BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City	)	
Power & Light Company's Request	)	Case No. ER-2014-0370
for Authority to Implement a General	)	
Rate Increase for Electric Service	)	

INITIAL POSTHEARING BRIEF

OF

MIDWEST ENERGY CONSUMERS GROUP

David L. Woodsmall
Woodsmall Law Office
308 E. High Street, Suite 204
Jefferson City, MO 65101
Phone: 573-636-6006
Fax: 573-636-6007
david.woodsmall@woodsmalllaw.com

ATTORNEY FOR MIDWEST
ENERGY CONSUMERS GROUP

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COME NOW the Midwest Energy Consumers' Group (collectively referred to herein as "MECG") by and through the undersigned counsel, pursuant to the Commission's December 12, 2014 *Order Setting Procedural Schedule and Establishing Test Year and Other Procedural Requirements*, and provides its initial post-hearing brief. In this brief, MECG will brief the following issues: (1) Cost of Capital (Issue I); (2) Fuel Adjustment Clause (Issue II); (3) Transmission Tracker (Issue III); (4) Property Tax Tracker (Issue IV); (5) CIP / Cyber-Security Tracker (Issue V); (6) Rate Case Expense (Issue XIV); (7) Management Audit (Issue XVII); (8) Income Tax-Related Issues (Issue XIX); and (9) Class Cost of Service / Rate Design (Issue XXV).

I. INTRODUCTION

On October 30, 2014, Kansas City Power & Light Company (KCPL or Company), a wholly owned subsidiary of Great Plains Energy Corporation (Great Plains or GPE), filed for a $120.9 million rate increase. In this case, the Commission will decide several different issues. 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, the Commission should be aware that, at the same time that KCPL is requesting the implementation of deferral accounting through a fuel adjustment clause and multiple tracker mechanisms, ***KCPL is virtually guaranteed a rate increase of over 11.5%***.[1] Adding insult to injury for ratepayers facing another double digit rate increase, KCPL expects this Commission to go outside the true-up time period to provide it additional revenue increases. Given that the Commission is charged with protecting ratepayers from the monopolistic actions of utilities like KCPL,[2] MECG expects the Commission to say "enough".

Additionally, as is more fully explained *infra*, MECG urges the Commission to consider the rapid increase in rates that have been imposed on KCPL customers since 2007 and ignore KCPL's misplaced claims that it has routinely earned below its authorized return on equity.

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[1] Exhibit 259, Staff Accounting Schedules.

[2] *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).

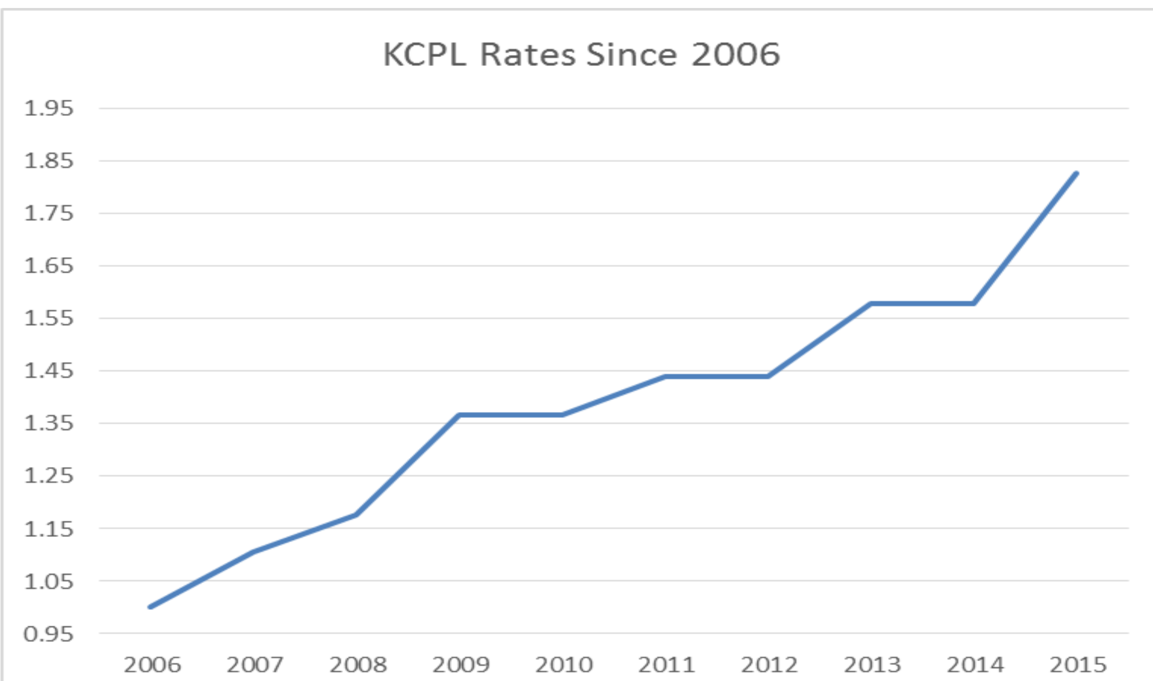
A. RAPID INCREASE IN KCPL RATES

Since 2006, KCPL rates have skyrocketed. Specifically, since that date, the Commission has authorized the following rate increases.[3]

• ER-2006-0314:	$50.6 million	10.46% increase
• ER-2007-0291:	$35.3 million	6.50% 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
	$283.1 million	57.69% increase

Recognizing that KCPL is still seeking a $120.9 million (15.75%) increase in this case, KCPL rates could potentially increase by over $404 million (82.53%) since 2007.

The tremendous increase in KCPL rates is particularly noticeably when viewed graphically. The following chart assumes KCPL's requested 15.75% rate increase.



[3] Exhibit 200, Staff Cost of Service Report, page 11.

Where KCPL's rates were once significantly below the regional and national average rates, that gap has now narrowed. Specifically, while the national average rate grew by only 30% between 2007 and 2013, KCPL's rate increased by over 57%. In fact, KCPL's rates are now well above the Missouri and regional average electric rates.[4]

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. Specifically, the average weekly wage of KCPL's customers has only increased by 11.47% over the same period of time.[5] During this period, inflation as measured by the consumer price index has grown 12.35%.[6] Thus, by any measure, KCPL's ratepayers are spending an ever increasing portion of their limited household income on the electricity provided by KCPL. In addition, as demonstrated below, concerns must begin to arise as to the affordability of KCPL's industrial customers to compete against companies located in areas with lower, slower-rising electric rates.

B. KCPL'S ALLEGATIONS OF UNDER-EARNINGS

In its effort to justify the multitude of deferral accounting mechanisms that it requested in this case (fuel adjustment clause and trackers), KCPL complained that the Missouri regulatory paradigm was broken and that it was incapable of earning its authorized return on equity.[7] Specifically, KCPL repeatedly claimed that it failed to authorize its authorized return on equity from the last case.[8]

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[4] Exhibit 212, Featherstone Surrebuttal, pages 7-8.
[5] Exhibit 202, Staff Cost of Service Report, page 11.
[6] *Id.*
[7] Exhibit 118, Ives Direct, pages 2-3 ("This case seeks to. . . establish certain alternative regulatory mechanisms in order to provide the Company a reasonable opportunity to earn its Commission-authorized return after this case.").
[8] *Id.* at page 2 ("While the Company raised rates January 26, 2013, in accordance with the Commission's order in Case No. ER-2014-0174, the Company has been unable to earn its authorized rate of return.").

As this section of the brief will show, however, KCPL's failure to earn its authorized return is overstated and, at least in large part, caused by its own actions: (1) Any failure to earn its authorized return is based in large part on KCPL's inability or unwillingness to control costs, especially A&G costs; (2) KCPL's alleged depressed return on equity is caused in large part by KCPL's desire to inflate affiliate returns by retaining excessive costs that should otherwise be allocated to those affiliates; (3) KCPL's alleged claims of depressed earnings are misleading because KCPL fails to consider "normal" levels of revenues, expenses and weather; (4) KCPL voluntarily accepted diminished returns on equity by forfeiting, to an affiliate, revenue streams associated with transmission projects; (5) There is significant evidence that, in its various surveillance reports, KCPL has manipulated its earnings to present a more depressing financial picture to the Commission. Of greatest concern, KCPL manipulated its calculation and use of the jurisdictional demand allocator; (6) KCPL's focus on earnings in a vacuum is misleading in that it fails to reflect its preferred metric, "total shareholder return."

First, as mentioned, KCPL's failure to earn its authorized return on equity is caused in large part by KCPL's unwillingness or inability to control costs. The record in this case is littered with examples of KCPL's inability to control its costs. Recognizing that the regulatory compact only provides the utility with the "opportunity" to earn its authorized return on equity, the utility's actual financial results are, in large part, based upon its desire and ability to control costs. Contrary to KCPL's implications, the authorized return on equity is not a guarantee of earnings despite the ineffectiveness of management.

For instance, in its audit, Staff uncovered significant concerns with officer expense accounts and the inflated cost contained in those billings. Specifically, KCPL initially sought recovery for costs associated with baby showers for employees and expenses related to travel and entertainment conducted on behalf of KCPL affiliates. Once confronted with discovery regarding the underlying rationale for recovery of these costs, KCPL "informed Staff that it was removing all GPE officer expense report costs."[9] While it removed such costs from its rate case request, KCPL still included these costs in its calculation of historical earnings. Certainly, a utility management that wants to take full advantage of its "opportunity" to earn an authorized return on equity would be cognizant of these excessive expenses and prevent them from occurring in the first place.

In addition, MECG presented evidence of KCPL's management's inability to control other costs. Specifically, as detailed in Section VIII, KCPL incurs the largest amount of A&G costs of any regional utility. On every metric (per customer; per kWh, and percentage of revenues basis), KCPL's A&G costs are significantly higher than other utilities.[10] Furthermore, when compared against KCPL's own self-defined peer group, KCPL's A&G costs are still the highest of any utility. Recognizing that Staff has raised similar concerns in past cases, the fact that KCPL's management has yet to bring such costs under control leads to concerns about its ability to actually manage these costs. Relevant to earnings, any reduction in A&G costs would result in an increase in KCPL's earnings. KCPL's allegation that it has consistently not earned its authorized return is, in large part, a result of its own inability to control A&G costs and make the most of its "opportunity" to earn its authorized return.

[9] Exhibit 216, Hyneman Surrebuttal, pages 36-40.
[10] Exhibit 500, Kollen Direct, page 8.

Second, questions regarding the adequacy of KCPL's past earnings must also consider KCPL's inability to properly allocate costs to its unregulated affiliates. Recognizing that KCPL acts as a service company for all of the Great Plains companies, all costs are initially incurred by KCPL. To the extent that KCPL fails to properly assign or allocate those costs to its affiliates, those costs remain at KCPL to depress KCPL's earnings. In this case, MECG raised several concerns with KCPL's failure to properly assign and allocate costs. Of utmost concern is the minimal amount of costs that KCPL allocates to its parent company. While Ameren allocates 6.9% of costs to its parent company and Southern Company allocates 3.8% of its costs to its parent, KCPL only allocated 0.49% of its costs to its parent Great Plains Energy.[11] Unquestionably, to the extent that KCPL fails to properly allocate these costs out of the Company and instead retains them, KCPL's earnings will be depressed and affiliate earnings will be inflated.

Third, KCPL's claimed earnings are necessarily suspect as a result of KCPL's failure to account for normal levels of revenues, expenses and weather. As the Commission noted in its recent Ameren decision, the failure to make such normalization makes book earnings inherently suspect.

> However, it is important to understand that the earnings levels reported in the ***surveillance reports*** are actual per book earnings of the utility and ***cannot be compared directly to an authorized return on equity*** to determine whether a utility is overearning. Actual per book earnings are often computed differently than earnings used for the purpose of establishing rates. When setting rates, the Commission looks at "normal" levels of ongoing revenues and expenses, while book earnings can be affected by abnormal, non-recurring and extraordinary events. A good example of this is the weather.[12]

[11] *Id.* at pages 3-6. KCPL avoided the implications of these issues by settling them. See, *Order Approving Stipulation and Agreement Regarding Certain Issues*, issued July 17, 2015, page 2, item 11 (corporate cost allocations, issue XVI).
[12] Case No. EC-2014-0223, *Report and Order*, issued October 1, 2014, at pages 8-9 (emphasis added).

Despite the clarity of the Commission's previous guidance, KCPL did not consider normal levels of revenues, expenses and weather in its reported return on equity. Given this, KCPL's allegations that it cannot earn its authorized return must ring hollow.

Fourth, KCPL's return on equity will naturally be depressed when one recognizes that KCPL forfeited revenue opportunities to its unregulated affiliate. Specifically, in 2009, SPP provided KCPL a "Notice to Construct" two transmission projects in the KCPL service area. These projects would have provided KCPL with additional revenue streams and increased earnings. Reflecting KCPL's willingness to sacrifice its own earnings for the benefit of Great Plains total company earnings, KCPL assigned these construction opportunities to an affiliate.[13] It is not surprising then, when a utility forfeits its revenue / earnings opportunities to an affiliate, that its own earnings may be depressed. Ratepayers, however, should not be expected to suffer from this decision.

Fifth, Staff made allegations in this case that KCPL has intentionally manipulated its reported earnings through its use and calculation of the jurisdictional demand allocator. Recognizing that this allocator is the basis behind allocating fixed production costs between the Missouri, Kansas and wholesale jurisdictions, any shift in that allocator can easily have the effect of depressing the return of the target jurisdiction. In this case, KCPL has repeatedly reported depressed 2014 earnings. Inexplicably, however, those 2014 earnings were calculated by KCPL using the 2013 demand allocator. Understanding that the 2013 demand allocator assigned a larger amount of costs to Missouri, the KCPL Missouri earnings were manipulated downward.[14]

[13] Exhibit 200, Staff Cost of Service Report, pages 143-144; Exhibit 210, Featherstone Direct, pages 40-41.
[14] Exhibit 210, Featherstone Direct, pages 50-54.

Sixth, KCPL's focus on earnings is intentionally designed to misrepresent its actual financial position. As Staff indicates, Great Plains Energy asserts that the more representative financial metric is "total shareholder return." This metric considers both corporate dividends as well as the increase in stock price. Based upon this metric, the financial picture is much brighter.

> In 2013, Great Plains Energy continued down a determined path to improve our total shareholder return. Our mantra of "Execute, Execute, Execute" focused on our ability to achieve operational excellence, manage costs and significantly reduce regulatory lag. I am proud to report that we delivered on this goal. ***Our 2013 total shareholder return of 24 percent placed us in Tier 1 of investor-owned utilities, which compared to a 17 percent return for the Edison Electric Institute Index***.[15]

In light of these numerous problems associated with KCPL's claimed earnings, one must necessarily question whether KCPL's earnings were depressed and, if they were, whether those depressed earnings were a result of KCPL's desire to inflate affiliate earnings at the expense of its own earnings. Given the questionable nature of KCPL's earnings assertions, the Commission should summarily disregard KCPL's claims that it suffers from an inherently flawed Missouri regulatory scheme. As the evidence clearly indicates, Missouri regulation appears to be squarely in the mainstream of state utilities commissions.[16] In the final analysis, KCPL should look itself in the mirror and take stock of the steps it can take towards availing itself of the "opportunity" to earn its authorized return on equity instead of casting stones at the regulators and stakeholders involved in this process.

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[15] Exhibit 212, Featherstone Surrebuttal, page 21 (citing to 2013 Great Plains Energy Incorporated Annual Report, page 1- CEO Terry Bassham's letter to shareholders).

[16] *Id.* at pages 21-22. Indeed, objective analysts including Standard & Poors have recently upgraded KCPL's credit rating on the basis of "constructive regulatory outcomes." (See, Exhibit 550, Gorman Direct, page 8).

II. OVERVIEW OF POSITIONS

RETURN ON EQUITY (ISSUE I): Consistent with the recommendation of MIEC / MECG Witness Gorman, the Commission should authorize KCPL to earn a return on equity of 9.10% (range of 8.80% to 9.40%). Unlike KCPL's testimony, this recommendation is consistent with previous Commission decisions and recognizes the continuing decline in utility capital costs. Furthermore, in several recent decisions, the Commission has found that KCPL is less risky than Ameren and has authorized KCPL a return on equity that is 10 to 20 basis points below that authorized to Ameren. In fact, KCPL's own witness, who also testified on behalf of Ameren, recommended that KCPL receive a return on equity that is 10 basis points below that awarded to Ameren. Recognizing that the Commission has recently awarded Ameren a return on equity of 9.53% and in light of Mr. Hevert's recommendation that KCPL receive 10 basis points less than Ameren, the Commission should award KCPL a return on equity that is no higher than 9.43%.

In the event that the Commission authorizes KCPL to implement a fuel adjustment clause or any of its requested tracker mechanisms, the Commission should consider granting a return on equity that is at the low end (8.80% to 9.10%) of Mr. Gorman's range. Granting a lower return on equity would recognize the reduced risk and lower cost of equity that KCPL would face as a result of these regulatory mechanisms.

FUEL ADJUSTMENT CLAUSE (ISSUE II): The Commission should find that, as a result of the provision in its 2005 Regulatory Plan, KCPL was precluded from seeking a fuel adjustment clause until after June 1, 2015. Given that KCPL's case was filed on October 30, 2014, KCPL's fuel adjustment clause is premature and should be rejected.

In the event that the Commission desires to address the fuel adjustment clause on the merits of its proposal, MECG recommends that the Commission adopt the positions advanced by MECG witness Brosch. Specifically, Mr. Brosch applies the criteria contained in 4 CSR 240-20.090(2)(C) to each of the costs that KCPL seeks to include in its fuel adjustment clause. From his analysis, Mr. Brosch concludes that KCPL's coal costs, nuclear costs, natural gas / oil costs, and transmission costs are not materially significant, not volatile, and / or within the control of KCPL's management. To the extent that the Commission decides to establish a fuel adjustment clause, that clause should be limited only to KCPL's off-system sales margins that have demonstrated some degree of volatility in the past decade.

Additionally, MECG points out that Section 386.266.1 limits the extent to which the Commission can include transmission costs in the fuel adjustment clause. This position is consistent with that adopted by the Commission in the recent Ameren and Empire rate cases. Further, in the event that the Commission implements a fuel adjustment clause, MECG recommends that the Commission recognize four different voltage classes and four different line losses for collection of fuel adjustment costs from the Large Power rate class. Finally, MECG points out that the fuel adjustment clause line item is one of the only points of distinction between bills provided to KCPL customers and those provided to GMO customers. Absent this point of distinction, KCPL and GMO customers will not be able to specifically identify their service provider, locate the appropriate rate schedule and independently calculate their bills. In the event that the

Commission authorizes KCPL to implement a fuel adjustment clause, it should require KCPL and GMO to properly distinguish their bills from each other.

PROPOSED TRACKERS (ISSUES III, IV AND V): As set forth herein, the Commission does not have specific statutory authority to utilize deferral accounting and trackers. Rather, any exception to the rule against retroactive ratemaking is solely contained within the court created authority to defer costs associated with "extraordinary" events. Recognizing the problems inherent in deferral accounting, the Commission has carefully spelled out criteria for considering past deferral requests. Based upon the extraordinary standard as well as these criteria, Mr. Brosch considered each of KCPL's proposed trackers. In the final analysis, based upon these criteria, the Commission should reject KCPL's proposed transmission, property tax and cyber-security trackers.

RATE CASE EXPENSE: In this brief, MECG proposes that the Commission disallow large amounts of KCPL's rate case expense as imprudent. First, it was repeatedly demonstrated throughout this hearing that KCPL relies heavily on the use of outside counsel. Given the obvious qualifications of its own in-house attorneys, MECG suggests that the Commission disallow, in its entirety, the legal fees associated with one of KCPL's outside attorneys. For the other outside attorney, MECG recommends that the Commission price those fees based upon a surrogate rate of $200.00 / hour as billed by Ameren counsel Jim Lowery. Second, MECG recommends that the Commission disallow, in its entirety, the class cost of service / rate design services provided by Management Application Consulting. It is clear from the qualifications of KCPL

Witness Rush that he has the capability to provide such services. As such, the services provided by Management Application Consulting were entirely redundant. In fact, this consultant never even provided testimony in this case. Given this, these fees should be disallowed. Third, MECG recommends that the Commission disallow the entirety of the fees associated with Mr. Overcast. As demonstrated in his live testimony, Mr. Overcast's services were largely irrelevant and redundant. Furthermore, Mr. Overcast repeatedly ventured opinions that were based upon speculation and well outside his scope of expertise. Finally, MECG recommends that the Commission allow Mr. Hevert's fees only to the $30,000 budget utilized by Mr. Gorman for this case. In fees above this surrogate budget should be disallowed.

MANAGEMENT AUDIT (ISSUE XVII): As set forth herein, KCPL suffers from an inflated level of A&G costs. As compared to other regional utilities, as well as those utilities included in KCPL's peer compensation group, KCPL's A&G are unquestionably inflated. This problem is not a recent development. Rather, Staff has documented this problem for several recent cases. The practical effect of these inflated A&G costs is to impose higher rates on KCPL ratepayers and depress KCPL's earnings.

Given KCPL's unwillingness or inability to control A&G costs, MECG recommends that the Commission order a management audit. As set forth in the testimony of Lane Kollen, such an audit is not unique. Rather, other utilities have voluntarily undergone such audits and state utility commissions have ordered such audits. While KCPL has yet to undergo a comprehensive audit, it has undergone similar audits with limited scope. As KCPL readily admits, such audits are "beneficial." Nevertheless, KCPL resists the current recommendation. Given the Commission's statutory duty to protect ratepayers from the monopolistic practices of the utility, the Commission should recognize this persistent problem and order a management audit.

INCOME TAX-RELATED ISSUES (ISSUE XIX): As detailed in the testimony of recognized expert Brosch, KCPL's revenue requirement is inflated as a result of four tax related issues. First, inconsistent with previous Commission orders, KCPL fails to include the CWIP-ADIT liability balance in rate base. Second, while KCPL includes the 1KC Place ADIT asset balance in rate base, it fails to include the offsetting accrued liability. Third, and similarly, while KCPL includes the deferred employee compensation ADIT asset balance in rate base, it fails to include the offsetting accrued liability. Fourth, Mr. Brosch recommends that the Commission protect KCPL ratepayers from the detrimental effect of the Great Plains Energy Tax Allocation Agreement. Contrary to the Commission's decision in the recent Ameren case, the Great Plains TAA has never been beneficial to KCPL ratepayers and is not projected to be beneficial. Moreover, that TAA is structured in a manner that it is inherently detrimental. Given the detrimental effect of the TAA, KCPL was unable to recognize its recent net operating loss. As a result, deferred taxes are reduced and rate base is inflated. The Commission should protect ratepayers from the detrimental impact of this faulty affiliate agreement.

CLASS COST OF SERVICE / RATE DESIGN (ISSUE XXV): MECG urges the Commission to adopt the Non-Unanimous Stipulation and Agreement filed on June 16, 2015. Consistent with this Agreement, the Commission should allocate any revenue increase on an equal percentage basis to all rate classes. Furthermore, the Commission should collect any revenue increase allocated to the Large General Service (LGS) / Large Power (LP) rate classes primarily through an increase in the demand charges and first energy block charge. By collecting less through the second energy block and tailblock energy rates, KCPL will more properly collect its fixed costs through the demand charges. This serves to reduce the intra-class subsidy that currently exists in the LGS and LP rate schedules.

