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-2016-0285**

INITIAL POSTHEARING BRIEF

OF

MIDWEST ENERGY CONSUMERS GROUP

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BEFORE THE PUBLIC SERVICE COMMISSION
<u>OF THE STATE OF MISSOURI</u>

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INITIAL POST-HEARING BRIEF OF
<u>MIDWEST ENERGY CONSUMERS' GROUP</u>

COME NOW the Midwest Energy Consumers' Group (collectively referred to herein as "MECG") by and through the undersigned counsel, pursuant to the Commission's August 10, 2016 *Order Adopting Procedural Schedule and Delegating Authority*, and provides its initial post-hearing brief. In this brief, MECG will brief the following issues: (1) Cost of Capital (Issue II) including Customer Experience (Issue XXVII); (2) Revenues (Issue XX); (3) Rate Design / Class Cost of Service (Issue XXI); and (4) Clean Charge Network (Issue XXII). MECG reserves the right to address other issues, including issues raised at the March 16 true-up hearing, in its reply brief.

I. INTRODUCTION

On July 1, 2016, Kansas City Power & Light Company ("KCPL" or "Company"), a wholly owned subsidiary of Great Plains Energy Corporation ("Great Plains" or "GPE"), filed for a $90.1 million (10.77%) rate increase. In this case, the Commission will decide several different issues. Several of these issues (class cost of service, clean charge network, return on equity reduction for inferior customer service) provide the Commission with the opportunity to implement policy goals. MECG urges the Commission to avoid deciding issues in a vacuum. Rather, MECG maintains that the Commission should view each issue in this case with recognition of the overall status of the case. Specifically, as demonstrated, *infra*, KCPL's rates have increased dramatically over the past 10 years. Despite such increases, KCPL's customer satisfaction ratings have plummeted in recent years. Furthermore, at the time that it filed this case, KCPL was earning above its authorized return. Given that the Commission is charged with protecting ratepayers from the monopolistic actions of utilities like KCPL,[1] MECG expects the Commission to say "enough".

A. RAPID INCREASE IN KCPL RATES

Since 2006, KCPL rates have skyrocketed. Specifically, since that date, the Commission has authorized the following rate increases.[2]

- ER-2006-0314: $50.6 million 10.46% increase
- ER-2007-0291: $35.3 million 6.50% increase

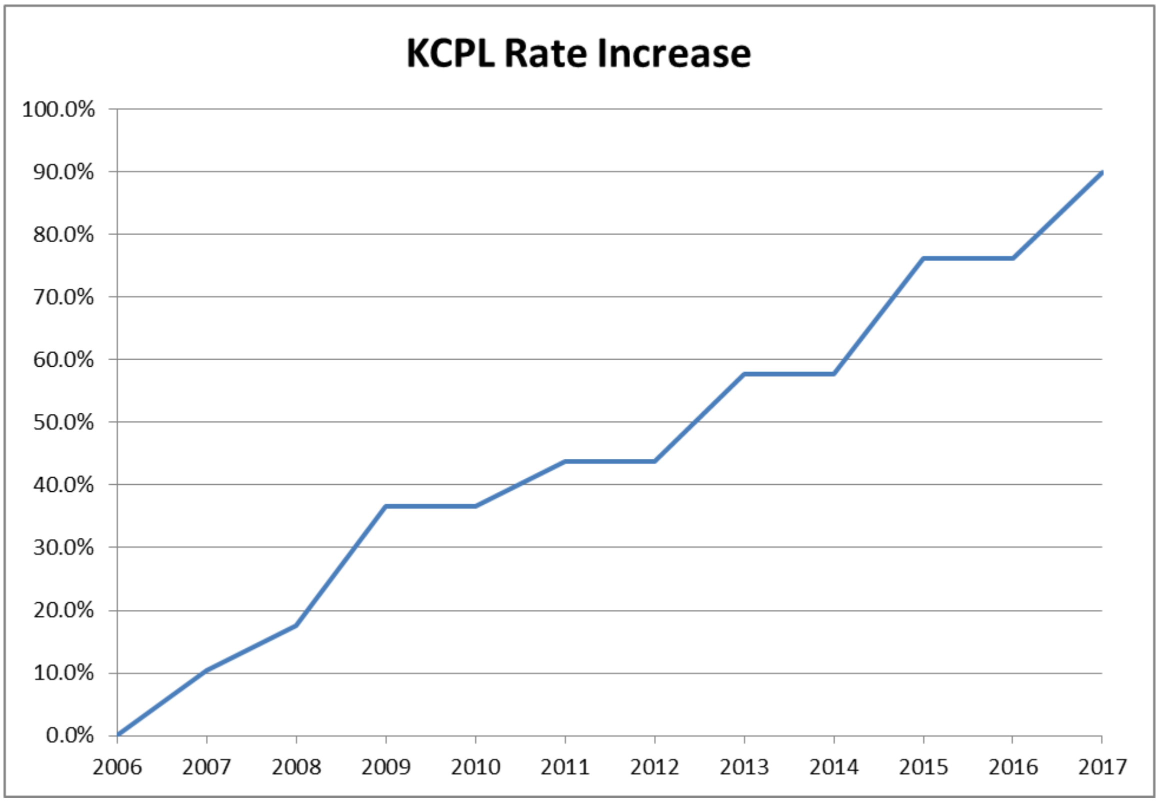
[1] *State ex rel. Utility Consumers Council of Missouri v. Public Service Commission*, 585 S.W.2d 41, 47 (Mo. banc 1979) ("*UCCM"*) (citing to *May Dep't Stores Co. v. Union Electric Light & Power Co.*, 107 S.W.2d 41, 48 (1937)). ("This court has previously recognized that its [Public Service Commission Act] ***purpose was to protect the consumer against the natural monopoly of a public utility***, as provider of a public necessity) (emphasis added).
[2] Exhibit 200, Staff Cost of Service Report, page 9.

- ER-2009-0089: $95.0 million 16.16% increase
- ER-2010-0355: $34.8 million 5.25% increase
- ER-2012-0174: $67.4 million 9.64% increase
- ER-2014-0370: $89.7 million 11.76% increase

ER-2009-0089:	$95.0 million	16.16% increase
ER-2010-0355:	$34.8 million	5.25% increase
ER-2012-0174:	$67.4 million	9.64% increase
ER-2014-0370:	$89.7 million	11.76% increase
	$372.8 million	**76.23% increase**

Recognizing that, at the time that it filed its true-up testimony, it was still seeking a $65.2 million (7.80%) increase in this case;[3] KCPL rates could potentially increase by over $438 million (89.98%) since 2007.

The tremendous increase in KCPL rates is particularly noticeably when viewed graphically. The following chart assumes KCPL's requested 7.80% true-up rate increase.



The impact of this rapid increase in KCPL rates is best realized when compared to how slow KCPL customers' household income has grown over the same period of time.

[3] Exhibit 173, Klote True-Up Direct, page 1.

Specifically, the average weekly wage of KCPL's customers has only increased by 17.62% over the same period of time.[4] During this period, inflation as measured by the consumer price index has grown 14.31%.[5] Thus, by any measure, KCPL's ratepayers are spending an ever increasing portion of their limited household income on the electricity provided by KCPL.

The increase in KCPL's rates is acutely felt by KCPL's industrial customers as well. Specifically, a large industrial customer has seen the following rapid increase in rates <u>since just 2009</u>.

Year	Rate (₵ / kWh)
2009	4.09
2010	4.67
2011	4.75
2012	4.89
2013	5.12
2014	5.50
2015	5.79
2016	6.61

Source: Exhibit 650, Gorman Direct, Schedule MPG-2.

Clearly then, by any measure, KCPL's customers, not its shareholders,[6] are the ones in dire need of rate relief. While national average rates have held steady over the last several years,[7] KCPL's rates have continued to climb.

<u>B. PLUMMETING CUSTOMER SATISFACTION</u>

While its rates have rapidly increased, KCPL's customer satisfaction has rapidly declined. While KCPL has historically bragged about its customer service and

[4] Exhibit 202, Staff Cost of Service Report, page 8.
[5] *Id.*
[6] In fact, since 2010, the Great Plains dividend to its shareholders as increased dramatically. Exhibit 218, Majors Surrebuttal, page 9.
[7] Indeed, during the period in which KCPL rates have increased by 76.23%, the national average electric rate has only increased 30.29%. *Id.* at page 21.

satisfaction,[8] it was notably quiet about its customer service and satisfaction performance in this case. The reason for KCPL's deviation from its past practice of bragging about customer service was readily apparent.

On January 17, 2017, JD Power announced the results of its Electric Utility Business Customer Satisfaction survey. Those results clearly indicate that KCPL's customer satisfaction performance, relative to other Midwest utilities, has dropped dramatically. Specifically, while KCPL was second among 14 large Midwest electric utilities in 2015,[9] it fell dramatically to 13th among those same 14 utilities in 2016.[10] In fact, among all electric utilities nationwide, KCPL ranks in the bottom quartile, finishing 64th out of 86 utilities.[11] Given this, it is not surprising that KCPL admits that its customer satisfaction performance is "significantly disappointing."[12] In fact, KCPL readily concedes that the JD Power survey information "is something that I think is valid for the Commission and all of our stakeholders to consider in determining how we do our job."[13]

C. EARNING ABOVE AUTHORIZED RETURN

In this case, the Commission should be hesitant to compare its final authorized rate increase against the $90.1 million rate increase initially requested by KCPL. The evidence clearly demonstrates that, for the 12 months ended September 30, 2016, KCPL

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[8] For instance, in 2010, KCPL sought a return on equity at the high end of the reasonable range. KCPL claimed that this return on equity was justified by its customer service. In support, KCPL directed the Commission's attention to its JD Power survey results. See, *Report and Order*, Case No. ER-2010-0355, issued April 12, 2011, at page 119.
[9] Exhibit 656.
[10] Exhibit 332.
[11] Tr. 1492.
[12] Tr. 1490.
[13] Tr. 1495.

earned a return on equity of 9.88%, above its authorized return of 9.50%.[14] Recognizing that rates from the last rate case went into effect on September 29, 2015, this surveillance report is significant. Specifically, this surveillance report represents the 12 month period immediately following the change in KCPL's rates.

Given that KCPL filed this case when it was already earnings above its authorized return, one should be a concerned about the legitimacy of its initial request to increase rates by $90.1 million (10.77%).[15] Clearly, based upon the 12 month period ended September 30, 2016, KCPL was already earning above its authorized return. As such, KCPL's request for a $90.1 million increase was vastly inflated. Given that the $90.1 million request was inflated, the Commission should be hesitant to decide issues with an eye towards what has been proven to be a faulty initial request.[16]

[14] Exhibit 217, Majors Rebuttal, page 4.
[15] Exhibit 130, Ives Direct, page 5.
[16] Indeed, at the time that it filed its true-up direct, KCPL acknowledged that it could only support an increase of $65.2 million. Exhibit 173, Klote True-Up Direct, page 1. Thus, almost 28% of KCPL's initial request was inflated or the product of KCPL's inability to forecast costs for the six months leading up to the true-up.

II. OVERVIEW OF POSITIONS

COST OF CAPITAL (ISSUE II) INCLUDING CUSTOMER EXPERIENCE (ISSUE XXVII): In his rebuttal testimony, MECG Witness Gorman provided an updated return on equity analysis. That analysis, relying on data ***after*** the recent Federal Reserve decision to increase in interest rates, results in a return on equity of 9.20% (midpoint of range of 8.90% to 9.50%). Mr. Gorman's analysis is consistent with previous Commission decisions, does not suffer from the flaws inherent in KCPL's methodology and recognizes the continued low cost of capital for domestic utilities costs.

Despite this recommendation, MECG urges the Commission to authorize a return on equity at the lower half of this range (8.90% to 9.20%). As developed during the hearing on Customer Experience (Issue XXVII), KCPL's customer satisfaction has plummeted dramatically since the Commission authorized a 9.5% return on equity in the last case. In addition, the last year has seen several instances of KCPL violating Commission rules and stipulation commitments. Moreover, despite its rising rates, KCPL has demonstrated an inability to control A&G costs. In response, the Commission has taken the unprecedented step of ordering a management audit of KCPL. Given its apathy towards customer service, as well as its continued willingness to violate rules and previous commitments to further the interests of its shareholders, the Commission should award a return in the lower half of the recommended return on equity range.

REVENUES (ISSUE XX): Consistent with the positions advanced by Staff and OPC, the Commission should not allow KCPL to include the effects of MEEIA Cycle 1 programs in its revenue normalization. KCPL has already recovered any lost revenues associated with these Cycle 1 programs through the throughput disincentive component of the Cycle 1 DSIM. Similarly, KCPL is recovering any lost revenues associated with its MEEIA Cycle 2 programs through a stipulated revenue normalization. Effectively, through this issue, KCPL is attempting to apply the lost revenue structure for Cycle 2 programs to its Cycle 1 programs. Recognizing that KCPL has already recovered these lost revenues through the throughput disincentive component of the DSIM, KCPL is attempting to double recover its lost revenues associated with the Cycle 1 programs.

RATE DESIGN / CLASS COST OF SERVICE (ISSUE XXI): MECG urges the Commission to adopt positions consistent with those advanced in this brief. Specifically, the Commission should adopt the A&E methodology for allocating fixed production costs among the various customer classes. Unlike the Staff faulty BIP methodology and the KCPL Peaking & Average approach which have been repeatedly rejected by this and other state utility commissions, the A&E methodology has garnered widespread respect and acceptance among state commissions.

Once the A&E methodology is adopted, the Commission should take steps to reduce the current residential subsidy by moving all classes 25% towards cost of service. Finally, the Commission should take steps to eliminate the current subsidy in the LGS / LPS rate classes by collecting more costs through the LGS / LPS demand and first energy blocks consistent with the recommendation of Mr. Brubaker.

CLEAN CHARGE NETWORK (ISSUE XXII): KCPL's investment in its Clean Charge Network, and its request to include such costs in utility rates, is an inappropriate attempt to extend its state-authorized monopoly to provide electric service to a service (electric vehicle charging) which should be provided in a competitive market. MECG supports the position advanced by OPC – that electric vehicle charging stations should not be regulated. As such, only those costs associated with extending the distribution network to the charging station, should be included in rates. All other costs, predominantly the investment and O&M costs associated with the charging station itself should not be included in regulated rates. Given the deregulated nature of the charging stations, KCPL should then be allowed to charge electric vehicle customers whatever amount it deems appropriate in order to recover its investment in this deregulated service.

III. BURDEN OF PROOF

Section 393.150(2) provides that, in any rate increase proceeding, the burden of proof is on the party seeking the increased rate. In considering the appropriate hearing schedule in a recent proceeding, the Commission adopted KCPL's schedule based solely upon its acknowledged burden of proof.

> Furthermore, the Commission will adopt the order of issues proposed by KCP&L. While the Commission understands the positions argued by Staff and MEUA, the Commission concludes that KCP&L has the burden to put on its case, and should be granted considerable leeway in the order in which it would like to present its evidence.[17]

Burden of proof, however, does not only mean that the utility gets the advantages when it comes to presenting its evidence. Burden of proof also means that the utility must accept the "burden" of proving its case.

In this regard, the Supreme Court has provided a great deal of insight regarding burden of proof. Specifically, as it applies to Commission proceedings, the Supreme Court has told us: (1) that burden of proof is a "substantial right" of the customers and (2) that burden of proof should be "rigidly enforced" by the Commission.

> The rules as to burden of proof are important and indispensable in the administration of justice, and constitutes a substantial right of the party of whose adversary the burden rests; they should be jealously guarded and rigidly enforced by the courts.[18]

The Supreme Court has also provided definition for the burden of proof.

> The burden of proof meaning the obligation to establish the truth of the claim by a preponderance of the evidence, rests throughout upon the party asserting the affirmative of the issue. The burden of proof never shifts during the course of the trial.[19]

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[17] *Order Setting Blocks of Exhibit Numbers*, Case No. ER-2010-0355, page 2 (issued January 12, 2011).
[18] *Highfill v. Brown*, 320 S.W.2d 493 (Mo. 1959).
[19] *Clapper v. Lakin*, 123 S.W.2d 27 (Mo. 1938).

