BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City	**)**	
Power & Light Company's Request	**)**	**Case No. ER-2016-0285**
for Authority to Implement a General	**)**	
Rate Increase for Electric Service	**)**	

INITIAL BRIEF OF MISSOURI INDUSTRIAL ENERGY CONSUMERS

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Comes now, the Missouri Industrial Energy Consumers ("MIEC") and, for its initial brief, states as follows:

CLASS COST OF SERVICE (CCOS) AND RATE DESIGN (ISSUE XXI)

A. Introduction

While the parties raised various issues of rate design, the MIEC is concerned with only the application of the final rate increase to the various classes of customers and the rate design within the LGS and LPS classes. In that regard it presented the testimony of Maurice Brubaker, who offered a CCOS study using the Average and Excess (A&E) methodology incorporating four non-coincident peaks (4NCP). But he also conducted studies using the A&E 2NCP and the four coincident peak (4CP) methodologies. The results of the three studies are similar and are reported in his Direct Schedule MEB-COS-5 and MEB-COS-Appendix, pages 1-4. Those studies show that the residential class's rates are currently too low relative to that class's cost of service. Likewise, they show that the other classes' rates are too high relative to their cost of service.

Three other parties performed CCOS studies: the US Department of Energy (DOE), Staff and KCPL. The DOE presented Dr. Michael Schmidt, who used the 4CP methodology. His

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results are similar to that of Brubaker, although his study shows that the residential class is underpaying by more than is shown in the Brubaker A&E 4NCP study.

The Company presented Marisol Miller, who used the Average and Peak (A&P) method of cost allocation. That method has recently been rejected by the Commission because it tends to punish high load factor customers to the benefit of low load factor customers, such as the residential class. But even using that method, the Company found that the residential class was still underpaying, although by less than found by Brubaker and Dr. Schmidt.

Staff presented the testimony of Sarah Kliethermes and Robin Kliethermes. They employed the Base Intermediate and Peak (BIP) method for class allocation. As explained in detail below, that method, unlike the methods of Brubaker and Dr. Schmidt, is not mainstream, and tends to skew the results in favor of low load factor customers and against high load factor customers. It does this largely by effectively allocating base load plant costs upon energy use without meaningful consideration of each class's contribution to peak demand. In addition, there are errors in the execution of the Staff study. While it found that high load factor customers should be assigned an above average cost of base load plant, the expensive plant to build but the plant having the lower fuel costs, it also found that those same customers should be responsible for an above average cost of fuel. Even more striking is the fact that Staff found that the low load factor residential class should receive a below average allocation of fixed production costs and also a below average allocation of fuel cost. The two conclusions are at odds with each other. Further, the Staff over-allocated distribution plant costs to high load factor customers in the LPS class by misunderstanding, ignoring, and/or misapplying the actual demands of the customers in that class. The result is that Staff's study is the only study to find that the low load factor customers in the residential class are currently overpaying in their rates. The results of the various studies are shown below. These figures represent the experts' proposed adjustments to class rates to reach an equal rate of return from each class prior to application of any rate increase ordered in this case:

	KCPL[1]	DOE[2]	MIEC[3]	Staff[4]
	Peak & Average	4CP	Average & Excess	BIP
Residential	+9.2%	+18.6%	+14.8%	-0.49%
Small G.S.	-13.1%	-9.5%	-7.7%	-5.01%
Medium G.S.	-7.4%	-7.1%	-6.2%	-5.18%
Large G.S.	-8.5%	-14.8%	-10.4%	-0.64%
Large Power	+3.4%	-8.5%	-7.4%	+7.45%
Lighting	-17.6%	-46.5%	-12.4%	-5.54%

B. <u>The MIEC Study</u>

The MIEC's witness, Maurice Brubaker, is an expert of unsurpassed qualification and experience. He holds bachelor's and master's degrees in electrical engineering (UM Rolla and Washington University) and a master's degree in business administration (Washington University). For over 46 years, he has provided technical guidance and support for utility ratemaking matters in Missouri, other states throughout the country, and Guam, having testified in over 35 different jurisdictions.[5] This Commission frequently cites Mr. Brubaker's testimony in support of its ratemaking decisions.

