule 3, page 10.
[2] *Id.* at page 8 (line 250). KCPL Total Production Plant = $6,341,671,037. Similarly, GMO's investment in production plant is approximately 47% of its total capital investment.

related costs. In fact, the need to meet both class energy needs as well as peak demand drives the utility decision as to the amount of capacity the utility must add as well as the type of capacity added.

In general, the various production allocators fall along a continuum with a pure energy allocator at one end of the spectrum and a 1 NCP demand allocator at the other end of the spectrum.[3] Given this, the various other production allocators fall within this continuum.

Energy Based ←——————————————————→ Demand Based

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Energy Only	BIP	Average & Peak	Average & Excess	1CP	1NCP

In this case, the Commission is faced with two alternatives for allocating fixed production costs: (1) the energy-intensive BIP methodology relied upon by Staff and (2) the A&E approach, which properly balances both class energy and peak demand, relied upon by **<u>both</u>** KCPL and MIEC. As can be seen, the methodologies lead to significantly different results for the residential class relative to the industrial classes. Specifically, the BIP method relied upon by Staff has the practical effect of shifting cost responsibility from the low load factor residential class to the high load factor industrial classes.

	KCPL / MIEC[4]	Staff[5]
	Average & Excess	BIP
Residential	17.5%	-1.82%
Small G.S.	-16.3%	-15.81%
Medium G.S.	-7.8%	-5.85%
Large G.S.	-12.4%	1.07%
Large Power	-10.0%	1.56%
Lighting	-16.1%	2.61%

[3] Sullivan Direct, page 18.
[4] Brubaker KCPL Direct, Schedule MEB-COS-4. Miller KCPL Direct, page 21 (The revenue neutral results can be reached by reducing the results by KCPL's initially proposed 1.9% rate increase).
[5] Staff Class Cost of Service Report, page 6.

The same observation can be made with regard to the GMO class cost of service studies.

	GMO / MIEC[6]	Staff[7]
	Average & Excess	BIP
Residential	6.2%	-7.47%
Small G.S.	-17.6%	-16.47%
Large G.S.	-1.7%	6.64%
Large Power	-3.7%	4.83%
Lighting	3.3%	1.64%

The evidence presented in this case by both KCPL and MIEC conclusively demonstrates that Staff's energy-intensive BIP methodology is faulty and should not be relied upon by the Commission for several reasons.

1. <u>THE BIP IS NOT COMPATIBLE WITH THE SPP INTEGRATED MARKETPLACE</u>

In this case, Staff relies upon the BIP methodology. The very basis of the BIP approach is that a utility's generating units can be effectively segregated into one of three types of units: (1) baseload units; (2) intermediate plants; and (3) peaking plants. After segregating units into these three categories, Staff then allocates the investment associated with each category in one of three ways. As can be seen then, the fundamental tenet of the BIP methodology is that a utility's generating units can be effectively segregated by the purpose of each generating unit.

The evidence in this case demonstrates, however, that this fundamental tenet, the segregation of generating units into one of three different categories, is no longer possible. Utilities once constructed generating units in a manner that allowed them to meet system needs in the most economical manner. For all practical purposes, utilities were left to meet system requirements entirely through utility generating assets. As such,

[6] Brubaker GMO Direct, Schedule MEB-COS-4. Miller GMO Direct, page 20 (The revenue neutral results can be reached by reducing the results by GMO's initially proposed 2.6% rate increase).
[7] Staff Class Cost of Service Report, page 24.

based upon the utility's dispatch order, it was easy to segregate baseload, intermediate and peaking units.

In 2014, however, KCPL began operating and dispatching within the SPP Integrated Marketplace. As a result, utilities were no longer entirely dependent on utility resources to meet system needs. Instead, a market was created that allowed utilities to meet those system needs. Now, KCPL's units are no longer directly dispatched to meet system needs, but instead are dispatched into the SPP marketplace. Simultaneously, KCPL purchases all energy needed to meet system requirements out of the SPP market. As a result, electricity became fungible. For all practical purposes then, it is no longer possible to effectively characterize certain units as either baseload, intermediate and peaking units.

While KCPL once utilized the BIP methodology, it expressly points to the introduction of the SPP Integrated Marketplace as a primary reason for its rejection of that allocator. "Expressing concern that the transition of the Southwest Power Pool ("SPP") to an Integrated Marketplace ("IM") with centralized dispatch would make it difficult to accurately assign the generating units into base, intermediate, and peak groups based on their use", KCPL has rejected the BIP methodology in favor of the A&E approach recommended in this case.[8]

Given the introduction of the SPP Integrated Marketplace, and KCPL's participation in that market, it is effectively impossible for parties to segregate the KCPL generating units into the baseload, intermediate and peaking categories. Given this, the basic premise of the BIP methodology is shattered. As a result, the BIP methodology is

[8] Lutz Direct, page 5-6.

an archaic allocation method that is no longer applicable in today's current electric marketplace.