As such, the burden of proof means that the proponent of higher rates in a Commission proceeding (the utility) has the "obligation to establish the truth" of its need for the higher rates. In this regard, customers are given the benefit of the doubt that the utility only needs the lower rate and that the utility must "prove" that the higher rate is necessary. Therefore, if there is any question regarding the legitimacy of a cost or expense; if the Commission does not adequately understand an issue; or if the Company fails to adequately explain its need for the higher rate, then the utility has failed to meet its burden of proof.

Finally, the Supreme Court has provided insight as to the implications to a party that fails to meet its burden of proof: "the failure of the plaintiff to sustain such burden ***is fatal*** to his or her relief or recovery."[20]

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[20] *Id.*

IV. COST OF CAPITAL INCLUDING CUSTOMER EXPERIENCE

Position: In his rebuttal testimony, MECG Witness Gorman provided an updated return on equity analysis. That analysis, relying on data ***after*** the recent Federal Reserve decision to increase in interest rates, results in a return on equity of 9.20% (midpoint of range of 8.90% to 9.50%). Mr. Gorman's analysis is consistent with previous Commission decisions, does not suffer from the flaws inherent in KCPL's methodology and recognizes the continued low cost of capital for domestic utilities costs.

Despite this recommendation, MECG urges the Commission to authorize a return on equity at the lower half of this range (8.90% to 9.20%). As developed during the hearing on Customer Experience (Issue XXVII), KCPL's customer satisfaction has plummeted dramatically since the Commission authorized a 9.5% return on equity in the last case. In addition, the last year has seen several instances of KCPL violating Commission rules and stipulation commitments. Moreover, despite its rising rates, KCPL has demonstrated an inability to control A&G costs. In response, the Commission has taken the unprecedented step of ordering a management audit of KCPL. Given its apathy towards customer service, as well as its continued willingness to violate rules and previous commitments, the Commission should award a return in the lower half of the recommended return on equity range.

A. INTRODUCTION AND OVERVIEW OF THE RECOMMENDATIONS

It is well established that public utility commissions have several basic objectives. Foremost among these objectives is to ensure adequate earnings for the utility while preventing excessive (monopoly) profits.[21] Absent regulatory control, the utility will inevitably seek to extract monopoly profits from the many (the ratepayers of Missouri) for the benefit of the few (the GPE shareholders scattered across the nation).

The attempt to extract monopoly profits in this case is best seen in KCPL's return on equity recommendation. Rather than simply seek that level of return that is "sufficient to ensure confidence in the financial soundness of the utility,"[22] KCPL instead seeks to bolster its corporate profits through an inflated return. As the Supreme Court has pointed out, however, the utility has no "right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures."[23]

In this case, KCPL requests an inflated profit margin (the return on equity) of 9.90%.[24] In support of this request, KCPL presents the flawed testimony of Robert Hevert. This recommendation would actually lead to a 40 basis point increase in KCPL's current 9.50% return on equity despite the continued low capital costs experienced by domestic utilities. KCPL's recommendation stands in stark contrast to the return on equity recommendations provided by the other two experts in this case. Specifically, MECG presented the expert testimony of Michael Gorman who arrives at a return on equity range of 8.90% to 9.50% with a recommended return on equity of 9.20.[25] Staff provided the expert testimony of Dr. Randall Woolridge who concludes that a return on

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[21] Phillips, Charles F. Jr., *The Economics of Regulation*, Rev. Ed. (1969) at page 124.
[22] *Bluefield Water Works and Improvement Co. v. Public Service Comm'n*, 262 U.S. 679, 692-693 (1923).
[23] *Id.*
[24] Exhibit 106, Bryant Direct, page 3.
[25] Exhibit 651, Gorman Rebuttal, page 29.

equity of 8.65% is reasonable[26] Clearly then, KCPL's recommendation is significantly higher than those recommended by the other return on equity experts.[27]

As this brief demonstrates, KCPL's recommendation is inflated because it is fundamentally flawed. In recent cases, the Commission has leveled specific criticisms at Mr. Hevert's assumptions and methodology. As a result, this Commission has repeatedly concluded that Mr. Hevert's recommendations were "too high" and rejected his recommendation.[28] Despite the clarity of the Commission's prior criticism and its repeated decision to summarily reject his recommendations, Mr. Hevert presented the same flawed analysis, relying upon the same inflated assumptions, in this case. For the same reasons as before, the Commission should disregard KCPL's return on equity recommendation in this case.

B. <u>GORMAN CREDIBILITY AND OBJECTIVE ANALYSIS</u>

In its consideration of the return on equity issue in recent rate cases, the Commission has frequently been presented with the expert analysis of Michael Gorman. Given the reasonableness of his approach, the Commission has repeatedly relied upon Mr. Gorman's methodology. In a recent Ameren decision, the Commission pointed out that Mr. Gorman was "a reliable rate of return expert."[29] In other decisions, the Commission's findings as to Mr. Gorman's reliability and credibility were even more glowing.

> [T]he Commission finds Michael Gorman to be the most credible and most understandable of the three ROE experts who testified in this case.[30]

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[26] Exhibit 200, Staff Cost of Service Report, page 3.

[27] The Commission has previously looked at the proximity of the various return on equity recommendations in rejecting outliers like the current Hevert recommendation. See, *Report and Order*, Case No. ER-2011-0028, issued July 13, 2011, at page 70, paragraph 22.

[28] Case No. ER-2012-0166, *Report and Order*, issued December 12, 2012, at pages 69-70.

[29] Case No. ER-2014-0258, *Report and Order*, issued April 29, 2015, at page 66.

[30] Case No. ER-2012-0166, *Report and Order*, issued December 12, 2012, at page 70.

> Michael Gorman, the witness for SIEUA, AG-P and FEA, did the best job of presenting the balanced analysis the Commission seeks.[31]
>
> In particular, the Commission accepts as credible the testimony of MIEC's witness, Michael Gorman. . . . Of the witnesses who testified in this case, Michael Gorman, the witness for MIEC, does the best job of presenting the balanced analysis that the Commission seeks.[32]

In this case, Mr. Gorman presents the same "credible" and "balanced" analysis relied upon by the Commission in those recent cases. As Mr. Gorman points out, his updated analysis was based upon data through December 16, 2016.[33] Given this update, Mr. Gorman's analysis reflects the most recent events that have occurred in the financial markets. Of utmost importance, Mr. Gorman's analysis reflects the recent change to a Trump administration as well as the December 14 increase in the Federal Funds rate.

> [I]t was only recently that the Federal Funds rate did increase interest rates, in December 2016, by 25 basis points. That change, along with the change in Administration, did have an impact on utilities' security valuations. However, since that change was made on December 14, those valuations were reflected in my updated analysis and recommended return on equity range of 8.9% to 9.5% as outlined in my rebuttal testimony.[34]

Realizing the Commission's previous interest in considering the results of multiple return on equity analyses, Mr. Gorman provided the results of five different analyses: (1) a constant growth discounted cash flow (DCF) analysis using analysts' 3-5 year growth rates; (2) a sustainable growth DCF analysis; (3) a multi-stage growth DCF analysis which relies on a long-term growth rate equal to the consensus analysts' projection of gross domestic product; (4) a risk premium analysis and (5) a Capital Asset

[31] Case No. ER-2007-0004, *Report and Order*, issued May 17, 2007, at page 62.
[32] Case No. ER-2007-0002, *Report and Order*, issued May 22, 2007, at pages 40-41.
[33] Exhibit 651, Gorman Rebuttal, page 29.
[34] Exhibit 652, Gorman Surrebuttal, pages 6-7.

Pricing Model analysis.[35] The average of all of these analyses results in a recommendation of 8.90-9.50%.[36] Mr. Gorman's results can be summarized as follows:

MODEL		RESULT
DCF	Constant Growth	9.02%[37]
	Sustainable Long-Term Growth	7.76%[38]
	Multi-Stage Growth	7.99%[39]
Risk Premium		9.50%[40]
CAPM		8.90%[41]
Recommendation		**8.90% - 9.50%[42]**

The reasonableness of Mr. Gorman's recommendation is also supported be a three external considerations. ***First***, the Commission should realize that KCPL implicitly admits that its return on equity should be lower than that authorized in the last case. Specifically, in the last case, KCPL recommended a return on equity of 10.3%.[43] In contrast, KCPL now recommends a return on equity of 9.9%.[44] Thus, KCPL implicitly acknowledges that its assessment of an appropriate return on equity has decreased by 40 basis points since the last case. Applying this 40 basis point reduction to the 9.50% return on equity authorized in the last case would result in a return on equity of 9.10%. This is virtually identical to the midpoint of 9.20% recommended by Mr. Gorman.

Second, contrary to KCPL's recommendation that the Commission increase its return on equity from 9.5% to 9.9%, interest rates since the Commission issued its

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[35] Exhibit 650, Gorman Direct, pages 26-31 (constant growth DCF); pages 31-32 (sustainable growth DCF); pages 32-39 (multi-stage growth DCF); pages 40-46 (risk premium analysis); and pages 47-52 (CAPM analysis).
[36] Exhibit 651, Gorman Rebuttal, pages 28-29.
[37] *Id.* at Schedule MPG-R-6.
[38] *Id.* at Schedule MPG-R-9.
[39] *Id.* at Schedule MPG-R-11.
[40] *Id.* at page 29.
[41] *Id.*
[42] *Id.*
[43] See, *Report and Order*, Case No. ER-2014-0370, issued September 2, 2015, at page 15.
[44] Exhibit 106, Bryant Direct, page 3.

decision in the last KCPL case are largely the same.[45] Thus, economic data does not support the notion that return on equity authorizations should increase.

<u>Third</u>, at the same time that KCPL was processing its 2014 Missouri rate case, it was also processing a Kansas rate proceeding. While the Missouri Commission authorized a return on equity of 9.5%, the Kansas Corporation Commission authorized a return of 9.3%.[46] Recognizing that both jurisdictions have now authorized a fuel adjustment clause, it is illogical that Missouri customers should have to pay higher rates to reflect a higher profit margin for virtually identical operations. Thus, Mr. Gorman's recommendation is also supported by the recent decision of the Kansas Corporation Commission.

After reaching his return on equity recommendation, Mr. Gorman then checks to ensure that his recommended return on equity will support an investment grade credit rating. Such an analysis is consistent with the directives of the *Hope* and *Bluefield* decisions. Specifically, Mr. Gorman undertook certain financial integrity tests for KCPL based upon a <u>9.00%</u> return on equity.[47] Mr. Gorman then compared the results of those financial integrity tests to the benchmarks for two critical S&P financial ratios: (1) Debt to EBITDA (Earnings Before Income Taxes, Depreciation and Amortizations); and (2) Funds from Operations to Total Debt.[48]

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[45] Tr. 243 ("We don't have higher interest rates today either. The interest rates for utility bonds today are comparable to what they were doing KCP&L's last rate case. They are comparable to what they were in 2015. They are higher than they were in July of this year. But again, they were reduced in July of this year, because of the international event that caused interest rates to drop. They have recovered since then. But interest rates are not higher today than they have been over the last couple years.").
[46] *Order on KCPL's Application for Rate Change*, Case No. 15-KCPE-116-RTS, issued September 10, 2015, at page 16.
[47] Exhibit 650, Gorman Direct, pages 54-57 and MPG-19.
[48] *Id.* at page 55 and MPG-19.

As Mr. Gorman's analysis reveals, a 9.00% return on equity will allow KCPL to meet the investment grade credit metrics for each of these financial ratios. As Mr. Gorman concludes, therefore, "[a]t my recommended return on equity of 9.00% and the Company's embedded debt cost and capital structure, KCPL's financial credit metrics continue to support credit metrics at an investment grade utility level."[49]

C. HEVERT'S LACK OF CREDIBILITY AND INFLATED ANALYSIS

In contrast to Gorman's impeccable credibility before this Commission, Mr. Hevert's credibility is questionable. Mr. Hevert has testified before this Commission on at least four separate occasions. In each instance, the Commission found that Mr. Hevert's assumptions and recommendations were "excessive" and "too high." In many cases, the Commission discussed specific problems with Mr. Hevert's methodology.

> <u>Case No. ER-2014-0370</u>: KCPL's expert witness, Robert Hevert, supports an increased return on equity at 10.3 percent. <u>***The Commission finds that such a return on equity would be excessive***</u>. Hevert's return on equity estimate is high because 1) his constant growth DCF results are based on excessive and unsustainable long-term growth rates, 2) his multi-stage DCF is based on a flawed accelerated dividend cash flow timing and an inflated gross domestic product growth estimate as a proxy for long-term sustainable growth, 3) his CAPM is based on inflated market risk premiums, and 4) his bond yield plus risk premium is based on inflated utility equity risk premiums.[50]
>
> <u>Case No. ER-2014-0258</u>: Ameren Missouri's expert witness, Robert Hevert, supports an increased ROE at 10.4 percent. <u>***The Commission finds that such an ROE would be excessive***</u>. In large part, Hevert's ROE estimate is high because he based his multi-stage DCF analysis calculations on an optimistic nominal long-term GDP growth rate outlook of 5.71 percent. As Gorman explains, that growth rate is substantially higher than consensus economists' forward-looking real GDP growth outlooks. Adjusting Hevert's optimistic growth rate outlook to the consensus economist level reduces his multi-stage growth DCF return from 10.02 percent to 8.80 percent for his proxy group.[51]

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[49] *Id.* at page 57.
[50] Case No. ER-2014-0370, *Report and Order*, issued September 15, 2015, pages 19-20 (emphasis added).
[51] Case No. ER-2014-0258, *Report and Order*, issued April 29, 2015, at page 66 (emphasis added).

> Case No. ER-2012-0166: However, ***Hevert's estimation of an appropriate ROE is too high***. MIEC's witness, Michael Gorman explains that Mr. Hevert relied on long-term sustainable growth rate estimates in his DCF models that are higher than the growth outlook of the economy as a whole. As he explained, it is not rational to expect that utilities can grow faster than the demand of the economies they serve.[52]

> Case No. ER-2011-0028: Hevert's recommended return on equity is higher than the other recommendations in large part because he over-estimates future long-term growth in his various DCF analyses, making them ***too high*** to be reasonable estimates of long-term sustainable growth. When Hevert's long-term growth rates are adjusted to use more sustainable growth estimates based on published analyst's projections, his multi-stage DCF analysis produces a rate of return more in line with the estimates of LaConte and Gorman.[53]

Missouri is not the only commission that has found that Mr. Hevert's recommendations are "too high." In 40 cases litigated and decided over the past five years, state utility commissions have always found that Mr. Hevert's recommended return on equity was too high. In fact, the actual return authorized in these cases averaged 73 basis points below the inflated return on equity recommended by Mr. Hevert.[54]

Consistent with previous Commission orders finding that Mr. Hevert's recommendations are "too high", the Oklahoma Commission, in an order from earlier this week, also rejected Mr. Hevert's analysis as "excessive" and "biased upward".

> Specifically, in this Cause, the Commission did not find Mr. Hevert's opinions persuasive. His recommended ROE of 10.25 percent was excessive in that each of his methods and the inputs he used appear to have been biased upward, resulting in a significantly inflated recommendation.[55]

[52] Case No. ER-2012-0166, *Report and Order,* issued December 12, 2012, at pages 69-70. (emphasis added).
[53] Case No. ER-2011-0028, *Report and Order*, issued July 13, 2011, at page 23. (emphasis added).
[54] Exhibit 655 and Tr. page 117.
[55] *In re: Oklahoma Gas & Electric*, Cause No. PUD 201500273, issued March 20, 2017, at page 5.

The reasons underlying Hevert's inflated recommendations are apparent when one digs further into Hevert's flawed methodologies. As the following demonstrates, Mr. Hevert's multi-stage growth DCF analysis, CAPM, and risk premium analyses are all flawed and result in inflated return on equity recommendations.

1. Multi-Stage Growth DCF Analysis

As reflected in his rebuttal testimony, Mr. Hevert's multi-stage growth rate DCF analysis is flawed for three specific reasons.