Only in the event that the Commission rejects the Non-Unanimous Stipulation and Agreement, 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. 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 / LP rate classes by collecting more costs through the LGS / LP demand and first energy blocks consistent with the recommendation of Mr. Brubaker.

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 <u>***is fatal***</u> to his or her relief or recovery."[20]

[20] *Id.*

IV. RETURN ON COMMON EQUITY

Position: Consistent with the recommendation of MIEC / MECG Witness Gorman, the Commission should authorize KCPL to earn a return on equity of 9.10% (range of 8.80% to 9.40%). Unlike KCPL's testimony, this recommendation is consistent with previous Commission decisions and recognizes the continuing decline in utility capital costs. In the event that the Commission authorizes KCPL to implement a fuel adjustment clause or any of its requested tracker mechanisms, the Commission should consider granting a return on equity that is at the low end (8.80% to 9.10%) of Mr. Gorman's range. Granting a lower return on equity is consistent with Section 386.266.7 and would recognize the reduced risk and lower cost of equity that KCPL would face as a result of these regulatory mechanisms.

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 controls, the utility will inevitably seek to extract monopoly profits from the many (the ratepayers of Missouri) for the benefit of the few (the utility 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

[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).

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 10.30%.[24] In support of this request, KCPL presents the flawed testimony of Robert Hevert. KCPL's recommendation stands in stark contrast to the return on equity recommendations provided by the other three experts in this case. Specifically, MIEC / MECG present the expert testimony of Michael Gorman who arrives at a return on equity range of 8.80% to 9.40% with a recommended return on equity of 9.10.[25] Staff provided the expert testimony of Zephania Marevangepo who concludes that a range of 9.00% to 9.50% with a recommended return of 9.25% is reasonable[26] Finally, the U.S. Department of Energy (DOE) presented the expert testimony of Maureen Reno who provides a range of 8.20% to 9.60% with a recommended return on equity of 9.00%.[27] Clearly then, KCPL's recommendation appears to be an outlier and stands out as significantly higher than those recommended by the other return on equity experts.[28]

As this brief demonstrates, KCPL's recommendation is inflated because it is fundamentally flawed. In recent cases, the Commission has pointed out specific criticisms with Mr. Hevert's assumptions and methodology. As a result, the Commission, in several recent decisions, concluded that Mr. Hevert's recommendations were "too high" and rejected his recommendation.[29] Despite the clarity of the

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[23] *Id.*
[24] Exhibit 115, Hevert Direct, page 2.
[25] Exhibit 550, Gorman Direct, page 2.
[26] Exhibit 200, Staff Cost of Service Report, page 4.
[27] Exhibit 700, Reno Direct, page 4.
[28] The Commission has previously looked at the consistency of the 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.
[29] Case No. ER-2012-0166, *Report and Order*, issued December 12, 2012, at pages 69-70.

Commission's prior criticism and its decision to summarily reject his recommendation, Mr. Hevert presented the same flawed analysis in this case relying upon the same problematic assumptions. For the same reasons as before, the Commission should disregard KCPL's recommendation in this case.

B. GORMAN CREDIBILITY AND OBJECTIVE ANALYSIS

In its consideration of the return on equity issue in recent rate cases, the Commission has frequently been presented with the analysis conducted by Mr. Gorman. In its recent Ameren decision, issued just two months ago, the Commission pointed out that Mr. Gorman was "a reliable rate of return expert."[30] In other decisions, the Commission's finding as to Mr. Gorman's reliability and credibility was 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.[31]
>
> Michael Gorman, the witness for SIEUA, AG-P and FEA, did the best job of presenting the balanced analysis the Commission seeks.[32]
>
> 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.[33]

In this case, Mr. Gorman presents the same "credible" and "balanced" analysis relied upon by the Commission in those recent cases. Here, 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

[30] Case No. ER-2014-0258, *Report and Order*, issued April 29, 2015, at page 66.
[31] Case No. ER-2012-0166, *Report and Order*, issued December 12, 2012, at page 70.
[32] Case No. ER-2007-0004, *Report and Order*, issued May 17, 2007, at page 62.
[33] Case No. ER-2007-0002, *Report and Order*, issued May 22, 2007, at pages 40-41.

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 Pricing Model analysis.[34] The average of all of these analyses result in a recommendation of 9.00-9.60%.[35] MECG's witness Gorman's results can be summarized:

MODEL		RESULT
DCF	Constant Growth	8.44% - 8.60% (Exhibit 550, page 17 and 27)
	Sustainable Long-Term Growth	8.39% - 8.48% (Exhibit 550, pages 20 and 27)
	Multi-Stage Growth	8.19% - 8.36% (Exhibit 550, pages 26 and 27)
Risk Premium		9.21% -9.56% (Exhibit 550, page 33)
CAPM		9.05% (Exhibit 550, page 38)
Recommendation		**9.10%** (Exhibit 55, page 39)

Unique among the recommendations provided by the return on equity experts in this case, and consistent with the directives of the *Hope* and *Bluefield* decisions, Mr. Gorman then checks to ensure that his recommended return on equity will support an investment grade credit rating. Specifically, Mr. Gorman undertook certain financial tests for KCPL based upon his recommended 9.10% return on equity.[36] Mr. Gorman then compared the results of those tests to the benchmarks for two critical S&P financial ratios: (1) debt to EBITDA (Earnings Before Income Taxes, Depreciation and

[34] Exhibit 551, Gorman Direct, pages 14-18 (constant growth DCF); pages 19-20 (sustainable growth DCF); pages 20-26 (multi-stage growth DCF); pages 27-33 (risk premium analysis); and pages 33-39 (CAPM analysis).
[35] *Id.* at page 38.
[36] *Id.* at pages 40-43 and MPG-17.

Amortizations); and (2) funds from operations to total debt.[37] As Mr. Gorman's analysis reveals, his recommended 9.10% 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 9.10% and the Company's proposed embedded debt cost and capital structure, KCPL's financial credit metrics are supportive of its investment grade utility bond rating"[38]

C. HEVERT'S FLAWED 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 three separate occasions. In each instance, the Commission found that Mr. Hevert's assumptions and recommendations were "excessive" and "too high." In each instance, the Commission found that Mr. Hevert's recommendation was faulty because of his use of inflated long-term sustainable growth rates.

> Ameren Missouri's expert witness, Robert Hevert, supports an increased ROE at 10.4 percent. The Commission finds that such an ROE would be ***excessive***. 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.[39]
>
> 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

[37] *Id.* page 40.
[38] *Id.* at page 43.
[39] Case No. ER-2014-0258, *Report and Order*, issued April 29, 2015, at page 66 (emphasis added).

> rational to expect that utilities can grow faster than the demand of the economies they serve.[40]
>
> 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.[41]

Missouri is not the only commission that has found that Mr. Hevert's recommendations are "too high." In fact, over the past 2 1/2 years, state utility commissions have always awarded a return on equity that is well below Mr. Hevert's recommendation. As Exhibit 505 indicates, in 23 cases reported since January 1, 2013, Mr. Hevert has recommended an average return on equity of 10.49%.[42] In contrast, the state utility commission return on equity decision in those 23 reported cases averaged 9.70%.[43] Therefore, Mr. Hevert's recommended return on equity has exceeded that authorized by the various state utility commissions by 79 basis points.[44]

The reasons underlying Hevert's inflated recommendations are apparent when one digs further into Hevert's flawed methodologies. In at least four different ways Hevert has inflated the results of his various analyses.

First, Mr. Hevert employed "excessive, unsustainable growth rates" in the calculation of his constant growth DCF analysis.[45] As Mr. Gorman pointed out, "[m]ost of his [Hevert's] DCF return estimates are based on growth rates that are too high to be

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[40] Case No. ER-2012-0166, *Report and Order*, issued December 12, 2012, at pages 69-70. (emphasis added).
[41] Case No. ER-2011-0028, *Report and Order*, issued July 13, 2011, at page 23. (emphasis added).
[42] Tr. 158.
[43] *Id.*
[44] *Id.*
[45] Exhibit 551, Gorman Rebuttal, pages 6 and 9-11.

reasonable estimates of long-term sustainable growth."[46] Specifically, in calculating his high-end DCF return on equity, Mr. Hevert employed a proxy group growth rate of 6.81%.[47] This is significantly above the actual proxy group average growth rate (5.29% to 5.89%)[48] that is already inflated in that it exceeds the projected GDP growth rate over that period (4.4% - 4.7%).[49]

> These proxy group mean growth estimates are substantially higher than the consensus economists' long-term growth outlooks of the U.S economy. The GDP growth of the U.S. general economy, which is a proxy for the growth rate of the economies in which these utilities operate, is between 4.4% and 4.7% indefinitely. It is simply not rational to expect that these companies can grow considerably faster than the economies in which they provide service over a long period of time.[50]

As previously indicated, this Commission has repeatedly criticized Hevert's analysis for employing growth rates which exceed "reasonable estimates of long-term sustainable growth."[51] As Mr. Gorman has shown, when more realistic growth rates are employed, Mr. Hevert's constant growth DCF analysis results in a DCF estimate of 8.46% to 9.65% with a midpoint of 9.05%.[52]

<u>Second</u>, in his multi-stage growth DCF analysis, Mr. Hevert's long-term sustainable growth rate is based on a nominal GDP growth rate that is "considerably higher" than consensus analysts' projections.[53] Specifically, Mr. Hevert uses a long-term historical real GDP return of 3.27%, as measured over the period of 1929 through 2013.

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[46] *Id*. at page 9.
[47] *Id.* at page 10.
[48] *Id.* at page 9.
[49] *Id.* at page 10.
[50] *Id.*
[51] See, Case No. ER-2012-0166, *Report and Order*, issued December 12, 2012, at pages 69-70 and Case No. ER-2011-0028, *Report and Order*, issued July 13, 2011, at page 23.
[52] Exhibit 551, Gorman Rebuttal, page 10.
[53] *Id.* at page 11.

He then adjusted for realized inflation to arrive at a long-term nominal GDP growth rate of 5.65%.[54]

It is readily apparent that Hevert's long-term GDP growth rate in his multi-stage DCF analysis is inflated. In contrast to Hevert's GDP growth of 5.65%, consensus economists' estimates of GDP growth over the next five to 10 year period range from 4.45% to 4.65%.[55] As such, Mr. Hevert's multi-stage growth DCF is inflated.

Third, in his multi-stage growth DCF analysis, Mr. Hevert "makes an inconsistent assumption on his long-term steady-state growth rate, in combination with his long-term steady-state dividend payout ratio."[56] Specifically, while he assumes an increasing dividend yield in his proxy group, Mr. Hevert also assumes an increasing dividend payout ratio for his proxy group. Therefore, while current proxy group dividend payout ratios are 60.43 – 62.00%, Hevert assumes that this payout ratio will increase to 67.23%.[57]

Hevert arrives at his assumption by conveniently replacing the payout ratio projections for his proxy companies with the historical dividend payout ratio for the electric utility industry as a whole.[58] As Mr. Gorman points out, "Mr. Hevert's changing payout ratio assumptions simply are not reasonable based on the similar projections made by *Value Line* for the industry and the individual companies included in the proxy group."[59] "Making this adjustment in his model simply inflates the growth rate for dividends relative to earnings growth. . . and increases his DCF return estimate."[60]

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[54] *Id*. at page 12.
[55] *Id.* at page 13.
[56] *Id.* at page 11.
[57] *Id.* at page 14.
[58] *Id.* at page 15 (errata).
[59] *Id.*
[60] *Id.*

When one corrects for both of the errors in his multi-stage growth DCF analysis, Mr. Hevert's multi-stage DCF analysis decreases from 9.90% to 8.78%.[61] This is clearly in line with the results of Mr. Gorman's multi-stage DCF analysis of 8.34% to 8.48%.[62]

Fourth, Mr. Hevert employed inflated market risk premiums in the calculation of his CAPM return. Specifically, Mr. Hevert's market CAPM analysis employs a growth rate of 11.31% and 11.89%.[63] As Gorman notes, "these growth rates are more than two times the growth rate of the U.S. GDP long-term growth outlook of 4.6%."[64] Utilizing a more reasonable estimate of market risk premium results in a CAPM of 8.28% to 9.29% with a midpoint of 8.80%[65] Again, Hevert's corrected analysis is consistent with the result of Gorman's CAPM analysis of 9.05%.[66]

Ultimately, the problem with Mr. Hevert's analysis is not in the models that he used. Rather, as indicated below, the ongoing 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 analysis leads to a reasonable result (8.70% - 9.10%).[67]

	MODEL	HEVERT RESULT	ADJUSTED HEVERT RESULT
DCF Analysis			
	CONSTANT GROWTH DCF	9.52% - 9.59%[68]	9.03 – 9.10%[69]
	MULTI-STAGE	9.95% - 10.03%[70]	8.74 – 8.82%[71]

[61] *Id.* at page 16.
[62] Exhibit 550, Gorman Direct, page 27.
[63] Exhibit 551, Gorman Rebuttal, page 17.
[64] *Id.* at pages 17-18.
[65] *Id.* at page 19.
[66] Exhibit 550, Gorman Direct, page 38.
[67] Exhibit 551, Gorman Rebuttal, page 8.
[68] Exhibit 115, Hevert Direct, page 20.
[69] Exhibit 551, Gorman Rebuttal, pages 8 and 10-11.
[70] Exhibit 115, Hevert Direct, page 25.

	GROWTH DCF		
CAPM		10.64% - 12.09%[72]	8.58% – 9.02%[73]
Risk Premium Analysis		10.12%-10.86[74]	7.95%[75]
Recommendation		10.20 – 10.60%[76]	**8.70% - 9.10%[77]**

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 2 1/2 years, state utility commissions have found Hevert's return on equity to be inflated by 79 basis points. As this brief has shown, the reason underlying Hevert's inflated recommendation is found in his faulty analysis and his reliance on inflated data. If the Commission simply recognized the same 79 basis points premium that other state utility commissions have found, then Hevert's recommendation is lowered from 10.3% to 9.51% and becomes consistent with the overall decrease in capital costs.

D. CAPITAL COSTS ARE DECREASING

It is indisputable that capital costs have continued to decline.[78] As Mr. Gorman explains, over the past four years, "[b]ond yields have gone down. Utility stock prices have gone up. Utility dividend yields have come way down with the increase in stock price. Based on that observable market evidence, market cost of equity for Missouri electric utilities is significantly lower today than it was in 2011."[79]

[71] Exhibit 551, Gorman Rebuttal, pages 8 and 11-16.
[72] Exhibit 115, Hevert Direct, pages 28-29.
[73] Exhibit 551, Gorman Rebuttal, pages 8 and 17-19.
[74] Exhibit 115, Hevert Direct, page 32.
[75] Exhibit 551, Gorman Rebuttal, pages 8 and 19-22.
[76] Exhibit 115, Hevert Direct, page 55.
[77] Exhibit 551, Gorman Rebuttal, page 8.
[78] Tr. 265.
[79] Tr. 279-280.

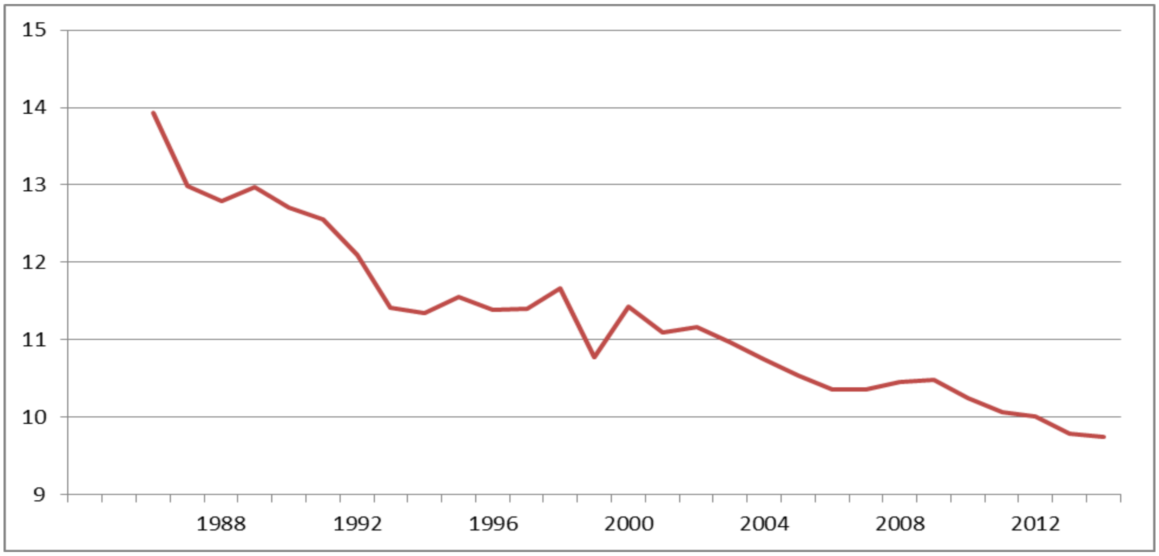
In its findings of fact in the recent Ameren case, the Commission adopted many of these points and expressly noted that capital costs have declined since the Commission issued its previous Ameren decision in December of 2012.

> In its decision regarding Ameren Missouri's last rate case, the Commission established an ROE of 9.8 percent. Since 2012, when that case was decided, interest rates have declined by approximately 37 basis points. Furthermore, utility stock prices have increased and their dividend yields have gone down. This indicates that utilities' cost of capital has decreased because they need to sell fewer shares to generate the capital they need to support their investments. As MIEC's witness, Michael Gorman, explained: "Because the price of stock has gone up and the other parameters of the stock have not significantly changed, that's a clear indication that investors have reduced their required cost of capital which has bid up the stock price." This suggests the ROE allowed to Ameren Missouri should also be decreased.[80]

Recognizing that the Commission's decision in the last KCPL case (ER-2012-0174) was issued less than a month after the 2012 Ameren decision, the same logic should apply. In that decision, the Commission authorized KCPL to earn a return on equity of 9.70%.[81] In the 2 years since the Commission issued its decision in ER-2012-0174, capital costs have continued to decrease. Specifically, since the end of the 2012, the national average authorized return on equity has declined by 25 basis points.[82] As the following graph indicates, this continues the decline in authorized return on equity that has existed since 1986.

[80] Case No. ER-2014-0258, *Report and Order*, issued April 29, 2015, at pages 65-66.
[81] Case No. ER-2012-0174, *Report and Order*, issued January 9, 2013, at page 15.
[82] Exhibit 550, Gorman Direct, Schedule MPG-11.

NATIONAL AVERAGE AUTHORITY RETURN ON EQUITY



Source: Exhibit 510, Gorman Direct, Schedule MPG-11.

Despite the decline in capital costs, KCPL's witness inexplicably insists that the Commission should increase KCPL's return on equity by 60 basis points from 9.70% to 10.30%. Such a recommendation is not surprising. State utility commissions have repeatedly found that Mr. Hevert's recommendations are "too high" by an average of 79 basis points. In contrast, Mr. Gorman's recommendation recognizes the continuing decline in utility capital costs. Specifically, Mr. Gorman recommends that the Commission reduce KCPL's authorized return on equity from 9.70% to 9.10% consistent with the referenced declining cost of capital.

In contrast to the substantial evidence demonstrating a continuing decline in capital costs, KCPL argued at the evidentiary hearing that recent metrics clearly indicate that the economy is picking up and driving up interest rates, particularly treasury yields. KCPL also suggests that none of the experts considered this increase in interest rates / bond yields in their studies. As the evidence indicates, however, KCPL's arguments are misplaced.

While Treasury Bond (T-bond) yields did increase at the time of the June hearing (approximately 3.1%), from those that were noticed when Staff and intervenors filed their direct testimony in early April, they still represent a decline from the 3.2% bond yields in existence at the time that KCPL filed its direct testimony in October 2014.[83] The real point is that, while there are bound to be minor fluctuations up and down over short periods of time, there is not yet a clear upward trend in those bond yields.

Secondly, KCPL's claim that such trends are not reflected in testimony is patently incorrect. As Mr. Gorman notes, the GDP outlook did project accelerated economic activity over the next five years, but projected that it would later slow over the following five years. Given that Mr. Gorman considered such GDP outlooks in his sustainable growth and multi-stage DCF calculation, he clearly reflected such predictions in the context of his overall recommendation.[84]

E. OTHER CONSIDERATIONS

In its consideration of the appropriate return on equity, there are two other factors that the Commission should consider. ***First***, the Commission has historically recognized that KCPL is less risky that Ameren. For instance, on April 12, 2011, the Commission issued its Report and Order authorizing KCPL to earn a 10.0% return on equity.[85] Just three months later, on July 13, 2011, the Commission issued its Report and Order authorizing Ameren to earn a 10.2% return on equity.[86] Thus, at that point in time, KCPL was perceived to be less risky than Ameren and was authorized a return on equity that was 20 basis points lower than Ameren.

[83] Exhibit 115, Hevert Direct, Schedule RBH-5, page 1.
[84] Exhibit 550, Gorman Direct, page 18.
[85] See, Case No. ER-2011-0355, *Report and Order*, issued April 12, 2011, at page 124
[86] See, Case No. ER-2011-0028, *Report and Order*, issued July 13, 2011, at page 74.

This trend continued in KCPL and Ameren's next cases. On December 12, 2012, the Commission issued its Report and Order in Ameren's next rate case. In that decision, the Commission authorized Ameren to earn a return on equity of 9.8%.[87] Less than one month later, on January 9, 2013, the Commission considered KCPL's rate case. In its Report and Order in that case, the Commission authorized KCPL to earn a return on equity of 9.7%.[88] Clearly then, the Commission still perceived KCPL as less risky and deserving of a lower return on equity than Ameren.[89]

KCPL's less risky nature is not only a historical fact, it is also reflected in the return on equity recommendations of Mr. Hevert. Specifically, Mr. Hevert testified on behalf of Ameren in its last rate proceeding. In that proceeding, Mr. Hevert recommended that Ameren be authorized a return on equity of 10.4%.[90] In testimony filed less than four months later, Mr. Hevert recommended that KCPL be granted a return on equity of 10.3%.[91] Thus, KCPL has not only been perceived by the Commission to be less risky than Ameren historically, but KCPL's own return on equity witness reflects that perception in his current recommendation.

Given that KCPL has historically and currently been perceived to be 10-20 basis points less risky than Ameren, and recognizing that the Commission authorized Ameren

[87] See, Case No. ER-2012-0166, *Report and Order*, issued December 12, 2012, at page 73.
[88] See, Case No. ER-2012-0174, *Report and Order*, issued January 9, 2013, at page 15.
[89] It is important to remember that, from a regulatory mechanism standpoint, Ameren and KCPL were identical to their status today. Specifically, Ameren had a fuel adjustment clause and KCPL was operating without a fuel adjustment clause.
[90] See, Case No. ER-2014-0258, *Report and Order*, issued April 29, 2015, at page 62.
[91] Exhibit 115, Hevert Direct, page 2.

to earn a return on equity of 9.53%,[92] KCPL should be authorized a return on equity of no more than 9.43%.[93]

Second, it is important to remember that the return on equity recommendations in this case are based upon KCPL's current risk profile.

> My recommended rate of return reflects KCPL's risk as it exists at the time of my analysis. To the extent new regulatory mechanisms are implemented in this proceeding which improve KCPL's likelihood of fully recovering fuel, capital and other costs of service, then its operating risk will be reduced prospectively. Hence, my rate of return on common equity would not reflect the prospective risk reductions created if KCPL's new regulatory mechanisms are approved.[94]

Given this, to the extent that the Commission authorizes any of KCPL's deferral mechanisms, the reduction in KCPL's risk profile going forward should be reflected in a return on equity that is below the mid-point of the reasonable range.