2. THE BIP METHODOLOGY FAILS TO RECOGNIZE THAT ALL GENERATING UNITS PROVIDE VALUE TOWARDS MEETING CAPACITY NEEDS

As indicated, the basic premise of the BIP methodology is that a utility's generating units can be properly segregated into either baseload, intermediate or peaking units. Based upon that categorization, the investment in each is allocated in a different manner. Based upon its inappropriate categorization of KCPL's generating units, Staff has classified the lion's share of KCPL's production plant investment as baseload units. As Staff points out then, this baseload investment is then allocated entirely on the basis as average demand (i.e., class energy usage).

The obvious problem with this approach is that, by allocating baseload investment entirely on energy usage, Staff implicitly concludes that these baseload units play no role in meeting a utility's capacity requirements. A utility's generating units not only serves to meet energy requirements, but also the utility's peak demand. This is the beauty of the Average & Excess approach advocated by both KCPL and MIEC. The A&E approach, unlike the flawed BIP methodology, recognizes that generating units serve to meet both energy and capacity needs and allocates this plant investment on a measure of both energy and peak demand.

As a result of Staff's categorization of a vast majority of KCPL's generating units as baseload investment, and the subsequent allocation of such baseload investment solely on the basis of class energy usage, the Staff's BIP methodology is essentially an energy allocator. In fact, because of the over categorization of production plant as baseload units and the allocation of such baseload investment on the basis of energy, approximately 80% of KCPL's total investment in production plant is on the basis of class energy. Effectively then, Staff is claiming that only 20% of KCPL's investment in production plant provides any value towards meeting utility capacity needs.

3. THE BIP METHODOLOGY, BECAUSE IT IS ESSENTIALLY AN ENERGY ALLOCATOR, PENALIZES HIGH LOAD FACTOR INDUSTRIAL CUSTOMERS.

As indicated, as a result of classifying the vast majority of KCPL's investment in production plants as baseload units, and then allocating such baseload investment on the basis of class energy usage, Staff's BIP methodology effectively becomes an energy allocator. By essentially allocating all production plant investment on the basis of energy, Staff's BIP methodology treats all energy usage on equal terms. In this way, the BIP methodology fails to account in any way for whether energy usage is being used by an industrial customer with a higher load factor or a residential customer with a lower load factor.

It is well established that high load factor customers utilize the utility system in a more efficient manner than low load factor customers. Specifically, a high load factor customer extracts more kWh of energy for each kW of demand it places on the utility system. Production allocators that consider both class demand and class energy recognize this fundamental notion of electric service and system planning.

Staff's BIP methodology, on the other hand, fails to recognize this fundamental concept. Specifically, Staff fails to recognize that high load factor customers are operating more efficiently. In fact, by allocating baseload production facilities entirely on the basis of class energy usage, Staff penalizes these high load factor customers for the benefit of low load factor customers that are using the system inefficiently.

4. GIVEN ITS NUMEROUS FLAWS, THE BIP METHODOLOGY HAS NOT BEEN ACCEPTED BY STATE UTILITY COMMISSIONS OR UTILITIES AND IS OUTSIDE THE MAINSTREAM.

As the evidence clearly indicates, the BIP Methodology is well outside of the mainstream of production allocators used by other utilities and state utility commissions.[9] As Mr. Brubaker points out, the BIP methodology is not widely accepted.[10] "The BIP method first surfaced circa 1980 as an approach that some thought might be useful when trying to develop time-differentiated rates. However, the BIP method never caught on and is only infrequently seen in regulatory proceedings. The BIP method is certainly not

[9] Utility criticism of the BIP methodology is not limited solely to Ameren, Empire or Westar. For instance, in a recent North Carolina proceeding, Duke Energy Carolinas witnesses pointed out all of the infirmities of the BIP methodology. Specifically, Duke Energy witness Hopkins testified that "use of the BIP methodology for allocation of Company's generation capital costs in its class cost of service study is inappropriate. He explained that the BIP methodology has not been adopted by any jurisdiction for class fully allocated studies and was not developed for the purposes of class cost allocations. Witness Hopkins stated that the BIP methodology, as used by witness Watkins, includes significant judgmental cost classifications, which are unsupported and result oriented. Further, the BIP method as proposed recognizes no value for meeting peak load demands for all of the generating units classified by him as base load. In addition, witness Hopkins pointed out that the adoption of the BIP methodology would conflict significantly with the Company's methods for both the FERC and South Carolina jurisdictions, and witness Watkins offered no reasons to justify changing prior Commission decisions that approved the Company's SCP methodology. Witness Hopkins testified that the longstanding use of an allocation methodology creates regulatory stability and is a desirable feature in ratemaking."