First, in his multi-stage growth DCF analysis, Mr. Hevert's long-term sustainable growth rate is "unreliable because he relied on a long-term GDP growth rate that does not reflect consensus market participant outlooks for future GDP growth.[56] Specifically, Mr. Hevert uses a long-term historical real GDP return of 3.24%, as measured over the period of 1929 through 2015. He then adjusted for projected inflation to arrive at a long-term nominal GDP growth rate of 5.28%.[57]

As Mr. Gorman points out, however, when attempting to measure the cost of equity demanded by current investors it is inappropriate to look at historical GDP growth rates. Instead, the cost of equity demanded by current investors is best measured by looking towards the "current consensus independent market participants' outlooks for future growth."[58]

It is readily apparent that, by relying on a historical GDP growth rate for purposes of calculating a long-term growth rate in his multi-state DCF analysis, instead of the consensus outlook for future growth, Mr. Hevert has effectively inflated the result of his multi-stage DCF analysis. Specifically, Mr. Hevert's historical GDP growth of 5.28% is

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[56] Exhibit 651, Gorman Rebuttal, page 7.
[57] *Id.*
[58] *Id.* at page 8.

significantly higher than consensus economists' estimates of GDP growth over the next five to 10 year period of 4.14% to 4.35%.[59] This has the effect of inflating his final multi-stage DCF analysis.

Second, Mr. Hevert also inflates his multi-stage growth DCF model as a result of a flawed assumption on dividend payout ratio.[60] Specifically, Mr. Hevert inexplicably assumes that that the dividend payout ratio for his proxy group will "converge to the historical industry average dividend payout ratio of 66.88%."[61] Again, this dividend payout ratio is significantly higher than the 63.00% dividend payout ratio assumed by consensus analysts.[62]

Third, Mr. Hevert's multi-state growth DCF analysis is further inflated through his incorrect assumptions regarding the terminal value P/E (price to earnings) ratio. Specifically, Mr. Hevert incorrectly projects that the proxy group P/E ratio "will approximately that of the overall market."[63] As Mr. Gorman points out, however, current P/E ratios are high as a result of the current capital investment programs being undertaken by electric utilities. This high P/E ratio is expected to contract as this capital investment cycle concludes in the near future.[64] By assuming that the proxy group P/E ratio will approximate that of the overall market, Mr. Hevert has effectively ignored the inevitable contraction that will result from the completion of the current utility construction cycle.

> That is an unreasonable assumption because after the current accelerated growth period ends, and growth declines to a lower sustainable level, it is

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[59] *Id.* at page 9.
[60] *Id.* at page 7.
[61] *Id.* at page 10.
[62] *Id.*
[63] Exhibit 127, Hevert Direct, page 32.
[64] Exhibit 651, Gorman Rebuttal, pages 11-12.

> reasonable to expect that the P/E ratio would also respond to those lower growth outlooks and decline. By overstating the terminal value price, based on a P/E ratio that does not reflect the decline in growth, Mr. Hevert is overstating the cash flows in his DCF study and overstating the multi-stage growth DCF return estimate.[65]

When one corrects for the three errors in his multi-stage growth DCF analysis, Mr. Hevert's multi-stage DCF result decreases from 9.71% to 8.21%.[66] This is clearly in line with the results of Mr. Gorman's multi-stage DCF analysis of 8.02%.[67]

2. <u>Capital Asset Pricing Model (CAPM)</u>

In addition to the flaws in his multi-stage DCF analysis, Mr. Hevert's CAPM analysis is also flawed. As Mr. Gorman points out, the CAPM analysis is based upon the theory that the market required rate of return for a security is equal to the risk-free rate, plus a risk premium associated with the specific security. The risk premium associated with the specific security is expressed mathematically as:

Bi x (Rm - Rf) where:

Bi = Beta - Measure of the risk for stock
Rm = Expected return for the market portfolio
Rf = Risk-free rate[68]

In order to calculate his expected return for the market (Rm), Mr. Hevert conducted a DCF analysis for the market. Much like the flaws discussed, *supra*, Mr. Hevert's DCF analysis for the market also relies upon an inflated long-term growth rate. Specifically, Mr. Hevert's market DCF underlying his CAPM analysis employs a growth rate of 11.08% and 11.71%.[69] As Gorman notes, these growth rates "are far too high to be a rational outlook for sustainable long-term market growth. These growth rates are

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[65] *Id.* at page 12.
[66] *Id.* at page 13.
[67] *Id.* at Schedule MPG-R-11.
[68] *Id.* at page 13.
[69] *Id.* at page 17.

more than two times the growth rate of the U.S. GDP long-term growth outlook of 4.25%."[70]

As with his multi-stage DCF analysis, Mr. Hevert's CAPM analysis is easily corrected. As Mr. Gorman points out, by employing more reasonable growth rates in the market return portion of the CAPM, Mr. Hevert's return on equity is reduced to 9.1%.[71]

3. Risk Premium Analysis

In addition, Mr. Hevert conducted two versions of a risk premium analysis: (1) the Primary Bond Yield Plus (BYP) analysis and (2) the Alternative BYP analysis. As Mr. Gorman details, both analyses are flawed.

The Primary BYP is premised on the notion that "equity risk premiums are inversely related to interest rates."[72] Such a premise is overly simplistic. While such a premise may have been accepted in the past, more recent research demonstrates that this relationship: (1) changes over time and (2) is influenced by changes in perception of the risk of bond investments relative to equity investments. As such, equity risk premiums do not change simply as a result of changes in interest rates.[73]

For instance, during the early 80s, "equity risk premiums were inversely related to interest rates, but that was likely attributable to the interest rate volatility that existed at that time."[74] Today, however, interest rate volatility is not as extreme. As such, changes in the perceived risk of bond investments relative to equity investments "cannot be measured simply by observing nominal interest rates."[75] Instead, the change in equity

[70] *Id.* at pages 14.
[71] *Id.* at page 16.
[72] *Id.* at page 17.
[73] *Id.*
[74] *Id.* at pages 17-18.
[75] *Id.* at page 18.

risk premiums is more dependent on "the relative changes to the risk of equity versus debt securities investments, and not simply changes in interest rates."[76]

Given these obvious flaws, Mr. Hevert then suggested an Alternative BYP. This analysis attempts to expand upon the overly simplistic Primary BYP and explain changes in equity risk premiums by comparing them against changes in (1) Treasure bond yields; (2) spreads between A-rated utility bonds and treasury bonds; and (3) market volatility index. As Mr. Gorman points out, the Alternative BYP, while an improvement over the Primary BYP, has not shown that the market volatility index "can accurately describe the difference between expected returns for utility securities and the general stock market. This is illustrated by the fact that utility companies have lower betas than that of the overall market. Hence, market volatility may explain increases in market return, but may overstate a fair return for a lower risk utility stock."[77]

By correcting these flaws in Mr. Hevert's Risk Premium analysis, Mr. Gorman demonstrated that a more reasonable return on equity of 9.73% to 9.75%

Ultimately, the problem with Mr. Hevert's analysis is not in the models that he used. Rather, as indicated below, the <u>ongoing</u> problem with the analysis is found in the assumptions employed. Once corrected, even Mr. Hevert's analysis falls in line with the other recommendations. Specifically, after accounting for and correcting the assumptions in his methodology, Mr. Hevert's revised analysis leads to a reasonable result (8.20% - 9.75%).[78]

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[76] *Id.*
[77] *Id.* at page 21.
[78] *Id.* at page 4.

	MODEL	HEVERT RESULT	ADJUSTED HEVERT RESULT
DCF Analysis			
	CONSTANT GROWTH DCF	8.86%	8.86%
	MULTI-STAGE GROWTH DCF	9.71%	8.21%
CAPM		9.92 – 11.62%	7.89 – 9.08%
Risk Premium Analysis		9.74 – 10.39%	8.75 – 9.75%
Recommendation		9.75 – 10.50%	**8.20 – 9.75%**

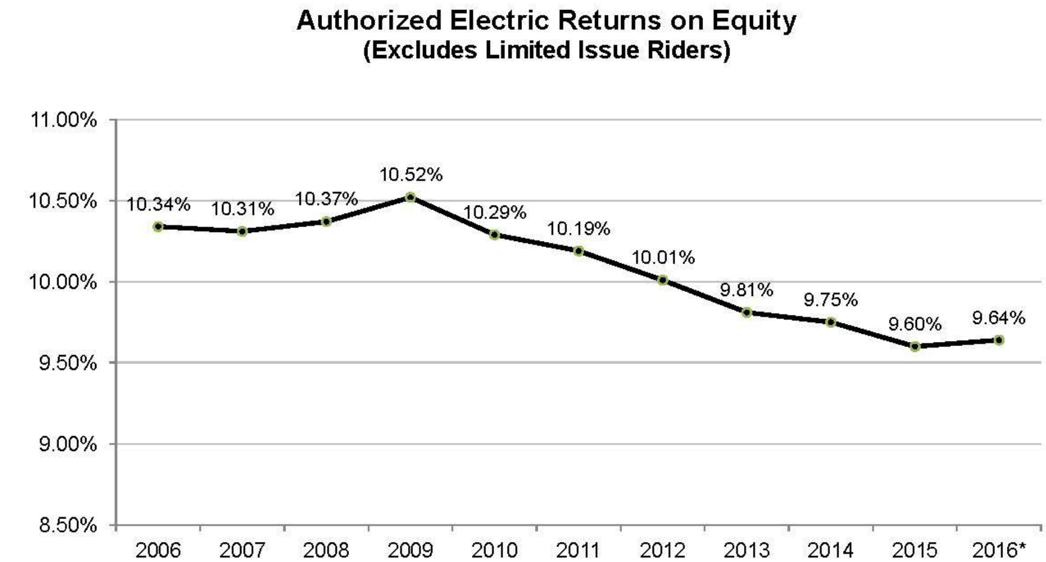
As can be seen then, Mr. Hevert routinely recommends a return on equity that state utility commissions have found to be "too high." In fact, over the last 5 years, state utility commissions have found Mr. Hevert's return on equity to be inflated by 73 basis points. Based upon Mr. Hevert's inflated analysis, KCPL asks for a return on equity of 9.90%. This would be a significant increase from the 9.50% authorized by this Commission in KCPL's last rate case. However, if the Commission simply recognizes the same 73 basis point premium that other state utility commissions have found is implicit in Mr. Hevert's analysis, then KCPL's recommendation becomes 9.17%. This is remarkably consistent with the 9.20% (midpoint of his 8.90% to 9.50% range) recommended by Mr. Gorman.

D. <u>CAPITAL COSTS REMAIN LOW</u>

It is indisputable that capital costs remain low. As Mr. Gorman points out, [a]uthorized returns on equity for electric utilities have been steadily declining over the last 10 years."[79]

[79] Exhibit 650, Gorman Direct, page 9.

Figure 1



Source and Note:
Regulatory Research Associates, Inc., Regulatory Focus, Major Rate Case Decisions -- January - September 2016, October 14, 2016 at page 6.

* The data includes the period Jan - Sep 2016.

Source: Exhibit 650, Gorman Direct, page 10.

The declining return on equity decisions have not placed increased pressure on utilities' credit ratings. In fact, over the past several years, utility credit rating upgrades have significantly exceeded the number of utility credit rating downgrades.

TABLE 2

Credit Rating Changes
(U.S. Shareholder-Owned Electric Utility Industry)

	2010	2011	2012	2013	2014	2015
Upgrades	29	39	37	60	103	35
Downgrades	51	21	39	20	3	15
% Upgrades	36%	65%	49%	75%	97%	70%
Total Rating Activity	**80**	**60**	**76**	**80**	**106**	**50**

Source: EEI Q4 2015 Credit Ratings, Tab IV Direction of Rating Action.

Source: Exhibit 650, Gorman Direct, page 11.

Despite the continued decline in return on equity decisions, the vast majority of electric utilities now have a credit rating that is BBB+ or better.

TABLE 3

S&P Ratings by Category
(Year End)

Description	2008	2012	2013	2014	2015	2016 Q3
Regulated						
A or higher	8%	6%	3%	3%	3%	5%
A-	10%	17%	20%	21%	22%	27%
BBB+	23%	14%	17%	32%	33%	35%
BBB	23%	36%	49%	37%	33%	22%
BBB-	23%	17%	6%	3%	3%	8%
Below BBB-	13%	11%	6%	5%	6%	3%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Sources: Edison Electric Institute, Electric Industry Credit Standing.

Source: Exhibit 650, Gorman Direct, page 12.

Clearly then, return on equity decisions have continued to decline. That said, the lower return on equity earned by electric utilities have not caused problems. Specifically, during the period of time in which return on equity decisions have declined, credit ratings have improved. It is not surprising, therefore that Mr. Gorman concludes that, "[b]ased on this review of credit outlooks and stock price performance, the market continues to embrace the regulated utility industry as a safe-haven investment and views utility equity and debt investments as low-risk securities."[80]

Despite the decline in capital costs, KCPL's inexplicably insists that the Commission should <u>increase</u> its return on equity by 40 basis points from 9.50% to 9.90%. As mentioned, given the fact that state utility commissions have found that Mr. Hevert's

[80] *Id.* at page 4.

recommendation is inflated by an average of 73 basis points, such a recommendation should not be surprising.

E. <u>OTHER CONSIDERATIONS</u>

In its 2010 rate case, KCPL asked "that the Commission set its return on equity at the upper half of the recommended range of return on equity - to reflect the Company's reliability and customer satisfaction achievements."[81] In support of its request, KCPL specifically referenced "the Commission to an annual Edison Electric Institute Reliability Survey and recent JD Power awards."[82]

The notion that the Commission can consider management efficiency and customer service in establishing a return on equity is well established.[83] Indeed, in a recent NIPSCO proceeding, the Indiana Utility Regulatory Commission set NIPSCO's return on equity at the low end of the reasonable range to "incent improved service."

> The Commission has previously expressed concerns with the soundness of NIPSCO's managerial and operational decisions. . . The Commission continues to have concerns regarding NIPSCO's managerial and operational decisions. . . . [T]he evidence presented in this Cause demonstrated that NIPSCO was in the bottom quartile of the J.D. Power studies in 2007 and 2008, and one of the worst-rated utilities in 2009.
>
> * * * * *
>
> The Commission has a unique role in regulating its jurisdictional utilities, which at times requires us to send a clear and direct message to utility management concerning the need for improvement in the provision of its utility service. Our determination of the authorized cost of common equity capital can be a very direct means to incent improved service. We anticipate that NIPSCO will respond accordingly and therefore anticipate that such authorized cost of equity capital will apply for a limited duration as identified below.

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[81] See, *Report and Order*, Case No. ER-2010-0355, issued April 12, 2011, at page 119.
[82] *Id.*
[83] See, *Bluefield Water Works v. Public Service Commission*, 262 U.S. 679 (1923) (Supreme Court specifically references an assumption of "efficient and economical management.").

*   *   *   *   *

> The Commission recognizes that a 9.9% return reflects the low end of the range discussed above, and that a higher return may be appropriate if NIPSCO is able to demonstrate improved company performance in its next base rate proceeding.[84]

Just as the Indiana Commission considered NIPSCO's service and performance in establishing a return on equity at the low end of the reasonable range, MECG asserts that the Missouri Commission should reach similar conclusions with KCPL in the hopes of "incenting improved service." Specifically, MECG suggests that the Commission consider the evidence elicited regarding: (1) KCPL's customer service and satisfaction; (2) KCPL's recent willingness to violate Commission rules and previous settlement provisions; and (3) KCPL's inability to control A&G costs and the need for the Commission to order a management audit of KCPL.

1. <u>Customer Service and Satisfaction</u>

Much like Indiana's concerns with NIPSCO's service and performance, similar criticisms have been leveled against KCPL in Missouri. During its deliberations in the last rate case, specific concerns were voiced regarding KCPL's approach to customer service and satisfaction. Specifically, in deliberations on August 12, 2015, the following statements were made:

> And I would like to proffer that few of the commissioners have made statements that Ameren had a 9.53 and I think that from the testimony we heard in this case along with the public testimony along with everything that we have seen from the company that <u>***KCPL is not Ameren. I do not believe that they are managed as well as Ameren, I don't think that they are run as well as Ameren, I don't think that they do customer service as well as Ameren***</u>. So, to base an ROE because one company is getting it in the state, I don't think that's the rational basis for granting an ROE, especially one that is higher than the median and the mean.