> If the Commission implements new regulatory mechanisms which improve KCPL's opportunity to earn its authorized return on equity, then its risk going forward will be lower than its risk in the past. My analysis is based on KCPL's existing risk. Therefore, if new regulatory mechanisms are approved which reduce that risk going forward, then that should be considered in awarding a return on equity lower than my recommended return for KCPL.
>
> My recommended point estimate of 9.10% is the midpoint of my estimated range of 8.80% to 9.40%. If new rider mechanisms are implemented, the Commission should award a return on equity below 9.10%, but above my low-end estimate of 8.80%. The actual point estimate below the midpoint cannot be precisely measured, however going below the midpoint of the estimated range would be reasonable.[95]

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[92] See, Case No. ER-2014-0258, *Report and Order*, issued April 29, 2015, at page 68.
[93] As the following section recognizes, the KCPL return on equity is based upon the current risk profile. The implementation of any deferral accounting mechanisms should be recognized in the return on equity decision.
[94] Exhibit 550, Gorman Direct, page 3.
[95] Exhibit 551, Gorman Rebuttal, page 5.

Indeed, the logic of such a recommendation, that the implementation of trackers reduce risk and therefore the authorized return on equity, was admitted by KCPL's own witnesses during the hearings:

> **Mr. Woodsmall**: Would you agree that the comparable company group is picked based on credit rating?
>
> **Mr. Overcast**: Yes. Among other things.
>
> **Mr. Woodsmall**: Okay.
>
> **Mr. Overcast**: Size, a variety of factors.
>
> **Mr. Woodsmall**: Okay. And I believe you did agree to Commissioner Hall's question that trackers reduce risk?
>
> **Mr. Overcast**: Yes, they do.
>
> **Mr. Woodsmall**: And as risk is reduced, credit rating can increase; is that correct?
>
> **Mr. Overcast**: Well, the credit rating will increase when –
>
> **Mr. Woodsmall**: It's a yes-or-no question. As risk is reduced, credit rating can increase; is that correct?
>
> **Mr. Overcast**: Well, I can't answer the question as posed.
>
> **Mr. Woodsmall**: You can't answer that question?
>
> **Mr. Overcast**: No, the reason I can't answer that question is because you said can the credit rating increase. There are lots of other factors. That's not the only one.
>
> **Mr. Woodsmall**: Okay. As -- holding all else equal, if risk goes down, credit rating may increase; is that correct?
>
> **Mr. Overcast**: It may, yes.
>
> **Mr. Woodsmall**: Okay. And in such a case, if credit rating goes up, the comparable group may change; is that correct?
>
> **Mr. Overcast**: It may.

> **Mr. Woodsmall**: Okay. So implementation of trackers could change the comparable company group; is that correct?
>
> **Mr. Overcast**: Yes.[96]

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 9.10% (range of 8.80% to 9.40%). 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 10.3% return on equity recommendation.

In its decision, the Commission should also recognize that it has historically found that KCPL is of a lower perceived risk and should be authorized a return on equity that is 10-20 basis points lower than Ameren. Indeed, this lower perceived risk is reflected in the fact that KCPL's own witness recommends a return on equity that is 10 basis points lower than the return on equity that he recommended for Ameren.

Finally, the Commission should recognize that the return on equity recommendations in this case are based upon KCPL's current risk profile. As KCPL"s own witness grudgingly recognizes, to the extent that the Commission implements any of KCPL's recommended deferral mechanisms (fuel adjustment clause or trackers), the Commission should reflect the reduced risk for KCPL by granting a return on equity that is at the lower end of the reasonable return.

[96] Tr. 1365-1367.

V. FUEL ADJUSTMENT CLAUSE

A. DOES KCPL'S FUEL ADJUSTMENT CLAUSE REQUEST VIOLATE THE STIPULATION AND AGREEMENT FROM CASE NO. EO-2005-0329? IF SO, SHOULD IT BE REJECTED? (ISSUE II(A))

1. Introduction

In 2005, KCPL sought a method by which it could construct the Iatan 2 generating station. Fearful of the financial implications of investing $1 billion over 5 years for its share of the generating station,[97] KCPL sought ratepayer support. As a result, KCPL engaged numerous stakeholders in discussions to address the construction of Iatan 2 as well as numerous other issues. Ultimately, those discussions led to a stipulation, now known as the KCPL Regulatory Plan.[98]

Among others, the KCPL Regulatory Plan contained two key provisions. First, among other benefits that KCPL received, the Regulatory Plan provided for ratepayers to pay additional Regulatory Amortizations. Specifically, despite the statutory prohibition against recognizing construction work in progress, ratepayers paid rates in excess of what were otherwise warranted in order to maintain KCPL's credit rating. Ultimately, ratepayers paid KCPL over $185 million, over and above what was otherwise justified through rates, in order to provide support for the construction of Iatan 2.[99]

Offsetting the receipt of Regulatory Amortizations was the second key provision of the Regulatory Plan. Specifically, in exchange for providing the additional rates, ratepayers received a commitment from KCPL not to seek a fuel adjustment clause or any

[97] Exhibit 201, Staff Accounting Schedules, Schedule 3, page 2.
[98] See, Case No. EO-2005-0329.
[99] Exhibit 200, Staff Cost of Service Report, page 163 ("Another $185 million is related to a period of Credit Metrics regulation that was put into effect during the construction of Iatan Unit 2 to increase KCPL's cash flow through regulatory amortizations directed towards keeping KCPL's credit rating from being reduced."). See also, pages 171-174.

other regulatory mechanisms envisioned under pending legislation called Senate Bill 179.[100] The specific provision is as follows:

> KCPL agrees that, prior to June 1, 2015, it will not seek to utilize any mechanism authorized in current legislation known as "SB 179" or other change in state law that would allow riders or surcharges or changes in rates outside of a general rate case based upon a consideration of less than all relevant factors. In exchange for this commitment, the Signatory Parties agree that if KCPL proposes an Interim Energy Charge ("IEC") in a general rate case filed before June 1, 2015 in accordance with the following parameters, they will not assert that such proposal constitutes retroactive ratemaking or fails to consider all relevant factors.[101]

In this case, KCPL has asked that the Commission allow it to implement a fuel adjustment clause. Given the provision in the Regulatory Plan prohibiting KCPL from seeking a mechanism under SB 179, several parties have claimed that KCPL's request violates the Regulatory Plan stipulation and should be rejected. Such claims have come from virtually every party to the Regulatory Plan. For instance, Staff points out:

> Staff cannot support the request for a fuel adjustment charge (FAC) in a rate case filed prior to June 1, 2015 since the Regulatory Plan prohibits KCPL from proposing a FAC prior to June 1, 2015.[102]

Similarly, OPC, another party to the Regulatory Plan, asserts that KCPL's requested fuel adjustment clause is premature and should be rejected.

> Because KCPL requested an FAC prior to June 1, 2015, the Commission should reject KCPL's request for an establishment of an FAC in this case and defer the matter until the next general rate proceeding filed by KCPL.[103]

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[100] Ultimately, Senate Bill 179 was passed by the General Assembly and signed by the Governor. SB 179 is codified at Section 386.266.
[101] See, Exhibit 503, Brosch Direct (Rate Design), pages 12-13 (citing to Case No. EO-2005-0329, *Stipulation and Agreement*, filed March 28, 2005, at page 7). See also, Exhibit 200, Staff Cost of Service Report, pages 189-194.
[102] Exhibit 200, Staff Cost of Service Report, page 194.
[103] Exhibit 309, Mantle Direct, page 10.

Finally, MECG, which includes Praxair, another signatory to the Regulatory Plan, points out the Regulatory Plan provision precludes KCPL from seeking a fuel adjustment clause and, instead, limits KCPL to seeking an Interim Energy Charge.[104]

Given the Regulatory Plan provisions which precludes KCPL from seeking a fuel adjustment clause prior to June 1, 2015, the Commission should reject KCPL's FAC.

2. The Regulatory Plan Provision is Not Ambiguous

Recognizing the Regulatory Plan prohibition and the widespread opposition to its requested fuel adjustment clause, KCPL seeks to introduce an ambiguity to the Regulatory Plan prohibition. Specifically, by focusing solely on the first sentence of the prohibition, KCPL claims that it is unclear whether the June 1, 2015 date pertains to the word "seek" or the word "utilize."

> "KCPL agrees that, prior to June 1, 2015, it will not seek to utilize any mechanism authorized in current legislation known as "SB 179"".

MECG agrees that, ***read in a vacuum as KCPL proposes***, it is unclear whether the June 1, 2015 date applies to a prohibition to "seek" an SB179 mechanism or a prohibition to "utilize" an SB179 mechanism. If the prohibition precludes KCPL from *seeking* a fuel adjustment clause, then KCPL's request is clearly premature. On the other hand, if the prohibition precludes KCPL from *utilizing* a fuel adjustment clause, then KCPL's request is timely. Fortunately, the second sentence of the Regulatory Plan prohibition removes any ambiguity and demonstrates that the prohibition applies to the act of "seeking" a fuel adjustment clause. As Staff points out:

> To provide meaning to the applicability of the June 1, 2015, date, both the first and the second sentences of the Regulatory Plan quoted above should be read together. It is significant that the date in both sentences – June 1, 2015 – is the same. The second sentence qualifies the first sentence by allowing KCPL to do something it could not under the first sentence. If the first sentence means that KCPL could request [seek] a SB 179 mechanism in a rate case filed before June 1, 2015, as long as that mechanism did not

[104] Exhibit 503, Brosch Direct (Rate Design), pages 12-14.

> become effective until after June 1, 2015, then the date in the second sentence would be meaningless. Therefore, the first sentence must mean that KCPL is not permitted to request a FAC or any other SB 179 mechanism before June 1, 2015, while the second creates an exception to that broad prohibition by allowing KCPL to request an IEC (but not a FAC) before June 1, 2015.[105]

Indeed, the unambiguous nature of the Regulatory Plan prohibition has previously been admitted by KCPL. Specifically, contrary to its current position, KCPL has previously admitted in sworn testimony that the Regulatory Plan stipulation prevents KCPL from "seeking" a fuel adjustment clause prior to June 1, 2015.

> Q: Does the Company have a Fuel Adjustment Clause ("FAC")?
>
> A: No, it does not. Per the Stipulation and Agreement ("Stipulation") approved in 2005 by the Commission in KCP&L's Experimental Regulatory Plan ("Regulatory Plan") docket, Case No. EO-2005-0329, the Company agreed that it **will not seek a FAC prior to June 1, 2015**. However, the Company is not prohibited from requesting an IEC.[106]

Still again, in a sworn filing with the SEC, KCPL recognized that its current fuel adjustment clause request is premature. Specifically, by placing the June 1, 2015 date in the same clause as the word "seek", and separating it apart from the word "utilize," KCPL recognized that the June 1, 2015 prohibition applies to the act of seeking a fuel adjustment clause.

> ***KCPL will not seek prior to June 1, 2015***, to utilize any mechanism authorized in pending legislation or other change in state law that would allow riders, surcharges or changes in rates outside of a general rate case based upon a consideration of less than all relevant factors.[107]

Clearly, when the first sentence is read in conjunction with the second sentence, it is apparent that the Regulatory Plan prohibition precludes KCPL from seeking a fuel

[105] Exhibit 200, Staff Cost of Service Report, page 192.
[106] *Id.* at pages 192-193 (citing to Direct Testimony of Tim M. Rush. Case No. ER-2012-0174. Page 10, lines 4-8).
[107] Exhibit 507.

adjustment clause prior to June 1, 2015. More importantly, despite its current claims of ambiguity, KCPL's own sworn testimony and SEC filings demonstrate that KCPL held this same interpretation of this key provision.

3. Extrinsic Evidence Supports the MECG Interpretation

In the previous sections, MECG has demonstrated that the Regulatory Plan provision, when read in its entirety, is unambiguous. Specifically, when read in conjunction with the second sentence, the first sentence provides a prohibition against KCPL seeking a fuel adjustment clause prior to June 1, 2015. Sworn testimony and KCPL filings with the SEC demonstrate the unambiguous nature of this provision. In the event that the Commission finds that the provision is ambiguous, however, there was extrinsic evidence offered to help the Commission interpret the Regulatory Plan prohibition.

Specifically, extrinsic evidence regarding the interpretation of the Regulatory Plan prohibition was offered in testimonial form by Staff Witness Featherstone and OPC Witness Mantle. Both witnesses were intimately involved in the Regulatory Plan workshops and negotiations.

As Mr. Featherstone relates, he was intimately involved in the meetings that resulted in the Regulatory Plan. Specifically, he notes that there were "countless meetings" through the winter and spring of 2005.[108] Given his actual attendance at those meetings and the negotiations that were occurring, Mr. Featherstone's insight is particularly informative. As he points out, the two sentences must be read in totality.

> That it was the two sentences have to be read in totality. You have to -- the first sentences have to be read in totality. The first sentence tells KCP&L what it cannot get and the second sentence is what it can get.

[108] Tr. 1391.

> And it's all linked to the June 1, 2015, date. And it was in my view that what we negotiated in this agreement, this contract was that they could not seek or request a fuel clause prior to June 1 of 2015.[109]

Interestingly, KCPL did not oppose this language. Given the significant amount of off-system sales that KCPL was making and their operational history without a fuel adjustment, KCPL did not find such a provision to be objectionable.

> They didn't have a fuel clause in Kansas and there was no indications that they – and Kansas did have some utilities that had fuel clauses. But going back ten-year span. . . I think, they didn't feel like they particularly needed the fuel clause, and this is my view. . . . They had a great deal of off-system sales and I think that a lot of the fuel clauses that were being structured, off-system sales were being flown in through those fuel clauses, so I'm not sure that that was very attractive to Kansas City Power & Light.

In questioning from the bench and OPC, Mr. Featherstone expounded on his belief that the Regulatory Plan provision did not allow KCPL to "seek" a fuel adjustment clause prior to June 1, 2015.

> **Commissioner Stoll**: And -- and your interpretation is that "will not seek" means will not propose to use this mechanism prior to June 1st, 2015, regardless of, you know, the rates going into effect after that?
>
> **Mr. Featherstone**: Correct. It's seek, will not file for, will not request. And I think that the -- for the Staff, and I think for other parties, the -- what really sort of captures or frames that first sentence is the second sentence in the stipulation where it addresses, but can we -- can we at least request an interim energy charge prior to June 1 of 2015. And I think that -- that sort of identifies for – for everyone, I don't believe the language is ambiguous at all. I agree with John Coffman on that, on that matter.
>
> I think that you will not have two – two different fuel mechanisms. You would not have the -- the IEC in place and then -- and then also be able to request the fuel mechanisms or the fuel clause that was envisioned with SB179.[110]

* * * * *

[109] Tr. 1391-1392.
[110] Tr. 1410.

Mr. Poston: Could you explain what you were just saying about you wouldn't -- the Company would be seeking both an IEC and an FAC. Explain -- can you just explain why that is and how that is covered by that agreement?

Mr. Featherstone: This was not a desire of theirs. It was the Office of Public Counsel and Mr. Conrad, really. And they came back and said, well, if we can't have a fuel clause, could we at least request during this prohibition an IEC? And we had used the IECs several times prior to that. . . . So this -- this provision, the second sentence was inserted at the request of KCP&L who said, well, if we can't have for a ten-year period of time the fuel clause, we can't seek one in that period of time, can we at least then have as an alternative an IEC.

Mr. Poston: So then under their interpretation, it would be permissible for them to request both an FAC and an IEC?

Mr. Featherstone: But that was the reason that was put in there so they could not ask for a fuel clause prior to that date but they could get an IEC prior to that date. My testimony is you would not need or you would not want to have a situation where the utility is having both mechanisms. So you wouldn't want this overlap, having an IEC and then having a fuel clause.[111]

OPC Witness Mantle, who was also intimately involved in the Regulatory Plan negotiations,[112] provided background on the specific language in the provision. Specifically, the language in the first sentence ("will not seek to utilize") was needed to recognize the uncertain posture of the legislation at the time the Stipulation was signed as well as the method that would be used for implementing a fuel adjustment clause.

Commissioner Hall: Now, I noticed in your in your direct testimony on page 10, when -- when you described the agreement on lines 1 and 2, you said KCP&L agreed that it would not seek an FAC?

Ms. Mantle: Yes.

Commissioner Hall: So you excluded the two words "to utilize?"

Ms. Mantle: Yes

Commissioner Hall: So do you believe that those two words are irrelevant, unnecessary, confusing, what?

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[111] Tr. 1411-1413.
[112] Tr. 1741-1742.

> **Ms. Mantle**: I believe now that we know the process of an FAC, we know what the legislation is, to utilize is not as important as the seek. As I explained yesterday, not knowing -- every state has different legislation and different ways that an FAC can -- can happen for a utility. Now that we have 20/20 hindsight, you know, we can -- we read it with our 20/20 hindsight. At that time, we did not know whether the Commission was going to be allowed to grant it, if it was going to be just automatically given, how things were going to happen. So I would -- you know, when I wrote this, of course it is OPC's position and my position that it was to seek and that's why I wrote that that way.[113]

MECG asserts that the Regulatory Plan provision is clear. When the provision, both the first and second sentences are read in totality, it is clear that the first sentence precludes KCPL from seeking a fuel adjustment clause prior to June 1, 2015, but the second provides KCPL the authority to seek an Interim Energy Charge for the period prior to June 1, 2015. Indeed, previous testimony from KCPL as well as SEC filings demonstrate that, prior to this case, KCPL held this same view. Now, when a different interpretation suits its needs, KCPL suddenly changes its mind.

Nevertheless, in the event that the Commission believes that the language of the Regulatory Plan is ambiguous, there is a significant amount of extrinsic evidence to assist in the Commission in its interpretation. Specifically, testimony of two witnesses that were intimately involved in the Regulatory Plan negotiations support the interpretation that KCPL was precluded from seeking a fuel adjustment clause prior to June 1, 2015. Given that this case was filed on October 30, 2014, KCPL's current request for a fuel adjustment clause is premature. As such, KCPL's request should be rejected.

[113] Tr. 1742-1743.

B. HAS KCPL MET THE CRITERIA FOR THE COMMISSION TO AUTHORIZE IT TO HAVE A FUEL ADJUSTMENT CLAUSE? (ISSUE II(B))

1. Introduction and Criteria

In 2007, the Commission first considered a utility request for a fuel adjustment clause. In that case, the Commission noted that it needs to be careful in its consideration of a request for a fuel adjustment clause.

> ***A fuel adjustment clause is a powerful regulatory tool to be used with careful consideration***. If a fuel adjustment clause is allowed in an inappropriate situation, the customers who pay for utility service can be forced to pay rates that are higher than they should be.[114]

Given the powerful nature of the fuel adjustment clause and the fact that an FAC can easily lead to higher rates than should otherwise be charged, the Commission carefully considered the appropriate criteria for consideration of a fuel adjustment clause.

In that case, the Commission considered the testimony of several witnesses in determining the appropriate criteria for implementation of a fuel adjustment clause; included in that testimony was the recommendations provided by Michael Brosch. The Commission found that, given "his experience from working with expense tracking mechanisms from other proceedings, . . [t]he Commission will apply [Brosch's] criteria in its evaluation of AmerenUE's request for a fuel adjustment clause."[115] Those criteria included: (1) Substantial enough to have a material impact upon revenue requirements and the financial performance of the business between rate cases; (2) beyond the control of management, where utility management has little influence over experienced revenue

[114] Case No. ER-2007-0002, *Report and Order*, issued May 22, 2007, at page 17.
[115] *Id.* at page 21.

or cost levels; and (3) volatile in amount, causing significant swings in income and cash flows if not tracked.[116]

As it applied the volatility criterion, the Commission provided additional guidance. Specifically, the Commission noted that volatility does not simply include costs that are expected to increase. Rather, "volatile prices tend to go up and down in an unpredictable manner."[117]

> Thus AmerenUE's fuel costs, while certainly rising, cannot be said to be volatile. ***<u>Markets in which prices are volatile tend to go up and down in an unpredictable manner</u>***. When a utility's fuel and purchased power costs are swinging in that way, the time consuming ratemaking process cannot possibly keep up with the swings. As a result, in those circumstances, a fuel adjustment clause may be needed to protect both the utility and its ratepayers from inappropriately low or high rates. ***<u>Because AmerenUE's costs are simply rising, that sort of protection is not needed</u>***.[118]

Ultimately, the criteria advanced by Mr. Brosch were codified in the Commission's rules.

> In determining which cost components to include in a RAM, the commission will consider, but is not limited to only considering, the ***<u>magnitude</u>*** of the costs, the ***<u>ability of the utility to manage the costs</u>***, the ***<u>volatility</u>*** of the cost component and the incentive provided to the utility as a result of the inclusion or exclusion of the cost component. The commission may, in its discretion, determine what portion of prudently incurred fuel and purchased power costs may be recovered in a RAM and what portion shall be recovered in base rates.[119]

The other important aspect of this rule is that the Commission expects these criteria to be applied on a specific cost basis ("in determining which cost components to include in a RAM"). As Mr. Brosch points out,

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[116] *Id.* at pages 20-21.
[117] *Id.* at page 23.
[118] *Id.* at page 23 (emphasis added).
[119] Exhibit 503, Brosch Direct (Rate Design), page 5 (citing to 4 CSR 240-20.090(2)(C).

> Thus, the Commission's rule does not specify that <u>all</u> elements of a utility's fuel and purchased power costs must be included in an FAC, but instead the Commission will consider the magnitude, volatility and ability of management to control costs to decide which types of costs are reasonably FAC-includable.[120]

In this case, MECG provided the testimony of Mr. Brosch. As the expert that originally formulated the criteria adopted by the Commission, his opinion of KCPL's proposed fuel adjustment clause is particularly relevant and insightful. Given the guidance in the Commission's rule, Mr. Brosch undertook an analysis by which he applied each of the stated criteria (magnitude, management ability to control and volatility) to each of the specific cost items[121] which KCPL seeks to include in its fuel adjustment clause (coal costs, nuclear fuel costs, gas and oil costs, purchased power costs / off-system sales revenues; and transmission costs). As his analysis reveals, and the following brief demonstrates, KCPL's proposed fuel adjustment clause <u>***does not***</u> satisfy the Commission's criteria for a fuel adjustment clause. Noting some volatility attached to KCPL's off-system sales margins, Mr. Brosch notes that a fuel adjustment clause may be appropriate solely for these costs.

> I recommend, for all the reasons stated herein and in my previously filed revenue requirement testimony, that the Company does not need and should not be granted a fuel adjustment clause. If the Commission concludes that some form of FAC is required, it should consider limiting the scope of the FAC to include only variances in the Company's off-system sales profit margins, using deferred accounting and a sharing of

[120] *Id.* at pages 5-6.

[121] It is important to recognize that, despite the clarity of the Commission rule requiring that the stated criteria be applied on an individual cost basis, KCPL failed to provide such an analysis. "The Company's witnesses do not offer any detailed analysis of the magnitude, volatility or management control over all of the specific cost elements that KCPL seeks to include in its FAC.. . .There is no detailed analysis offered for the multitude of discrete costs listed in the proposed FAC tariff or any systematic application of the criteria within the FAC rule to the broad categories of coal, nuclear fuel, gas fuel and other expenses that have been incurred historically or that are projected to be incurred prospectively buy KCPL" (Exhibit 503, Brosch Direct (Rate Design), page 8).