Brubaker advocates cost based rates since they are the fairest and send the appropriate price signals to customers.[6] In order to determine the costs attributable to each class of KCPL's customers, Brubaker performed a class cost of service study that fairly allocated the cost of production plant by using the A&E 4NCP cost allocation methodology, the same method

[1] Exhibit 136, Miller Direct, page 14 (after removing KCPL's 10.8% rate increase request).
[2] Exhibit 501, Schmidt Direct, page 12.
[3] Exhibit 853, Schedule MEB-COS-5.
[4] Exhibit 202, Staff Rate Design Report, page 4.
[5] Exhibit 856.
[6] Exhibit 853, Brubaker Direct, p. 23, l. 4 – p. 25, l. 22.

employed by Ameren Missouri, Empire and Westar.[7] That methodology is widely accepted since it fairly considers both the customer class's contribution to the peak demand (kW), upon which the utility must design its production and distribution plant, and the amount of energy (kWh) each class uses:

> Under the A&E method, the average demand is allocated to classes in proportion to their average demand (energy usage). The difference between the system average demand and the system peak(s) is then allocated to customer classes on the basis of a measure that represents their contribution to the "peaking" or variability in usage.[8]

Under Brubaker's study, the residential class's rates are under-recovering the costs attributable to that class, while the other classes' rates are over-recovering.[9] Recognizing the principle of gradualism, Brubaker does not propose to remove the residential "subsidy" entirely, but rather to remove either 25 percent or 50 percent of it, depending on how large the overall rate increase for KCPL is.[10] Under his proposal, the other customer classes, including those customers that the MIEC represents, will still be subsidizing the residential class.[11]

Brubaker also advocates intra-class rate design for the LGS and LPS classes. He proposes to freeze the energy charge in the tail blocks of the LGS and LPS rates and to assign 75 percent of the classes' overall rate increase to the energy charge for the intermediate block. Those classes' remaining charges would be above the classes' overall rate increase to compensate for the lower than average impact to the intermediate and tail block rates. He proposes this because the current charges in those two blocks are very high relative to the variable costs of production:

[7] Exhibit 854, Brubaker Rebuttal, p. 4, ll. 3-5.
[8] Id., p. 18, ll. 3-7 (citing NARUC Electric Utility Cost Allocation Manual).
[9] Id., p. 26, ll. 7-19, Schedule MEB-COS-5, column 4.
[10] Id., p. 27, ll. 12-19.
[11] The MIEC uses the term "subsidizing" to mean that one class is paying less than its fair share at the expense of other classes who then are paying more than their fair share. "Fair share" means their share based upon the costs that the utility must incur to serve them.

> 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.
>
> This structure would collect more costs through demand charges and provide better price signals to customers. It would also be a more equitable rate because it will charge high load factor and low load factor customers more appropriately. This structure also would improve the stability of KCPL's earnings. Because customer demands are generally more stable than their energy purchases, this rate design would make KCPL's revenue collection and earnings less volatile.[12]

In addition to performing the A&E 4 NCP study, Brubaker also performed studies using the A&E 2NCP and the 4 CP methodologies. The results of the three studies are similar and are reported in his Direct Schedule MEB-COS-Appendix, pages 1-4.

C. <u>The USDOE Study</u>

The DOE presented Dr. Michael Schmidt, also an expert having impeccable qualifications. He has a BS in physics/math (Minnesota University), a BA in business administration (Minnesota University) and an MBA and a Ph.D. (Indiana University) with emphasis in public utility economics. He has over 30 years of experience in the public utility field as both regulator and consultant and published six books on public utility issues, including *Rate Design for Public Power Systems*.[13] Dr. Schmidt's CCOS was determined by the coincident peak (CP) method. While that method is different than the A&E method recommended by Brubaker, the results of the two studies are similar, except that the CP study found that the residential subsidy, and the over-recoveries from the other classes, is even greater than found by Brubaker.[14] Both the CP and the A&E cost allocation methods are in the

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[12] Exhibit 853, Brubaker Direct, p. 31, ll. 10-20.
[13] Exhibit 501, Schmidt Direct, App. A.
[14] Compare Brubaker Direct, Schedule MECda-COS-5 and Schmidt Direct, p. 12.

mainstream and regularly used by utility commissions; either method was acceptable to Brubaker:[15] "Along with the A&E method, the coincident peak method is the most widely used method in the industry today."[16]

The results of Dr. Schmidt's and Brubaker's studies are:

> quite comparable. For the residential class, [Brubaker's] A&E-4NCP study calculates a rate of return of current rates of approximately 2.5%, while Dr. Schmidt calculates a rate of return of 2.8% under his 4CP method. Both of these are in stark contrast to Staff's BIP rate of return of 7.2%.
>
> For the Large Power Service class, the rate of return that [Brubaker] calculate[s] with the A&E-4NCP study is 8.1%, and Dr. Schmidt calculates a rate of return of 7.0%. Both stand in stark contrast to the 4.5% rate of return that Staff calculates under its BIP method.[17]

D. The Company's Study

The Company used the Peak & Average (P&A) method. It provides no support for its use of this method other than that the method is mentioned in the NARUC Cost Allocation Manual.[18] That is an insufficient basis for this Commission to accept it:

> The fact that a particular method is noted in the NARUC Manual simply means that the individuals who prepared the NARUC Manual included it because it had been recommended by participants in one or more rate cases at or near the time the NARUC Manual was published – 1992. There are a number of allocation methods that are described in the NARUC Manual that are not commonly used and that have not found wide support in the industry. KCPL's A&P method clearly falls into that category.[19]

The P&A Method has serious flaws:

> Accordingly, in the [P&A] method when roughly equal weighting is given to the average demand and the contribution to system peak demand, the <u>average demand is double-counted</u>. This is a serious error, and has the effect of allocating significantly more costs to high load factor customers than is appropriate.[20]

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[15] Exhibit 853, Brubaker Direct, p. 19, ll. 12-24; Brubaker Rebuttal, Exhibit 854, p. 6, ll. 3-7.
[16] Exhibit 854, Brubaker Rebuttal, p. 18, ll. 7-9.
[17] Id., p. 18, ll. 12-19.
[18] Id., p. 4, ll. 6-10.
[19] Id., p. 4, ll. 15-21.
[20] Id., p. 6, ll. 14-18.

And this Commission recently rejected the P&A Method for that very reason:

> The weakness with the P&A methodology is that after dividing the average and excess components, instead of allocating just the excess average demand to the cost-causing classes, it allocates the entire peak demand to the various classes. That has the effect of double counting the average demand and allocates more costs to large industrials that have a steady but high average demand that does not contribute as much to the system peaks. That method works to the benefit of the residential class whose usage varies more by time of day and time of year.[21]

Assuming that cost-based rates are still desirable, and understanding that the P&A method does not yield cost-based rates, the Commission should continue to reject the P&A Method.

E. Staff's Study

1. Staff's Allocation of Production Plant

Last, the Staff offered its CCOS study employing the BIP methodology. The Staff BIP method works this way:

> With this study, generation plants are identified as base, intermediate or peaking. Then, Staff looks at class load curves and attempts to associate class demand levels with different plants, on the assumption that each class uses a different combination of base, intermediate and peaking facilities. The demands for each class for each type of plant assumed in Staff's study appear on page 16 of the Staff Report, and the development of the production system fixed cost allocation factor appears at the bottom of page 19 of the Staff Report.[22]

The BIP Method, especially how it was implemented by Staff, is particularly unfair and objectionable because it allocates the expensive base load plants on the basis of class energy usage rather than at least some measure of demand:

> Although Staff goes through a very data-intensive analysis that entails looking at the load of each customer class in each hour, the end result is that with this method, <u>the fixed costs associated with base load generation essentially are allocated on a measure of class energy consumption as demonstrated below</u>. The intermediate plants are allocated as a function of class 12 monthly coincident peaks minus base demands, and facilities identified as peaking facilities are allocated on class four summer coincident peak demands reduced by the base and intermediate demands.

[21] Id., p. 7, ll. 1-10, citing ER-2014-0258 Report & Order, pages 70-71, paragraph 6, April 29, 2015.
[22] Id., p. 12, ll. 1-8.

Since 100% of the fixed costs associated with plants designated as base load are allocated to customer classes using the customer class energy requirement factor as the basis for the allocation, Staff does not include any consideration of the times that energy is consumed (i.e., when demands occur), and would therefore attribute the same base load capacity cost to a customer that takes all of its load at the system peak hour as it would to a class with the same amount of energy consumption taken steadily at the same amount every hour throughout the year.[23]

So the first step in Staff's model, the allocation of base plant fixed costs, contains a significant conceptual error. The remaining steps flow from the first, and thus further that conceptual error. The table below shows that the base load plants are effectively allocated on energy use without any meaningful consideration of class demand.