[84] NIPSCO Order, 2010 Ind. PUC LEXIS 294, issued August 25, 2010, pages 31-33.

*   *   *   *   *

> If nothing else comes out of this, ***I would hope that the Company is listening and that they fully understand you are not in the electric utility business, you are in the customer service business and your product is power***. And I think if the culture and the mindset of that Company understands that, I think you will see a dramatic shift in the culture of the Company or maybe just at least how this Commission views the Company. Because I believe most of us if not all of us at this table, when we went back comparing them to other utilities, I don't think that we can say that they are the same. I think there are stark differences. And ***I think that those differences, at the heart of it, come down to how customer focused the Company is. And I think a management audit will help identify these efficiencies and reconnect them with the customers that they serve from a customer service standpoint***.[85]

Despite these expressed concerns, KCPL's approach to customer service is clearly not working. In fact, while it ranked second among 14 large Midwest electric utilities in the 2015 JD Power survey,[86] KCPL fell dramatically to 13th among these 14 utilities in 2016.[87] Worse still, KCPL ranks 64 out of 86 among all electric utilities nationwide.[88] Given this, it is not surprising that KCPL readily admits that JD Power is a "valid measure of customer sentiment"[89] and that its customer satisfaction performance is "significantly disappointing."[90] In fact, KCPL agrees with MECG that the JD Power survey information "is something that I think is valid for the Commission and all of our stakeholders to consider in determining how we do our job."[91]

2. KCPL Violation of Rules and Settlement Provisions

KCPL's attitude towards customer service mirrors its view towards regulation and Commission rules in general. Since the last case was decided, the Commission has been

[85] See, Commission deliberations of August 12, 2015.
[86] Exhibit 656.
[87] Exhibit 332.
[88] Tr. 1492.
[89] Tr. 1494.
[90] Tr. 1490.
[91] Tr. 1495.

presented multiple situations involving KCPL in which violations of stipulations and Commission regulations were alleged.

Shortly after the Commission deliberated its decision in KCPL's last rate case, it was confronted with a complaint from its Staff. In its complaint, Staff alleged that KCPL had violated the Commission's affiliate transaction rule by transferring customer information to Allconnect, Inc.[92] ultimately, the Commission agreed.

> KCP&L and GMO attempt to mask the true nature of the transaction by having Allconnect "confirm" the accuracy of the customer information already taken by KCP&L and GMO's customer service representatives. The evidence established that the KCP&L and GMO customer service representatives are capable of "confirming" the accuracy of the information they obtain from their customers. They did so for many years before KCP&L and GMO entered into their contract with Allconnect and are capable of doing so now. Rather, ***the confirmation function performed by Allconnect is a pretext to attempt to avoid regulatory problems of the type represented by Staff's complaint. Indeed, the confirmation function serves as a marketing hook to discourage utility customers from dropping off the line when their call is transferred to Allconnect***.
>
> The Commission finds and concludes that KCP&L and GMO have made customer specific information available to Allconnect without the consent of their customers in violation of 4 CSR 240-20.015(2)(C).[93]

After ordering a specific script for the use of KCPL customer service representatives prior to the transfer of customers to Allconnect, KCPL still appears unable to follow the Commission's order. In fact, Public Counsel has recently filed another complaint alleging that KCPL has failed to comply with this Commission-ordered script.[94]

KCPL's apathy extends beyond Commission rules. Recently, MECG filed a complaint against Great Plains alleging that it violated a Commission order by failing to

[92] See, Case No. EC-2015-0309.
[93] *Report and Order*, Case No. EC-2015-0309, issued April 27, 2016, at page 19 (emphasis added).
[94] See, Case No. EC-2017-0175.

seek Commission approval for its acquisition of Westar Energy. Again, the Commission agreed.

> Applying law to the facts in reaching its conclusion, the Commission finds that based on competent and substantial evidence, MECG met its burden of proof. GPE violated the terms of the 2001 Agreement and the Commission order approving the 2001 Agreement by failing to seek Commission approval for the Westar Merger.
>
> The Commission will direct GPE to comply with the terms of Section 7 of the 2001 Agreement and file an application for prior approval of the Westar Merger, requesting the Commission's determination that the Westar Merger is not detrimental to the public interest.[95]

More troubling than GPE's violation of the Commission reorganization order was the apparent disregard it has shown towards its prior settlement commitments.

> ***<u>GPE's position is troublesome</u>*** from a public policy perspective. At the time of the 2001 Agreement, the Commission and the parties relied on KCPL's and GPE's assurances that Section 7 authorized the Commission's oversight over the future holding company. The Commission ordered the parties to comply with the terms of the agreement. Were the Commission to agree with GPE's analysis, it would render the terms of a negotiated stipulation and agreement meaningless and unenforceable; a result that should be avoided. For public policy reasons, all sides have a vested interest in maintaining trust in the settlement process. Parties must be confident that when they enter into a settlement agreement, each party can be relied upon to comply with the terms included, and that the Commission will indeed enforce all conditions. Should trust in the settlement process falter, the ultimate victims will be the ratepayers who will be forced to pay for the resulting lengthy litigation.[96]

3. <u>Excessive A&G Costs and Need for Management Audit</u>

As demonstrated, *supra*, KCPL's rates have increased dramatically. Specifically, with its true-up rate increase sought in this case, KCPL's rates will have increased 89.98% over the last 10 years. While customers expect some level of rate increases,

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[95] *Report and Order*, Case No. EC-2017-0107, issued February 22, 2017, pages 20-21.

[96] *Id.* at page 20 (emphasis added).

customers also expect KCPL to aggressively manage costs to minimize the magnitude of these increases and ensure that rates remain competitive with other utilities and states.

In its last case, the Commission made findings that demonstrate that KCPL is either apathetic towards its cost minimization responsibility or is incapable of successfully managing such costs. In fact, the Commission found that that "KCPL's A&G expenses are significantly higher than its peers."[97] Specifically, the Commission referenced evidence provided by its Staff which "credibly demonstrated that KCPL has some of the highest A&G expenses of its national peers and Missouri utilities. Of the group examined, KCPL has the highest A&G costs per customer, per dollar of revenue, and compared to its operations and maintenance expense, and the third highest A&G expense per megawatt hour of electricity sold."[98]

Given KCPL's unwillingness or inability to control A&G costs, the Commission took the unprecedented step of ordering its Staff to conduct a management audit of KCPL.[99] Recently, in a stipulation with Public Counsel, KCPL voluntarily expanded the scope of this management audit so that it will now be conducted by expert third parties.

> GPE, KCP&L, and GMO shall agree to an independent third party management audit of GPE, KCP&L and GMO corporate cost allocations and affiliate transaction protocols. . . . The audit shall be designed to assess compliance with the Commission's Affiliate Transactions Rule (4 CSR 240-20.015) as well as the appropriateness of the allocation of corporate costs among GPE, KCP&L, GMO and affiliates. GPE, KCP&L and GMO shall cooperate fully with the auditor by providing all information required to complete the audit.[100]

[97] *Report and Order*, Case No. ER-2014-0370, issued September 2, 2015, at page 73.
[98] *Id.*
[99] *Id.*
[100] See, *Stipulation and Agreement*, Case No. EE-2017-0113, filed October 26, 2016, page 3.

F. CONCLUSION

As reflected in this brief, the Commission has historically found Mr. Gorman to be its most credible return on equity witness. Consistent with the methodologies previously adopted by the Commission, Mr. Gorman recommends a return on equity of 9.20% (range of 8.90% to 9.50%). As mentioned, this analysis was based upon data as of December 16, 2016. Therefore, it considers the impact of the change to the Trump administration as well as the December 14 decision by the Federal Reserve to increase interest rates.

In contrast, the Commission has repeatedly held that Mr. Hevert's recommendations and growth rate assumptions are "too high." Recognizing that Mr. Hevert has failed to address any of the Commission's previous criticisms and, instead, has repeated such mistakes, the Commission should disregard Mr. Hevert's 9.90% recommended return on equity.

After deciding to adopt the recommendation of Mr. Gorman, MECG recommends that the Commission authorize a return on equity at the lower end of his range (8.90% to 9.20%).[101] Such a recommendation is based upon continuing concerns with KCPL's customer service and satisfaction. Furthermore, such a recommendation reflects the unique problems faced by the various stakeholders to the PSC process with KCPL's repeated willingness to violate Commission rules and orders as well as the stipulated provisions agreed to by KCPL in previous cases. By making an explicit movement to the

[101] It is important to recognize that a return on equity of 9.00% would still comply with the *Hope* and *Bluefield* standards. In his testimony, Mr. Gorman conducted a financial integrity analysis. As he found, even at a 9.0% return on equity, KCPL's financial credit metrics continue to support credit metrics at an investment grade utility level." Exhibit 650, Gorman Direct, page 57. Thus, the Commission may comfortably reduce KCPL's return on equity to the lower end of Gorman's range and still be satisfied that KCPL will be able to attract capital and continue to provide safe and adequate service.

lower end of Mr. Gorman's range, the Commission can send a signal to KCPL to improve its performance in these areas. Much as the Indiana Commission has previously found, a reduction in a utility's return on equity "can be a very direct means to incent improved service." Hopefully, KCPL will respond accordingly and improve the manner in which it treats customers and the stakeholders to the Commission process.

V. REVENUES

POSITION: In this section, MECG addresses issue XX(A): Should KCPL be permitted to make an adjustment to annualize kWh sales in this rate case as a result of KCPL's Missouri Energy Efficiency Investment Act ("MEEIA") Cycle 1 demand-side programs? Consistent with the positions advanced by Staff and OPC, the Commission should not allow KCPL to include the effects of MEEIA Cycle 1 programs in its revenue normalization. KCPL has already recovered any lost revenues associated with these Cycle 1 programs through the throughput disincentive component of the Cycle1 DSIM. Similarly, KCPL is recovering any lost revenues associated with its MEEIA Cycle 2 programs through a revenue normalization. Effectively, KCPL is attempting to apply the lost revenue structure for Cycle 2 programs to its Cycle 1 programs. Recognizing that KCPL has already recovered these effects through the throughput disincentive component of the DSIM, KCPL is attempting to double recover its lost revenues associated with the Cycle 1 programs.

As part of any rate case, the parties seek to annualize revenues. Given that any rate increase relies upon an accurate assessment of the utility's earnings, an accurate depiction of revenues is necessary. Among other things, parties will annualize revenues to account for changes in the number of customers and customer usage that have occurred in the most recent 12 months as well as to ensure that annualized revenues reflect 12 months of any previous rate increases. To the extent that the annualization results in an increase in revenues over that actually experienced in the test year, then the rate increase will <u>decrease</u>. Similarly, if the annualization results in a decrease in revenues, then the rate increase will become larger.

Through the immediate issue, KCPL seeks to annualize revenues to a lower level. KCPL claims that the reduction in annualized revenues is necessary to account for decreased revenues resulting from the MEEIA Cycle 1 programs and is consistent with MEEIA stipulations. KCPL's attempt to annualize to a lower level of revenues and to extract a higher rate increase in this case is misplaced. KCPL fails to recognize that they have already been compensated for revenues lost through the MEEIA Cycle 1 programs through the throughput disincentive feature of the Demand Side Investment Mechanism ("DSIM").

In 2009, the General Assembly enacted SB376, codified as Section 393.1075. This legislation, known as the Missouri Energy Efficiency Investment Act ("MEEIA") sought to eliminate any disincentives associated with the utility offering energy efficiency programs. Specifically, since the utility recovered a significant amount of its fixed costs through energy sales, the utility would not collect all of its fixed costs if it engaged in energy efficiency and sold less electricity. As such, MEEIA and Commission rules sought to eliminate this disincentive by allowing the utility to recover three things: (1) the energy efficiency program costs;[102] (2) lost revenues associated with the energy efficiency programs;[103] and (3) earnings opportunities associated with lost investment in future generation assets.[104]

While the Commission allowed for recovery of lost revenues, its rules did not dictate the specific manner in which lost revenues would be recovered. Rather, the

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[102] 4 CSR 240-20.093(2)(F)
[103] 4 CSR 240-20.093(2)(G)
[104] 4 CSR 240-20.093(2)(H)

Commission clearly indicated that the recovery of lost revenues could come in different ways.[105] The only explicit requirement in the Commission rules was that the lost revenue recovery mechanism must be spelled out at the time that the Commission approved the utility's energy efficiency programs.[106]

In 2014, KCPL filed for Commission approval of its MEEIA Cycle 1 energy efficiency programs. In addition, KCPL filed for approval of its DSIM to recover the various costs including any lost revenues.[107] On May 27, 2014, the various parties executed a stipulation that provided for implementation of MEEIA Cycle 1 programs and recovery of costs ("MEEIA Cycle 1 Stipulation").[108] As reflected in that settlement, KCPL would recover MEEIA Cycle 1 lost revenues through the Throughput Disincentive – Net Shared Benefits ("TD-NSB") feature of the DSIM.[109] Thus, contrary to its immediate effort to recover lost revenues through a revenue annualization, the parties clearly contemplated that lost revenues for Cycle 1 programs would be recovered through the TD-NSB feature of the DSIM.

In August 2015, KCPL filed for Commission approval of its MEEIA Cycle 2 energy efficiency programs as well as another DSIM.[110] On November 23, 2015, various parties executed a Non-Unanimous Stipulation addressing MEEIA Cycle 2 ("MEEIA Cycle 2 Stipulation"). On March 2, 2016, the Commission issued its Report and Order approving the MEEIA Cycle 2 Stipulation. Unlike the MEEIA Cycle 1 DSIM, that relied

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[105] 4 CSR 249-20.093(2)(G)(4)
[106] 4 CSR 249-20.093(2)(G)(2)
[107] See, Case No. EO-2014-0095.
[108] Exhibit 225, Rogers Surrebuttal, Schedule JAR-s5.
[109] *Id.* at Schedule JAR-s5 (page 3 of 20) ("KCP&L's Throughput Disincentive Net Shared Benefits ("TD-NSB") Share that is intended to recover lost margin revenues, and any earned Performance Incentive Award. The Company will begin recovery through a DSIM Rider in the August 2014 billing or as soon as practical thereafter.").
[110] See, Case No. EO-2015-0240.

upon the throughput disincentive feature of the DSIM for recovery of lost revenues, the MEEIA Cycle 2 Stipulation contemplated that lost revenues would be recovered through a revenue annualization in subsequent KCPL rate cases.[111]

In this case, KCPL inappropriately attempts to utilize the MEEIA Cycle 2 revenue annualization method for recovery of lost revenues and apply it to MEEIA Cycle 1 programs. In essence, since it has already recovered the MEEIA Cycle 1 lost revenues through the TD-NSB feature, KCPL is attempting to double recover its MEEIA Cycle 1 lost revenues.

KCPL justifies its request to apply the MEEIA Cycle 2 revenue annualization approach to its MEEIA Cycle 1 programs by selectively focusing on one phrase from the MEEIA Cycle 2 Stipulation. Specifically, the MEEIA Cycle 2 Stipulation provides for a revenue annualization for "all active MEEIA programs."[112] Arguing that several of the MEEIA Cycle 1 programs were active at the start of the test year, KCPL asserts that the MEEIA Cycle 2 revenue annualization must also apply to these Cycle 1 programs.[113]

The objection to KCPL's attempt to apply the MEEIA Cycle 2 revenue annualization to the Cycle 1 programs was immediate. In its testimony, both Staff and OPC pointed out that KCPL's proposal is contrary to the MEEIA Cycle 1 Stipulation as well as the MEEIA Cycle 2 Stipulation and would allow for double recovery of these lost revenues.

For instance, in his rebuttal testimony, OPC witness Marke objects to KCPL's attempts to use the revenue annualization feature of the MEEIA Cycle 2 Stipulation to double recover MEEIA Cycle 1 lost revenues.