> both favorable and unfavorable variances in such margins, relative to test year established levels.[122]

2. Coal Costs

In his testimony, Mr. Brosch applied the Commission's fuel adjustment criteria to KCPL's coal cost. As Mr. Brosch readily admits, KCPL's coal costs are of "sufficient magnitude to merit consideration for inclusion in a fuel adjustment clause."[123] Specifically, Mr. Brosch notes:

> Coal is a large element of the Company's overall cost of service. In the Company's test year revenue requirement, the adjusted cost for coal fuel included in the proposed FAC Base Calculation is approximately $318.8 million. In relation to Total Operating Expenses, as reported by KCPL in its 2014 SEC Form 10K of $1,380.7 million, a $318.8 million component of fuel expense represents about 23 percent of overall expenses.[124]

While KCPL's coal costs meet the Commission's criteria that costs be of a sufficient magnitude, Mr. Brosch demonstrates that these costs are neither volatile and are not beyond the control of KCPL management.

Mr. Brosch concludes that coal costs are not volatile for two primary reasons. ***First***, recognizing that KCPL had approximately 95% of its 2015 coal requirements under contract at year-end 2014,[125] KCPL has little exposure to changes in the market price of coal. Specifically, KCPL reported to its investors that "a hypothetical 10% increase in the market price of coal would result in an approximately $2.1 million increase in fuel expense for 2015."[126] Given its total operating cost portfolio, "a $2.1

[122] *Id.* at page 54.
[123] *Id.* at page 16.
[124] *Id.* at pages 16-17 (citing to Great Plains Energy SEC Form 10K, at page 54.).
[125] *Id.* at page 17 (citing to Great Plains Energy SEC Form 10K, at page 46.).
[126] *Id.*

million increase in fuel expense represents only about 0.15 percent of overall expenses.”[127]

<u>Second</u>, while KCPL has limited exposure to coal market prices, it is also undisputed that KCPL has experienced stable coal and coal freight prices. As Mr. Brosch concludes from the following graph, KCPL’s coal costs, including freight costs, have remained stable in recent history.

**

Source: Exhibit 503, Brosch Direct (Rate Design), page 20. **

In addition to the fact that coal costs have not demonstrated volatility in the last several years and are not expected to show any volatility in the near future, KCPL has also demonstrated an ability to exert a significant amount of management control over its exposure to coal price volatility. This management control is exhibited in two ways.

[127] *Id.* at page 18.

First, KCPL controls its exposure to coal prices changes through the use of coal price hedging program relying on a "strategy of laddering into a portfolio of forward contracts with staggered terms so that a portion of the portfolio will roll over each year."[128] In this way, KCPL signs multi-year coal contracts such that coal requirements in the near term are largely covered and KCPL has limited exposure to market price changes. For instance, KCPL may sign a coal contract in 2012 which may cover 30% of KCPL's coal needs for 2013-2015. In addition, KCPL may sign another coal contract in 2013 which meets 30% of KCPL's coal needs for 2014-2016. Finally, KCPL may sign a third coal contract which meets 30% of KCPL's coal needs for 2015-2017. The practical effect is that these laddered contracts provide relatively fixed costs for 90% of KCPL's coal needs in 2015. Thus, KCPL has invested significant time and resources in order to limit the Company's exposure to any fluctuations in the market price of coal.

Second, KCPL management controls its exposure to the delivered price of coal through the use of long-term rail freight contracts. As Mr. Brosch explains, "More than **___** of the per ton delivered cost of PRB coal is rail freight. . . . KCPL's primary rail freight contracts with **____________________** are for terms of **____________________** and at per-ton prices that are largely fixed.[129]

The practical effect of KCPL's use of laddered coal contracts and long-term freight contracts is that KCPL experiences stable prices for the delivered cost of coal. Specifically, KCPL's cost for coal in 2014 was **______** per ton, and projected to be **______** in 2015 and **______** in 2016.[130]

[128] Exhibit 103, Blunk Direct, pages 24-25.
[129] Exhibit 503, Brosch Direct (Rate Design), page 21.
[130] *Id.* at pages 21-22.

Ultimately, given the lack of volatility in KCPL's price of coal as well as the significant control KCPL's management has demonstrated, Mr. Brosch recommends that the Commission not include either coal or freight cost recovery within in any fuel adjustment clause. In fact, Mr. Brosch claims that a fuel adjustment clause, as applied to coal costs, would reduce KCPL's incentive to continue to manage these costs.

> While coal and coal freight costs are large overall, the prices of this fuel supply remain stable and the Company has established effective hedging strategies using term contracts with railroads and coal suppliers to mitigate fluctuations in delivered coal costs. KCPL invests significant staffing and other resources in its efforts to manage fuel costs and approval of an FAC would diminish the incentive the Company now has to aggressively manage the minimization of coal fuel costs.[131]

3. <u>Nuclear Fuel Costs</u>

Next, Mr. Brosch applied the Commission's fuel adjustment clause criteria to KCPL's nuclear fuel costs. As he concludes[132], KCPL's nuclear fuel costs meet none of the Commission's stated criteria.

First, unlike coal, KCPL's nuclear costs are not of a significant magnitude. For the test year, KCPL's nuclear fuel costs were expected to be approximately $27.8 million. As Mr. Brosch points out a $27.8 million component of fuel expense represents only about 2.0 percent of overall expenses."[133] Given this, Mr. Brosch concludes "nuclear fuel expense in isolation would not be reasonably expected to adversely impact the Company's future financial stability or access to capital on reasonable terms. Nuclear fuel expenses can be reasonably addressed in traditional rate cases".[134]

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[131] *Id.* at page 27.
[132]
[133] *Id.* at page 29.
[134] *Id.*

Second, KCPL's nuclear fuel costs demonstrate very little volatility. Like coal costs, KCPL's historical nuclear costs have been very stable.

Year	**Amount**
2011	$24,810,000
2012	$26,681,000
2013	$26,557,000
Test Year	$27,834,000

Source: Exhibit 503, Brosch Direct (Rate Design)

Moreover, information provided by KCPL indicates that KCPL has extremely limited exposure to nuclear cost fluctuations in the near future as a result of the fact that "all of the uranium and conversion services needed to operate Wolf Creek through September 2016" are already on site or under contract and "all of the uranium enrichment and fabrication required to support reactor operation through March 2027 and September 2025, respectively" is under contract.[135] As a result, Mr. Brosch concludes that KCPL's nuclear fuel costs demonstrate "remarkably stable pricing expectations over the next 8 years."[136]

Finally, as with coal price exposure, KCPL's management has demonstrated significant control over its exposure to nuclear fuel costs. "Through the use of long term supply contracts, utility management is clearly able to control and limit the utility's financial exposure to the impact of market forces upon nuclear fuel expenses."[137]

[135] *Id.* at pages 29-30.
[136] *Id.* at page 30.
[137] *Id.*

4. Gas and Oil Costs

Next, Mr. Brosch analyzed KCPL's natural gas and oil costs in light of the Commission's fuel adjustment clause criteria. Given its reliance on coal and nuclear generation, KCPL has very little generation from natural gas.[138] Given its minimal reliance on natural gas, it is not surprising that such costs are not of a significant magnitude. Specifically, for the test year, natural gas fuel costs were only $10.2 million. As such, natural gas costs represent about 0.7 percent of overall expenses."[139]

Additionally, KCPL's use of natural gas has demonstrated very little volatility over the last several years. While natural gas prices showed some volatility in the distant past,[140] natural gas prices in recent years demonstrate an absence of volatility. In fact, since 2010, natural gas costs have declined dramatically.

Year	**Natural Gas Costs[141]**
2010	**__________**
2011	**__________**
2012	**__________**
2013	**__________**
2014	**__________**

Source: Exhibit 503, Brosch Direct (Rate Design), page 32.

Finally, information provided by KCPL tends to indicate that its management exerts some degree of control as to its exposure to natural gas costs. Specifically,

[138] *Id.* at page 31.
[139] *Id.* at pages 32-33.
[140] KCPL refers to natural gas prices that "change dramatically" from 2004 to 2006. (Exhibit 102, Blunk Direct, 37).
[141] Natural Gas Costs include commodity costs, variable transport costs and fixed transport costs.

through its natural gas hedging program, KCPL admits that it is "protect[ed] from large unexpected upward price fluctuations."[142]

Ultimately, given the insignificant amount of natural gas utilized by KCPL in its generation portfolio, the stability of historical natural gas prices and KCPL's limited exposure to upward price fluctuations, a fuel adjustment clause is not needed to protect KCPL from natural gas prices.

5. <u>Purchased Power / Off-System Sales</u>

Additionally, recognizing that KCPL seeks to include purchased power and off-system sales in its requested fuel adjustment clause, Mr. Brosch applied the Commission's criteria to these costs. Ultimately, while he concludes that these costs are of a limited magnitude, the volatility in the off-system sales market provides some justification for a fuel adjustment clause.

Specifically, in the test year, KCPL's off-system sales profit margin was **_____ ______**. As such, off-system sales represents only **____** of KCPL's Total Operating Expenses. Given this, Mr. Brosch concludes that the Company has "limited exposure to adverse impacts from fluctuations in off-system sales margins."[143]

While off-system sales margins have been of a limited magnitude, these margins have historically demonstrated some volatility.[144] As KCPL admits, this volatility is driven by two factors: (1) quantity of sales and (2) price. Volatility associated with sales volumes is largely associated with "unit availability and KCPL's Native Load

[142] Exhibit 503, Brosch Direct (Rate Design), page 35 (citing to Exhibit 103, Blunk Direct, pages 28-32).
[143] *Id.* at page 38.
[144] Again, the Commission has previously defined volatility. "Markets in which prices are volatile tend to go up and down in an unpredictable manner." (Case No. ER-2007-0002, *Report and Order*, issued May 22, 2007, at page 23).

obligations" while price volatility is driven primarily by the "price of natural gas."[145] As can be seen, the volatility in these two factors has driven volatility in KCPL's overall off-system sales profit margins.

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Source: Exhibit 503, Brosch Direct (Rate Design), page 40. **

While Mr. Brosch concludes that KCPL's management has some degree of control over these margins, through their efforts to increase unit availability and efficiency, he ultimately concludes that volatility may justify the creation of a fuel adjustment clause solely for off-system sales margins. "Therefore, a reasonable alternative to an FAC for this utility could be the installation of a limited FAC tracking mechanism for ***only*** variations in off-system sales margins that occur between rate cases."[146]

[145] *Id.* at page 41.
[146] *Id.* at page 39.

6. Transmission Costs

The last cost items which KCPL seeks to include in a fuel adjustment clause are transmission costs. After applying the Commission's criteria to these costs, Mr. Brosch concludes that transmission costs do not meet any of these stated criteria.

First, transmission costs are not of a significant magnitude. Recognizing that net costs (transmission costs less transmission revenues) are only $53.8 million, they constitute only 3.9% of KCPL's total operating expenses.[147]

Second, while transmission costs are "expected to continue to increase over the next few years,"[148] a pattern of increasing costs is not reflective of volatility. Specifically, the Commission has defined volatility as prices which "go up and down in an unpredictable manner."[149] As Mr. Brosch concludes, therefore, "steady and predictable growth in a specific expense associated with expansion of transmission facilities is not justification for FAC inclusion. In fact, steady upward growth is exactly the opposite of the type of unpredictable upward and downward volatility in market expenses that an FAC is designed to address."[150] Indeed, in its recent Empire decision, the Commission held that these SPP transmission costs were not volatile. "The projected five year SPP related transmission expansion costs are expected to increase, but ***do not demonstrate volatility***. Empire's Missouri jurisdictional RTO transmission costs are reasonably projected and thus ***not volatile***."[151]

Ultimately, Mr. Brosch concludes that transmission costs do not meet the Commission's criteria and do not justify inclusion in a fuel adjustment clause. As can be

[147] *Id.* at page 43.
[148] *Id.* at pages 48-49.
[149] Case No. ER-2007-0002, *Report and Order*, issued May 22, 2007, at page 23.
[150] Exhibit 503, Brosch Direct (Rate Design), page 49.
[151] Case No. ER-2014-0351, *Report and Order*, issued June 24, 2015, at page 25 (emphasis added).

seen in the following section, there is another factor which limits the inclusion of transmission costs in a fuel adjustment clause. Specifically, Section 386.266.1 limits costs in a fuel adjustment clause to those associated with fuel and purchased power. Given that the vast majority of transmission costs are not associated with fuel and purchased power, but instead are associated with transmission of power from KCPL's generators to its native load, these costs do not meet the statutory criteria.

7. Conclusion

After applying the Commission's stated criteria to each of the cost items which KCPL seeks to include in its requested fuel adjustment clause, Mr. Brosch concludes that the vast majority of these cost items do not meet the Commission's criteria. Specifically, other than coal costs and off-system sales margins, none of the other costs meet the standard for materiality. Second, other than off-system sales margins, none of the costs meet the standard for volatility. In fact, most of these costs have demonstrated historically stable prices and are expected to remain stable in the near future. Finally, KCPL's management, through long-term contracts, laddering of coal contracts and hedging programs, exerts a significant degree of control over many of these costs.

In his final analysis, Mr. Brosch concludes that only off-system sales margins may meet the standard for inclusion in a fuel adjustment clause. As such, he recommends:

> I conclude that only the Company's off-system sales ("OSS") profit margins exhibit any significant volatility and lack of management control, such that if an FAC is approved for KCPL, it should be limited to only variations in OSS profit margins.[152]

[152] Exhibit 503, Brosch Direct (Rate Design), page 2.

C. IF THE COMMISSION AUTHORIZES KCPL TO HAVE A FUEL ADJUSTMENT CLAUSE, SHOULD TRANSMISSION COSTS BE INCLUDED IN THE FAC? (ISSUE II(D)(iv) and (v))

In its filing, KCPL seeks to include an extensive list of SPP transmission costs in its fuel adjustment clause.[153] Specifically, KCPL seeks to include "all of its wholesale transmission expenses and revenues" in its FAC.[154] This includes transmission costs reflected in FERC Account 565 (Transmission of Electricity by Others). In addition, KCPL seeks to include those costs booked to: (1) Account 561.4 (Scheduling, System Control and Dispatch Services); (2) Account 561.8 (Reliability Planning and Standards Development Services; (3) Account 575.5 (Market Facilitation, Monitoring and Compliance Services); and (4) Account 928 (Regulatory Commission Expense).[155]

As the Commission has recently held, however, Missouri law authorizing fuel adjustment clauses only allows for the inclusion of transmission costs to the extent that those costs are related to the transmission of purchased power to KCPL's load or the sales of excess energy. As such, the inclusion of transmission costs associated with the transmission of power from KCPL's own generation to its load is beyond the scope of the authorizing statute and, therefore, not eligible for inclusion in the fuel adjustment clause.

In 1979, while addressing the legality of the fuel adjustment clause, the Missouri Supreme Court set forth a general prohibition against retroactive ratemaking.

> The Companies take the risk that rates filed by them will be inadequate, or excessive, each time they seek rate approval. To permit them to collect additional amounts simply because they had additional past expenses not covered by either clause is ***retroactive rate making, i.e., the setting of rates which permit a utility to recover past losses or which require it to refund past excess profits collected under a rate that did not perfectly match expenses plus rate-of-return with the rate actually established***.

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[153] Exhibit 134, Rush Direct, Schedule TMR-2 (pages 3-4) and TMR-7, sheet 50.2.
[154] Exhibit 557, Dauphinais Rebuttal, page 7.
[155] *Id.*

> Past expenses are used as a basis for determining what rate is reasonable to be charged in the future in order to avoid further excess profits or future losses, but under the prospective language of the statutes, *§§ 393.270(3)* and 393.140(5) they cannot be used to set future rates to recover for past losses due to imperfect matching of rates with expenses.[156]

Finding that the Commission had no statutory authority, the Supreme Court held that the Commission's use of a fuel adjustment clause was unlawful.[157]

Given this prohibition, Missouri law is clear, <u>absent express statutory authorization</u>, utilities may not surcharge increased costs between rate cases.

> It is for the legislature, not the PSC, to set the extent of the latter's jurisdiction. The mere fact that the commission has approved similar clauses in the past, or that other states permit them, is irrelevant if they are not permitted under our statute[.][158]

After *UCCM*, the Missouri General Assembly enacted statutory authorization for fuel adjustment clauses.

> Subject to the requirements of this section, any electrical corporation may make an application to the commission to approve rate schedules authorizing an interim energy charge, or periodic rate adjustments outside of general rate proceedings to reflect increases and decreases in its prudently incurred fuel and purchased-power costs, including transportation[.][159]

Therefore, the costs to be included in a fuel adjustment clause are allowed only to the extent that section 386.266.1 authorizes their inclusion.

Very recently, the Commission had its first opportunity to interpret the scope of Section 386.266 as it pertains to the inclusion of transmission costs. In its Report and Order in the recent Ameren case (ER-2014-0258), the Commission noted that utilities

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[156] *UCCM* at 59.
[157] *Id.* at 47 ("We have concluded that application of an FAC to residential and small commercial customers, as was done in this case, was beyond the statutory authority of the commission and that the FAC, roll-in, and surcharge were therefore unauthorized and cannot continue in effect.")
[158] *Id.* at 54.
[159] Section 386.266.

incur transmission costs for three reasons: (1) to transmit power from its own generation to its own load; (2) to transmit power from other parties' generation to its own load; and (3) to sell excess power to third parties (off-system sales). Recognizing that Section 386.266 is limited to transmission costs for "purchased power", the Commission held that Ameren could not include transmission costs associated with transmitting power from its own generation to its own load.[160]

> The evidence demonstrated that for purposes of operation of the MISO tariff, Ameren Missouri sells all the power it generates into the MISO market and buys back whatever power its needs to serve its native load. From that fact, Ameren Missouri leaps to its conclusion that since it sells all its power to MISO and buys all that power back, all such transactions are off-system sales and purchased power within the meaning of the FAC statute. The Commission does not accept this point of view.
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> Therefore, of the three reasons Ameren Missouri incurs transmission costs cited earlier, the costs that should be included in the FAC are 1) costs to transmit electric power it did not generate to its own load (true purchased power) and 2) costs to transmit excess electric power it is selling to third parties to locations outside of MISO (off-system sales). Any other interpretation would expand the reach of the FAC beyond its intent.[161]

Given the limited scope of Section 386.266, KCPL's proposal to include all transmission costs in a fuel adjustment should be rejected. Specifically, KCPL seeks to include <u>all</u> transmission costs recorded in Account 565.[162] As the Commission has held, however, the Account 565 transmission costs also include the transmission costs associated with transmitting electricity from a utility's own load.[163] Clearly, such costs are beyond the scope of Section 386.266 and should be excluded from the fuel adjustment clause.

[160] The Commission repeated these findings in its recent Empire decision. See, Case No. ER-2014-0351, *Report and Order*, issued June 24, 2015, at pages 27-29.
[161] *Report and Order*, Case No. ER-2014-0258, issued April 29, 2014, at pages 115-116.
[162] Exhibit 134, Rush Direct, Schedule TMR-2 (pages 3-4) and TMR-7, sheet 50.2.
[163] *Report and Order*, Case No. ER-2014-0258, issued April 29, 2014, at page 113.

In rebuttal testimony, MIEC / OPC witness Dauphinais quantified the impact of excluding the Account 565 transmission costs.

> [O]nly a very small portion, approximately 7.3% of KCPL's total SPP wholesale transmission expenses incurred for [Network Integration Transmission Service] can be reasonably classified as being for transportation of fuel or purchased power. The other 92.7% of KCPL's total SPP wholesale transmission expenses incurred for [Network Integration Transmission Service] should be classified as being for the transportation of power from KCPL's own generation to its own load.[164]

In addition, Mr. Dauphinais pointed out that KCPL has failed to show that NERC, FERC and SPP Administration Charges (Accounts 561.4, 561.8, 575.5 and 928) are "incurred for the transportation of fuel or purchased power."[165] As such, given the statutory limitation in Section 386.266.1, these costs should also be excluded from KCPL's proposed fuel adjustment clause.[166]

D. IF THE COMMISSION AUTHORIZES KCPL TO HAVE A FUEL ADJUSTMENT CLAUSE, HOW MANY DIFFERENT VOLTAGE LEVELS OF SERVICE SHOULD BE RECOGNIZED FOR PURPOSES OF APPLYING LOSS FACTORS?

The requirement to recognize voltage level differences represents proper cost of service ratemaking. As Mr. Brubaker graphically demonstrates, there are cost differences between customers taking service at transmission, substation, primary distribution and secondary distribution voltage levels.[167] "Additional investment and expenses are required to serve customers at secondary voltages, compared to the cost of serving customers at higher voltages."[168] Customers that require service at lower voltage levels

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[164] Exhibit 557, Dauphinais Rebuttal, page 12.
[165] *Id.* at page 17.
[166] *Id.*
[167] Exhibit 554, Brubaker Direct (Rate Design), page 7.
[168] *Id.* at page 8.

impose costs on the utility. For instance, customers that take service at substation voltage impose substation costs that are not required for customers taking service at transmission voltage. Similarly, customers taking service at distribution level voltage impose costs associated with varying degrees of line transformers.

As Mr. Brubaker then recognizes, customers that need to take service at lower voltage levels impose more than just additional investment; each level of voltage transformation also increases the level of electric line losses. "Each additional transformation, thus, requires additional investment, additional expenses and ***results in some additional electrical losses***."[169]

These additional line losses are unquestioned. As Mr. Brubaker demonstrates, line losses increase dramatically as voltage transformations occur.

Voltage Level	Line Loss
Transmission	1.015651%
Substation	1.024828%
Primary	1.037072%
Secondary	1.061288%

Source: Exhibit 554, Brubaker Direct (Rate Design), Schedule MEB-COS-9

This fact, that voltage transformation results in line losses should be recognized in proper ratemaking. For this reason, Commission Rule 4 CSR 240-3.161 requires a utility to provide "calculations supporting the voltage differentiation of the FAC collection rates, if any, to account for differences in line losses by voltage level of service."[170]

While KCPL recognizes four different voltage levels for calculating base rates (secondary voltage; primary voltage; substation voltage and transmission level voltage), KCPL only proposes to recognize two (primary level and secondary level) voltage levels and line loss values for use in its fuel adjustment clause. Specifically, while transmission

[169] *Id.* at page 9 (emphasis added).
[170] 4 CSR 240-3/161(7)(A)(3).

level and substation voltage customers impose significantly less line losses, KCPL inexplicably proposes to lump these customers in with the primary voltage customers for purposes of calculating the fuel adjustment charge.[171] The impact on the substation and voltage levels customers is obvious. "[C]harging substation customers the primary voltage level line loss factor would essentially overcharge them by 50% for losses (3.7072% versus the correct 2.4828%); and would overcharge transmission level customers by 140% for losses compared to what they should be charged (3.7072% instead of the correct 1.5651%)."[172]

Given that proper ratemaking dictates that varying line losses be recognized, and the ready availability of such line loss data, Mr. Brubaker recommends that, in any case in which the Commission authorizes KCPL to utilize a fuel adjustment clause, KCPL should be required to "charge customers according to the four separate voltage levels at which delivery takes place, and not the two levels it has proposed in this case."[173]

E. IF THE COMMISSION AUTHORIZES KCPL TO HAVE A FUEL ADJUSTMENT CLAUSE, SHOULD KCPL BE REQUIRED TO CLEARLY DIFFERENTIATE ITSELF FROM GMO ON CUSTOMER BILLS?