TABLE 1

Comparison of Allocation of Base Load Plant Investment in Staff's Detailed BIP Study to an Allocation Based on Class Energy Usage

Line	Class	Staff's Base Capacity by Class[1] Costs (1)	Staff's Base Capacity by Class[1] Percent (2)	Energy by Class MWh at Generation[2] (3)	Energy by Class Percent (4)
1	Residential	$ 187,361,696	31.39%	2,843,707	31.39%
2	Small General Service	$ 27,247,972	4.57%	413,558	4.57%
3	Medium General Service	$ 83,294,759	13.96%	1,264,218	13.96%
4	Large General Service	$ 151,127,261	25.32%	2,293,757	25.32%
5	Large Power Service	$ 141,786,418	23.76%	2,151,978	23.76%
6	Lighting	$ 6,005,405	1.01%	91,144	1.01%
7	Missouri Retail	$ 596,823,511	100.00%	9,058,362	100.00%

[1] Staff's Rate Design and Class Cost-of-Service Report, page 19.
[2] Workpaper of S Kliethermes - market energy.xlsx, market compare tab.

[23] Id., p. 12, l. 11 – p. 13, l. 2 (emphasis added).

This table appears on page 13 of Brubaker Rebuttal, but nowhere in Staff's surrebuttal did it make any meaningful attempt to deny the facts contained therein and Staff appeared to accept those facts during trial: "I don't allocate base load. But I assign it using average demand, which average demand is going to be proportionate to energy. Yes."[24]

The following question and answer explain why class contribution to demand, and particularly peak demand, is an important consideration:

> **Q DOES THE CONCEPT OF ALLOCATING BASE LOAD PLANT ON A MEASURE OF CLASS ENERGY MAKE SENSE IN LIGHT OF SYSTEM PLANNING CONSIDERATIONS?**
>
> A No. The BIP approach effectively attempts to assign only one purpose for each class of plant. In reality, when systems are planned, the utility attempts to install that combination of generation facilities which, giving consideration to fixed costs and variable costs, as well as to all other relevant factors, is expected to serve the needs of all customers, collectively, on a least-cost basis. <u>All plants contribute to meeting peak demands, and the failure to allocate the fixed costs associated with base load plants on a measure of peak demand produces a biased result that over-allocates costs to high load factor customers and under-allocates costs to low load factor customers.</u>[25]

Brubaker's criticism is consistent with the Commission's basis for rejecting the P&A Method:

> That has the effect of double counting the average demand and allocates more costs to large industrials that have a steady but high average demand that does not contribute as much to the system peaks. That method works to the benefit of the residential class whose usage varies more by time of day and time of year.[26]

For the fixed costs of base load plant, Staff's BIP method has no significant consideration of demand at all since those significant fixed costs are effectively allocated on the amount of energy use. "That method works to the benefit of the residential class whose usage varies more by time of day and time of year."

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[24] Tr. 980, S. Kliethermes, ll. 3-5.
[25] Id., p. 13, ll. 1-12 (emphasis added).
[26] Id., p. 7, ll. 1-10, citing ER-2014-0258 Report & Order, pages 70-71, paragraph 6, April 29, 2015.

Brubaker's exchange with the Chairman brings out this point:

> Q (By Chairman Hall) But does that [BIP]—in and of itself, does that favor residential customers?
> A (By Brubaker) Yes, it does.
> Q Why?
> A Okay. Because when you allocate fixed cost on energy, residential customers get much lesser share of the cost than if you allocate fixed costs on demand, which is the traditional way to allocate fixed costs.[27]

Not surprisingly, Staff's Study is the only one claiming that the residential class is currently overpaying, by 0.49%, while the other studies show that it is underpaying by between 9.2% and 18.6%, with Brubaker's study in the middle showing that the residential class is underpaying by 14.8%.