"Witness Hopkins further testified that the use of the BIP method as proposed by witness Watkins would classify and allocate 75% of the Company's generation capital costs as being solely related to annual energy use. According to witness Hopkins, this is an extraordinary result that would penalize the higher load factor use and off-peak use classes for no cost-based reason. He concluded that this result is especially troubling because these classes add significantly to the system's overall efficiency and thereby lower costs enjoyed by all customer classes." *Re: Duke Carolinas Energy*, North Carolina Utilities Commission, 279 P.U.R.4th 320 (December 7, 2009).

[10] The fact that the BIP methodology is out of the mainstream has been repeated in numerous jurisdictions. For instance, in a Wyoming proceeding, the BIP methodology was described as "an arcane methodology that is not used by any regulatory commission." *Re: Rocky Mountain Power*, Wyoming Public Service Commission, Case No. 20000-384-ER-10, issued September 22, 2011.

among the frequently used mainstream cost allocation methodologies, and lacks precedent for its use."[11]

In fact, consistent with Mr. Brubaker's conclusion that the BIP methodology is out of the mainstream, the evidence indicates that the BIP methodology has been rejected by virtually every utility and public utility commission in the nation. Specifically, while Mr. Brubaker has testified in rate design proceedings in 34 states, he is not aware of any utilities or state utility commissions that have utilized the BIP methodology.[12] Thus, the use of the archaic BIP methodology appears to be limited solely to the Missouri Staff. In fact, when asked in a data request regarding its understanding regarding the presentation of the BIP methodology in other states or the adoption by other state utility commission, Staff could simply point to its BIP recommendation in previous Missouri cases.[13]

In fact, while none of the other Midwest states rely upon the BIP methodology, its adoption by the Missouri Commission would send a negative signal to industrial customers. As KCPL Witness Sullivan points out, the A&E methodology has been adopted by numerous other utilities and state utility commissions. The relevance of this is that utilities are continually competing for industrial customers. So long as other utilities are using the A&E methodology, while KCPL is stuck using the archaic BIP methodology, it is put at a competitive disadvantage for retaining and attracting industrial customers.

> If the CCOS study is used as a principle tool in assigning the utility revenue requirement to customer classes and thus rate design, industrial cost responsibility and thus industrial rates for utilities using the A&E

[11] Exhibit 555, Brubaker Rebuttal, page 17.
[12] Tr. 1203-1204. See also, Exhibit 856 for Mr. Brubaker's credentials including a list of the 34 jurisdictions in which he has addressed class cost of service and the appropriateness of production cost allocation methodologies.
[13] Brubakfer Rebuttal, page 8.

> methodology will be lower than using either of the other two methodologies, all other things being equal. ***Thus, if the rates for the two major utilities with which KCP&L competes are using the A&E methodology and KCP&L is not, KCP&L will be at a competitive disadvantage in attracting and retaining industrial load.***[14]

Given an economy with budget problems and a need for additional jobs, the adoption of the BIP approach by the Missouri Commission could further hinder Missouri's ability to create jobs or attract business to the state. Indeed, the Louisiana Commission has previously rejected energy intensive allocators, such as Staff's BIP, because of the effect that it would have on industrial rates and on the ability of industrial customers to compete.

> In addition, it [the A&E methodology] 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."[15]

As such, this issue is not simply an academic exercise. Instead, this issue has very real implications on the businesses that Missouri is relying upon to help drive job growth.

5. THE BIP METHODOLOGY WILL EXACERBATE KCPL'S UNCOMPETITIVE INDUSTRIAL RATES.

By failing to recognize the capacity value inherent in all production plant investment and allocating baseload investment entirely on the basis of class energy usage, Staff's flawed BIP methodology is punitive to high load factor industrial customers. This is troublesome because, as KCPL readily admits, its industrial rates are already not competitive with other Midwest states.

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[14] Sullivan Direct, page 25.

[15] Re: Gulf States Utilities Company, Louisiana Public Service Commission, Docket No. U-14495, issued November 17, 1980. *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.").

> The Company is aware of the [uncompetitive industrial rate] assertions made and although disagreement may persist as to why the rates are as they are, or the value received from all customers as a result of those cost increases, but the fact that Company [industrial] rates at face value, do not compare well with other locations is difficult to debate.[16]

In his testimony, Mr. Brubaker analyzed and compared KCPL's rates to other Midwest utilities. That analysis confirms KCPL's concerns that its industrial rates "do not compare well with other locations." Specifically, Mr. Brubaker's analysis[17] shows that KCPL's industrial rates are the sixth <u>highest</u> of forty-one Midwest utilities.