Prior to 2008, Aquila operated in Missouri as two separate divisions: (1) MPS Division and (2) L&P Division. In 2008, the Commission authorized the acquisition of Aquila by Great Plains Energy.[174] Upon acquisition, the Aquila service company was named KCP&L – Greater Missouri Operations ("GMO"). While a separate legal entity,

[171] KCPL provides no substantive basis for its failure to recognize four different voltage level line losses. Specifically, KCPL witness Rush simply states that he believes that two voltage levels "are sufficient to appropriately distinguish the cost recovery." (Exhibit 135, Rush Rebuttal, page 21).
[172] Exhibit 554, Brubaker Direct (Rate Design), page 35.
[173] *Id.*
[174] See, Case No. EM-2007-0374.

GMO nonetheless held itself out to the general public as KCPL. As such, customers that had previously been served and provided a bill that indicated Aquila as their electric service provider now received a bill that indicated that their provider was KCPL. The problem is, KCPL is a separate legal entity with a service area and rates that are significantly different from GMO. Immediately, customer confusion was created as GMO customers, receiving a bill that indicated that their provider was KCPL, had no knowledge that GMO even existed.[175]

GMO's refusal to properly identify itself as the provider of electricity undermines one of the fundamental purposes of the Public Service Commission. Specifically, Section 393.140(11) provides for the publication of utility rate schedules. No longer could GMO customers, thinking that they were served by KCPL, identify the applicable rate schedule underlying their electric service. Given the inability to locate the appropriate rate schedules, GMO customers are no longer able to calculate their electric bills.

To date, consumer advocates have been able to assist these customers by a single distinction between the KCPL and GMO bills. . . the existence of a fuel adjustment clause line item on the GMO bills. This distinction is seen in the KCPL and GMO bills provided in this case.[176] With KCPL's request that the Commission authorize it to

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[175] The fact that customer confusion exists is obvious. The following statements from Commissioner Kenney, a GMO customer that was not aware that he was a GMO customer is indicative of the confusion realized by these customers.

COMMISSIONER KENNEY: I will tell you I've been a GMO customer, Aquila customer, and ***<u>I had to ask my staff to look up and see whether I was KCP&L or GMO.</u>***

* * * * *

Well, the reason I checked into it is because when we had the public hearings, there were no public hearings in my -- you know, the cities of Lee's Summit and Blue Springs.

MR. WOODSMALL: Confusing, yes. (Tr. 1587, emphasis added).

[176] See, Exhibit 503, Brosch Direct (Rate Design), Schedule MLB-23.

implement a fuel adjustment clause, this distinction between the KCPL and GMO bills will be eliminated. It will be increasingly difficult for consumer advocates like MECG and OPC, as well as the Commission's Customer Services staff, to distinguish between the KCPL and GMO bills. Given this inability to properly identify the correct electric service provider, these parties will not be able to assist these customers with questions about their service provider, the rates for service or the calculation of their bills.

Given this potential inability to properly distinguish between KCPL and GMO bills, MECG recommends "that some specific information be provided on customers' bills to identify which set of KCPL rate schedules are applicable to the rendered billing."[177] Such a distinction will preserve one of the fundamental customer service purposes of the Public Service Commission.

[177] *Id.* at page 53.

VI. PROPOSED TRACKERS

A. INTRODUCTION

In the previous section, MECG addressed KCPL's request to implement deferral accounting through the authorization of a fuel adjustment clause. In addition to the deferral accounting contained within that FAC request, KCPL also asks that the Commission implement deferral accounting through the creation of several tracking mechanisms.[178] The principal purpose of deferral accounting, from a utility standpoint, is obvious; it improves current earnings and increases future revenues.

> The proposed tracking mechanisms are intended to defer increased costs into a future case and, thus, secure incremental revenue increases in that [future] case beyond the amounts available through normal rate case processes. Since these increased costs are not considered in the current period, this also has the effect of improving current earnings and increasing future revenues.[179]

Reflecting KCPL's obvious desire to improve current earnings and increase future revenues, KCPL initially sought: (1) a property tax tracker;[180] (2) a vegetation management tracker;[181] (3) a CIP / Cyber-Security Tracker;[182] and (4) a Transmission Tracker.[183] Through a settlement, and undoubtedly in recognition of the Commission's

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[178] In this brief, deferral accounting is used as a general concept that provides for the deferral of costs from a prior period for potential recovery in a later period. The mechanism that creates the deferral accounting (adjustment mechanism, tracker mechanism or accounting authority order) is simply a matter of regulatory semantics. This lack of distinction between the various adjustment mechanisms is best seen by the fact that, in Case No. EU-2014-0077, KCPL asked the Commission for authority to implement either a transmission tracker or an accounting authority order. ("The Companies therefore respectfully request that the Commission give them the authorization to defer these transmission expenses until the next rate case ***<u>through an AAO or a transmission tracker</u>***."). Exhibit 504, Brosch Surrebuttal, page 23. As Mr. Dauphinais points out, "they [trackers and AAOs] essentially do the same thing" (Tr. 1751-1752). Putting semantics aside, each of these regulatory tools suffers from the same infirmities as discussed herein.

[179] Exhibit 502, Brosch Direct (Revenue Requirement), page 9.

[180] Exhibit 134, Rush Direct, pages 27-29.

[181] *Id.* at pages 29-31.

[182] *Id.* at pages 31-34.

[183] Exhibit 135, Rush Direct, page 11. KCPL did not initially request a transmission tracker. Instead, KCPL asked that all transmission costs be granted deferral accounting through its requested fuel adjustment clause. On April 29, 2015, the Commission issued its Report and Order in the Ameren rate proceeding and

view of vegetation management trackers,[184] KCPL subsequently withdrew its request for a vegetation management tracker.[185]

As this brief will show, there is a lack of statutory authorization for the tracker mechanisms requested by KCPL.[186] The lack of statutory authorization is not surprising when one recognizes the two fundamental ratemaking problems inherent in the implementation of deferral accounting. Of utmost concern, deferral accounting is piecemeal ratemaking that selects individual elements of the overall revenue requirement for preferential ratemaking treatment, while ignoring the potential for cost reductions elsewhere in the utility to offset discretely increasing costs. Thus, deferral accounting destroys the essential "matching" of all costs and revenues within a rate case test year. Of additional concern, deferral accounting eliminates the utility's incentive to minimize the tracked cost. Because of these fundamental problems, tracker mechanisms should be used only where unique and compelling circumstances justify extraordinary ratemaking mechanisms.

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found that Section 386.266.1 only allowed for the inclusion of transmission costs in the fuel adjustment clause to the extent that they were related to purchased power or off-system sales. As such, transmission costs associated with transmitting electricity from a utility's generators to its load were not allowed in the fuel adjustment clause. Eight days later, KCPL filed rebuttal testimony seeking to implement the deferral accounting for transmission costs (i.e., transmission tracker) that the Commission had previously found was not lawful under the fuel adjustment clause.

[184] The Commission terminated Ameren's vegetation management tracker (Case No. ER-2014-0258¸ *Report and Order*, issued April 29, 2015, at pages 51-52 as well as the Empire vegetation management tracker (Case No. ER-2014-0351, *Report and Order*, issued June 24, 2015, at page 9).

[185] See, *Order Approving Stipulation and Agreement Regarding Certain Issues*, issued July 17, 2015, at page 1.

[186] Over eight months into the case, KCPL had still not provided statutory authority for its requested tracker mechanisms. KCPL finally promised that such a legal analysis would be forthcoming in its Initial Brief. (Tr. 1839). ("Our view is that there's ample statutory authority for the Commission to use trackers. The Commission has done so for years and wouldn't have done so or been able to do so in the absence of that authority. We'll fully brief that issue when the time comes."). Recognizing that the Supreme Court has previously not accepted the argument that "this is the way the Commission has done for years," MECG is anxious to see KCPL's legal analysis (See, *Utility Consumers Council of Missouri v. Public Service Commission*, 585 S.W.2d 41, 54 (Mo. banc 1979) ("It is for the legislature, not the PSC, to set the extent of the latter's jurisdiction. The mere fact that the commission has approved similar clauses in the past, or that other states permit them, is irrelevant if they are not permitted under our statute.")

In the event that the Commission claims some statutory authority or finds that the costs are somehow "extraordinary", MECG sets forth the criteria that should be applied to any request for the implementation of a tracker mechanism. MECG then applies these criteria to KCPL's request for a transmission tracker, a property tax tracker and a CIP / Cyber-Security tracker. From this analysis, the Commission will recognize that, in addition to the lack of statutory authorization, KCPL's tracker requests do not meet the expressed criteria and should be rejected.

B. LACK OF STATUTORY AUTHORIZATION

1. Utility Consumers Council of Missouri Decision

In 1979, the Missouri Supreme Court considered the Commission's utilization of deferral accounting through the implementation of a fuel adjustment clause.[187] That decision provides several important points relevant to the Commission's current decision.

First, the Commission is limited to the powers conferred by statute. In any appeal addressing a Commission order, the reviewing court is required to determine whether the Commission's order is lawful and reasonable. "On appeal, our role is to determine whether the commission's report and order was lawful and, if so, whether it was reasonable."[188] Unlike the reasonableness of a commission order, however, there is no deference to the Commission's interpretation of statutory authority. "In determining the statutory authorization for, or lawfulness of, the order we need not defer to the commission, which has no authority to declare or enforce principles of law or equity."[189]

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[187] See, *Utility Consumers Council of Misouri v. Public Service Commission*, 585 S.W.2d 41 (Mo. banc 1979 ("*UCCM"*).
[188] *UCCM* at 47 (citing to *State ex rel. Dyer v. Public Service Commission*, 341 S.W.2d 795, 802 (Mo.App. 1960).
[189] *Id.* (citing to *Board of Public Works of Rolla v. Show-Me Power Corp.*, 244 S.W.2d 55 (Mo. banc 1952).

In such an appeal, the reviewing court will look for specific statutory authority for the Commission's action.

> Since it is purely a creature of statute, the Public Service Commission's powers are limited to those conferred by the above statutes, either expressly, or by clear implication as necessary to carry out the powers specifically granted. Thus, while these statutes are remedial in nature, and should be liberally construed in order to effectuate the purpose for which they were enacted, "neither convenience, expediency or necessity are proper matters for consideration in the determination of" whether or not an act of the commission is authorized by the statute.[190]

Second, statutory authority: (1) cannot be created out of a Commission's perceived need for such authority; (2) cannot be found in the fact that the Commission and other state utility commissions have historically exercised such authority; or (3) cannot be divined out of the broad general authority conveyed in Sections 386 and 393. Rather, specific statutory authority is required to be shown. (Counsel apologizes for the length of the following quotes. The underlying Supreme Court decision is over 20 pages. Counsel has endeavored to only provide the necessary passages so that the Commission can realize the inquiry of any reviewing court and the Commission's need to be mindful of specific statutory authority).

> Respondents argue application of the FAC to its residential rate structure is authorized because the commission carefully reviewed the legal basis for authorizing those rates, and because the commission and other states in the past permitted such rates. This information, of course, does not aid our inquiry into whether such rates are authorized. Of no greater help is the summary statement that chapter 393, RSMo 1969, gives the PSC full authority over rates.[191]
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> Respondents themselves have difficulty pointing to what provisions in the statutes give them authority to utilize a fuel adjustment clause. In their

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[190] *Id.* at page 49 (citations omitted).
[191] *Id.* at page 51.

brief, as noted *supra*, they simply argue that "it is clear that the statutes and case law in Missouri authorize such provisions." In oral argument, they admitted that it was hard to find specific sections authorizing an FAC, but that we should approve it on the basis of *§§ 393.130*, 393.140, and 393.270, and through application of the principle that where an agency is given broad supervisory authority, deference should be given to its interpretation of a statute. Since FAC's have been used in regard to industrial and large commercial users for 60 years, and because other jurisdictions approve them, it is posited that we should also approve them.

It is for the legislature, not the PSC, to set the extent of the latter's jurisdiction. The mere fact that the commission has approved similar clauses in the past, or that other states permit them, is irrelevant if they are not permitted under our statute.[192]

* * * * *

Respondents, however, state that the statutes as a whole do support their power to utilize a fuel adjustment clause. *Section 393.130* generally sets out basic rules governing the giving of safe and adequate service by the utility, and prevents preferential rates being given one customer. ***<u>Section 393.140 sets out the general powers of the commission</u>***. While this statute gives the PSC general supervisory power over electric utilities, as discussed *supra*, it gives the PSC broad discretion only *within* the circumference of the powers conferred on it by the legislature; ***<u>the provision cannot in itself give the PSC authority to change the rate making scheme set up by the legislature</u>***.

Section 393.270 empowers the commission to investigate matters about which complaint may be made, or to investigate to ascertain facts necessary to the exercise of its powers and to fix *maximum* rates after hearing and investigation upon consideration of all relevant factors. These provisions give no authority, as we read them, to establish a variable rate by use of a fuel adjustment clause, and in fact disallow such a clause, in that they establish a fixed-rate rather than a variable-rate system, *§ 393.270(2)*, (3), and prescribe the manner in which such rates are to be established.[193]

Since there is no authority to permit a fuel adjustment clause, . . . [w]e thus reverse the judgment of the circuit court affirming the order of the commission allowing the fuel adjustment clause.[194]

[192] *Id.* at 54 (citations omitted).
[193] *Id.* at 55-56.
[194] *Id.* at 57-58 (emphasis added).

Third, absent express statutory authority, deferral accounting, because it results in retroactive ratemaking, is unlawful. In that Supreme Court case, the Court had the opportunity to address costs that were to be deferred from previous periods for collection in a future rate case (the "surcharge").[195] The Court held that it was unlawful retroactive ratemaking ("the setting of rates which permit a utility to recover past losses or which require it to refund past excess profits collected under a rate that did not perfectly match expenses plus rate-of-return with the rate actually established") to allow the utility to collect such deferred fuel costs.

> Under the terms of the FAC approved in 1974, fuel expenses could not be recovered until after a 60-120 day time lag required to determine the proper amount of recovery. The 1976 order reduced this lag. However, fuel costs incurred in the final months before the effective date (June 1, 1976) of the FAC approved in 1976 were not collectible under the old clause because it expired before the necessary lag-time had elapsed. The commission thus enacted a surcharge to allow the utilities to collect these expenses incurred when the old clause was in effect but not collectible under the old clause before it expired. This surcharge is of course illegal in that it is intended to allow collection of monies which could only be collectible due to authorization of a fuel adjustment clause. However, even if a fuel adjustment clause were permitted, the question arises whether the surcharge would be allowable or whether it is unwarranted under any theory.
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> The utilities argue that this order was permissible, assuming a fuel adjustment clause was permissible, because the commission had a right to treat these uncollected expenses differently than other expenses, and that these are "current fuel expenses which were being collected (with an admitted lag) under the previous fuel adjustment", and thus their collection by surcharge was not retroactive rate making. We disagree.
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> The utilities cannot mean that the amount of the fuel adjustment charge is determined by *present* ("current") expenses in the month collected, and the fuel expenses of two or three months earlier are simply used as "test month" expenses, because from their brief and under the commission's order, it is apparent that their complaint is that no recovery was had for expenses *incurred* in one of the months during which the fuel charge was

[195] *Id.* at page 58.

> in effect. There would be no need to "surcharge" if present expenses were at issue for then the new FAC would cover these expenses.
>
> The utilities take the risk that rates filed by them will be inadequate, or excessive, each time they seek rate approval. To permit them to collect additional amounts simply because they had additional past expenses not covered by either clause is retroactive rate making, i.e., the setting of rates which permit a utility to recover past losses or which require it to refund past excess profits collected under a rate that did not perfectly match expenses plus rate-of-return with the rate actually established. Past expenses are used as a basis for determining what rate is reasonable to be charged in the future in order to avoid further excess profits or future losses, but under the prospective language of the statutes, *§§ 393.270(3)* and 393.140(5) they cannot be used to set future rates to recover for past losses due to imperfect matching of rates with expenses.

Thus, a careful reading of the *UCCM* decision provides two undeniable conclusions. ***First***, it is unlawful retroactive ratemaking for the commission to allow recovery of past deferred costs. ***Second***, such unlawful retroactive ratemaking is only allowed where the Commission is provided specific statutory authority. While the Commission has specific statutory authority to utilize deferral accounting in Section 386.266 and in the MEEIA legislation, there is no other statutory authority for the Commission to engage in any other instances of deferral accounting. As the following analysis indicates, such deferral accounting is only allowed where costs are "extraordinary."

2. Sibley Decision

In 1993, the Commission considered Missouri Public Service Company's request to defer depreciation and carrying costs associated with its renovation of the Sibley generating station. In that case, the Commission was repeatedly told that the deferral of costs, as requested by Missouri Public Service, was unlawful retroactive ratemaking as defined by the *UCCM* court. In response, the Commission sought to carve out an exception to the doctrine against retroactive ratemaking for "extraordinary" costs.

> The Commission does not consider the granting of the deferrals of extraordinary items either single-issue or retroactive ratemaking as argued by Public Counsel. Retroactive ratemaking occurs when rates are set to recover for past deficiencies or to refund past excesses. . . The deferrals approved in Case No. EO-91-358 do not constitute retroactive ratemaking since they involve items which have been found to be extraordinary and therefore outside the current period match of revenues and expenses. Costs associated with extraordinary events such as losses, cancellations or service threatening timing differences have been authorized by the Commission. The Commission's discretion on what items to include in ordering operating expense and what are extraordinary items is broad.[196]

On review, the Court of Appeals agreed with the Commission's claim that there is a limited exception from the doctrine against retroactive ratemaking (deferral accounting) for extraordinary events.

> The Commission's decision to grant authority to defer the costs associated with the Sibley reconstruction and coal conversion projects by recording the costs in Account No. 186 was the result of the Commission's determination that the construction projects were unusual and nonrecurring, and therefore, extraordinary. . . . Because rates are set to recover continuing operating expenses plus a reasonable return on investment, ***only an extraordinary event should be permitted to adjust the balance to permit costs to be deferred for consideration in a later period.***[197]

Thus, absent specific statutory authority, the only authority for the Commission to engage in deferral accounting (i.e., retroactive ratemaking) is the limited exception provided by Sibley court. Specifically, absent specific statutory authority, the Commission's authority to defer costs is where such costs are extraordinary ("unusual and nonrecurring, and therefore extraordinary").

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[196] Case No. EO-91-358, *Report and Order*, issued December 20, 1991, 1 Mo.PSC 3d 200, 212-213.
[197] *State ex rel. Office of the Public Counsel v. Public Service Commission*, 858 S.W.2d 806, 811 (Mo.App. 1993) ("*Sibley*")

Recognizing that there is no specific statutory authority for a property tax, transmission or cyber-security tracker, the Commission's ability to defer such costs is dependent on its ability to find that such costs are "unusual and nonrecurring, and therefore extraordinary."

C. FUNDAMENTAL PROBLEMS WITH DEFERRAL ACCOUNTING

As Mr. Brosch sets forth in his direct testimony, there are at least four significant problems associated with the deferral of costs from prior periods for recovery in later periods. ***First***, the consideration of select cost items from previous periods for future recovery destroys the critical "matching" concept inherent in good ratemaking and ignores the possibility of offsetting costs and revenues from that prior period. As Mr. Brosch explains:

> The many diverse elements of electric utility revenue requirements are constantly changing between test years. Some utility costs increase while others decline. . . . Any attempt to isolate and track selected costs that are expected to increase, while ignoring the other continuous changes in the utility's revenue requirement elsewhere that may offset such cost increases opens the regulatory system up to gaming and excessive rates. The isolation of only cost increases for regulatory tracking and future recovery creates a problem of "piecemeal ratemaking" that destroys the essential balance and "matching" of costs and revenues that is performed by measuring all of the elements of the test year revenue requirement at the same point in time and in a balanced manner in formal rate cases.[198]

The concept of offsetting costs and revenues is not mythical. As Mr. Brosch demonstrates, there are numerous offsetting cost items that will be ignored under KCPL's tracking mechanisms. For instance, investment in plant assets result in reduced maintenance costs.[199] Declining interest rates provide utilities, including KCPL, an opportunity refinance debt at lower rates and, thus, reduce their overall revenue

[198] Exhibit 502, Brosch Direct (Revenue Requirement), pages 11-12.
[199] *Id.*

requirement.[200] Workforce realignment programs result in lower employee workforce and decreased payroll costs.[201] Supply chain transformation programs results in inventory optimization.[202] Each of these measures has resulted in offsetting costs for KCPL that would go ignored under KCPL's tracking proposals.

Second, the implementation of tracking mechanisms eliminates some of the key aspects of traditional regulation through formal rate cases. These include the use of a test year in which costs are "quantified in a balanced and internally consistent manner with appropriate matching of costs and revenues."[203] In addition, the regulatory lag inherent in rate cases acts as an "efficiency incentive which financially rewards the utility for achieving cost reductions."[204] Procedural provisions and rules regarding burden of proof provide for a regulatory oversight that is largely eliminated for deferred costs.[205]

Third, the utilization of deferral accounting creates an environment where utility management becomes indifferent to cost levels for those costs that are tracked.

> As mentioned, an important element of traditional test period regulation is the incentive created for management to control and reduce costs, so as to maximize the opportunity to actually earn at or above the authorized return level between rate cases. . . . Changes in actual costs or sales levels between rate cases can increase or decrease a utility's profit levels before such changes can be translated into revised prices after a "next" rate case. This passage of time between rate cases, commonly referred to as "regulatory lag," serves as an efficiency incentive and moderates the counter-incentive that results when prices are based upon costs to serve.[206]

Normally, management, when confronted with the incentives of regulatory lag, will seek to control costs between cases. Under deferral accounting, management loses the

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[200] *Id.*
[201] *Id.* at Schedule MLB-6.
[202] *Id.*
[203] *Id.* at page 13.
[204] *Id.*
[205] *Id.* at page 14.
[206] *Id.* at page 15.

incentive to control such costs. In fact, as Mr. Brosch explains, given the lack of incentive to control costs, management may be expected to forego cost minimization opportunities that carry some degree of risk.

> If every dollar of a tracked type of cost is eligible for deferral and future rate recovery, management can afford to be less concerned about efficiency and the aggressive pursuit of cost containment for that type of cost and can be expected to focus attention on other areas of the business where earnings will be impacted by cost changes. In fact, if the pursuit of new efficiencies in connection with a tracked cost involves any significant risks or the incurrence of other costs that are not tracked, rational business behavior would discourage the pursuit of such efficiencies.[207]

Fourth, the implementation of trackers and the utilization of deferral accounting, while beneficial to the utility, imposes regulatory burdens on the other stakeholders to the utility regulation process.

> Each new cost tracking mechanism imposes additional regulatory burdens upon the Commission, its Staff, and concerned intervenors, through the creation of incremental monthly cost deferral accounting entries with carrying charges that should be rigorously analyzed for accuracy and prudence before being converted into incremental future rate increases. However, while increasing the burden, the incremental regulatory resources required for this needed critical analysis is often limited.[208]

Ultimately, it is obvious that the utilization of deferral accounting and the implementation of tracker mechanisms constitutes a "heads we win, tails you lose" situation for the utility. As mentioned, the utility likely realizes improved current earnings and increased future revenues. On the other hand, consumers see higher rates caused by: (1) the regulator's failure to consider offsetting costs and revenues; (2) the elimination of consumer protections inherent in the ratemaking process; (3) the elimination of management incentives to minimize costs; and (4) the imposition of increased regulatory burdens without the addition of resources to handle those burdens.