2. Staff's Fuel Allocation Model Shows the Error of the BIP Model

Further evidence of the problems inherent in Staff's execution of the BIP Study can be found in the results of Staff's fuel cost allocations. Staff's Fuel Study allocates above average fuel costs ($/MWh) to high load factor customers and below average fuel costs to low load factor customers. That makes no sense since the base load units have much lower fuel costs and an above average share of their fixed costs was assigned to high load factor customers (and below average share to low load factor customers). As Brubaker explains, the fuel costs of the generating units are not uniform:

> They are quite diverse. For example, the fuel cost for the Wolf Creek nuclear unit is about 0.7¢ per kWh, the base load coal plants have fuel costs in the range of 1.5¢ to 2.0¢ per kWh, the combined cycle unit has fuel costs of about 5¢ per kWh, and peakers have costs that are 5¢ per kWh to 7¢ per kWh. (Note: These fuel costs are taken from KCPL's 2015 FERC Form 1 report.) <u>Obviously, if some classes are allocated higher capacity costs than others, they should be entitled to at least an above-average share of the energy output from the higher capital cost, more fuel efficient, base load type generating units, which would make their fuel cost per kWh lower than average</u>.[28]

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[27] Tr. p. 1214, l. 24 – p. 1215, l. 7.
[28] Exhibit 854, Brubaker Rebuttal, p. 10, ll. 11-19.

The results of the Staff's fuel cost allocation thus also demonstrate the flaw in the BIP allocation of production plant:

> The end result of Staff's fuel cost allocation clearly demonstrates that the BIP Study is flawed. The LPS class (which has the highest load factor) is allocated fuel cost that is slightly higher than the overall average fuel cost (see Schedule MEB-COS-R-2). In particular, as compared to an allocation of fuel cost on a kWh basis, Staff allocates to the LPS class $0.09 per MWh, or 0.6%, more than the average. This clearly is contrary to expectations and at odds with the inverse relationship between fuel cost and capital cost. While the numerical difference from average cost is not significant, it does point out a conceptual flaw.
>
> Even more telling is the fact that Staff's detailed BIP fuel cost allocation produces a <u>below average cost per kWh for the low load factor residential class</u>. For the residential class, the detailed BIP fuel allocation is less than the average fuel cost by an astounding $1.15 per MWh, or by about 7.8%. As noted above, it is [counterintuitive] that this low load factor class (the lowest of all) would have not only below average capital costs but also below average fuel costs.
>
> These kinds of anomalies are another reason why the BIP methodology and its results must be regarded with skepticism, and also helps to explain why the method has not received support in the industry.[29]

Brubaker's Rebuttal Schedule MEB-COS-R-2 demonstrates this point. According to Staff's erroneous BIP theory, the high load factor customers are, on a relative basis, served more by base load plants, and low load factor customers are, on a relative basis, served relatively more by peaking units. As demonstrated above, the base load plants have much lower fuel costs and the peaking units much higher fuel costs per MWh. As shown in Schedule MEB-COS-R-2, column (2), the low load factor residential class buys 31.39 percent of the MWh sold, with the high load factor LGS and LPS classes buying 25.32 percent and 23.76 percent, respectively. Given the Staff's erroneous BIP assumptions, one would expect that the low load factor residential class, which is assigned a higher relative share of the high fuel cost peaking units, would be assigned significantly more than 31.39 percent of the overall fuel costs. Likewise,

[29] Id., p. 16, ll. 7-23 (emphasis original).

given the Staff's erroneous BIP assumptions, one would expect that the high load factor LGS and LPS classes, which are assigned a lower relative share of the high fuel cost peaking units and a higher relative share of the low fuel cost base load plants, would be assigned significantly less than 25.32 percent and 23.76 percent, respectively, of the overall fuel costs. But in Staff's fuel Study the opposite is true, as shown in column (6) of Schedule MEB-COS-R-2. Staff assigns 28.93 percent of fuel cost to residential customers and 26.78 and 23.90 percent, respectively, to the LGS and LPS classes.

3. Other Errors in Staff's CCOS Report

Staff's CCOS Report also contains numerous additional errors in allocation. Brubaker explains that those errors involve "the allocation of production non-fuel O&M expense, the allocation of A&G expense and the allocation of the costs of the distribution system:"[30]