[16] Lutz Rebuttal, page 22.
[17] Brubaker Direct, Schedule MEB-COS-2.

Line	Utility	State	¢/kWh	Ranking
1	Madison Gas & Electric Company	Wisconsin	9.52	1
2	Entergy New Orleans, Inc.	Louisiana	9.09	2
3	We Energies (formerly Wisconsin Electric)	Wisconsin	8.90	3
4	Kansas City Power & Light Company	Kansas	8.62	4
5	Montana-Dakota Utilities Company	North Dakota	8.49	5
6	**Kansas City Power & Light Company**	**Missouri**	**8.49**	6
7	Northwestern Wisconsin Electric Company	Wisconsin	8.43	7
8	Northern States Power Company	Minnesota	8.38	8
9	Northern States Power Company	South Dakota	7.95	9
10	Otter Tail Power Company	Minnesota	7.93	10
11	Empire District Electric Company	Missouri	7.89	11
12	Northern States Power Company	North Dakota	7.78	12
13	Minnesota Power Company	Minnesota	7.78	13
14	CLECO Power LLC	Louisiana	7.75	14
15	Northern States Power Company	Wisconsin	7.48	15
16	WP&L	Wisconsin	7.36	16
17	Westar Energy-KGE	Kansas	7.25	17
18	Westar Energy-KPL	Kansas	7.25	18
19	Montana-Dakota Utilities Company	South Dakota	7.12	19
20	Otter Tail Power Company	North Dakota	6.89	20
21	Northwestern Energy	South Dakota	6.88	21
22	Wisconsin Public Service Corporation	Wisconsin	6.83	22
23	Empire District Electric Company	Arkansas	6.81	23
24	Interstate Power & Light	Iowa	6.57	24
25	Entergy Louisiana, Inc.	Louisiana	6.50	25
26	Superior Water, Light & Power Company	Wisconsin	6.50	26
27	Kansas City Power & Light - GMO	Missouri	6.46	27
28	Ameren Missouri	Missouri	6.22	28
29	Otter Tail Power Company	South Dakota	6.21	29
30	Empire District Electric Company	Kansas	6.09	30
31	Empire District Electric Company	Oklahoma	6.06	31
32	Black Hills Power, Inc. d/b/a Black Hills Energy	South Dakota	5.86	32
33	Entergy Arkansas, Inc.	Arkansas	5.85	33
34	Southwestern Electric Power Company	Louisiana	5.63	34
35	OG&E Electric Services	Arkansas	5.60	35
36	Entergy Louisiana, LLC (formerly Entergy Gulf States, Inc.)	Louisiana	5.40	36
37	Southwestern Electric Power Company	Arkansas	5.34	37
38	MidAmerican Energy	Iowa	4.79	38
39	Public Service Company of Oklahoma	Oklahoma	4.20	39
40	OG&E Electric Services	Oklahoma	3.76	40
41	MidAmerican Energy	South Dakota	3.32	41

Source: EEI Typical Bills and Average Rates Report

The practical effect of KCPL's uncompetitive industrial rates is not surprising, over the past 10 years, KCPL has lost a significant amount of its industrial base. As data request responses from KCPL readily reveal, from 2006 - 2017, KCPL has seen the number of industrial customers decline from 1,145 to 945.[18] While Mr. Brubaker does not assert that uncompetitive industrial rates are solely responsible for the loss of 17% of KCPL's industrial base, it is evident that there is a problem; and KCPL's industrial rates in Missouri are undoubtedly a contributing factor.

In a recent Empire decision, the Commission specifically pointed to uncompetitive industrial rates, and the detrimental impact associated with a utility losing its industrial base, as a basis for eliminating the residential subsidy in a much more rapid fashion than proposed by Staff.

> 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.[19]

Bottom line, KCPL's industrial rates are uncompetitive primarily as a result of Staff's adherence to its faulty, anti-industrial customer, BIP methodology. Even when faced with utility admissions that its industrial rates are uncompetitive as well as the resulting rapid migration of that utility's industrial base, Staff continues to steadfastly apply its methodology. Unfortunately for industrial customers, this is not simply an academic exercise. Faced with competitive alternatives, those customers will continue to leave KCPL's system in greater and greater numbers. Ultimately, as the Commission has previously recognized, KCPL's remaining customers will "bear the burden of covering [KCPL's] fixed costs with a smaller amount of billing determinants."