[207] *Id.*
[208] *Id.* at page 16.

In the final analysis, it is understandable why the Missouri Courts have limited deferral accounting to extraordinary events.

D. APPLICABLE CRITERIA

Given the problems inherent in the utilization of deferral accounting and the implementation of trackers, the Commission has been understandably guarded regarding the utilization of deferral accounting mechanisms. Nevertheless, there may be situations where such mechanisms are appropriate.

> There can be extraordinary circumstances where traditional test year ratemaking should be supplemented with cost tracking mechanisms. . . There can be unusual and infrequently occurring large and volatile costs. . . incurred by the utilities where traditional test year ratemaking may be incapable of producing reasonable results that properly balance the interests of the utility and its ratepayers.[209]

For instance, "the Commission has granted expense tracking treatment for the extraordinary costs incurred by electric utility in Missouri after the Commission implemented vegetation management rules and for the extraordinary costs incurred by gas utilities to comply with the Commission's gas safety rules."[210]

Given that there are limited situations in which deferral accounting is appropriate, Mr. Brosch has developed, based largely upon previous Commission decisions and his experience in other states, specific criteria that should guide the Commission's decision on requests for deferral accounting. Given the statutory limitations, as explained *supra*, the primary criteria is that deferral accounting be limited solely to extraordinary events. In addition to this primary criterion, Mr. Brosch recommends that any costs to be deferred or tracked through a rider "should also have all of the following attributes to merit such exceptional and preferential rate recovery treatment."

[209] *Id.* at pages 16-17.
[210] *Id.*

1. Substantial enough to have a material impact upon revenue requirements and the financial performance of the business between rate cases.

2. Beyond the control of management, where utility management has little influence over experienced revenue or cost levels.

3. Volatile in amount, causing significant swings upward and downward in income and cash flows if not tracked.[211]

4. Straightforward and simple to administer, readily audited and verified through expedited regulatory reviews.

5. Balanced, such that any known factors that mitigate cost impacts are accounted for in a manner that preserves test year matching principles.[212]

Given the customer protection attributes of these criteria, MECG urges the Commission to expressly adopt these criteria. Recognizing the universal applicability of these criteria, Mr. Brosch then applied them to each of KCPL's tracker proposals.

E. TRANSMISSION TRACKER (ISSUE III)

As mentioned, KCPL initially sought to include all transmission costs within its proposed fuel adjustment clause. On April 29, 2015, the Commission issued its order in the recent Ameren proceeding holding that Section 386.266.1 limits transmission costs to be included in a fuel adjustment clause to the extent that those costs are related to purchased power or off-system sales. Given this statutory limitation, the Commission excluded those costs related to the transmission of electricity from Ameren's generators to its own load.[213] On June 24, 2015, the Commission issued a similar decision in the recent Empire rate proceeding.[214]

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[211] As with its volatility criterion for fuel adjustment clauses, volatility does not simply include costs that are expected to increase. Rather, "volatile prices tend to go up and down in an unpredictable manner." Case No. ER-2007-0002, *Report and Order*, issued May 22, 2007, at page 23.
[212] Exhibit 502, Brosch Direct (Revenue Requirement), page 18.
[213] *Report and Order*, Case No. ER-2014-0258, issued April 29, 2014, at pages 115-116.
[214] Case No. ER-2014-0351, *Report and Order*, issued June 24, 2015, at pages 27-29.

Recognizing that approximately 92.7% of KCPL's transmission expenses are associated with the transportation of power from KCPL's own generation to its own load,[215] KCPL seeks to undermine the statute and implement a mechanism that allows it to do what the statute otherwise prohibits. Specifically, KCPL now seeks to implement a transmission tracker that recognizes 100% of KCPL's transmission costs, net of transmission revenues.

Less than 12 months ago, KCPL asked the Commission to take this identical step. Specifically, KCPL asked that the Commission allow it to implement a transmission tracker or an accounting authority order to track the change in transmission costs from amounts included in base rates.[216] In that Order, the Commission applied the "extraordinary" standard and rejected KCPL's proposed transmission tracker.

> In Missouri, rates are normally established based off of a historic test year. The courts have stated than an AAO allows the deferral of a final decision on current *extraordinary* costs until a rate case and therefore is not retroactive ratemaking. Consistent with the language in General Instruction No. 7, the Commission has evaluated the transmission costs for which Companies seek an AAO to determine if they are an unusual and infrequent occurrence. The Commission concludes they are not.
>
> Companies began incurring transmission expenses when they began providing retail electric service. Transmission costs are part of the ordinary and normal costs of providing electric service and are expected to continue in the foreseeable future. Furthermore, while the transmission costs at issue may have a significant effect on Companies, they are not "abnormal and significantly different from the ordinary and typical activities" of the Companies. The increase in transmission costs was anticipated and is indeed the norm for all electric utility members of SPP. Therefore, the transmission costs are not extraordinary.[217]

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[215] Exhibit 557, Dauphinais Rebuttal, page 12.

[216] As previously indicated in footnote 178, there is no fundamental difference between a tracker and an accounting authority order. Rather, both mechanisms allow the utility to defer changes in costs for recovery in future cases. Ultimately, any differences are largely semantic.

[217] Case No. EU-2014-0077, *Report and Order*, issued July 30, 2014, at page 10.

In this case, KCPL again asks that the Commission allow it to implement a transmission tracker. As the following analysis indicates, KCPL's proposal still fails to meet the Commission's criteria and should be rejected.

First, as with the previous case, KCPL's transmission costs are not extraordinary. Rather, "transmission costs are part of the ordinary and normal costs of providing electric service and are expected to continue in the foreseeable future."[218] Indeed, recognizing that Ameren and Empire have also asked for deferral accounting for such costs, it is apparent that all electric utilities incur such costs. Clearly, these costs are not extraordinary.

Second, are not a substantial enough to have a material impact upon the KCPL's financial performance. As Mr. Brosch demonstrates, such costs are about 3.9% of KCPL's overall expenses.[219] Given this, Mr. Brosch concludes that the Company has "limited exposure" to the expected gradual increases in SPP transmission charges.[220]

Third, transmission costs are not volatile. While such costs have been "increasing historically," steady and predictable growth is not indicative of a volatile cost.[221] "In fact, steady upward growth is exactly the opposite of the type of unpredictable upward and downward volatility in market expenses that [a tracker] is designed to address."[222] Indeed, in its recent Empire decision, the Commission held that these SPP transmission costs were not volatile. "The projected five year SPP related transmission expansion

[218] *Id.*
[219] Exhibit 503, Brosch Direct (Rate Design), pages 43-44.
[220] *Id.*
[221] *Id.* at page 49.
[222] *Id.*.

costs are expected to increase, but ***do not demonstrate volatility***. Empire's Missouri jurisdictional RTO transmission costs are reasonably projected and thus ***not volatile***."[223]

Recognizing that KCPL's transmission costs are not extraordinary, are not of a significant magnitude and are not volatile, the Commission should reject KCPL's proposal to implement a transmission tracker.

F. PROPERTY TAX TRACKER (ISSUE IV)

Based largely upon claims that "property tax expenses have been escalating over the past five years," KCPL asks that the Commission implement a tracker mechanism for such costs.[224] At pages 18-23 of his Direct Testimony, Mr. Brosch applies the tracker (deferral accounting) criteria to KCPL's request for a property tax tracker. As Mr. Brosch concludes, KCPL's property tax tracker request fails to meet the established criteria for several different reasons.

First, contrary to the limited authority for the Commission to utilize deferral accounting, property taxes are not extraordinary. As Mr. Brosch points out, KCPL "pays property taxes every year in the normal course of business."[225] Also demonstrating the fact that such costs are not extraordinary, every utility, indeed every business with tangible assets, pays property taxes.

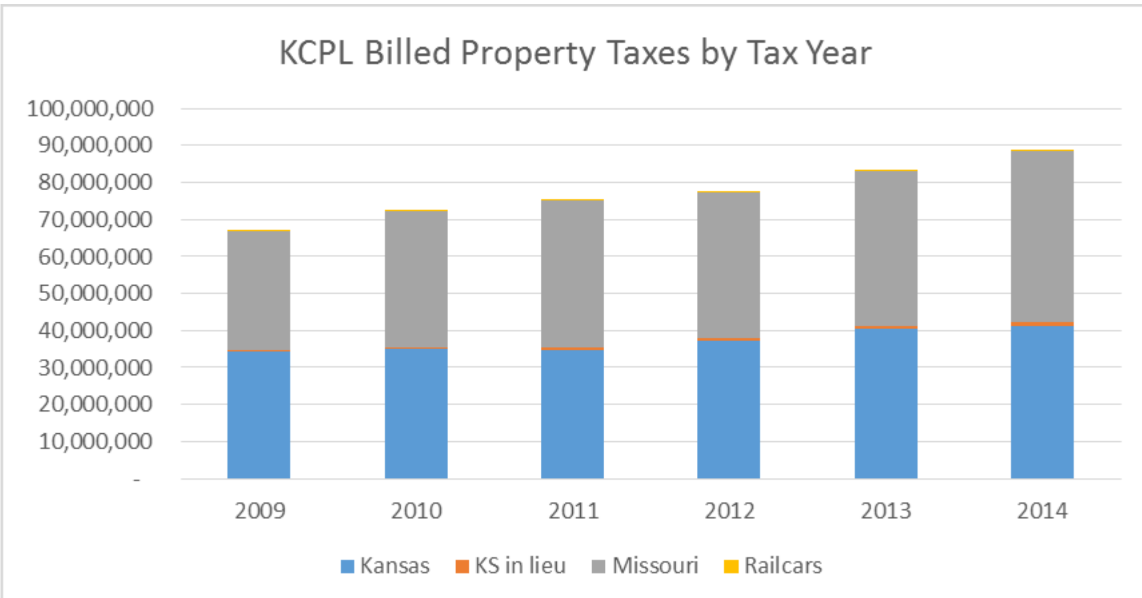
Second, property tax expenses are not a substantial enough to have a material impact upon the KCPL's financial performance.

> Given the limited overall amount of expense involved, as a percentage of overall costs and revenues, property taxes in isolation would not be reasonably expected to adversely impact the Company's future financial stability or access to capital on reasonable terms. Moreover, given the

[223] Case No. ER-2014-0351, *Report and Order*, issued June 24, 2015, at page 25 (emphasis added).
[224] Exhibit 118, Ives Direct, page 27.
[225] Exhibit 502, Brosch Direct (Revenue Requirement), page 19.

> predictable nature of when increased property taxes will occur, they can be reasonably addressed in traditional rate cases, where these taxes have been handled in previous Missouri rate case proceedings.[226]

Third, KCPL's property tax levels are not volatile from year to year. As Mr. Brosch concludes, property taxes show "gradual, single digit percentage increases" from year to year "rather than any volatility or extreme levels of change in any recent year."[227]



Source: Exhibit 502, Brosch Direct (Revenue Requirement), page 21.

Fourth, KCPL has demonstrated some degree of management control over property taxes. Specifically, while tax assessments and mill levy rates may be largely outside of management control,

> KCPL dedicates significant personnel time, including one full-time experienced tax accountant, to "…proactively ensure that the Company's property tax compliance is well managed and that the Company pays the minimum amount of its legally owed property tax in conformity with current tax laws and regulations." Errors have been noted in property tax bills and, "[o]ver the past five years, KCPL has verbally communicated errors in tax bills significantly exceeding $1 million, for which all bills were subsequently re-billed correctly prior to payment." . . . One would

[226] *Id.* at page 20.
[227] *Id.* at page 21.

> question whether KCPL would be willing to take such steps if it was guaranteed recovery of all property tax increases.[228]

Ultimately, based upon this analysis, Mr. Brosch concludes that the Commission should reject KCPL's proposed property tax tracker. "Property tax expenses incurred by KCPL are normal and ongoing annual expenses that are not sufficiently large and volatile to merit extraordinary expense tracking treatment. Additionally, KCPL management exercises some control over property tax expenses and the incentive for ongoing cost control efforts and costs would be blunted if expense tracker treatment was implemented."[229]

G. CIP / CYBER-SECURITY TRACKER (ISSUE V)

Next, Mr. Brosch applied the previously stated criteria to KCPL's request for a CIP / Cyber-Security tracker. As a preliminary matter, Mr. Brosch points out that KCPL has failed to define with any specificity the incremental future costs that would be included in the proposed tracker.

> The proposed tracking mechanism is open ended and Mr. Rush simply states, "[t]he cost to comply is undefined at this time, but will be substantial" and that "KCP&L is working diligently to develop an overall plan….[t]he plan is to establish an amount reflecting personnel hired directly attributable to the CIP in the true-up and also include any defined costs that may have already been incurred.[230]

The failure to properly identify the costs to be included in such a tracker was recently referenced by the West Virginia Public Service Commission in its decision to deny a similar tracker to American Electric Power.

> The Commission is aware of the increased security dangers presented in the modern world, particularly to the electric utility system. We know that extraordinary steps will become necessary (and may become common), but the Commission concludes that in the absence of concrete plans to implement specific security measures, projected costs, or new regulatory

[228] *Id.* at pages 21-22, quoting from KCPL's response to MECG data request 2-18 and 11-6.
[229] *Id*. at page 23.
[230] *Id.* at page 30.

> requirements, the proposal of the Companies to implement a Security Rider is premature.[231]

In addition to KCPL's failure to provide any actual definition to its cyber-security tracker proposal, Mr. Brosch concludes that KCPL's proposal also fails to meet the identified criteria for tracker treatment of costs.

First, Mr. Brosch points out that KCPL's incurrence of cyber-security costs is not extraordinary. "These types of costs are not unusual or infrequently incurred. The Company has incurred costs to secure its facilities and automated systems and to comply with established security standards for many years."[232] Moreover, as reflected by the fact that American Electric Power has also requested a similar mechanism, these types of costs are being incurred by every other electric utility.

Second, historical actual as well as projected cyber-security expenses are not substantial enough to have a material impact upon KCPL's financial performance. Specifically, 2014 expense levels of $4.1 million represent approximately 0.29% of KCPL's total operating expenses. Similarly, future budgeted amounts are never expected to exceed $8.5 million, which is less than 0.61% of KCPL's total operating expenses.[233] Given this, Mr. Brosch concludes that "[g]iven the modest overall amount of historical and forecasted expenses involved, as a percentage of overall costs and revenues, these costs in isolation would not be reasonably expected to adversely impact the Company's future financial stability or access to capital on reasonable terms."[234]

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[231] 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 95.
[232] Exhibit 502, Brosch Direct (Revenue Requirement), page 19.
[233] *Id.* at page 33.
[234] *Id.*

Third, projected levels of KCPL cyber-security costs demonstrated that such costs are not volatile. Based upon the following projected cost data prepared by KCPL, Mr. Brosch concludes that the Company has forecasted "relatively stable O&M spending and declining capital investment levels, rather than any volatility or extreme levels of change in any future year."[235]

Table 3: KCPL Projected Critical Infrastructure Protection / Cybersecurity Costs

Forecasted Costs:	2015	2016	2017
Non-Labor O&M	$ 8,541,288	$ 8,295,878	$ 6,752,557
Labor O&M	3,152,125	4,603,025	4,929,085
Capital Investment	12,932,083	5,129,262	6,205,815
Total Estimate	$ 24,625,495	$ 18,028,166	$ 17,887,458

Source: Exhibit 502, Brosch Direct (Revenue Requirement), page 32.

Fourth, while KCPL's need to meet cyber-security regulations may be largely outside of management control, KCPL's management has complete control over how to meet these directives. "Utility management has responsibility and control over decisions regarding the hiring, testing, training, new capital investments and security modifications to facilities and automated systems that are made in order to achieve and maintain compliance."[236] Given that its response is entirely within the control of KCPL management, "[i]t would not be reasonable to approve a full recovery expense tracker covering any and all future labor and non-labor expenses that KCPL judges to have been incrementally incurred for CIP and Cybersecurity compliance, because such a tracker would eliminate management incentives to implement cost-effective solutions to achieve compliance."[237]

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[235] *Id.* at page 34.
[236] *Id.*
[237] *Id.*

Finally, recognizing that KCPL's requested cyber-security tracker includes internal labor costs, it would be essentially impossible for the tracker to be administered and audited in a straightforward and simple manner. Specifically, given that there are no clear lines of demarcation between the incremental labor deployed to meet cyber-security needs and the labor necessary to meet other ongoing IT requirements, it would be difficult to administer and audit the proposed tracker. In fact, this inability to determine whether increased labor costs are associated with cyber-security versus ongoing IT support, provides the utility management with a financial incentive to incorrectly classify such costs.[238]

> With a tracking mechanism in place, utility management would face a financial incentive to classify new spending as somehow related to CIP or Cybersecurity in instances where costs actually relate to more than just these needs. For instance, when a significant information technology system is being maintained or upgraded by KCPL employees or contractors, it may be necessary to subjectively determine what portion of upgrade time and labor could be characterized as for security enhancements, with only costs in these security-related costs qualifying for tracker recovery. A fundamental challenge with any regulatory tracking mechanism is the need to clearly specify includable costs using defined criteria that are administratively simple to apply and verify.[239]

Given that the proposed cyber-security tracker fails to meet these criteria, Mr. Brosch recommends that the Commission reject KCPL's proposal.

[238] KCPL appears to have recognized this deficiency in its recent Kansas rate proceeding. There, certain parties agreed to allow KCPL to implement a cyber-security tracker. That said, recognizing the obvious problems with including internal labor costs in such a tracker, the Kansas tracker included only non-labor costs. (Tr. 1853).
[239] *Id.* at pages 35-36.

VII. RATE CASE EXPENSE

A. WERE ANY RATE CASE EXPENSES CLAIMED BY KCPL IMPRUDENTLY INCURRED?

The evidence presented in this case conclusively demonstrates that KCPL has incurred a significant amount of rate cases expenses that were imprudent. Specifically, evidence indicates that costs related to KCPL outside legal expenses as well as KCPL technical consultants were imprudently incurred. KCPL's incurrence of such imprudent costs, seemingly without regard to the reasonableness of such costs, is especially disconcerting to MECG members. Through the various allocations, MECG members pay for rate cases expenses for four different entities. ***First***, MECG members pay for their own legal and consultant costs. ***Second***, MECG members pay, through KCPL's collection of the PSC assessment, for Staff's legal and technical costs. ***Third***, and in a similar manner, MECG members pay for OPC's legal and technical costs. ***Finally***, MECG members are expected to pay for KCPL's rate case expenses. While rate case expenses are usually considered to be a cost of service, it is always premised upon the prudence and reasonableness of such costs. Once again, ratepayers are at the mercy of the Commission to protect them from the imprudent costs incurred by KCPL. Once disallowed in this case, KCPL may finally seek to question the reasonableness of costs of their outside attorneys and consultants in future cases rather than simply extending them carte blanche to charge any amounts.

1. Legal Expenses

In a recent Ameren case, the Commission questioned Ameren counsel on its legal costs. In that case, Mr. Lowery indicated that his "rates are effectively $200 an hour."[240]

[240] Exhibit 308, Addo Surrebuttal, page 29.

It is unquestioned that Mr. Lowery is well respected among the Commissioners and members of the Public Service Commission bar. Furthermore, as Public Counsel points out, Mr. Lowery's firm is the oldest firm in Columbia and one of the largest in central Missouri. The firm has earned a AV Peer Review rating indicating the "highest levels of professional performance as attorneys."[241]

Given Mr. Lowery's rate and his ability as a utility regulation attorney, one must necessarily question the following legal expenses of KCPL.

Law Firm	Level	Hourly Rates
Dentons US LLP, Kansas City:		
➢ Zobrist, Karl	Partner	$ 485.00
➢ Gilbreath, Lisa	Associate	$ 240.00
➢ Wood, Eric	Legal Assistant	$ 150.00
Fischer & Dority, PC:		
➢ Mr. James M. Fisher	Senior Partner	$ 325.00

Source: Exhibit 308, Addo Surrebuttal, page 27.

Not only should the Commission question the rates paid by KCPL to its outside legal counsel, the Commission should also question the significant degree to which KCPL relies on such outside counsel. As the Commission is undoubtedly aware, KCPL was also represented by in-house counsel. Both of these individuals have significant utility regulation experience. Mr. Hack was initially hired at the Public Service Commission in February 1989 and was the Commission's General Counsel for 3 years.[242] As such, Mr. Hack has over 26 years of experience practicing before the Commission. In

[241] *Id.*

[242] See Public Service Commission Reports, Volume 29 New Series (page vii); Volume 1 3d Series (page vii) and Volume 3 3d Series (page vii).

addition, Mr. Steiner was initially hired at the Public Service Commission in April 1994.[243] As such, Mr. Steiner has over 21 years of regulatory experience.

Given the significant amount of shared experience between Mr. Hack and Steiner, one wonders why KCPL relies so heavily on outside counsel. Repeatedly throughout this case, KCPL was relying on four attorneys to sit in the hearing room.[244] Despite the obvious qualifications of its own in-house counsel, those attorneys sat by and watched outside counsel provide opening statements and conduct cross-examination. Even a matter as simple as a true-up hearing necessitated three KCPL attorneys. Customers are naturally offended when KCPL asks them to pay the salary and benefits of in-house corporate attorneys while also paying for expensive outside counsel. If in-house counsel is incapable of such duties, despite 47 years of shared experience, it is time for KCPL to replace those attorneys, not rely on expensive outside counsel.

Given KCPL's unfettered use of outside counsel and its lack of concern for the rates charged by those attorneys, MECG asks that the Commission make certain disallowances. Specifically, MECG suggests that, given KCPL's capable in-house attorneys, that the Commission disallow all of the costs associated with one of KCPL's outside attorneys. For the remaining attorney, MECG recommends that the Commission reduce that attorney's rate down to the rate charged by Ameren's outside counsel ($200 / hour). To the extent that KCPL deems it is important for it to have additional counsel, then shareholders, not ratepayers, should be expected to suffer the costs of the luxury.

243 See, Public Service Commission Reports Volume 1 3d Series (page viii)
244 Tr. 109.

2. Technical Consultants

In addition to KCPL's heavy reliance on outside counsel, KCPL also imprudently relied on the use of outside technical consultants. Repeatedly throughout this case KCPL provided the testimony of consultants when similar work could have been done by KCPL employees. In some situations, the use of such consultants was simply redundant to that already performed by those KCPL employees. Other times, given the irrelevant nature of the inquiry performed by the consultant, the testimony was utterly lacking in any benefit to ratepayers.

►For instance, in this case, KCPL relied upon its Director of Regulatory Affairs, Mr. Rush, for the preparation and presentation of KCPL's class cost of service study and rate design proposals. As Mr. Rush's testimony indicates, he has over 38 years of electric utility regulatory experience.[245] Nevertheless, KCPL seeks to recover **__________** associated with the services of Management Application Consulting.[246] Clearly, given his expertise and experience, Mr. Rush is fully capable of providing such testimony. Nevertheless, KCPL hired and asks ratepayers to pay for the services of Management Application Consulting. MECG suggests that the Commission disallow all costs associated with this consultant firm.