> Q WHAT IS THE ISSUE WITH RESPECT TO THE ALLOCATION OF PRODUCTION SYSTEM NON-FUEL O&M EXPENSE?
>
> A Staff develops something that it calls BIP O&M Allocator, which is based on energy.
>
> Q HOW ARE THESE COSTS TYPICALLY ALLOCATED?
>
> A They typically are treated as demand-related costs because they "follow plant," meaning that expenses are closely related to the existence of the plant facilities. KCPL used the demand allocator, as I advocate, for these costs, and, in fact, the Staff's accounting witnesses used a demand allocation factor when allocating these costs between Kansas and Missouri.
>
> Q WHAT IS THE ISSUE WITH RESPECT TO THE ALLOCATION OF A&G EXPENSE?
>
> A A significant portion of A&G expense is allocated to classes on the basis of other O&M expenses, which include significant amounts of fuel and purchased power expense. Fuel and purchased power expense do not give rise to the incurrence of A&G expense in proportion to the level of fuel and purchased power expense because these costs are largely generated externally, as opposed to the labor and other costs of maintaining the generation, transmission, distribution and other functions of the utility, which are internally incurred and do give rise to the occurrence of A&G expense.

[30] Id., p. 19, ll. 5-6.

Q **STAFF HAS REFERRED TO THE NARUC MANUAL FOR CERTAIN ALLOCATIONS. DOES THE NARUC MANUAL CONTAIN A DISCUSSION OF THE ALLOCATION OF GENERAL PLANT AND A&G EXPENSES?**

A Yes. Pages 105-107 of the January 1992 NARUC Manual discusses A&G expenses. I have attached these pages as Schedule MEB-COS-R-3. Note that the majority of A&G expenses are allocated on labor. Wherever the Manual refers to a more general category of expenses, note that the phrase "less fuel and purchased power" appears. This means that fuel and purchased power should be excluded from the allocations.

From a cost causation point of view, most expenses do not vary with energy consumption. This is why it is traditional to exclude fuel and purchased power from any allocation of A&G expenses and focus on the cost-causative nature for these expenses. That is what I have done; it clearly is not what Staff has done.[31]

Staff "responds" to the first concern that O&M is improperly allocated to classes only by energy use, by stating that "Staff's O&M allocation is calculated by prorating capacity-based costs to kWh, which appropriately considers both the capacity of the plant and its energy output in ultimately allocating O&M costs."[32] Staff cites pages 18-19 of its CCOS Report (with no line numbers) as support for this unclear statement ("prorating capacity based costs to kWh"). Specifically, it is unclear whether this is a denial that any production O&M costs were derived only from energy usage. In the Report, at page 18, Staff states:

> Staff also used the assignments of generating plant to BIP components to develop allocators for KCPL's production-related operating and maintenance expense, and fuel stored on site. This method expressly assigns the expenses of each plant to follow that plant. Each of the generating plants causes production plant operating and maintenance expenses. Staff found the level of expense for each plant assigned under the BIP components, and developed allocation factors to apply to all production-related O&M based on each customer class's assigned plant responsibility.[33]

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[31] Id., p. 19, l. 7 – p. 20, l. 15.
[32] Exhibit 213, S. Kliethermes Surrebuttal, p. 5, ll. 21-23.
[33] Exhibit 202, Staff CCOS Report, p. 18, ll. 6-12.

Again, this is unclear as well and seems to imply that Staff used its production plant fixed cost allocators under its BIP method to allocate the O&M expenses for production plants. As clearly established above, the BIP allocator for the base load plants was effectively based solely on class energy usage.

As far as the MIEC can tell, Staff did not respond to the second concern above, namely that the Staff's allocation of A&G expenses was improper.

4. Staff Errors in Allocating Distribution Plant Costs

Brubaker noted three problems with the Staff's determination of demands to allocate distribution plant to the LPS class:

> The first error is that Staff uses the demand of all LPS customers to develop an allocator for distribution plant. Staff uses a non-coincident peak ("NCP") at distribution of 337,000 kW. This is incorrect because, as clearly shown in KCPL's workpapers, approximately 49,000 kW[34] of LPS load is served at the transmission level, does not use the distribution system, and should not be allocated any part of the distribution system.
>
> ***
>
> The second error is Staff's failure to recognize that approximately 49,000 kW of LPS load takes what is referred to as substation service, and therefore does not utilize any of the primary or secondary distribution facilities. Nevertheless, Staff allocated costs to them as if they did.
>
> ***
>
> The third error is in the development of the demand associated with secondary distribution level customers in the LPS class. In estimating that secondary customers have an NCP of approximately 158,000 kW, Staff started with the overstated class NCP (which includes transmission level service customers and distribution substation level service customers), and then subtracted from that number what it calls the load of primary service customers to arrive at 158,000 kW of LPS secondary demand. The amount which Staff subtracts for primary service customers is too small because it uses the average load of all LPS customers, and not just the average load of primary service level customers, which is higher. KCPL's workpapers clearly show that the demand attributable to secondary voltage level service customers in the LPS class is only about 66,000 kW. <u>Staff's calculation of demand and demand responsibility associated with</u>