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[18] Brubaker Surrebuttal, page 11 (citing to Schedule MEB-COS-SR-3 and KCPL response to MECG Data Request 9-1).
[19] *Report and Order*, Case No. ER-2014-0351, issued June 24, 2015, at page 18.

6. IN CONTRAST TO THE FLAWED BIP METHODOLOGY, THE AVERAGE & EXCESS APPROACH PROPERLY CONSIDERS BOTH CLASS PEAK DEMAND AS WELL AS ENERGY REQUIREMENTS. GIVEN ITS LOGICAL NATURE, THE A&E HAS BEEN ADOPTED BY NUMEROUS STATES.

As mentioned, the utility's load profile is a "primary" consideration in the determination of a production allocator. As Mr. Sullivan points out, if a utility system is operated at a high load factor, the utility could "generally build base load generating facilities" to meet the high system load factor. Only if system load factor decreases does the need for a utility to make "increasing investments in peaking units" necessary.[20]

In this case, KCPL's overall system load factor is 56 percent and ranges from a residential load factor of 39 percent to a load factor for the Large Power rate class of 82%.

Line No.	Customer Class	Load Factor
1	Residential	39.00%
2	Small General Service	57.13%
3	Medium General Service	58.68%
4	Large General Service	66.68%
5	Large Power Service	82.04%
6	Lighting	100.00%
7	Total System	55.64%

Source: Sullivan Direct, Schedule TJS-5

Therefore, "the Residential class [is] the primary contributor to the system's relative low load factor."[21]

Given the residential class' low load factor as well as the numerous flaws inherent in a Staff's energy-intensive BIP production allocator, both KCPL witness Sullivan and

[20] Sullivan Direct, page 19.
[21] *Id.* at page 21.

MIEC witness Brubaker rejected Staff's flawed BIP methodology. Instead, recognizing that both class peak demand <u>and</u> energy usage are important to the utility's decision as to the amount and type of capacity to be added,[22] both KCPL and Mr. Brubaker advocate in favor of the Average & Excess production allocator methodology.[23] As Mr. Brubaker points out, the A&E methodology relies upon both class energy and peak demand in its calculation of a production allocator.

> As the name implies, A&E makes a conceptual split of the system into an "average" component and an "excess" component. The "average" demand is simply the total kWh usage divided by the total number of hours in the year. This is the amount of capacity that would be required to produce the energy if it were taken at the same demand rate each hour. The system "excess" demand is the difference between the system peak demand and the system average demand.[24]

KCPL witness Sullivan echoes the logic underlying the A&E approach. "The A&E method is a hybrid method combining average demand [energy] and peak demand components."[25] Given that the A&E methodology considers both: (1) <u>Average</u>: class energy and (2) <u>Excess</u>: class peak demand, it recognizes both aspects of the utility's capacity addition decision: the <u>amount</u> of capacity to add and the <u>type</u> of capacity to add.

Recognizing that the A&E method properly considers both the utility's need to meet peak demands and energy usage, it has been repeatedly adopted by numerous Midwest state utility commissions for the purpose of allocating production plant.

► <u>Louisiana</u>: "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

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[22] Since the A&E methodology considers both class energy and peak demand, it is obviously a reasonable compromise between energy intensive allocators (BIP and Peak & Average) and pure demand allocators (4CP).
[23] Brubaker Direct, page 19; Sullivan Direct, page 4.
[24] Exhibit 853, Brubaker Direct, pages 17-18.
[25] Sullivan Direct, page 26.

allocation. This approach furthers the overall interests historically considered by the commission in designing rates and is consistent with the purposes of PURPA. ***<u>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</u>***."[26]

► <u>Oklahoma</u>: "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."[27]

► <u>Texas</u>: "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.

<u>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</u>

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[26] 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.").

[27] Re Public Service Company of Oklahoma, Oklahoma Corporation Commission, Cause No. PUD 201000050, issued January 5, 2011. *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.

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."[28]

►Arkansas: Recently the General Assembly passed Act 725. Codified at 23-4-422(b)(2), that legislation mandated 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 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.

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[28] 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.

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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."[29]

7. GIVEN KCPL'S UNCOMPETITIVE INDUSTRIAL RATES AND THE RAPID DECLINE IN THE NUMBER OF INDUSTRIAL CUSTOMERS, THE COMMISSION SHOULD TAKE SIGNIFICANT STEPS TO ELIMINATE THE RESIDENTIAL SUBSIDY.