[111] Exhibit 143, Rush Rebuttal, Schedule TMR-6 (pages 12-15).
[112] *Id.* at page 13.
[113] *Id.*

> Such an adjustment has already taken place through the MEEIA surcharge and to do it again here would result in double recovery of assumed lost revenues. Mr. Bass is mistaken if he believes that the energy efficiency adjustment should occur based on the stipulation in EO-2015-0240.[114]

Staff agrees. In his surrebuttal testimony, Staff witness Rogers points out that "KCPL's annualization of kWh in this rate case due to its Cycle 1 demand-side programs is prohibited under" the Cycle 1 Stipulation as well as the Cycle 2 Stipulation.[115] Specifically, Mr. Rogers provides five separate reasons that the phrase "all active MEEIA programs" from the MEEIA Cycle 2 revenue annualization provision could not and should not apply to the Cycle 1 programs.

> The language "all active MEEIA programs" in the Cycle 2 Stipulation does not express or create an unintended opportunity for KCPL to annualize kWh sales from its Cycle 1 demand-side programs. To the contrary, Cycle 1 demand-side programs are explicitly excluded from the kWh annualization process in the Cycle 2 Stipulation and the Cycle 2 DSIM Rider because:
>
> 1. The language "all active MEEIA programs" occurs exactly four (4) times in the Cycle 2 Stipulation and all four (4) occurrences are in paragraph 10: Annualizations of the Cycle 2 Stipulation;
>
> 2. Paragraph 10 a.(ii) of the Cycle 2 Stipulation clearly specifies that the various steps to annualize kWh sales for "all active MEEIA programs" is the methodology in KCPL's Tariff Sheets 49K and 49L;
>
> 3. KCPL's Tariff Sheets 49K and 49L refer only to "programs", "all programs" or "Cycle 2 programs" and do not use phrases such as "all active programs," "all active MEEIA programs" or "Cycle 1 programs";
>
> 4. KCPL's Tariff Sheet 49L explicitly defines "Programs" as Cycle 2 programs and does not include Cycle 1 programs: "Programs–MEEIA Cycle 2 programs listed in Tariff Sheet 1.04C and added in accordance with the Commission's rule 4 CSR 240-20.094(4);" and
>
> 5. KCPL Tariff Sheet 1.04C includes only KCPL's MEEIA Cycle 2 demand-side programs and is provided as Schedule JAR-s2.[116]

[114] Exhibit 310, Marke Rebuttal, page 28.
[115] Exhibit 225, Rogers Surrebuttal, pages 1-2.
[116] *Id.* at pages 2-3.

As can be seen, Staff's argument against applying revenue annualization feature of MEEIA Cycle 2 stipulation to MEEIA Cycle 1 is premised upon a clear reading of the tariffs approved by the Commission. Recognizing that all parties have explicitly agreed that any differences between the MEEIA Cycle 2 Stipulation and the tariffs will be governed by the language in the tariffs,[117] then KCPL's opportunistic attempt to double recover its MEEIA Cycle 1 lost revenues must fail.

[117] See, MEEIA Cycle 2 Stipulation (attached as Exhibit 143, Rush Rebuttal, Schedule TMR-6 (page 10 – provision 9) ("The Signatories agree to the DSIM described in this Stipulation and attached as tariff sheets in Appendix D. To the extent this Section 9 differs from tariff sheets, the tariff sheets govern.").

VI. RATE DESIGN / CLASS COST OF SERVICE

Position: In this section, MECG addresses issue XXI(A) concerning the appropriate methodology for allocation of fixed production plant costs among the various customer classes. As contained in the testimony of Mr. Brubaker, MECG urges the Commission to adopt the Average & Excess ("A&E") methodology for allocating these costs. As this brief demonstrates, the Commission has repeatedly rejected the KCPL Peak & Average production allocator. Furthermore, the record indicates that Staff's Base / Intermediate / Peak ("BIP") methodology is fundamentally flawed. Specifically, the Staff's BIP methodology is flawed in that it: (1) provides results that are an outlier as compared to other studies; (2) is a historical relic that is inconsistent with the SPP Integrated Marketplace; (3) fails to properly consider that baseload units are not simply operated for purposes of providing energy, but also provide value towards meeting peak demand; (4) penalizes high load factor customers that use the KCPL system in an efficient manner; and (5) is outside of the mainstream and has not been utilized by any other utilities or state utility commissions. MECG urges the Commission to adopt the guidance from its decision in the 2010 Ameren case and utilize the A&E methodology.

Based upon the use of the A&E production allocator, MECG urges the Commission to provide answers to Issues XXI(B) concerning the allocation of any revenue increase among the various customer classes. In this section, MECG notes that this Commission, and numerous other commissions, has taken steps recently to reduce the residential subsidy and make commercial / industrial rates more affordable. Given this, MECG recommends that the Commission adopt the revenue allocation proposal contained in the testimony of Mr. Brubaker and eliminate 25% of the residential subsidy.

Finally, MECG recommends that the Commission allocate any revenue increase to the LGS / LPS rate schedules in a manner consistent with the proposal contained in Mr. Brubaker's testimony. This methodology has been adopted by the Commission in the last three KCPL rate cases as well as a recent Empire rate case. This proposal seeks to eliminate any intra-class subsidy by collecting more of the rate increase through the demand charges and first block energy charges. In this way, less fixed costs are collected through the second block and tailblock energy charges. As a result, the current LGS and LPS intra-class subsidy, that benefits low load factor customers, is reduced.

A. WHAT INTERCLASS SHIFTS IN REVENUE RESPONSIBILITY, IF ANY, SHOULD THE COMMISSION ORDER IN THIS CASE?

Position: As the following section demonstrates, the Commission should expressly adopt the Brubaker class cost of service study which relies upon the Average & Excess production allocator. The Staff's BIP methodology is flawed in that it: (1) provides results that are an outlier as compared to other studies; (2) is a historical relic that is inconsistent with the SPP Integrated Marketplace; (3) fails to properly consider that baseload units provide value towards meeting system peak demand and are not simply operated for purposes of providing energy; (4) penalizes high load factor customers that use the KCPL system in an efficient manner; and (5) is outside of the mainstream and has not been utilized by any other utilities or state utility commissions. Similarly, this Commission, and other commissions, have rejected the KCPL Peak & Average methodology because it is inherently flawed in that it double counts class energy usage.

In contrast, the A&E production allocator considers both class energy usage as well as class peak in allocating production costs. As such, the methodology is consistent with the way in which generation units are planned and constructed. Given its reasoned approach, the A&E methodology has seen widespread acceptance from the FERC as well as numerous other state utility commissions. Given that the adoption of either the Staff or KCPL approach will place Missouri industrial customers at a competitive disadvantage relative to the many other states that use the A&E methodology, it is contrary to current state policies to foster growth in jobs and industry. For all of these reasons, the Commission should expressly adopt the Brubaker analysis that relies on the A&E production allocator.

1. Introduction and Study Results

As reflected in the various pieces of testimony in this case, "a class cost of service is the starting point and most important guideline for establishing the level of rates charged to customers."[118] The class cost of service is conducted by apportioning "each item of cost among the various rate classes. Adding up the individual pieces gives the total cost for each customer class."[119]

It is well established that the electric industry is very capital intensive. The evidence indicates that KCPL has invested almost $9.6 billion in its production, transmission and distribution facilities.[120] Of this, almost 64%, is associated with KCPL's investment in its various generating units.[121] As such, 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.

[118] Exhibit 853, Brubaker Direct, page 2.
[119] *Id.* at page 8
[120] Exhibit 201, Accounting Schedules, Accounting Schedule 3, page 10.
[121] *Id.* at page 8 (line 250).

While there are different methods utilized for allocating generation fixed costs, the difference in these methodologies generally concerns the extent to which generation plant is deemed to be an energy-related cost (focused on meeting system energy usage) or a demand-related cost (focused on meeting system peak demand). The evidence indicates, however, that all production plant investments are both energy and demand related costs.[122] 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 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. 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.[123]

In this case, the Commission has been presented several different methodologies for allocating production costs. Specifically, the Commission has been presented with class cost of service studies conducted by Staff, KCPL, MIEC and DOE. The revenue

[122] Indeed, many state utility commissions have noted that the A&E methodology, proposed by Mr. Brubaker, is a logical compromise between energy extensive allocators, like Peak & Average and Staff's BIP methodology, and true demand allocators. "Proponents of a 12-CP or other peak demand method claim that a utility's production plant is built only for the purpose of serving peak load, whether individual monthly peaks or the annual system peak. Thus, all demand-related production costs must be allocated to customer classes on the basis of each class's contribution to the system peak. Under this scenario, if a customer class, such as street lighting, does not use the system at the time of system peak, no production costs would be allocated to it. Proponents of an average and excess method or some other energy weighting method claim that a utility's production plant is built not only to serve peak demand but also to serve off-peak base load. For this reason, all classes should bear some of the costs of producing electricity regardless of a class's use of the system at the time of system peak." *Re: Union Light, Heat and Power Company*, 134 P.U.R.4th 139 (Kentucky Public Service Commission 1992).

[123] Exhibit 854, Brubaker Rebuttal, page 14 (emphasis added).

neutral results of those studies, and the production allocators relied upon are as follows:[124]

	KCPL[125]	DOE[126]	MIEC[127]	Staff[128]
	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%

As the following sections indicate, the Staff's BIP methodology is inherently flawed. That methodology: (1) leads to results that are entirely inconsistent with other well-established production allocators; (2) is inconsistent with KCPL's participation in the SPP Integrated Marketplace; (3) fails to recognize the importance of demand in system planning or the role that all plants play in meeting system demand; (4) penalizes high load factor customers and (5) is outside the mainstream and not accepted by other utilities or commissions. On the other hand, the Commission has repeatedly rejected KCPL's proposed Peak & Average methodology because it double counts class energy usage.

Given the flaws inherent in both the KCPL and Staff approach, the Commission should choose either the DOE 4CP methodology or the MIEC A&E methodology. As will be shown, the A&E methodology has seen universal acceptance among state utility

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[124] It is important to recognize that Public Counsel has expressly supported the Peak & Average methodology utilized by KCPL. (See, Tr. 1167 "our formal position was actually to support company's A&P method.") Thus, even Public Counsel recognizes the existence of a residential subsidy. In fact, given its support of the KCPL class cost of service study, Public Counsel agrees that, on a revenue neutral basis, residential rates should be increased 9.2% to bring them to cost of service. Recognizing that Public Counsel expressly acknowledges the need for a revenue neutral increase to the residential class, the only issue is the identity of the classes that will receive the benefit of the shift of costs to the residential class.

[125] Exhibit 136, Miller Direct, page 14 (remove KCPL's 10.8% rate increase request).

[126] Exhibit 500, Schmidt Direct, page 12.

[127] Exhibit 853, Schedule MEB-COS-5.

[128] Exhibit 202, Staff Rate Design Report, page 4.

commissions. Given this widespread acceptance, MECG urges the Commission to adopt Mr. Brubaker's class cost of service study that relies upon the A&E methodology.

2. Staff's Flawed Class Cost of Service Study

a. STAFF'S FLAWED BIP PRODUCTION ALLOCATOR

In its Rate Design report, Staff calculates each class' cost of service by relying upon the Base / Intermediate / Peak ("BIP") method for allocating production plant. Under this methodology, Staff attempts to categorize each of KCPL's generating units as either Base, Intermediate or Peaking facilities. The investment in Base facilities is then allocated on the basis of class average demand (energy). The investment in Intermediate facilities is allocated on the basis of the class 12 CP demand, less its previously allocated average demand (energy). Finally, the investment in Peak facilities is allocated on the basis of the class 4 CP demand, less the previously allocated base and intermediate components.[129] The evidence, however, demonstrates that Staff's BIP study is inherently flawed in at least 5 ways.

First, Staff's BIP Methodology leads to results that are an outlier as compared to other production allocation methodologies. As mentioned, the Commission has been presented with four class cost of service studies. Each of these studies relies upon a different methodology for allocating production plant. In general, while the studies reach a different conclusion in magnitude, each study reaches a similar directional conclusion – that is the KCPL, DOE and MIEC study all agree that residential rates are significantly below cost of service. Standing in stark contrast, however, the Staff's BIP methodology reaches a dramatically different conclusion. Specifically, Staff's BIP methodology

[129] *Id.* at pages 17-18.

concludes that residential rates are actually above cost of service. Clearly then, Staff's methodology is an outlier.

The fact that Staff's BIP methodology reaches a result that is incompatible with other methodologies is not unique to this case. In the pending Ameren rate case, Ameren's witness similarly concluded that "it is clear that Staff's analysis is an outlier when compared to the other studies."

Importantly, the Commission has previously pointed out the fact that a particular methodology is an "outlier" and leads to results that are incompatible with other studies as a factor in rejecting that methodology.[130] For similar reasons, the Commission should reject the Staff's BIP methodology in this case that is clearly an outlier.

Second, the BIP Methodology is not compatible with KCPL's participation in the SPP Integrated Marketplace. Historically, utilities self-generated to meet native load requirements. Considering both fixed and variable costs of production, the utility would construct and operate baseload, intermediate or peaking facilities.[131] As such, native load peak demand and energy needs were met exclusively through some mixture of baseload, intermediate and peaking facilities.

In recent years, however, the paradigm for meeting native load has changed. Now, rather than relying on self-generation, utilities now rely on purchases of energy. Specifically, starting March 1, 2014, the Southwest Power Pool launched its Integrated Marketplace. Rather than relying upon self-generation, a marketplace is now established for utilities to meet their native load needs. In fact, all utilities meet native load by

[130] See, *Report and Order*, Case No. ER-2014-0258, page 70 (Commission specifically pointed out that the Peak & Average methodology was an "outlier" and should be rejected).
[131] In general, baseload facilities have a higher upfront capital cost, but a lower variable cost. On the other hand, peaking facilities had a lower upfront capital cost, but a much higher variable cost.

selling the output of their generating facilities in the marketplace and then make offsetting purchases to meet native load.

While the paradigm has changed dramatically, Staff's BIP methodology continues to rely on the outdated view that native load is met entirely through self-generation. As mentioned, Staff's BIP methodology attempts to segregate costs associated with baseload, intermediate and peaking facilities. That said, however, KCPL facilities are no longer independently dispatched as baseload, intermediate or peaking facilities. Instead, all production facilities are dispatched in the same manner into the SPP Integrated Marketplace. Similarly, when purchases are made, the utility is simply purchasing energy and is oblivious to whether that energy was generated using a facility that was once considered a baseload, intermediate or peaking facility. Truly, energy has become fungible.

The launch of the SPP Integrated Marketplace and the fungible nature of energy, whether generated from a facility once deemed baseload, intermediate or peaking, are repeatedly referenced by utilities as a basis for rejecting the BIP methodology. For instance, while once advocating for the BIP methodology, KCPL now rejects the use of this methodology for its Kansas jurisdiction. In fact, KCPL specifically points to the introduction of the SPP Integrated Marketplace as the basis for the BIP no longer being relevant.

> The BIP method has been endorsed by the Company in the last two rate proceedings. The method has served us well and has been generally well-received. I believe parties recognize the detail and precision it brings in allocating production plant. However, using the BIP allocator is not a simple task. At its core, the BIP allocator requires the Company to divide its production fleet between the base, intermediate, and peak levels. The Company believes that, although the BIP model is capable to model changing conditions, ***<u>it will become increasingly difficult to make this</u>***

> ***assignment given the way we expect to utilize and plan our generation assets in the future in light of the SPP Integrated Marketplace***.[132]

KCPL's rejection of the BIP methodology was even more emphatic in a recent Missouri case. In fact, KCPL's specifically discusses the implementation of the SPP Integrated Marketplace as a reason that the BIP methodology is no longer "suitable".