►Still again, despite having obvious employees capable of presenting testimony on deferral accounting / tracker mechanisms and regulatory lag,[247] KCPL retained the services of Mr. Overcast. Upon cross-examination it became apparent that Mr. Overcast was hired simply to provide canned testimony that had no relevance to Missouri

[245] Exhibit 134, Rush Direct, page 2.
[246] Exhibit 318, Addo True-Up Direct, page 9.
[247] See, Exhibits 118, 120 and 121, Ives Direct, Rebuttal and Surrebuttal. See also, Exhibits 134, 135 and 135, Rush Direct, Rebuttal and Surrebuttal.

regulation. Specifically, Mr. Overcast attempted to portray Missouri as prehistoric when it comes to its use of deferral accounting[248] by providing a survey of the use of tracker mechanisms in other states. Interestingly though, Mr. Overcast never consulted any of the underlying statutes, rules or case law to determine their relevance to Missouri.[249]

In questioning from the Commission it became apparent that Mr. Overcast was simply willing to over an opinion that was based on pure speculation. For instance, when asked questions about internal KCPL documents that indicate a constructive Missouri regulatory environment, Mr. Overcast simply speculated that this referred to the KCPL Regulatory Plan.[250] Upon cross examination and, after finally admitting that the Regulatory Plan had expired and that he had never actually read the Regulatory Plan,[251] it became apparent that Mr. Overcast's opinion was nothing more than simple speculation. Similarly, while not an attorney, Mr. Overcast felt qualified to point out that the "extraordinary" standard does not apply to tracker mechanisms.[252] Upon cross-examination, it became apparent that Mr. Overcast offered his unqualified opinion without even consulting the Commission's recent order applying the "extraordinary" standard to a request for a transmission tracker.[253]

Mr. Overcast's willingness to go outside his scope of expertise was also demonstrated when he opined that the implementation of a fuel adjustment clause or tracker mechanisms should not be accompanied by a reduction in the authorized return on

[248] Tr. 1354-1355 ("I think the regulatory environment in Missouri is more difficult than it needs to be because you have -- you don't have fuel adjustment clauses that are consistent with what other jurisdictions have and you have severe limits on the number of other kinds of cost recovery mechanisms that are available.").
[249] Tr. 1340-1341.
[250] Tr. 1356-1357.
[251] Tr. 1356-1360.
[252] Tr. 1353-1354.
[253] Tr. 1360-1361.

equity.[254] Upon cross-examination, it became apparent that Mr. Overcast had no credentials as it pertains to return on equity analysis.[255] Ultimately, however, Mr. Overcast recognized that, because the implementation of deferral accounting reduces a utility's business risk, it may change its comparable company group. Given the difference in the comparable company group, the recommended return on equity is bound to change.[256]

Given the lack of value that was offered by Mr. Overcast's testimony, his eagerness to venture speculative opinions outside of his expertise and the fact that his testimony was redundant of that offered by other KCPL witnesses, ratepayers should not be expected to pay his consultant fees. At the time of the true-up hearing, Mr. Overcast's consultant fees were **__________** Recognizing that these costs do not include the costs incurred during and following the hearings, MECG urges the Commission to simply disallow Mr. Overcast's fees in their entirety.

►Finally, KCPL relied upon the technical services of Mr. Hevert to provide his return on equity recommendation. In the past, the Commission has repeatedly criticized Mr. Hevert's analysis on the basis that his growth rates were "too high." Despite the clarity of this criticism, Mr. Hevert simply repeated his same flawed analysis. Ultimately, repeating such flaws were necessary to deliver the inflated return on equity desired by KCPL. As a result, the Commission has repeatedly dismissed Mr. Hevert's recommendation.

Given the lack of value associated with providing testimony that the Commission simply dismisses, and Mr. Hevert's refusal to correct for the criticisms previously leveled

[254] Tr. 1351.
[255] Tr. 1365-1366.
[256] Tr. 1365-1366.

by the Commission, ratepayers must wonder why they should be expected to pay for Mr. Hevert's services.

Not only are Mr. Hevert's services of questionable value, they also come with an inflated price tag. Specifically, while Mr. Hevert's budget for this case is $99,660, that figure does not include costs associated with Surrebuttal testimony.[257] As such, his costs may go above this budgeted figure.[258] In fact, in his last five litigated rate cases, Mr. Hevert's fees were: $167,000; $111,000, $92,000; $165,000; and $176,000.[259]

In contrast to Mr. Hevert's inflated fees, the evidence also shows the budget for Mr. Gorman's services. As the Commission undoubtedly remembers, Mr. Gorman's recommendation has been repeatedly relied upon by the Commission. Unlike Mr. Hevert's inflated fees, Mr. Gorman only budgeted $30,000 for this proceeding.[260]

Given that it has repeatedly dismissed Mr. Hevert's recommendation, the Commission should consider simply disallowing the entirety of Mr. Hevert's costs. On the other hand, much as requested for outside legal expenses, MECG suggests that Mr. Hevert's fees be allowed to the same extent as those for other recognized experts. In this case, the Commission should only allow KCPL to recover $30,000 for Mr. Hevert's costs.

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[257] Tr. 162.
[258] *Id.*
[259] Tr. 163.
[260] Tr. 305.

VIII. MANAGEMENT AUDIT

As indicated on pages 6-7, KCPL's rates in Missouri have experienced a rapid increase. Since January 1, 2007, KCPL's rates have increased 57.69%. Recognizing that KCPL is seeking a $120.9 million (15.75%) increase in this case, KCPL rates will have increased by over $404 million (82.53%) since 2007.

In light of this rapid increase in rates, MECG attempted to identify those types of costs which cause KCPL's rates to be excessive. MECG compared KCPL's costs with other regional utility costs as reported in utility FERC annual reports using various metrics. MECG concluded that KCPL's Administrative & General ("A&G") costs appear to be excessive. Specifically, based upon several different metrics (per customer, per MWh, per revenue dollar), KCPL's A&G costs over the last three years are clearly much higher than any other regional utility (Empire, Westar and Ameren).

Cost Comparison
Utilities Operating In Region
2010-2013 Average Administrative & General Expenses

2010-2013 Average	KCPL	GMO	Combined KCPL and GMO	Empire	Westar	Ameren Missouri	Combined All Others
A&G Expenses	635,355,647	282,292,118	917,647,765	156,328,251	383,555,264	999,658,816	1,539,542,331
Average Number of Customers	2,051,453	1,253,522	3,304,975	670,111	1,482,442	4,772,332	6,924,885
A&G Cost per Customer	309.71	225.20	277.66	233.29	258.73	209.47	222.32
Megawatt Hours Sold	85,554,742	34,134,396	119,689,138	23,047,113	69,998,449	182,058,211	275,103,773
A&G Cost per MWh Sold	7.43	8.27	7.67	6.78	5.48	5.49	5.60
Total Electric Operating Revenues	6,326,726,047	3,058,038,351	9,384,764,398	2,048,559,990	5,114,588,848	12,563,872,818	19,727,021,656
A&G Cost per Electric Revenue Dollar	0.1004	0.0923	0.0978	0.0763	0.0750	0.0796	0.0780

Source: Exhibit 500, Kollen Direct, page 8.

The practical effect on rates of KCPL's excessive A&G costs is obvious. KCPL's A&G costs on a per customer basis ($309.71 / customer), is higher than Empire ($233.29 / customer); Westar ($258.73 / customer) and Ameren ($209.47 / customer). If KCPL's rates were reduced to that of the second highest utility (Westar @ $258.73 / customer), KCPL's Missouri rates would be approximately $17.5 million lower.[261] Similarly, if KCPL's A&G costs (on a per MWh basis) were reduced to that of the second highest utility (Empire @ $6.78 / MWh), KCPL's Missouri rates would be approximately $10 million lower. Finally, if KCPL's A&G costs (on a percentage of revenue basis) were reduced to that of the second highest utility (Ameren @ 7.96%), KCPL's Missouri rates would be approximately $22 million lower.

Based upon these metrics, Mr. Kollen concludes that "it is clear that [KCPL's] A&G expenses are excessive compared to the other utilities operating in the region."[262] While the reasons for such excessive costs are not yet known, Mr. Kollen concludes that "this appears to be a structural problem."[263] Recognizing the time and resource limitations inherent in a ratemaking setting, Mr. Kollen points out that "the Commission cannot resolve this structural problem through ratemaking adjustments alone."[264]

In its testimony, Staff takes this A&G analysis beyond simply the regional electric utilities. Rather, recognizing that KCPL compares itself to several other utilities for purposes of calculating executive compensation, Staff compared KCPL's A&G costs to

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[261] KCPL had 2,051,453 customers over a 3 year period in Kansas and Missouri. Therefore, if KCPL reduced its A&G costs by $50.98 / customer to that of Westar, KCPL's rates over a 3 year period would have been $104,583,074 less (or $35 / million per year). Recognizing that approximately half of KCPL's customers are in Missouri, Missouri rates would be about $17.5 million lower.
[262] Exhibit 500, Kollen Direct, page 14.
[263] *Id.*
[264] *Id.*

KCPL's self-described group of peers.[265] As Staff's expanded analysis indicates, even among KCPL's self-described group of peers, KCPL's A&G costs (on a per customer basis) is higher than any other company.

2013 and 2014 A&G Per Customer

Peer Company	2013 A&G per Customer	2013 Ranking	2014 A&G per Customer	2014 Ranking
Alliant	$176	14	$181	13
Avista	$176	13	$185	12
Black Hills	$298	3	$289	4
Cleco	$190	10	$201	9
GMO	$237	7	$236	7
IdaCorp	$299	2	$305	2
KCPL	**$303**	**1**	**$312**	**1**
KCPL & GMO	$278	5	$283	5
OGE	$139	16	$146	16
Pinnacle	$186	12	$165	14
PNM	$266	6	$257	6
Portland	$189	11	$192	10
TECO	$209	8	$187	11
UNS	$209	9	$221	8
Westar	$292	4	$299	3
Wisconsin	$172	15	$147	15

Source: Exhibit 246, Majors Testimony (corrected), page 52.

Given that these metrics indicate excessive A&G costs at KCPL, and recognizing the structural problems underlying these excessive costs, Mr. Kollen recommends that "the Commission direct KCP&L to undergo a management audit by an independent auditor for the purpose of identifying cost savings and efficiencies. This audit should

[265] KCPL's group of peers for purposes of its executive compensation study and Staff's A&G analysis are: Alliant Energy Corporation; Avista Corporation; Black Hills Corporation; Cleco Corporation; IdaCorp, Inc.; OGE Energy Corporation; Pinnacle West Capital Corporation; PNM Resources, Inc.; Portland General Electric Company; TECO Energy Inc.; UNS Energy Corporation; Westar Energy, Inc. and Wisconsin Energy Corporation. (Exhibit 246, page 52.

encompass all functional operation and maintenance activities and expenses as well as all administrative and general activities and expenses."[266]

As Mr. Kollen points out, there is no downside to the KCPL or its customers from the Company undergoing a management audit. In fact, given the existence of regulatory lag, all cost saving measures will initially inure to the benefit of KCPL's shareholders.

> While there is an initial cost involved to implement such an audit, customers should benefit on an order of magnitude greater, particularly when you compare the one-time cost of an audit to the sum of annual savings over a number of years. There is significant upside if the management audit is focused on identifying and achieving efficiencies and cost reductions rather than simply justifying the present cost structure. While KCP&L witnesses attempt to portray regulatory lag as a negative aspect of the current Missouri regulatory paradigm, there is no question that it can work to the benefit of utility shareholders. Specifically, in those situations where costs decrease between rate cases, those savings completely inure to the benefit of the utility shareholders until such time as another rate case is initiated and rates are rebased. Similarly, to the extent that a management audit identifies cost savings, KCP&L shareholders will retain the entirety of those cost savings until a subsequent rate case. As such, my recommended management audit may be beneficial to KCP&L shareholders.[267]

As Mr. Kollen points out, this recommendation was not simply a knee-jerk reaction to an obvious problem. Rather, given his involvement in previous management audits, he has seen the benefits of these utility audits.[268] In addition, Mr. Kollen provides a list of firms, not his own, that specialize in performing such audits[269] as well as an extensive list of utilities that have undergone such audits.[270] In fact, the Kentucky Public Service Commission has recently ordered Big River Electric to undergo a similar audit.[271]

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[266] *Id.*
[267] Exhibit 501, Kollen Surrebuttal, page 12.
[268] *Id.* at pages 14-15.
[269] *Id.* at page 13.
[270] *Id.* at pages 13-14.
[271] *Id.* at page 14 (citing to Case No. 2013-0199, Kentucky Public Service Commission.

Finally, Mr. Kollen provides guidance on how the audit process should commence and progress. Specifically, Mr. Kollen suggests that the Commission, through its Staff, should oversee the process from start to finish and be focused on "achieving savings and cost reductions without compromising safety or customer service."[272] As with the Big River Electric audit, Mr. Kollen suggests that a Request for Proposal ("RFP") be developed by Staff and KCPL as well as a timeline for awarding the contract, completing the audit, submission of a report and implementation of recommendations.[273] From the proposals that it receives in response to the RFP, KCPL should submit rank and submit a short list to the Staff. This would be followed by interviews and the selection of an auditor.[274]

> The auditor should develop and submit a timeline and detailed audit workplan for review and approval by the Company and the Staff and then conduct the audit. It should prepare and submit monthly progress reports to the Company and Staff and then a draft of the Report, including its findings and recommendations to the Company and Staff. The Report should include a timeline for implementation and quantification of the savings that may be achieved for each recommendation if the Company successfully implements the recommendation.[275]

The Company should then provide a detailed response indicating its agreement or disagreement with the recommendations as well as its plan for implementing those recommendations and its quantification of the savings that can be achieved.[276]

As mentioned, given the existence of regulatory lag and its ability to initially keep all savings resulting from this audit, KCPL should be eager to undergo this review. That said, KCPL has continually rejected this recommendation. Again, KCPL's unwillingness

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[272] *Id.*
[273] *Id.* at page 15.
[274] *Id.*
[275] *Id.* at pages 15-16.
[276] *Id.*

to accept such a recommendation is confusing given that KCPL readily admits that past audits, conducted with a much smaller scope, have been "beneficial" to KCPL.

> **Mr. Woodsmall:** Okay. So do you believe that these external -- these process reviews that have been conducted in the past that you talked about with Commissioner Hall, do you believe those have been beneficial?
>
> **Mr. Bresette:** Yes. Otherwise I don't think the Company would have made the decision to engage a third party for -- for review of processes. The Company only makes prudent business expenses.
>
> **Mr. Woodsmall:** Okay. So with regard to the first one, you agree that there are times that outside consultants can provide benefits to management outside their normal operations; is that true?
>
> **Mr. Bresette:** Generally I would agree.
>
> **Mr. Woodsmall:** Okay. And you would also agree that there are consultants out there that may be able to provide benefits beyond what have already been identified by the consultants that you have retained; is that true?
>
> **Mr. Bresette:** I -- I guess it's possible.[277]

Given its unwillingness to have outside experts review their various process and procedures, but recognizing that the benefits of such a review are undeniable, KCPL instead attempts to undermine the basis for the recommended audit.

First, KCPL attempts to question the accuracy of the A&G analysis conducted by both Mr. Kollen and Staff. Specifically, at the hearing, KCPL's witness questioned whether the Westar data included in the analysis was accurate since it failed to distinguish between the various operating companies of Westar.[278] Based upon this criticism, Staff expanded the analysis to include the various Westar operating companies. From this analysis, it is apparent that KCPL's criticism is unfounded.[279]

[277] Tr. 1169-1171,
[278] 1175-1176.
[279] Exhibit 246.

Second, KCPL attempts to undermine the A&G analysis by questioning the underlying data (utility FERC Form 1s) used in that analysis. As. Mr. Kollen points out, however, given the common definitions and instructions, the FERC Form 1 data is inherently reliable.

> The data provided in an electric utility FERC Form 1 is compiled, segregated and assigned to specific accounts pursuant to detailed account definitions and instructions. These accounts, definitions and instructions are known as the FERC Uniform System of Accounts. Furthermore, the utility is required to attest that the data conforms to the Uniform System of Accounts. Finally, the FERC Form 1 is required to be signed by an independent auditor. As such, there is a heightened level of reliability underlying this data and, as a result of common accounts and definitions, an increased level of comparability between different utilities.[280]

Finally, KCPL attempts to divert attention from the Staff and MECG analysis by providing its own self-serving analysis. In its Rebuttal Testimony, KCPL provided an A&G analysis conducted by PA Consulting. Not surprisingly, that analysis provided KCPL the answer that it desired, "KCPL's A&G costs are not excessive and are, in fact, below the median of the other utilities that participated in the benchmark study."[281] As the record indicates, however, there are fundamental problems with the KCPL benchmark study.

As Mr. Kollen points out, the benchmark analysies relied upon by KCPL "are not structured by FERC account in the same manner that test year costs are developed and presented."[282] Second, recognizing that the Company refused to provide the underlying cost data, the results could not be verified or evaluated.[283] Third, "the comparisons were

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[280] Exhibit 501, Kollen Surrebuttal, page 9.
[281] Exhibit 105, Bresette Rebuttal, page 11.
[282] Exhibit 501, Kollen Surrebuttal, page 8.
[283] *Id.* While KCPL was allowed to provide its own identity within the benchmark study it "is bound by a contractual obligation that we are not to reveal any of the participants in this study." (Tr. 1161). In fact, given the confidentiality problems, KCPL did not attempt to verify the accuracy of any of the underlying data. (Tr. 1164).

not comprehensive, but were limited to specific functions / activities."[284] Fourth, unlike the analysis conducted based upon FERC Form 1 data, the KCPL study does not appear to be based upon common account definitions and instructions.[285]

In the final analysis, it is undeniable that KCPL's A&G costs are excessive. The reasons for these excessive costs are structural and incapable of being adequately addressed in a rate case. Given this, MECG urges the Commission to fulfill its customer protect mission and order that KCPL undergo an audit for the purpose of process improvement and reducing these excessive costs.

[284] *Id.* at pages 8-9.
[285] *Id.* at page 9

IX. INCOME TAX RELATED ISSUES

A. INTRODUCTION

In his testimony, MECG witness Brosch addressed a number of income tax related issues. Mr. Brosch's expertise as it relates to income tax issues is unquestioned. In fact, while a member of a regional accounting firm, he taught its first class on "utility income taxation - ratemaking and accounting considerations" in 1982.[286] Indeed, Mr. Brosch's expertise related to income taxes was on display in this proceeding. In his direct testimony, Mr. Brosch made several adjustments to KCPL's income tax calculation. In its rebuttal, KCPL expressly recognized the errors contained in its calculations and agreed with Mr. Brosch.

> Q. ***Do you agree with Mr. Brosch's assertion*** that tax straight-line depreciation, tax straight-line amortization and nuclear fuel amortization used to compute income tax expense is understated in the direct filing?
>
> A: ***Yes***. Several errors were made in the original computation of these items in the direct filing by the Company. We have attempted to correct all of the issues and will adjust the true up amounts in this case to reflect the corrected amounts.
>
> Q: ***Is Mr. Brosch correct*** that "inconsistencies" in the numbers for the tax straight-line depreciation, tax straight-line amortization and nuclear fuel used in the data requests still includes $1.1 million of unreconciled differences even after the errors were corrected?
>
> A: ***Yes***. Due to a number of estimates and assumptions used to compute these amounts for the rate case, we were not able to reconcile the amounts fully.[287]

Despite repeatedly recognizing the accuracy of Mr. Brosch's income tax adjustments, KCPL challenges ***four*** of Mr. Brosch's adjustments. ***First***, consistent with the Commission's decision in ER-2012-0166, Mr. Brosch disputed KCPL's decision to exclude from rate base CWIP-Related Accumulated Deferred Income Taxes ("ADIT").

[286] See, Exhibit 502, Brosch Direct (Revenue Requirement), Attachment A.
[287] Exhibit 112, Hardesty Rebuttal, pages 19-20.

Second¸ while KCPL proposes to increase rate base for the 1 KC Place ADIT asset item, KCPL fails to include the corresponding accrued lease liability balance that would reduce rate base if included. As Mr. Brosch explains, this is an unreasonable mismatch and both the accrued lease liability balance and the ADIT asset should be reflected in rate base. ***Third***, and in a similar fashion, KCPL improperly proposes to include in rate base the ADIT asset while excluding the corresponding liability balance associated with accrued employee compensation. ***Fourth***, Mr. Brosch proposes an adjustment to correct the negative effects on ratepayers of the Great Plains Energy Tax Allocation Agreement. As Mr. Brosch demonstrates, that tax agreement is a non-arm's length affiliate agreement that has always been and is always projected to be detrimental to KCPL ratepayers. Specifically, Mr. Brosch proposes to disregard the significant amounts of Net Operating Loss Carryforward amounts assigned to KCPL because of affiliated company tax losses in order to inflate rate base and, instead, replace them with the Net Operating Losses calculated on a KCPL stand-alone basis.

B. ACCUMULATED DEFERRED INCOME TAXES

In calculating its financial statements, companies, including utilities, utilize accrual accounting as required by Generally Accepted Accounting Principles ("GAAP"). In contrast, the accounting methods used for calculating taxable income rely upon the Internal Revenue Code ("IRC"). Differences between GAAP and IRC accounting create book / tax differences.

As Mr. Brosch explains, "[m]any of these book / tax differences are temporary because they arise from timing differences."[288] Specific provisions in GAAP accounting require the recognition of income tax impacts associated with these timing differences.

[288] Exhibit 502, Brosch Direct (Revenue Requirement), page 46.

This recognition takes the form of accumulated deferred income taxes ("ADIT") assets or liabilities.[289]

The classic example of a timing difference between book and tax accounting is associated with depreciation. While book accounting relies on straight-line depreciation, tax accounting allows for accelerated lives and / or bonus depreciation.[290] The practical effect of this difference is that tax accounting, because it relies on accelerated lives, will create a larger depreciation deduction in the early years of an asset's life than is allowed under book accounting. As a result, income tax expenses under tax accounting will be less than income taxes under GAAP. This tax difference associated with varying depreciation methods creates an ADIT liability. Recognizing, however, that book depreciation will provide for a larger depreciation deduction in later years, the ADIT balance will eventually reverse itself. By the end of the asset's useful life, the ADIT liability balance should be zero as early ADIT balances are eliminated because of larger depreciation deductions in the later years provided by book depreciation.[291] "ADIT balances exist to recognize that certain tax expenses are determinable today, but actually become payable in the future whenever book / tax timing differences ultimately reverse."[292]

As Mr. Brosch explains, it is important that utility regulators recognize these ADIT balances. Recognizing that utilities are capital intensive, these businesses routinely generate large income tax deductions associated with bonus / accelerated depreciation. While the utility is allowed to take these increased depreciation deductions

[289] *Id.* at page 47.
[290] *Id.*
[291] *Id.* at pages 46-47.
[292] *Id.* at page 47.

for tax purposes, regulators are prevented from recognizing these same deductions and lower tax expenses for calculating rates. As a result, in the early years of an asset, ratepayers will pay for a larger amount of income taxes in rates than the utility actually pays. This difference between the amount of taxes paid by the utility and the amount recovered in rates effectively "represent a form of zero-cost capital to the utility."[293] In order to prevent the utility from earning a return on this capital that was not supplied by the shareholder, ADIT balances are normally included in rate base as an offset to rate base. Through this rate base offset, the utility is only allowed to earn "a return on the <u>net</u> amount of investor-supplied capital to support rate base assets."[294]

The same concept can work in reverse. For instance, there are situations in which current taxes under tax accounting are greater than current taxes under book accounting. In this situation an ADIT asset balance is created. In such a situation, while the ADIT asset balance may be reflected in rate base, the offsetting liability should be used to offset that balance.