After rejecting Staff's flawed BIP approach and adopting the A&E methodology advanced by both KCPL and MIEC, the Commission should take aggressive steps to rapidly eliminate the residential subsidy. As Mr. Brubaker and KCPL both demonstrate, the residential subsidy embedded in KCPL and GMO rates is significant and results in uncompetitive industrial rates. Specifically, the KCPL and MIEC studies show that residential rates are currently 17.5% below KCPL's actual cost of serving that class. Meanwhile, KCPL's Large General Service and Large Power rates are 12.4% and 10.0% above their cost of service.

[29] 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.

	KCPL / MIEC[30] Average & Excess
Residential	17.5%
Small G.S.	-16.3%
Medium G.S.	-7.8%
Large G.S.	-12.4%
Large Power	-10.0%
Lighting	-16.1%

While not to the same magnitude, the same observation can be made with regard to the GMO class cost of service studies. Specifically, both GMO and MIEC agree that residential rates are currently 6.2% below cost of service. As a result, Large General Service and Large Power rates are 1.7% and 3.7% above cost of service.

	GMO / MIEC[31] Average & Excess
Residential	6.2%
Small G.S.	-17.6%
Large G.S.	-1.7%
Large Power	-3.7%
Lighting	3.3%

In an effort to avoid rate shock for KCPL and GMO residential customers, Mr. Brubaker recommends that the Commission eliminate 50% of the residential subsidy in this case with the remaining amount to be eliminated in KCPL and GMO's next case. As a result, for KCPL, after the 2.39% rate reduction associated with the revenue requirement settlement, KCPL residential customers would receive an 8.8% revenue neutral increase for a total residential impact associated with this case of 6.41%. As an alternative, Mr. Brubaker also provides a similar calculation for the elimination of 25% of the residential subsidy in this case. As he points out, however, recognizing that KCPL would be subjected to a rate moratorium under the PISA provision of SB564, the

[30] Brubaker KCPL Direct, Schedule MEB-COS-4. Miller KCPL Direct, page 21 (The revenue neutral results can be reached by reducing the results by KCPL's initially proposed 1.9% rate increase).
[31] Brubaker GMO Direct, Schedule MEB-COS-4. Miller GMO Direct, page 20 (The revenue neutral results can be reached by reducing the results by GMO's initially proposed 2.6% rate increase).

Commission's "next opportunity [to address the residential subsidy] will be at least three years from when rates from this case will go into effect."[32]

Class	50% Revenue Neutral Shift	25% Revenue Neutral Shift
Residential	8.8%	4.4%
Small General Service	(8.2%)	(4.1%)
Med. General Service	(3.9%)	(1.9%)
Large General Service	(6.2%)	(3.1%)
Large Power	(5.0%)	(2.5%)
Lighting	(8.1%)	(4.0%)

Source: Brubaker KCPL Direct, Schedule MEB-COS-5

Similarly, for GMO, after the 3.22% rate reduction associated with the revenue requirement settlement, GMO residential customers would receive an increase of 3.1%. Therefore, even after eliminating half of the residential subsidy, GMO residential customers would still be receiving a rate reduction of 0.12%.

Class	50% Revenue Neutral Shift	25% Revenue Neutral Shift
Residential	3.1%	1.6%
General Service	(8.8%)	(4.4%)
Large General Service	(0.9%)	(0.4%)
Large Power	(1.9%)	(0.9%)
General TOD	(6.7%)	(3.4%)
Thermal Service	4.3%	2.1%
Lighting	1.6%	0.8%

Source: Brubaker GMO Direct, Schedule MEB-COS-5

c. Non-Residential Rate Design: What Rate Designs should be ordered for each utility's non-residential classes?

As designed, the Large General Service and Large Power Service rate schedule "consist of a series of charges differentiated by voltage level."[33] Specifically, KCPL collects revenues from LGS and LPS customers through customer, facilities, demand and

[32] Brubaker Direct, page 26.
[33] Brubaker KCPL Direct, page 28. Brubaker GMO Direct, page 28.

energy charges for customers taking service at: (1) secondary voltage; (2) primary voltage; (3) substation voltage or (4) transmission voltage levels.[34] In each case, the demand and energy charges are seasonally differentiated.[35] The need to differentiate between the various voltage service levels is necessary to reflect the additional facilities and attendant costs associated with serving customers at the lower voltage levels.[36]

Of particular importance, the demand charge for each voltage service level decreases based upon increased levels of electricity demand (on a per kW basis) and the energy charges decrease based upon the increased energy usage (on a kWh per kW basis). As explained by Mr. Brubaker:

> These are what are known as hours use, or load factor based charges. The rates decrease as the hours use increases to recognize the spreading of fixed costs over more kilowatthours (kWh) as the number of hours use, or load factor, increases. The structure also recognizes that energy consumed in the high load factor block likely will be off-peak or at times when energy costs are lower than during on-peak periods.[37]