> The Company has utilized the BIP method previously in Missouri. I believe the BIP method is reasonable but I also have concerns that it is difficult to use for our generation portfolio in that the Company has a lot of base load generation. ***The recent transition of the SPP to an Integrated Marketplace (IM) with centralized dispatch has raised some concern about the BIP allocator***. To utilize the BIP allocator one must assign the generating units into base, intermediate, and peak groups based on their use. Prior to the IM market, the Company provided its own generation to meet its load requirements. ***With the introduction of the IM market, we no longer use our generation to meet the Company's load requirements, but instead sell generate into the SPP market and buy our load requirements from the SPP market. I believe the IM market change impacts the suitability of the BIP method as the production allocator***.[133]

Concerns with the relevance of the BIP methodology, in light of the introduction of the SPP Integrated Marketplace, are not limited solely to KCPL. In fact, the U.S. Department of Energy also pointed out that the BIP methodology was a historical relic rendered outdated by the SPP IM.

> In today's SPP-IM, SPP member entities like KCP&L do not directly generate to load – it is the SPP system that determines, based on offered prices, which generators are chosen in the "stack" from an extensive portfolio of resources. That stack may or may not match the load characteristics of an individual utility within SPP. . . KCPL is a buyer and takes electricity from SPP market without regard to its generation source.[134]

As mentioned, Staff's BIP methodology is premised on the notion that generating units can be segregated into three distinct categories - baseload, intermediate or peaking

[132] Tr. 937-938 (citing to Lutz Direct, Kansas Case No. 15-KCPE-116-RTS, page 9 (emphasis added)).
[133] Tr. 938-939 (citing to Rush Rebuttal, Case No. ER-2014-0370, pages 46-47 (emphasis added)).
[134] Exhibit 502, Schmidt Rebuttal, page 2.

facilities. That said, the introduction of the SPP Integrated Marketplace has eliminated any distinction between generating facilities. Now, all facilities are generated into the SPP marketplace. Given this, the underlying premise of Staff's BIP methodology is shattered. Recognizing that the BIP methodology is no longer relevant in light of this centralized dispatch marketplace, it should be rejected by the Commission.

<u>Third</u>, the BIP Methodology does not properly recognize that baseload facilities do more than just generate energy. Those facilities are also critical in meeting the utilities peak demand. While Staff explicitly recognizes that "KCPL's generation facilities are predominantly considered fixed assets for purposes of setting rates, and so the costs of ***<u>these are assets are considered to be demand-related</u>***,"[135] Staff then ignores class demand and inexplicably allocates 84.2% of these fixed costs (the baseload units)[136] on the basis of class energy.[137] Effectively, Staff's BIP method falsely assumes that <u>all</u> base load plant investment is utilized solely for the purpose of providing energy. Implicit in this assumption is the mistaken belief that base load facilities do not provide any capacity value.

By effectively choosing to allocate 100% of base load investment on the basis of class energy, Staff wrongly assumes that investment in base load plants is not driven at all by total system demands. As witnesses for MIEC and DOE recognize, Staff's failure

[135] Exhibit 202, Staff Rate Design Report, page 13 (emphasis added).
[136] Staff notes that Wolf Creek, Iatan 1 and 2, Hawthorn 5 and LaCygne Units 1 and 2 are all baseload units. (Exhibit 202, Staff Class Cost of Service / Rate Design Report, pages 13-14). The cost of these units (Wolf Creek = $1,732,998,193; Iatan 1 = $525,876,886; Iatan 2 = $1,015,926,506; Iatan common = $346,541,522; Hawthorn 5 = $509,053,894; LaCygne 1 = $426,497,046; LaCygne 2 = $368,253,577; LaCygne common = $214,005,348) represent a total of $5,139,152,972 of KCPL's total production plant investment of $6,101,097,870. (Exhibit 201, Accounting Schedules, Accounting Schedule 3, pages 1-6).
[137] Staff states that the "relative expensive capacity costs of base generation" is allocated on "each class' base level of demand." (Exhibit 202, Staff Rate Design Report, page 17). As Mr. Brubaker shows, Staff's use of the term "base level of demand" is simply designed to hide the fact that Staff allocated all baseload production investment on the basis of energy. In fact, the class base level of demand "exactly equals" the class energy usage. (Exhibit 854, Brubaker Rebuttal, page 13).

to properly consider class peak demand is a fundamental flaw of its BIP production allocator. As Mr. Brubaker points out:

> We all know that this is not the basis for system planning. . . . 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.[138]

DOE witness Dr. Schmidt agrees:

> Staff's application of the BIP methodology fails to recognize that all generation units, whether baseload, intermediate or peaking, also serve the purpose of meeting peak demand. . . . Given that an electric utility plans and constructs generation or transmission plant and purchases power to meet peak demand, and all customers contribute to the peak, peak demand should be used to allocate demand-related (fixed) production and transmission costs.[139]

Criticism of Staff's extensive reliance on class energy usage, and its failure to consider class demand, in allocating production plant is not limited solely to large commercial and industrial customers. Empire witnesses have also pointed out Staff's failure to consider class demand as its basis for rejecting Staff's BIP methodology.

> The Staff also uses a methodology that is arbitrary and suffers from incorrect assumptions and arbitrary weightings. The Base – Intermediate = Peaking ("BIP") method is based on the assumption that the capacity costs of production facilities can be assigned to different components of the load – base load, intermediate load, and peaking load. While it is true that plants have different characteristics in terms of the duration of hours when they operate, the implicit assumptions of the model are not valid in terms of the operating reality, the economics of the plant, or the planning of the capacity additions. It is not correct to assume that all of the costs of a baseload plant are incurred solely to meet the average load of the system. . . . ***Simply, since baseload plants are operating at the system peak, they are also providing a system peaking resource. The BIP method incorrectly assumes that all of the capacity costs of baseload plants are incurred solely to meet the baseload energy requirements. The fundamental problem with the base allocation on average demand fails to recognize that some portion of that total capacity costs is incurred to***

[138] Exhibit 854, Brubaker Rebuttal, pages 11 and 14.
[139] Exhibit 502, Schmidt Rebuttal, page 2.

have adequate resources at the peak. The same conclusion also holds for intermediate capacity. That is all capacity has some component of cost that is caused by the need to meet peak loads reliably. The BIP method does not reflect this cost causation principle.[140]

In the past, the Commission has rejected methodologies, like Staff's BIP methodology that rely heavily on class energy usage.[141] For instance, in a recent Ameren case, in which it expressly adopted the use of the A&E methodology, the Commission rejected a fixed production cost allocation methodology that allocated 55% of generation fixed costs on the basis of class energy.[142] Interestingly, in this case, Staff's BIP model suffers from the same extensive reliance on class energy. Specifically, Staff's methodology weights class energy usage as 53% of its allocation methodology.[143] As such, Staff's methodology is equally as flawed as those previously rejected by the Commission.

The ludicrous nature of Staff's decision to ignore class demand, and allocate baseload plant entirely on the basis of class energy, is best realized by the fact that utilities continue to construct baseload generation. If generation was solely designed to meet class energy needs, then baseload units would never be built. Instead, given its low capital costs and virtually non-existent operating costs, utilities would rely entirely on wind generation. In fact, given the theory underlying Staff's methodology, all future generation will be wind units. The fact that utilities continue to build these fossil fuel units show the importance that meeting peak demand plans in planning and operating a generation fleet. Staff's methodology fails to recognize this fundamental premise.

[140] Overcast Rebuttal, Case No. 2014-0351, page 6 (emphasis added).
[141] See, Exhibit 854, Brubaker Rebuttal, pages 14-15 (citing to Case No. ER-2010-0036, *Report and Order*, issued May 28, 2010, at page 85.
[142] *Id.* at page 15.
[143] *Id.* It is important to understand that the Staff methodology allocates 100% of baseload investment on the basis of energy. Intermediate and peaking facilities are allocated on an alternative basis. Thus, 53% of total investment is allocated on the basis of energy.

Fourth, Staff's BIP Methodology penalizes those classes that use the KCPL system in an efficient manner. 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.

> The BIP methodology shifts costs to the higher load factor customers. This occurs because the BIP methodology partially uses energy consumption as an allocator during the base, intermediate and peak periods. I do not support the use of energy consumption, which is variable in nature, to allocate fixed costs. Fixed costs do not vary with consumption and must be paid by customers regardless of usage. How those costs are allocated should be linked to peak demands that the capacity was built to serve.[144]

Fifth, the BIP Methodology is well outside of the mainstream of production allocators used by other utilities and state utility commissions.[145] As Mr. Brubaker points

[144] Exhibit 502, Schmidt Rebuttal, page 6.

[145] 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

out, the BIP methodology is not widely accepted.[146] "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 among the frequently used mainstream cost allocation methodologies, and lacks precedent for its use."[147]

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.[148] Similarly, while DOE witness Dr. Schmidt has testified in approximately 50 rate proceedings, before 15 state utility commissions, he is not aware of any other utility that has relied

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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).

[146] 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.

[147] Exhibit 555, Brubaker Rebuttal, page 17.

[148] 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.

upon the BIP methodology.[149] Thus, the use of the archaic BIP methodology appears to be limited solely to the Missouri Staff.

The use of the BIP methodology by Staff, and the possible adoption by the Missouri Commission, poses a real risk to the competitiveness of Missouri's industrial rates. As counsel for residential advocate CCM readily admits, the BIP methodology "is better for the residential class."[150] As such, as demonstrated by the results of Staff's class cost of service study, the BIP methodology is detrimental to industrial customers.

It is well established that KCPL's industrial rates are not competitive with other Midwest utilities. In fact, while KCPL's industrial rate placed 9th out of 10 Midwest states as recently as 2009, KCPL's industrial rates are now the third highest.[151] Given that the BIP methodology is detrimental to high load factor customers, its adoption will place additional pressure on KCPL's uncompetitive industrial rates.

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. 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.

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[149] Tr. 1095-1096. In response to comments made in the opening statement of CCM (Tr. 873) indicating that a utility in Texas had utilized the BIP methodology, Dr. Schmidt pointed that the use of the BIP approach was limited to the City of Austin, a municipal utility. There, the City of Austin is a standalone utility, that is not interconnected with other utilities. Given this, the City of Austin entirely self generates. As such, unlike KCPL which is integrated into SPP, the City of Austin is able to differentiate between base, intermediate and peaking facilities. See, Tr. 1096-1097.

[150] Tr. 873.

[151] Exhibit 650, Gorman Direct, Schedule MPG-2.

> 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."[152]

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.

b. STAFF'S ALLOCATION OF FUEL IS INCOMPATIBLE WITH ITS ALLOCATION OF FIXED PRODUCTION COSTS

As mentioned, Staff's faulty BIP methodology ignores class peak demand and, instead, allocates a significant amount of KCPL's investment in baseload units entirely on the basis of energy usage. Thus, the high load factor commercial and industrial classes are allocated a disproportionate amount of baseload investment. This has the effect of significantly increasing the cost of service for these industrial customers.

Staff's faulty methodology for allocating baseload investment may be more tolerable if Staff allocated a corresponding amount of the low cost energy associated with these baseload units to these high load factor industrial customers. It is well established that, while baseload units have high capital costs, they also have much lower operating costs. In contrast, while peaking units have low capital costs, they typically have much higher operating costs.[153] As Mr. Brubaker points out, while Staff's class cost of service study allocates the high cost of investment in the baseload units to industrial customers, it then denies those customers the low cost of energy provided by those same units.

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[152] 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.").

[153] For instance, Mr. Brubaker points out baseload units have much lower energy costs. For instance, the fuel cost of the Wolf Creek nuclear unit is about 0.7₵ / kWh. Similarly, the baseload cost units have fuel costs in the range of 1.5₵ to 2.0₵ / kWh. On the other hand, peaking units have costs from 5.0₵ to 7.0₵ / kWh. See, Exhibit 854, Brubaker Rebuttal, page 10.

> These studies [Staff BIP and KCPL Peak & Average] allocate significantly more generation fixed costs to high load factor customers than do the traditional studies. . . . Given these allocations of capital costs, it would not be appropriate to use the same fuel costs for all classes. Rather, the fuel cost allocation should recognize that the higher load factor customer classes should receive below average fuel costs to correspond to the above-average capital costs (similar to base load units) allocated to them, and the lower load factor classes should get an allocation of fuel costs that is above the average, corresponding to the lower then average capital costs (i.e., peaking units) allocated to them.[154]

Given this, Staff's faulty study over-allocates capital costs to industrial customers, and unfairly denies those classes the cheap energy produced by those same baseload units. Instead, Staff allocates energy to all classes at the same average cost.[155] As Mr. Brubaker concludes, the Staff and KCPL methodologies "burden high load factor classes with above-average capacity costs, but do not allow them to benefit from the lower cost of energy that goes with the higher capacity costs. No theory supports this result and these types of studies should be rejected."[156]

c. STAFF'S FLAWED ALLOCATION OF DISTRIBUTION COSTS

In addition to its flawed methods for allocating production plant between the various customer classes as well as allocating energy costs, the Staff class cost of service study also allocates distribution plant costs in a faulty manner.

The LPS rate schedule allows for customers to take service at either of four different voltage levels: (1) secondary voltage; (2) primary voltage; (3) substation voltage; or (4) transmission voltage. The higher the voltage level for service, the less

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[154] *Id.* at page 8.
[155] This problem underlying Staff's BIP methodology and its failure to equitably allocated fuel in light of the over-allocation of baseload investment is well established. See, *Re: Nova Scotia Power Incorporated*, Nova Scotia Board of Commissioners of Public Utilities, Case No. M05473, issued March 11, 2014 ("If the BP or BIP fixed classification methods were to be adopted, it could also have implications on the apportionment of fuel costs among rate classes. If, for example, the BP logic were applied to fuel costs, class responsibility for fuel costs would not be based on annual class usage but on relative shares of energy being supplied by plant type.").
[156] Exhibit 854, Brubaker Rebuttal, page 11.

distribution facilities needed to serve the customer.[157] In fact, customers taking service at transmission voltage levels utilize no distribution facilities and should not be allocated any such costs. Similarly, customers taking service at the substation voltage level will not use any of the primary or secondary distribution facilities. Finally, customers taking service at the primary voltage level will not use any secondary distribution facilities and should not be allocated any of the secondary distribution costs.[158]

In its initial study, Staff failed to recognize this distinction. Specifically, Staff's distribution methodology fails to recognize that 49,000 kW of the LPS class non-coincident peak is associated with customers served at transmission level that should not be allocated any distribution costs. Similarly, Staff's distribution methodology fails to recognize that 49,000 kW of the LPS class non-coincident peak is associated with customers taking service at substation voltage that should not be allocated any secondary or primary distribution costs. Finally, Staff's distribution methodology fails to recognize that 158,000 kW of the LPS class non-coincident peak is associated with customers taking service at primary voltage. As such, these customers do not utilize any secondary distribution facilities and should not be allocated any of these costs.[159]

When confronted with this problem, Staff admitted its obvious mistake.

> Q. On page 22 of Mr. Brubaker's rebuttal testimony, he mentions that Staff's allocator to allocate distribution substation costs did not remove a level of demand representing customers served at transmission. Mr. Brubaker also mentions that Staff's allocator use to allocate distribution primary costs to customers did not remove a level of demand for customers served at substation and transmission. Is this correct?

[157] See, Exhibit 853, Brubaker Direct, page 7 for a graphical depiction of the need for additional distribution facilities needed to provide service at lower voltage levels.
[158] Exhibit 854, Brubaker Rebuttal, page 22.
[159] *Id.*

> A. Yes. Staff has recalculated its distribution allocators to remove an estimate of non-coincident demand from the non-coincident demand representing the entire Large Power Service ("LPS") class to account for customers served at transmission and substation.[160]

While Staff recognizes the problem in its allocation methodology, its solution to solve that problem ("recalculating its distribution allocators to remove an ***estimate*** of non-coincident demand from the non-coincident demand representing the entire Large Power Service class") falls well short of fixing this problem.[161]

Specifically, in attempting to solve the obvious shortcomings of its distribution allocator, Staff simply took the overall class demand (336,338 kW)[162] and divided it by the number of customers served in the LPS class (68 customers).[163] 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.[164] KCPL's load data, however, conclusively proves that Staff's assumption is incorrect. Not surprisingly, LPS customers taking service at transmission and substation voltage levels use much more than the average amount of demand.