[34] This figure may be a typo. The transmission demand is 47,000 kW. *See* Ex. 857, first column with numbers.

secondary level service customers in the LPS class has been overstated by approximately 92,000 kW.[35]

Staff recognized, and represented that it had corrected, these errors.[36] However, as demonstrated in MIEC Ex. 857, Staff still has not corrected these errors. In that exhibit, Brubaker used the KCPL COS data (verified by actual customer subclass billing determinants) to show that the Staff's "corrected" calculations were still invalid. This is shown by Exhibit 857:

[35] Exhibit 854, Brubaker Rebuttal, p. 22, l. 3 – p. 23, l. 8 (emphasis added).
[36] Exhibit 211, R. Kliethermes Surrebuttal, p 6. l. 2 – p. 8, l. 2.

KANSAS CITY POWER AND LIGHT COMPANY

Demand Comparison for Rate LP

	KCPL		Staff
Description	**COS Data**	**Billing Determinants Data***	**COS Data**
NCP kW by Voltage Level of Service			
Secondary	63,015	71,619	118,824
Primary	157,974	176,984	177,906
Substation	49,295	51,982	14,853
Transmission	47,163	51,937	24,755
TOTAL LP	317,447	352,522	336,338
Average # of Customers Served at Voltage Level			
Secondary	26	26	24
Primary	40	36	36
Substation	3	3	3
Transmission	5	5	5
TOTAL LP	74	70	68
Demand per Customer by Voltage Level of Service			
Secondary	2,424	2,760	4,951
Primary	3,949	4,925	4,951
Substation	16,432	17,473	4,951
Transmission	9,433	10,200	4,951
TOTAL LP	4,290	5,040	4,951
Distribution Demand (NCP) at Each Voltage Level			
NCP kW			
Secondary/Line Transformer	65,809		118,832
Primary	220,989		297,079
Substation	270,284		311,933
Transmission	317,447		336,690
% of System			
Secondary/Line Transformer	3.103%		6.646%
Primary	11.227%		14.733%
Substation	13.396%		15.357%
Transmission	15.374%		16.576%

* NCP kW is based on Facilities Charge kW.

As the Commission can plainly see, even after the Staff's "correction" its secondary/line transformer distribution plant allocation of 6.646 percent is more than double the correct allocator of 3.103 percent for the secondary/line transformer voltage level. At other voltage levels, the differences are not as stark, but the differences are still significant.

Staff simply made a mistake in its "correction," just as it had made a mistake in its original allocation. Specifically, in attempting to solve the obvious shortcomings of its distribution plant allocator, Staff simply took the overall class demand (336,338 kW)[37] and divided it by the number of customers served in the LPS class (68 customers).[38] Staff completely disregarded KCPL's detailed load analysis and simplistically and erroneously assumed that all LPS customers had the same 4,951 kW of demand.[39] KCPL's load data, however, conclusively proves that Staff's assumption is incorrect. Not surprisingly, transmission and substation customers, the ones who either do not use the distribution system at all, or use it at a reduced level, use much more than the average demand, as shown below.[40]

	KCPL Demand Per Customer	**Staff Assumed Demand Per Customer**
Transmission	9,433 kW	4,951 kW
Substation	16,432 kW	4,951 kW
Primary	3,949 kW	4,951 kW
Secondary	2,424 kW	4,951 kW

When Staff uses its erroneous assumption to remove demand from the total LPS demand in order to recognize that some customers are served at high voltage (with no or little distribution service), it fails to remove enough demand because the higher voltage customers are larger in size, with higher demands, than Staff has assumed.

[37] Exhibit 857, third column, (Staff COS Data) section "NCP kW by Voltage Level of Service."
[38] Exhibit 857, third column, (Staff COS Data) section "Average # of Customers Served at Voltage Level."
[39] Exhibit 857, third column, (Staff COS Data) section "Demand per Customer by Voltage Level of Service."
[40] Exhibit 857, section labeled "Demand per Customer by Voltage Level of Service."