As applied to KCPL's current LGS / LPS rate schedules, the specific energy charges to be applied to a particular customer's usage decrease as the customer's load factor increases. Specifically, energy usage (on a kWh basis) is charged in a sequential fashion. Energy is first billed at the initial 180 hour energy block rate; any usage in excess of this is billed at the second 180 hour energy block and finally, any remaining usage is billed at the tail block rate.[38] In order to receive the benefit of the lower energy charges in the second energy block and the tail block, customers must first fill the preceding blocks and pay for energy at the associated higher energy rate. Customers

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[34] *Id.*
[35] *Id.* at pages 28-29.
[36] *Id.* at page 29.
[37] *Id.*
[38] *Id.*

receiving service exclusively out of the first energy block have a load factor less than or equal to 25%. Given that these customers will usually take service only during the peak hours of the day when energy costs are higher (Monday – Friday, 8:00 a.m. through 5:00 p.m.), they are billed at a higher energy charge.[39] Similarly, customers using enough energy to fill both the first and second energy block have a load factor of 50%. These customers will likely be taking energy during the same peak hours as well as some usage during evening and nights or weekends.[40] Finally, customers using energy in excess of the second energy block will have a load factor in excess of 50% and will receive the benefit of the lowest energy charge. These customers are taking energy at the lowest cost off-peak periods experienced by the utility.

As can be seen, the KCPL LGS / LPS tariff is structured in such a manner that it recognizes the lower cost associated with providing service during off-peak hours as well as the closely related concept of the lower cost of serving customers with high load-factors. Despite the efficient structure of the rate schedule, there is a flaw currently inherent in the levels of the charges contained in that tariff. This flaw forms the basis of Mr. Brubaker's rate design proposal.

As was detailed, KCPL's LGS / LPS tariffs collect revenues through, among others, a demand and an energy charge. In general, the demand charges are designed to recover the fixed costs of providing service (i.e., the plant-related costs, property taxes, depreciation and the return on rate base). While these costs will vary with the quantity of plant, they will not vary as a result of the amount of usage. On the other hand, energy

[39] *Id.*
[40] *Id.*

charges designed to recover the variable costs associated with providing electric service (i.e., fuel and fuel handling) will vary on the quantity of kilowatt-hours produced.

After analyzing KCPL's filed revenue requirement request, including the breakdown of fixed and variable costs, it became apparent that KCPL is collecting a significant portion of its fixed costs through LGS and LPS energy charges. Specifically, while the LPS energy blocks range from 2.5¢/kWh to 2.7¢/kWh,[41] KCPL's average variable cost is less than 2.1¢/kWh – 2.2¢/kWh.[42] Therefore, the LGS and LPS energy blocks collect more than variable costs; those charges also collect a significant amount of fixed costs. "I believe the high load factor block energy charges collect more fixed costs than is appropriate."[43] Given this, Mr. Brubaker recommends that the LGS / LPS tailblocks be brought closer to KCPL and GMO's actual variable cost.

> Recognizing that most of the fixed costs should be collected from use during the on-peak period and that consumption in the high load factor block occurs mostly during evening and weekend periods when KCPL's energy costs would be lower than they are during the on-peak periods, it is reasonable that the high load factor energy block be at a level approximating the utility's average variable costs.[44]

Specifically, since both KCPL and GMO's revenue requirement is being reduced as a result of the revenue requirement settlement, Mr. Brubaker recommends that "the high load factor bock of each voltage level [be decreased] by a uniform amount per kilowatthour equal to the total revenue decrease for the rate schedule divided by the total number of kilowatthours sold under the rate schedule.[45] In this way, KCPL would begin

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[41] *Id.* at page 30. Mr. Brubaker also notes that the LGS energy blocks ranges from 3.6¢/kWh to 4.4¢/kWh. Similarly, GMO's LP energy blocks range from 3.3¢/kWh to 3.7¢/kWh, while the LGS energy blocks range from 3.6¢/kWh to 4.8¢/kWh

[42] *Id.* at page 31 (citing to Miller Direct, Schedule MEM-2). Similarly, GMO's average variable cost is between 2.4¢/kWh – 2.6¢/kWh. (Brubaker GMO Direct, page 31).

[43] *Id.*

[44] *Id.*

[45] *Id.* at page 32.

to collect a larger portion of its fixed costs through its demand charge rather than through its energy charge.