	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

Source: Exhibit 857

When Staff uses its erroneous assumption to remove demand from the total LPS demand in order to recognize that some customers are served at higher voltage, it doesn't

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[160] Exhibit 211, Kliethermes Surrebuttal, page 6.
[161] See, Tr. 1222-1226.
[162] Exhibit 857, third column, (Staff COS Data) section "NCP kW by Voltage Level of Service"
[163] Exhibit 857, third column, (Staff COS Data) section "Average # of Customers Served at Voltage Level"
[164] Exhibit 857, third column, (Staff COS Data) section "Demand per Customer by Voltage Level of Service"

remove enough because the higher voltage customers are larger in size than it has assumed.

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 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 transmission customers 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 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, it should have been allocated costs based on only 270,284 kW. 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. 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 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 materially overstates the amount of substation costs allocated to the LPS class.

Mr. Brubaker validated KCPL's demand estimates by comparing the data KCPL used in its cost of service study (shown in the first column of Exhibit 854) 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 on Exhibit 854. 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 (which Mr. Brubaker used) is shown to be much closer to actually known bill data than Staff's overly simplistic and erroneous assumption that use of the class average 4,951 kW is appropriate. Clearly, it is not.

Ultimately, Mr. Brubaker estimates that Staff's faulty distribution allocation methodology, based upon the erroneously assumed average demand per LPS customer, over-allocates $4 million of distribution cost revenue requirements to the LPS class.[165]

Based upon the significant flaws in Staff's BIP production allocator, as well as its misplaced distribution allocation methodology, Mr. Brubaker concludes that "Staff's class cost of service study should not be relied upon for any purpose."[166]

[165] Tr. 1208.
[166] Exhibit 854, Brubaker Rebuttal, page 23.

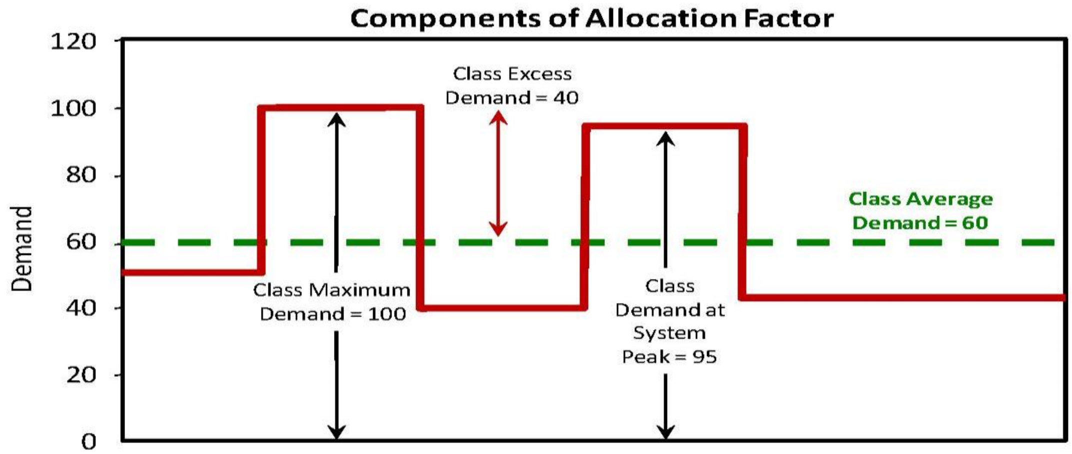
3. KCPL's Peak and Average Methodology

As mentioned, KCPL previously relied upon the BIP methodology. Upon the introduction of the SPP Integrated Marketplace, KCPL recognized that the BIP methodology was no longer relevant and rejected its continued applicability as a production allocator. Instead, KCPL now relies upon another approach (the Peak & Average methodology) that has been repeatedly rejected by this Commission as inappropriate for allocating production costs. Specifically, the Commission has rejected this approach because it double counts the average demand [energy] of customer classes.[167]

As the evidence indicates, the average component of both the Average & Excess (to be discussed *infra*) and Peak & Average methodologies are calculated in the same fashion. In the A&E method, however, the difference between this average usage and the overall system peak is utilized for the excess component. In contrast, the faulty P&A methodology considers the entire system peak for its second component. This recognition of the entire peak demand, instead of just the excess, introduces the fatal flaw (class energy usage is double counted) inherent in the P&A methodology.

In his rebuttal testimony, Mr. Brubaker graphically illustrates the differences between the A&E method and the flawed P&A method.

[167] See, Case No. ER-2010-0036, *Report and Order,* issued May 28, 2010, at page 85.



Source: Exhibit 854, Brubaker Rebuttal, page 5.

In this diagram, the maximum demand of this class is 100 MW, its contribution at the time of the system peak is 95 MW, its average demand is 60 MW, and the excess demand is 40 MW.

As Mr. Brubaker explains, the A&E method "combines the class average demand with the class excess demand in order to construct an allocation factor that reflects average use as well as the excess of each class' maximum demand over its average demand. The A&E allocation factor is developed using the average demand (60) and the excess demand (40) for this class."[168]

Unlike the A&E method which combines the average demand with the excess (40), the KCPL Peak & Average method "combines the average demand (60) with the class monthly peak demand (100)."[169] Recognizing that "the average peak demand (60) is a component or sub-set of the class peak demand (100) and of the class load coincident with the system peak (95)," "***the average demand is double-counted***."[170]

[168] Exhibit 854, Brubaker Rebuttal, at page 6.
[169] *Id*.
[170] *Id.* (emphasis in original).

The practical result of KCPL's Peak & Average methodology is to benefit low load factor customers (e.g., residential class) that utilize the KCPL system in an inefficient manner to the detriment of the efficient high load factor customers (e.g., industrial class). This double counting causes high load factor customers to be allocated an inequitable share of production plant investment. Also, because higher-load factor customers demonstrate a better correlation between average demands and peak demands than do lower-load factor customers, higher-load factor customers receive a disproportionate share of the non-average demand portion of production plant investment under the P&A method.

In a recent Ameren decision regarding the appropriate methodology for allocating production plant, the Commission expressly noted the double-counting of class energy as a flaw inherent in the Peak & Average methodology. As a result, the Commission disregarded this methodology as "unreliable."

> The Peak and Average method, in contrast, initially allocates average costs to each 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***.[171]

In a more recent decision, the Commission again rejected the Peak and Average approach.

> 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

[171] Case No. ER-2010-0036, *Report and Order*, issued May 28, 2010, at page 85.

> system peaks. That method works to the benefit of the residential class whose usage varies more by time of day and time of year.[172]

Further evidence of the unreliability of the Peak and Average methodology is found in the fact that all regional utilities, except for KCPL, have entirely rejected its use. Specifically, Ameren, Empire and Westar have each rejected the Peak and Average method in favor of the more reasoned approach contained in the A&E methodology.[173]

Other commissions have also recognized the flaws inherent in the Peak and Average approach. The following citation, though lengthy, is especially informative because it represents the discussion of another regional state utility commission considering the benefits of a demand-related allocator (A&E) and the detriments of an energy-related allocator (Average & Peak). In this decision, the Iowa Utilities Board expressly adopted the A&E methodology.

> *Allocation of Generation Demand Costs*
>
> IPL advocated for continued use of the average and excess (A&E) method for allocating generation costs. In the context of A&E demand, the A&E method allocates capacity on an average cost per kW basis, similar to how energy is allocated to the various classes on an average cost per kWh basis. Consumer Advocate argued that the average and peak demand (APD) method should be used to allocate generation costs. The APD method allocates the excess portion of A&E demand by full class peak demands, rather than only the excess portion of class peak demands. ICC and LEG both supported continued use of the A&E method.
>
> Consumer Advocate said that the A&E method fails to accurately allocate the cost of the various generating plants that are built and used to serve each customer class because too much emphasis is placed on class peak demands and not enough emphasis on class energy usage, which does not take into account the tradeoffs between energy and capacity costs in determining the generation mix. Consumer Advocate argued that the APD method more fairly recognizes the fact that expensive base load plants are built to serve sustained energy loads, whereas less expensive peaking plants are built to serve peak loads.

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[172] Case No. ER-2014-0258, *Report and Order*, issued April 29, 2015, at pages 70-71.
[173] Exhibit 854, Brubaker Rebuttal, at page 4.

ICC argued that the APD method would inappropriately double count the energy, or average demand, component of A&E demand by also including it in the allocation of A&E excess demand. ICC said the APD method results in higher load factor customers being asymmetrically allocated the higher capacity costs of base load generation without the benefit of the lower energy costs associated with that generation. ICC noted the APD method has been rejected by the Missouri and Texas public utility commissions.

LEG said that the APD method allocates a greater share of fixed capacity costs as energy-related costs, which would inappropriately under-price demand-related costs and over-price energy, thereby encouraging the use of capacity and accelerating the need for additional capacity. LEG argued that the A&E method provides a reasonable balance between demand and energy allocations of generation capacity and recognizes that generation capacity is built to serve both peak demand and usage throughout the year.

The APD method is similar to the A&E method in some ways, but differs by giving extra emphasis to class average demand by including it in the allocation of A&E excess demand. The result is an allocation factor that resembles a hybrid between A&E demand and an energy-based allocator, which tends to benefit low load factor residential and general service customers at the expense of higher load factor large general service and bulk power customers.

The Board has previously found the A&E method to be in compliance with 199 IAC 20.10(2)"c," which provides that generating capacity allocations among and within classes shall recognize that utility systems are designed to serve both peak and off-peak demand, and shall attribute costs based upon both peak period demand and the contribution of off-peak period demand in determining generation mix. (Tr. 1593). While Consumer Advocate argues that the APD method better reflects the supply planning process, which involves consideration of both energy and capacity costs, ICC appropriately pointed out that once generation is selected and built, capacity cost and energy costs are allocated separately; the purpose of the A&E method is to allocate capacity costs.

As noted by ICC, the APD method uses average demand twice, first in the allocation of average system demand, and again in the allocation of excess system peak demand, which effectively incorporates a double-counting of class energy usage in the allocation of capacity costs. In the context of class A&E demands, this results in higher capacity costs being allocated to high load factor customers on a per-kW basis. According to Consumer Advocate, this treatment is intended to allocate more of the higher capacity costs of base load generating units based on the sustained energy usage of high load factor customers. However, since the tradeoff of higher base load capacity costs is lower fuel costs, and since energy costs are

> allocated on an average per-kWh basis, the APD method would produce a non-symmetrical allocation of capacity and energy costs.
>
> ***The Board is not persuaded to depart from the A&E method for the allocation of generation demand costs. Because energy continues to be allocated among classes on an average per-kWh basis, it is reasonable and symmetrical to also allocate capacity costs on an average per-kW basis***.[174]

Clearly, the Peak & Average methodology, like the Staff's BIP methodology, is flawed and should be rejected by this Commission.

4. Average & Excess Production Allocator

Given the numerous flaws inherent in a production allocator that relies extensively on class energy usage, MIEC witness Brubaker rejects both Staff's BIP and KCPL's Peak & Average methodology. Recognizing that both class peak demand and energy usage are important to the utility's decision as to the amount and type of capacity to be added, Mr. Brubaker relies upon the Average & Excess production allocator methodology.[175] 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

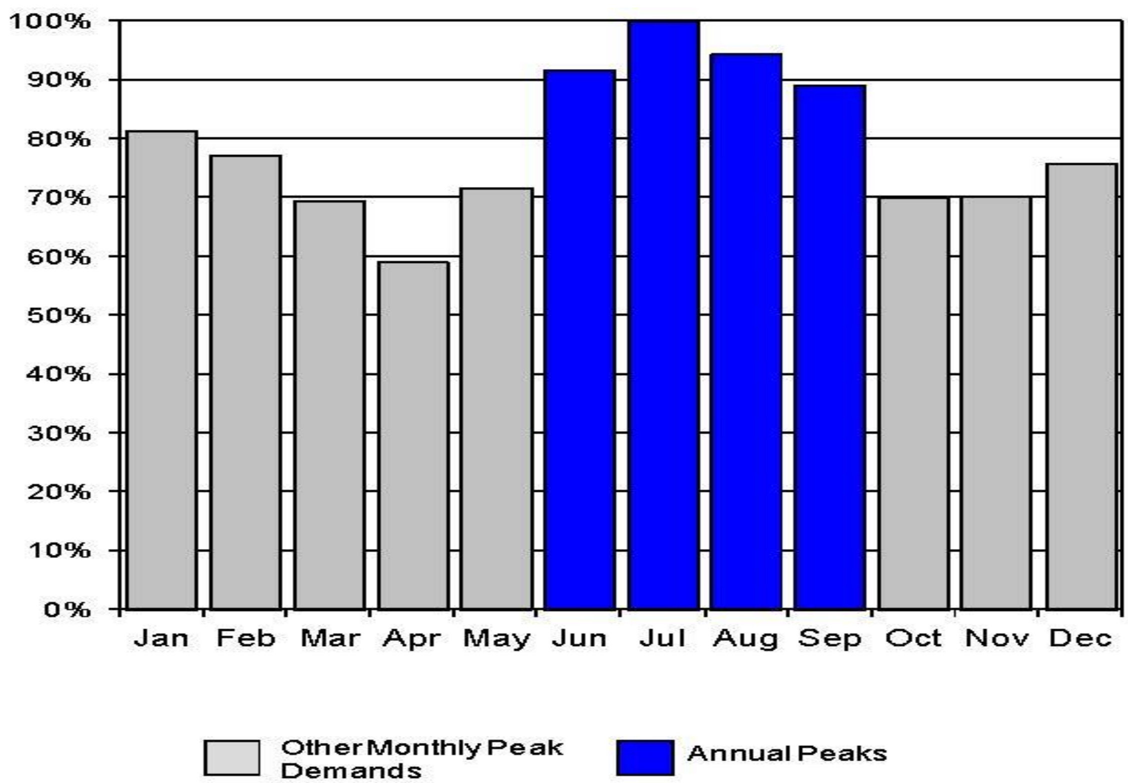
[174] Re: Interstate Power and Light Company, Iowa Utilities Board, Docket No. RPU-2010-0001; issued January 10, 2011, 287 P.U.R.4th 201 (emphasis added) (citations omitted); *See also,* Re: Interstate Power and Light Company, Iowa Utilities Board, Docket No. RPU-02-3; issued April 15, 2001, 225 P.U.R.4th 165 ("It is reasonable to use the average and excess method for allocating generation and transmission demand costs, including interruptible and lighting loads in development of the allocation factor, and to allocate other costs as proposed in IPL's class cost-of-service study."); Re: Interstate Power and Light Company, Iowa Utilities Board, Docket No. RPU-02-7; issued May 15, 2003, 225 P.U.R.4th 227 ("The Board has consistently favored the A&E method in electric rate proceedings."); Re: Interstate Power and Light Company, Iowa Utilities Board, Docket No. RPU-04-1; issued January 14, 2005, 239 P.U.R.4th 309.

[175] As mentioned in footnote 122, the A&E methodology considers both class energy and peak demand. As such, it is looked upon as a reasonable compromise between energy intensive allocators (BIP and Peak & Average) and pure demand allocators (4CP).

"excess" demand is the difference between the system peak demand and the system average demand.[176]

Given that the A&E methodology considers both: (1) Average: class energy and (2) Excess: class peak demand, it recognizes both aspects of the utility's capacity addition decision: the amount of capacity to add and the type of capacity to add.

While the class peak demand is a necessary component of the A&E methodology, not all monthly peaks influence the utility's decision to add capacity. Rather, only the largest monthly peaks should be considered. The evidence indicates that, during the test year, KCPL experienced its annual peak demands in June through September.



Source: Exhibit 853, Brubaker Direct, page 15.

Recognizing that production plant is constructed based, in large part, upon the need to meet peak demand, it is apparent that only the annual peaks are important to the

[176] Exhibit 853, Brubaker Direct, pages 17-18.

decision to add additional generation.[177] Given the definite summer peaking nature of KCPL, it is these summer peaks that drive generation additions. In a similar nature, it should be these definite summer peaks that drive any allocation of fixed production costs among the customer classes.