The practical effect of Staff's assumed demand is that it fails to properly recognize the amount of LPS demand that should be allocated substation, primary and secondary distribution costs. Specifically, by relying on its estimate of 4,951 kW for each of the five transmission customers, Staff assumes that only 24,755 kW of demand (5 customers times 4,951 kW per customer) is associated with transmission customers. Therefore, the rest of the LPS demand (311,583 kW) is associated with customers that should be allocated substation costs. In reality, however, the KCPL data shows that LPS <u>transmission level customers</u> have an average demand (9,433 kW) almost twice as large as the average LPS customer (4,951 kW). Therefore, instead of removing 24,755 kW of demand associated with the five transmission level customers, the KCPL data shows that 47,163 kW of demand is actually associated with these transmission level customers and therefore should be removed from the LPS class in order to properly allocate distribution costs. So, instead of allocating substation costs to LPS based on 311,933 kW of demand, those costs should have been allocated based on 270,284 kW of demand. Similarly, Staff's faulty methodology allocates significantly more primary and secondary distribution costs to the LPS class.

After properly accounting for the demands of transmission level customers, the next step is to properly account for the demand of customers served at the substation level who should not be allocated any primary or secondary distribution costs since those facilities do not serve them. In contrast to Staff's assumption of 4,951 kW per customer for substation customers, KCPL's data unequivocally shows an average demand of 16,432 kW per customer. There are three such customers and Staff removed only 14,853 kW of demand to account for customers at the substation level, when in fact the amount that should have been removed is three times 16,432 kW, or 49,296 kW. This error also materially overstates the amount of costs allocated to the LPS class.

Brubaker did not blindly rely on KCPL's demand estimates. Rather, he validated them by comparing those estimates, the data KCPL used in its cost of service study (shown in the first column of numbers in Exhibit 857), with the billing determinant data that represents the results of actual measurements by billing meters used by KCPL to charge customers. This data is shown in the second column of numbers on Exhibit 857. Because of diversity between customers, it is to be expected that the billing determinant data would be slightly higher than the cost of service demands, and it is. For the high voltage customers (transmission level and substation level) whose loads must be removed from the total in order to properly allocate costs to the LPS class, the KCPL data that Brubaker used is shown to be much closer to the actually known billing data than Staff's overly simplistic and erroneous assumption that the class average 4,951 kW demand is appropriate for each customer in the class. Clearly, Staff's assumption was not correct.

Staff's mistaken assumption assigns too much cost of distribution plant to high load factor customers in the LPS class. Ultimately, Brubaker estimates that Staff's faulty "corrected" distribution allocation methodology, based upon the erroneously assumed average demand per LPS customer, over-allocates $4 million of distribution cost revenue requirement to the LPS class.[41]

5. Conclusion as to Staff's CCOS

Based upon the significant conceptual flaws in Staff's BIP production allocator as well as its distribution allocation methodology, Brubaker concludes that "Staff's class cost of service

[41] Tr. 1208.

study should not be relied upon for any purpose."[42] Brubaker's conclusion in that regard is the only reasonable conclusion one can reach based upon the evidence of record.

F. Conclusion for CCOS and Rate Design

The large industrial customers that the MIEC represents seek to pay their fair share. They understand that cost based rates are the fairest and also send the appropriate price signals to customers so that those who cause the most cost per kWh should pay the most and have the most incentive to conserve. The CCOS study sponsored by Brubaker employs time-tested, widely accepted, and widely used principles of ratemaking, as does the study of Dr. Schmidt, although the latter study shows that residential customers are receiving larger subsidies and at greater expense to the LGS and LPS classes than as shown by Brubaker. The Commission should accept Brubaker's study results and follow his recommendation to remove 25 percent or 50 percent of the residential subsidy, depending on the level of rate increase ordered by the Commission, and accept his intra-class rate design for the LGS and LPS classes.

The Staff's and Company's CCOS studies should be rejected because they are founded upon incorrect allocation principles and, in the case of Staff's study, was erroneously executed in any event.

Respectfully submitted,

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[42] Exhibit 854, Brubaker Rebuttal, page 23.

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CERTIFICATE OF SERVICE

I do hereby certify that a true and correct copy of the foregoing document has been emailed this 22nd day of March, 2017, to all counsel of record.

*/s/ Edward F. Downey*______