Mr. Brubaker's proposal is not new. In fact, Mr. Brubaker's rate design proposal for the LGS and LPS rate schedules has been adopted by the Commission in KCPL Case Nos. ER-2010-0355;[46] ER-2012-0174;[47] ER-2014-0370[48] and in the recent Empire Case No. ER-2016-0023.[49] Clearly, this proposal is based upon solid ratemaking theory and movement towards cost of service based rates for the LGS and LPS rate schedules should be continued in this case.

The benefits of Mr. Brubaker's proposal are that this structure will collect more costs through demand charges and provide better price signals to customers. It also will be a more equitable rate because it will charge high load factor and low load factor customers more appropriately. This structure also improves the stability of KCPL's earnings. Because customer demands are generally more stable than their energy purchases, this rate design makes KCPL's revenue collection and earnings less volatile.

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[46] See, *Non-Unanimous Stipulation and Agreement as to Class Cost of Service / Rate Design*, Case No. ER-2010-0355, filed February 4, 2011. Stipulation attached to and approved by *Report and Order*, issued April 12, 2011, pages 8-9).

[47] See, *Order of Clarification*, Case No. ER-2012-0174, issued January 11, 2013, pages 2-3 ("Specifically, Mr. Brubaker testified on behalf of the large industrial customers who will be most affected by the rate design for the LGS and LP classes. He proposes to maintain the energy charges for the high load factor block at their current levels, increase the middle blocks by three quarters of the average percentage increase, and to collect the balance of the revenue requirement for the tariff by applying a uniform percentage increase to the remaining charges in the tariff. The Commission finds Mr. Brubaker's testimony on this matter to be credible and persuasive and unopposed. The Commission independently finds and concludes that the terms proposed in the I.6.e statement support safe and adequate service at just and reasonable rates.").

[48] See, *Non-Unanimous Stipulation and Agreement Regarding Class Kilowatt-Hours, Revenues and Billing Determinants, and Rate Switcher Revenue Adjustments*, Case No. ER-2014-0370, filed August 3, 2015, page 2 (provision 4). Stipulation attached to and approved by *Report and Order*, issued September 2, 2015, attachment A.

[49] See, *Stipulation and Agreement*, Case No. ER-2016-0023, filed June 20, 2016, page 9 (provision 19) ("For the LP class, the volumetric energy charges shall not be increased as part of this case.").

The benefits inherent in Mr. Brubaker's proposal are remarkably similar to those advanced by the Commission in adopting a straight fixed variable rate design for its gas utilities. Recently, the Commission has begun to recognize the appropriateness of utilizing a rate design which more appropriately aligns the nature of the cost (fixed v. variable) with the corresponding rate element (demand v. commodity). For instance, in a recent Atmos decision, the Commission adopted the use of a "straight fixed variable" rate design.[50] As discussed, this rate design would allow the utility to recover "the entire amount of the non-gas, or margin, costs in a fixed monthly delivery charge."[51] In a similar fashion, the volumetric charge would be used to collect only the variable costs. As presented, this purer type of rate design would: "(1) remove disincentives for utilities to encourage and assist customers in making conservation and efficiency investments; and (2) reduce the effects of weather on utility revenues and customers' bills."[52] Ultimately, the Commission pointed out, in adopting the straight fixed variable rate design that "the proposed fixed monthly rate design will eliminate the inherent conflict between the shareholders (whose returns increase if more gas is sold) and the ratepayers (who will only pay less by using less)."[53] The same logic was relied upon when the Commission adopted the straight fixed variable rate design for Missouri Gas Energy.[54]

Interestingly, no party disputes any of the benefits asserted by Mr. Brubaker in his testimony. For instance, no one refutes: (1) that KCPL's average variable cost is approximately 2.1¢/kWh – 2.2¢/kWh;[55] (2) that Mr. Brubaker's adjustment will allow for

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[50] *In re: Atmos Energy Corporation*, Case No. GR-2006-0387, issued February 22, 2007, at pages 13-25.
[51] *Id.* at page 14.
[52] *Id.*
[53] *Id.* at page 20.
[54] *In re: Missouri Gas Energy*, Case No. GR-2006-0422, issued March 22, 2007, at pages 9-13.
[55] In fact, Staff calculates that the true-up base factor for the KCPL FAC at $0.01675 cents / kWh and for the GMO FAC at .02240 cents / kWh. See, Non-Unanimous Stipulation and Agreement.

a more equitable collection of fixed costs through the demand charge rather than the energy charge; (3) that Mr. Brubaker's adjustment will treat high load factor and low load factor customers in a more appropriate manner; and (4) that Mr. Brubaker's adjustment will increase the stability of their revenue collection and earnings.

Given the numerous benefits associated with Mr. Brubaker's rate design proposal, the Commission should implement his proposal for collecting any revenue increase in the LGS and LPS rate schedules.

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: September 19, 2018