In its last explicit statement on an appropriate production allocator, the Commission expressly recognized the logic inherent in the A&E methodology and adopted it for purposes of an Ameren class cost of service study.

> The Peak and Average method, in contrast, initially allocates average costs to each class, but then, instead of allocating just the excess of the peak usage period to the various lasses 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. . . . <u>***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***</u>.[178]

The logic inherent in the A&E methodology has not only been recognized by the Missouri Commission. Instead, 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

[177] Exhibit 501, Schmidt Direct, page 8 ("System peak demands drive the need for production capacity, and customer contributions to system peaks should be the principal component of factors used to allocate fixed production costs. If production and transmission plant costs are allocated on the basis of average energy use, then low load factor customers receive the benefits of cheaper baseload (and intermediate) energy without paying a fair share of the capital costs for these plants.").

[178] Case No. ER-2010-0036, *Report and Order*, issued May 28, 2010, at pages 85-86 (emphasis added).

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***."[179]

► 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."[180]

► 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

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[179] 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.").

[180] 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."[181]

►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.

Reliance upon the Average & Excess allocation methodology extends beyond Midwest state utility commissions.

[181] 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.

► 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."[182]

► 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***."[183]

► 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

[182] 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.

[183] 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 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).

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***."[184]

► 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"[185]

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

[184] 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).
[185] 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,[186] Maryland Public Service Commission,[187] and Connecticut Department of Public Utility Control.[188]

5. Conclusion

As this brief clearly demonstrates, the Commission should adopt the MIEC class cost of service study that relies upon the A&E production allocator. This methodology is well established and has been adopted by FERC and numerous other states. In contrast, both the Staff BIP and KCPL Peak & Average methodology are out of the mainstream or have been rejected by this Commission as inherently flawed. As detailed in the following section, once the Commission has adopted the MIEC A&E production allocator and class cost of service study, it should make revenue neutral shifts designed to move each class' rates towards cost of service.

B. HOW SHOULD ANY INCREASE ORDERED IN THIS CASE BE APPLIED TO EACH CLASS?

Position: Consistent with recent decisions, the Commission should take affirmative steps to recognize and eliminate the current residential subsidy by moving all customer classes 25% toward cost of service.

As previously indicated, there were four class cost of service provided in this case: (1) KCPL's study relying on Peak & Average production allocator; (2) Staff study relying on BIP production allocator; (3) MIEC study relying on A&E production

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

[187] 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.

[188] 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.

allocator; and (4) DOE study relying on A&E (4CP) production allocator).[189] As pointed out, *supra*, the KCPL and Staff methodologies are inherently flawed and have previously been rejected by this and other state utility commissions. As such, the Commission should summarily reject the KCPL and Staff cost of service studies. In contrast, the Commission has previously found that the A&E production allocator is reasonable. Moreover, the A&E approach has been adopted by FERC and numerous other state utility commissions. Given this, the Commission should expressly rely on the MIEC study, advanced by Mr. Brubaker.

The reasonableness of Mr. Brubaker's approach is demonstrated by comparing the revenue neutral shifts necessary under his A&E approach to those provided by the <u>energy</u> intensive approach advocated by KCPL and the <u>demand</u> intensive (4CP) approach recommended by DOE. Specifically, for the residential class, the A&E methodology provides for a revenue neutral increase of 14.8% which fits neatly between the 9.2% revenue neutral increase under the energy weighted Peak & Average methodology and the 18.6% revenue neutral increase under the demand weighted 4CP methodology. Similarly, for the large industrial class, the A&E methodology provides for a revenue neutral decrease of 7.4% as compared to the 3.4% increase provided under the energy weighted Peak & Average approach and the 8.5% revenue neutral decrease provided by the demand weighted 4CP approach.

[189] As mentioned, Public Counsel has expressly supported the Peak & Average methodology utilized by KCPL. (See, Tr. 1167 "our formal position was actually to support company's A&P method.") Thus, even Public Counsel recognizes the existence of a residential subsidy. Therefore, Public Counsel agrees that, on a revenue neutral basis, residential rates should be increased 9.2% to bring them to cost of service. Recognizing that Public Counsel expressly acknowledges the need for a revenue neutral increase to the residential class, the only issue is the identity of the classes that will receive the benefit of the shift of costs to the residential class.

	KCPL[190]	**MIEC**[191]	**DOE**[192]
	Revenue Neutral Change	Revenue Neutral Change	Revenue Neutral Change
Residential	+9.2%	+14.8%	+18.6%
Small Gen. Svc.	-13.1%	-7.7%	-9.5%
Med. Gen. Svc.	-7.4%	-6.2%	-7.1%
Large Gen. Svc.	-8.5%	-10.4%	-14.8%
Large Power	+3.4%	-7.4%	-8.5%
Total Lighting	-17.6%	-12.4%	-46.5%

Given the significant and long-standing nature of the current residential subsidy, MECG asks the Commission to take definitive steps to address the residential subsidy and to address the industrial rates that are significantly above cost of service. Specifically, MECG recommends that each class be moved 25% towards cost of service.[193] Such a step would be a definite step towards cost of service, while still recognizing the often-cited consideration of gradualism. In fact, by making a 25% movement, it would take at least three more cases to eliminate the current subsidy. Given that KCPL has averaged a case every 21 months, the current subsidy would continue for 63 months - over 5 more years.[194]

A decision to move classes 25% towards cost of service is also consistent with recent decisions of this Commission as well as that of other state utility commissions. For instance, in the recent Empire rate case, the Commission decided to eliminate 25% of

[190] See, Exhibit 136, Miller Direct, page 14. (Ms. Miller's results include KCPL's proposed 10.8% rate increase. As such, in order to arrive at revenue neutral results, this 10.8% rate increase was removed from Mr. Rush's results).
[191] See, Exhibit 853, Brubaker Direct, Schedule MEB-COS-5.
[192] See, Exhibit 500, Schmidt Direct, page 12.
[193] Exhibit 853, Brubaker Direct, page 27.
[194] Exhibit 200, Staff Cost of Service Report, page 9 (KCPL will have had 6 rate increases in the 124 months between January 1, 2007 and May 27, 2017. Therefore, KCPL has had a rate increase every 21 months.).

the residential subsidy.[195] Similarly, in a recent American Electric Power decision, the West Virginia Commission decided to eliminate 33% of the residential subsidy.[196]

Given MECG's recommendation to eliminate 25% of class subsidies, the Commission should order the revenue neutral shifts in the third column:

Class	Cost of Service Result	25% Elimination
Residential	+14.8%	+3.7%
Small General Service	-7.7%	-1.9%
Medium General Service	-6.2%	-1.5%
Large General Service	-10.4%	-2.6%
Large Power	-7.4%	-1.9%
Lighting	-12.4%	-3.1%

Source: Exhibit 853, Brubaker Direct, Schedules MEB-COS-5 and MEB-COS-6.

C. HOW SHOULD ANY INCREASE TO RATES LGS AND LPS BE DISTRIBUTED?

Position: Proper ratemaking dictates that fixed costs should be collected on a per kW basis through either facilities or demand charges. Given this, variable costs, primarily fuel, should be collected on a per kWh basis through energy charges. Contrary to this proper ratemaking principle, KCPL currently collects a significant amount of fixed costs through the energy charges in its LGS and LPS rate schedules. The collection of fixed costs through energy charges creates a subsidy in these rate schedules for the benefit of low load factor customers and to the detriment of high load factor customers. Given this, the Commission should adopt Mr. Brubaker's proposal to collect more of any rate increase in this case through demand charges.

[195] See, Case No. ER-2014-0258, *Report and Order*, issued June 24, 2015, page 20.

[196] See, Case No. 14-1152-E-42T, *Commission Order on the Tariff Filing of Appalachian Power Company and Wheeling Power Company to Increase Rates, and Petition to Change Depreciation Rates*, issued May 26, 2015, at page 101.

As designed, the Large General Service and Large Power Service rate schedule "consist of a series of charges differentiated by voltage level."[197] Specifically, KCPL collects revenues from LGS and LPS customers through customer, facilities, demand and energy charges for customers taking service at: (1) secondary voltage; (2) primary voltage; (3) substation voltage or (4) transmission voltage levels.[198] In each case, the demand and energy charges are seasonally differentiated.[199] 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.[200]

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.[201]

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

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[197] Exhibit 853, Brubaker Direct, page 28.
[198] *Id.*
[199] *Id.*
[200] *Id.*
[201] *Id.* at page 29.

usage is billed at the tail block rate.[202] 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 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.[203] 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.[204] 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 LPS tariff collects 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,

[202] *Id.*
[203] *Id.*
[204] *Id.*

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 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 2.4¢/kWh to 2.6¢/kWh,[205] KCPL's average variable cost is less than 2.0¢/kWh – 2.1¢/kWh.[206] Therefore, the LGS and LPS energy blocks collect more than variable costs; those charges also collect a significant amount of fixed costs.

In order to bring the energy charge more in-line with the amount of variable costs it is designed to collect, Mr. Brubaker 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."[207] In this way, KCPL would begin 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

[205] *Id.* at page 30. Mr. Brubaker also notes that the LGS energy blocks ranges from 3.5¢/kWh to 4.3¢/kWh.
[206] *Id.*
[207] *Id.* at page 32.

Nos. ER-2010-0355;[208] ER-2012-0174;[209] ER-2014-0370[210] and in the recent Empire Case No. ER-2016-0023.[211] 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.

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

[208] 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).

[209] 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.").

[210] 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.

[211] 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.").

recent Atmos decision, the Commission adopted the use of a "straight fixed variable" rate design.[212] 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."[213] 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."[214] 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)."[215] The same logic was relied upon when the Commission adopted the straight fixed variable rate design for Missouri Gas Energy.[216]

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 2.0¢/kWh – 2.1¢/kWh;[217] (2) that Mr. Brubaker's adjustment will allow for 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.

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[212] *In re: Atmos Energy Corporation*, Case No. GR-2006-0387, issued February 22, 2007, at pages 13-25.
[213] *Id.* at page 14.
[214] *Id.*
[215] *Id.* at page 20.
[216] *In re: Missouri Gas Energy*, Case No. GR-2006-0422, issued March 22, 2007, at pages 9-13.
[217] In fact, Staff calculates that the true-up "base factor for the KCPL FAC is $0.01545." See, Exhibit 253, Sarver True-Up Rebuttal, page 2 and Schedule CCOS-3.

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.

VII. CLEAN CHARGE NETWORK

Position: KCPL's investment in its Clean Charge Network, and its request to include such costs in utility rates, is an inappropriate attempt to extend its state-authorized monopoly to provide electric service to a service (electric vehicle charging) which should be provided in a competitive market. MECG supports the position advanced by OPC and asserts that electric vehicle charging stations should not be regulated. As such, only those costs associated with extending the distribution network to the charging station, should be included in rates. All other costs, predominantly the investment and O&M costs associated with the charging station itself should not be included in regulated rates. Rather, KCPL should be allowed to charge those customers using the charging station whatever amount it deems appropriate in order to recover its investment in this deregulated service.

In its case, KCPL seeks to recover costs associated with the rollout of its clean charge network. Specifically, KCPL seeks to earn a return on its investment, a return of its investment (depreciation) and recover O&M costs associated with the clean charge network. Once included in rates, KCPL then claims that these costs should be recovered from all other ratepayers in the event that the revenues received from the charging stations do not fully recover the associated costs.

In its opening statement, MECG expressed concern that KCPL is seeking to create another subsidy. Specifically, KCPL seeks to establish a subsidy flowing from KCPL's captive customers and flowing to the benefit of those customers that actually the clean charge network, but do not pay rates that recover the cost of that network. Interestingly, given that there is no assurance that the customers using the clean charge network are from Missouri, it is possible / probable that many of these customers will reside outside of the KCPL service area and possibly outside of Missouri. Thus, the subsidy that KCPL seeks to create will not even benefit other Missourians.

Recently, the Commission has begun to deliberate a companion case to decide the appropriate treatment of the Ameren clean charge network.[218] In recent deliberations in that matter, the Commission has expressed concerns with whether the clean charge network should be regulated and included in rates. In the alternative, the Commission appears to ponder whether the investment in a clean charge network should be a competitive service.

The Commission's hesitance to allow KCPL to extend its regulated monopoly to include the rollout of a clean charge network is based upon solid economic principles. Prior to 1968, the Federal Communications Commission allowed AT&T to extend its regulated telephone monopoly to include the sale of customer premise equipment ("CPE").[219] When other companies sought to market CPE that would interconnect with the public switched network, AT&T threatened lawsuits that the marketed CPE violated their FCC tariff.[220]

In 1968, the FCC considered the lawfulness of the Carterfone device. In a landmark decision, the Commission ruled that AT&T's telephone monopoly should not extend to the provision of CPE.

> We agree with and adopt the examiner's findings that the Carterfone fills a need and that it does not adversely affect the telephone system. They are fully supported by the record. We also agree that the tariff broadly prohibits the use of interconnection devices, including the Carterfone. Its provisions are clear as to this. Finally, in view of the above findings, we hold, as did the examiner, that application of the tariff to bar the Carterfone in the future would be unreasonable and unduly discriminatory. However, for the reasons to be given, we also conclude that the tariff has been unreasonable, discriminatory, and unlawful in the

[218] See, Case No. ET-2016-0246.
[219] See, *In re Carterfone Device v. AT&T*, 13 FCC2d 420 (1968).
[220] The FCC approved tariff provided "[n]o equipment, apparatus, circuit or device not furnished by the telephone company shall be attached to or connected with the facilities furnished by the telephone company, whether physically, by induction or otherwise." *Id.* at 422.

> past, and that the provisions prohibiting the use of customer-provided interconnecting devices should accordingly be stricken.[221]

Just as AT&T sought to extend its government sanction monopoly over the provision of telephone service to include the provision of CPE, KCPL now seeks to extend its government sanctioned monopoly to provide electric service to include the provision of charging stations for electric vehicles. Just as the FCC was hesitant to extend AT&T's monopoly to include CPE, this Commission should be skeptical of KCPL's attempts to extend its monopoly to clean charge networks.

For this reason, MECG supports the Commission's efforts to draw a clear line between: (1) the extension of distribution system (including the meter) to the charger (a regulated service) and (2) the construction and operation of the charger (a deregulated service).[222] Given this distinction, the construction and operation of a charger is no different than any other type of battery charger. . . it is simply another device to be plugged into regulated electric distribution system. And, the simple fact that the charger is plugged into the distribution system does not make the charger "electric plant" or mean that the costs should be included in regulated rates. Given this, MECG urges the Commission to find that the non-distribution costs associated with KCPL's clean charge network should not be included in regulated rates.

[221] *Id.* at page 423.
[222] See, Exhibit 169.

VIII. CONCLUSION

MECG respectfully requests that the Commission issue its Report and Order consistent with the positions advanced herein. Specifically, MECG asks that the Commission adopt the following positions:

1. The Commission should deny KCPL's request to annualize revenues to account for MEEIA Cycle 1 programs. Specifically, the Commission should find that this request is in violation of the Cycle 1 and Cycle 2 stipulations and would result in KCPL double recovering its lost revenues associated with the MEEIA Cycle 1 programs.

2. The Commission should draw a distinct line between: (1) KCPL's extension of distribution network to an electric vehicle charger and (2) its investment and operating costs associated with its Clean Charge Network. Only those costs associated with extension of the distribution network should be included in retail rates.

3. The Commission should authorize KCPL a return on equity at the lower end of Mr. Gorman's recommended range (lower range = 9.9% to 10.2%). By including a return on equity at the lower range, the Commission can send a clear signal that KCPL's customer satisfaction is inferior as compared to other utilities and that improvement is needed.

4. The Commission should adopt Mr. Brubaker's class cost of service study which relies on the Average & Excess production allocator. Unlike the flawed Staff and KCPL approaches, the A&E methodology is well established among numerous state utility commissions. Furthermore, this methodology should allow Missouri industry to better compete with these other states that rely on the A&E methodology to set retail rates.

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: March 22, 2017