In this case, KCPL has improperly treated several of the ADIT balances. As the following analysis demonstrates, adjustments should be made to protect ratepayers from the higher revenue requirement that results from KCPL's ADIT mistakes.

C. <u>CWIP-RELATED ADIT</u>

In its revenue requirement calculation, KCPL properly recognizes the ADIT liability balances as an offset to rate base for those assets which are operational and in-service. That said, KCPL mistakenly excludes the ADIT liability balances from rate base for those assets with are still considered Construction Work in Progress. The failure to

[293] *Id.* at page 48.
[294] *Id.*

include these ADIT liability balances in the rate base calculation as the effect of significantly overstating rate base.[295] KCPL argues that since it is not allowed to include CWIP in rate base and earn a return on these construction projects, it should not be required to include the related ADIT liability balances as an offset to rate base.[296]

In its decision in ER-2012-0166, the Commission provided an excellent analysis of the negative impact on ratepayers of a utility decision to exclude these CWIP-ADIT balances from rate base.[297] Responding to identical arguments as those set forth by KCPL today,[298] the Commission rejected Ameren's argument.

> Even though Ameren Missouri cannot add CWIP to its rate base, and therefore cannot earn a return on that investment, until the property is fully operational and used for service, it is allowed to earn an Allowance for Funds Used for Construction (AFUDC) before the property under construction is added to rate base. AFUDC is accrued during the process of construction and is added to the balances of plant in service that is included in rate base when the plant is placed in service. It is then recovered from ratepayers over the remaining life of the property.
>
> ***CWIP related ADIT balances must be accounted for in rate base*** because AFUDC is applied to Ameren Missouri's gross investment in CWIP, with no recognition given to the CWIP-related ADIT amounts that serve to reduce the company's actual net capital requirements for CWIP. . . . In other words, ***failure to recognize the CWIP-related ADIT balance in the company's rate base will overstate the companies AFUDC costs and future rate base, essentially allowing the company to earn AFUDC and a return on capital supplied by ratepayers***.[299]

In this case with identical facts and the same witness addressing the issue, MECG thoroughly agrees with the logic of that previous Commission decision. KCPL's exclusion of the ADIT liability balances associated with CWIP projects fails to recognize

[295] *Id.* at page 50.
[296] *Id.*
[297] See, Case No. ER-2012-0166, *Report and Order*, issued December 12, 2012, at pages 26-30.
[298] *Id.* at page 29 ("Ameren Missouri does not disagree with the general principle to use credit ADIT balances as an off-set to rate base. However, disagreement arises over the treatment of that portion of the ADIT balance related to construction costs incurred for projects that remain in construction work in progress (CWIP) accounts at the end of the test period.").
[299] *Id.* at pages 28-30 (emphasis added).

that ratepayers provide KCPL a return on such projects through AFUDC. While it is not a current cash return, the AFUDC return is capitalized into the overall cost of the construction project and KCPL is allowed to fully recover this deferred return once the construction project is operational. Since ratepayers are providing KCPL a return on these construction projects through AFUDC, they should also receive the benefits of the associated ADIT balances. By excluding these ADIT balances as an offset to rate base, KCPL is earning the return and keeping all of the benefits of accumulated depreciation (e.g., lower current income taxes).[300]

Given the clarity of the previous Commission decision, as well as the equity associated with giving ratepayers credit for the ADIT liability balances that result from construction projects in which those ratepayers provide an AFUDC return, MECG urges the Commission to correct KCPL's oversight and adopt Mr. Brosch's adjustment.

D. 1KC PLACE LEASE ADIT

In the previous example, CWIP-related tax deductions created an ADIT liability balance. This issue concerns an ADIT asset balance that is created by the fact that KCPL has received rent abatement benefits associated with its lease of headquarters space at 1KC Place. Under this rent abatement, KCPL pays a lower amount of deductible cash rent in the early years of its lease. Given the business expense deduction for rent, this lower amount of rent will result in a higher level of current income taxes. On the other hand, KCPL will pay a higher amount of rent in the later years of the lease that is recognized as an accrued expense on the books. At that future point in time, this higher amount of rent will drive larger business expense deductions and a lower amount of

[300] Exhibit 502, Brosch Direct (Revenue Requirement), pages 51-52.

income taxes. The timing difference that occurs when "tax deductibility for expenses is subsequent to the book recognition of the expense" results in an ADIT asset.[301]

KCPL has recognized a significant liability on current books to recognize the delayed obligation to make additional lease payments in the future. In connection with this liability balance a large and offsetting deferred tax asset was recorded to recognize that the accrued but unpaid future lease costs are not currently deductible for income tax purposes. While KCPL proposes to include the ADIT asset item in order to increase rate base, KCPL has failed to recognize the corresponding accrued lease liability balance that would reduce rate base if recognized. This is an unreasonable mismatch that must be corrected.[302]

In its rebuttal testimony, KCPL acknowledges that it has not included in rate base the offsetting "accrued liability for the deferred rent payment on the 1KC Lease."[303] KCPL made the decision to not recognize this accrued liability based upon the mistaken belief that the impact of this liability has been recognized through KCPL's cash working capital lead / lag study.[304] In data request responses, KCPL admits that including this accrued liability in rate base through cash working capital "is not financial [sic] equivalent to fully including the 1KC liability in rate base."[305]

Putting aside KCPL's admission that cash working capital recognition of the accrued liability would not be "financially equivalent" to including the liability in rate base, Mr. Brosch also points out that KCPL's contention is inherently illogical and produces a result entirely contrary to that suggested by KCPL. As Mr. Brosch points out,

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[301] *Id.* at page 47.
[302] *Id.* at page 55.
[303] Exhibit 112, Hardesty Rebuttal, page 6.
[304] *Id.*
[305] Exhibit 504, Brosch Surrebuttal, page 9.

"the effect of including a reduced expense on the "Cash Vouchers" line of the Company's lead lag study would actually increase rate base, producing a result completely inconsistent with recognition of deferred lease payment liabilities that would reduce rate base if recognized."[306]

Recognizing that KCPL has not yet paid the abated rent associated with its lease of 1KC Place and has not reduced rate base to recognize the accrued liability for higher future rent payments, it should not be allowed to increase rate base associated with the ADIT asset balance that is created. Rather, any ADIT asset balance included in rate base should also include the accrued liability balance in order to maintain the proper matching and protect the ratepayers from inflated rates. As such, MECG urges the Commission to adopt Mr. Brosch's ADIT-1KC Place adjustment.

E. <u>ACCRUED EMPLOYEE COMPENSATION ADIT</u>

In much the same way that KCPL recorded an ADIT asset balance associated with its future payment of higher income taxes associated with rent abatement, KCPL also recorded an ADIT asset balance associated with deferred employee compensation.[307] Accrual accounting under GAAP requires KCPL to recognize the liability for payment of this future compensation on its books. On the other hand, tax accounting does not recognize this expense as tax deductible until the compensation is actually paid at a future date. Again, this situation where "tax deductibility for expenses is subsequent to the book recognition of the expense" resulting an ADIT asset balance.[308]

As with the ADIT asset balance for 1KC Place, KCPL proposes to include the ADIT asset item in order to increase rate base. That said, KCPL has failed to recognize

[306] *Id.*
[307] Exhibit 502, Brosch Direct (Revenue Requirement), page 56
[308] *Id.* at page 47.

the corresponding accrued lease liability balance that would reduce rate base if recognized. This is an unreasonable mismatch that must be corrected.[309]

Again, KCPL acknowledges that it has not included in rate base the offsetting accrued liability for the accrued employee compensation.[310] As with the 1KC Place ADIT asset, KCPL made the decision to not recognize this accrued liability based upon the mistaken belief that the impact of this liability has been recognized through KCPL's cash working capital lead / lag study.[311] In data request responses, KCPL admits that including this accrued liability in rate base through cash working capital "is not financially equivalent to fully including the bonus and deferred compensation liabilities in rate base."[312] As with the 1KC Place ADIT asset, KCPL's suggestion that it has recognized this liability through its cash working capital study is inherently illogical and produces a result entirely contrary to that suggested by KCPL.

Recognizing that KCPL has not yet paid the deferred compensation and has not reduced rate base to recognize the accrued liability for higher future compensation payments, it should not be allowed to increase rate base by including the corresponding ADIT asset balance that is created. Rather, any ADIT asset balance included in rate base should also include the accrued liability balance in order to maintain the proper matching and protect the ratepayers from inflated rates. As such, MECG urges the Commission to adopt Mr. Brosch's ADIT-accrued employee compensation adjustment.

[309] *Id.* at page 55.
[310] Exhibit 112, Hardesty Rebuttal, page 7.
[311] *Id.*
[312] Exhibit 504, Brosch Surrebuttal, page 11.

F. NET OPERATING TAX LOSSES

1. Introduction

In 2000, the Commission promulgated its Affiliate Transaction Rule.[313] As clearly set forth in the Purpose of that rule, "[t]his rule is intended to prevent regulated utilities from subsidizing their nonregulated operations." Specifically, the rule was designed to recognize that regulated affiliates have an inherent incentive to take actions that, while detrimental to the utility and its ratepayers, are beneficial to the utility's unregulated affiliates and to the overall interest of the consolidated company. Among other things, a utility may accept an unreasonably large share of allocated costs in order to: (1) depress regulated earnings and thus allow larger rate increases while (2) increase the earnings of non-regulated affiliates and the parent company.

As the following discussion points out, KCPL has executed a Tax Allocation Agreement with its affiliates that causes it, through the allocation of consolidated income tax Net Operating Losses ("NOLs"), to pay an increased share of consolidated income taxes than it would otherwise pay absent the Tax Allocation Agreement. In a recent Ameren case, the Commission approved rate case recognition of that utility's Tax Allocation Agreement because: (1) there was no evidence to show that the Tax Allocation Agreement was structured so as to be detrimental to Ameren Missouri and (2) Ameren Missouri ratepayers had previously benefited through a lower rate base because of the Tax Allocation Agreement. In this case, neither of these conditions applies. Rather, as the evidence indicates, the Great Plains Energy Tax Allocation Agreement is inherently and persistently detrimental to KCPL and its ratepayers. Furthermore, unlike the previous Ameren case, KCPL ratepayers have never benefitted under the Great Plains

[313] 4 CSR 240-20.015.

Energy Tax Allocation Agreement and, given KCPL's own admissions and financial forecasts, are not anticipated to benefit from that affiliate agreement in future years.

2. The Great Plains Tax Allocation Agreement is Detrimental to Ratepayers

In 2008, with its acquisition of Aquila, Great Plains Energy executed a Tax Allocation Agreement ("TAA") with all of its affiliates. Among other things, that agreement provides that all of the affiliates will join in the filing of consolidated federal and state income tax returns. Once determined each year, the consolidated income tax liability or benefit of Great Plains Energy is allocated among the affiliates as directed in the TAA.

The existence of such an agreement among affiliates of a regulated utility should automatically raise concerns with regulators. As a result of such an agreement, income tax losses and the resulting rate base net ADIT balance for the regulated utility is no longer calculated on a stand-alone basis. Rather, income tax losses attributed to the utility become dependent on the earnings and losses of affiliates. The nature and profitability of these affiliates can, as a result of the TAA, be detrimental to the regulated ratepayers. As Mr. Brosch points out:

> Utility holding companies are free to invest in both regulated and non-regulated subsidiaries and to structure cost allocation and affiliate transaction arrangements between the controlled subsidiaries that may be more beneficial to its non-regulated subsidies and shareholders than its regulated subsidies and ratepayers. Great Plains Energy, Inc. oversees a portfolio of investments, some of which are regulated and others that are not regulated. ***This holding company structure introduces an opportunity for complex affiliated company transactions and intercompany allocations to unreasonably impact the costs borne by the regulated utility businesses within the portfolio***.[314]

[314] Exhibit 502, Brosch Direct (Revenue Requirement), page 60.

In this case, general suspicions regarding the existence of such an agreement have proven to be well-placed. Specifically, "[t]he TAA produces a higher NOLC [Net Operating Loss Carryforward] amount for the KCPL utility business than results from calculation of the Company's NOLC on a stand-alone KCPL basis through tax year 2014."[315] Because the NOLC deferred tax asset is included in rate base, the higher NOLC produced under the TAA yields an overstated revenue requirement.

As Mr. Brosch points out, these inflated levels of NOLC are largely the result of Great Plains Energy's acquisition of Aquila in 2008. Recognizing the significant losses that were generated as a result of its ill-timed venture into deregulated markets, Aquila generated huge losses as well as **____ ____**[316] As a result of these poor business decisions, Aquila had to sell off its profitable utility operations. Ultimately, Great Plains Energy acquired the remaining operations of Aquila including these **____**[317]

The practical effect of the TAA and these **______________________________ ______________________** that are being carried forward is that, when KCPL **____

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______________________** As it effects current ratepayers, **____ **. As such, contrary to the

[315] *Id.* at page 57.
[316] Exhibit 504, Brosch Surrebuttal, page 16.
[317] Exhibit 504, Brosch Direct, page 58.

Commission's Affiliate Transactions Rule, the TAA is beneficial to KCPL's affiliates and detrimental to KCPL ratepayers.[318]

In attempting to defend its detrimental TAA, KCPL will undoubtedly refer the Commission back to its decision in the most recent Ameren case. There, the Commission decided a comparable issue in favor of Ameren and found that Ameren ratepayers had previously benefitted from Ameren's consolidated tax agreement that allocated tax liability among the Ameren subsidiaries.

> There is no evidence in this case to show that Ameren's Tax Allocation Agreement is structured in a way that would be detrimental to Ameren Missouri and its ratepayers. Instead, for several years, Ameren Missouri's ratepayers benefited from a lower rate base because of the Tax Allocation Agreement. The Tax Allocation Agreement has not changed, but in more recent years ratepayers have not benefitted from that agreement, although that may change again in the future. That fluctuation does not mean the agreement is unreasonable, and there is no evidence the fluctuation was intentionally created in order to change who benefits from the Tax Allocation Agreement.[319]

Given that ratepayers had previously benefitted from the Ameren Tax Allocation Agreement and recognizing that it was unable to find that the Ameren agreement was structured in a way that is detrimental to ratepayers, the Commission rejected a net operating loss adjustment calculated on a stand-alone basis for Ameren Missouri.

As Mr. Brosch shows, however, the facts underlying this case and the recent Ameren case are decidedly different. First, as Mr. Brosch explains, the Great Plains Energy TAA, unlike the comparable Ameren agreement, is structured in a way that it is "inherently detrimental to KCPL and its ratepayers."

> The Great Plains TAA is structured to combine the tax attributes of Great Plain's **____**, with the utility businesses that have experienced tax losses only rarely

318 Id.

319 Report and Order, Union Electric Company d/b/a Ameren Missouri, April 29, 2015, page 21.

> historically and should remain profitable in future years if bonus depreciation is not extended past 2014, when it expired under current tax law. ***<u>This structure causes the Great Plains utility businesses to systematically subsidize the holding company and non-utility businesses, by providing taxable income to accelerate the tax benefit realization of non-utility losses while any non-utility losses may displace or delay the realization of utility tax credits and utility NOLs</u>***. In contrast, the Ameren TAA, that was addressed by the Commission in Case No. ER-2014-0258, was favorable to Ameren Missouri ratepayers in the years 2008 through 2012, when it served to accelerate the realization of utility NOL benefits by combining such utility losses with positive taxable income from Ameren Corporation's non-regulated generating and energy marketing businesses.[320]

Second, unlike the Ameren case, KCPL ratepayers have <u>never</u> benefitted from the Great Plains Energy TAA.[321] In fact, as KCPL readily admits, it does not project that ratepayers will ever benefit from the GPE TAA. Finally, GPE acquired certain confidential net operating loss carryforward amounts associated with its acquisition of Aquila that make the Great Plains TAA decidedly disadvantages KCPL ratepayers in future periods.

> This is a major distinction, in comparison to the Ameren Missouri situation, where the Ameren TAA over time has produced a mix of historical benefits in some years and detriments to Ameren Missouri in other years, with results that could switch back and forth in the future. In fact, in response to MECG Data Request 15-53(d), Ms. Hardesty stated, "[w]e only have financial projections for 2015-2019, and we do not expect KCPL to see a benefit by filing with the consolidated group during this period."[322]

In light of all of these differences, Mr. Brosch concludes that the Great Plains Energy Tax Allocation Agreement is structured in a way that causes it to be inherently detrimental to KCPL ratepayers.

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[320] Exhibit 504, Brosch Surrebuttal, page 17.
[321] Id. page 15.
[322] *Id.* at page 16 and Schedule MLB-25 (citing to KCPL Response to MECG question 15-53(d).

Given that KCPL ratepayers are harmed by the detrimental Great Plains Energy TAA, have never benefitted from that affiliate agreement and are not projected to benefit from that agreement, MECG urges the Commission to protect the ratepayers from the harms that befall them from this unreasonable affiliate agreement. Specifically, MECG urges the Commission to adopt the adjustment proposed by Mr. Brosch.

X. CLASS COST OF SERVICE / REVENUE ALLOCATION / RATE DESIGN

A. INTRODUCTION

On June 16, 2015, Staff, Public Counsel, MIEC, MECG, Consumers Council, Missouri Division of Energy, and the United States Department of Energy filed a Non-Unanimous Stipulation and Agreement. That Agreement addresses all issues denominated as Issues XXV(A) (Class Cost of Service) and XXV(B) (Rate Design). Among other resolutions, the Agreement provides for any revenue increase to be allocated among the classes on an equal percentage basis. As such, the Agreement is consistent with the pre-filed equal percent revenue allocation positions of KCPL,[323] Staff,[324] and Public Counsel.[325] While KCPL has objected to the entirety of the Non-Unanimous Stipulation, since the Settlement incorporates KCPL's position on revenue allocation, the Signatory Parties "do not believe that the Commission needs to make specific findings as to the appropriate methodology for allocating production plant costs among the customer classes."[326]

Additionally, the Agreement provides that any increase in Large Power and Large General Service rates will be increased using the rate design proposals contained in Maurice Brubaker's Direct Testimony.[327] Specifically, a larger amount of any LP and LGS revenue increase will be collected through the demand charges and first energy block rates.[328]

On June 22, 2015, KCPL filed its Objection to the Non-Unanimous Stipulation and Agreement. Based upon statements at the hearing as well as its questioning of witnesses, it

[323] Exhibit 134, Rush Direct, page 57.
[324] Exhibit 237, Scheperle Direct, page 4.
[325] Exhibit 303, Dismukes Direct, page 3.
[326] See, *Non-Unanimous Stipulation and Agreement on Certain Issues*, filed June 16, 2015, at page 2, paragraph 3.
[327] Exhibit 554, Brubaker Direct (Rate Design), pages 28-34.
[328] While KCPL initially objected to this specific provision, MECG understands that, from the true-up testimony, KCPL is no longer objecting to this provision and will be filing a pleading indicating its concurrence. Given that such a pleading has not been filed, at the time of this brief, MECG has briefed all issues.

appears that KCPL's objection is largely two-fold. First, KCPL objects to the provision of the Settlement which maintains the residential customer charge as its current level. Second, KCPL objects to the LGS / LP rate design provision to the extent that it may cause a loss of revenues as a result of customer migration between the various rate classes. KCPL's objection on both points is misplaced.

First, KCPL's request to implement a residential customer charge of $25.00 is misplaced. In its testimony, Staff points out that its class cost of service study justifies a residential customer charge of $11.88.[329] As such, KCPL's request is clearly not supported by competent and substantial evidence. In contrast, the Settlement provision leaving the residential customer charge at $9.00 is supported by this testimony. In addition, it should be pointed out that in recent decisions, the Commission has pointed out that, in order for energy efficiency to be maximized, residential customers should have control over their monthly bills. Given this goal, residential energy charges should not be decreased. Recognizing that an increase in the residential customer charge would result in a decrease to the residential energy charges, this energy efficiency goal would be undermined.[330] As such, the Commission maintained the Ameren residential customer charge at $8.00.[331] Similarly, the Commission maintained the Empire residential customer charge at its current levels.[332] The Signatories to the Settlement recognized the Commission's previous decisions and maintained the residential customer charge at its current $9.00 level.

Second, KCPL's concerns with the Settlement's provision to implement any LGS / LP rate increase primarily through demand charges and the first energy block rate is also without merit. The agreed upon LGS / LP rate design proposal was provided in testimony on

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[329] Exhibit 247.
[330] Case No. ER-2014-0258, *Report and Order*, issued April 29, 2015, at pages 76-77.
[331] *Id.* at page 77.
[332] Case No. ER-2014-0351, *Report and Order*, issued June 24, 2015, at page 14.

April 16, 2015. While KCPL expressly acknowledged the LGS / LP rate design proposal in its rebuttal testimony,[333] KCPL expressed no concerns with its design. Similarly, KCPL did not address this proposal in its surrebuttal. Surprisingly, two months after it was initially proposed. KCPL made vague references about potential lost revenues associated with the LGS / LP rate design. The evidence indicates that Staff has thoroughly reviewed this issue and finds such concerns to be misplaced. Specifically, Staff points out that, at KCPL's fully requested increase of 15.75%, any lost revenues associated with the LGS / LP rate design would be about $250,000. Staff then notes that, at a lower overall revenue requirement increase, this lost revenue figure would decrease.[334] Furthermore, it should be pointed out that the LGS / LP rate design proposal is not new. Specifically, KCPL has agreed to this proposal in each of the last three rate cases.[335] As such, KCPL is acutely familiar with this proposal and was fully capable of expressing any concerns that it had associated with this proposal. The fact that KCPL failed to enunciate any objection in its rebuttal testimony reinforces the reasonableness of the proposal.

Given the reasonableness of the Settlement, as well as the fact that the Settlement was supported by all of the customers in this case, MECG urges the Commission to approve the terms of the Settlement. In the event, however, that the Commission rejects the Settlement and makes findings on the individual issues contained therein, MECG provides the following brief. Specifically, in this brief, MECG addresses issue XXV(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 A&E methodology for allocating these costs. As this brief

[333] Exhibit 135, Rush Direct, page 51.
[334] Tr. 458-460.
[335] See, Case No. ER-2012-0174, *Order of Clarification*, issued January 11, 2013, at pages 2-3. See also, Case No. ER-2010-0355, *Non-Unanimous Stipulation and Agreement*, filed February 4, 2011; Case No. ER-2009-0089, *Non-Unanimous Stipulation and Agreement*, filed April 24, 2009, pages 2-3.

demonstrates, the Commission has repeatedly rejected the KCPL and OPC Peak & Average production allocator. Furthermore, the record indicates that Staff's Base / Intermediate / Peak methodology is fundamentally flawed. Specifically, despite using the BIP method in previous cases, KCPL now asserts that this method does not reflect the realities of the current SPP Integrated Marketplace. MECG urges the Commission to adopt the guidance from its previous 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 XXV(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, have 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.

Finally, MECG recommends that the Commission allocate any revenue increase to the LGS / LP 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. 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 LP intra-class subsidies, that benefit low load factor customers, are reduced.

B. WHAT METHODOLOGY SHOULD THE COMMISSION USE TO ALLOCATE FIXED PRODUCTION PLANT COSTS AMONG CUSTOMER CLASSES?

Position: The Commission should utilize the Average & Excess (4 NCP) methodology to allocate generation fixed costs among the customer classes.

1. Introduction

In general, utilities incur three categories of costs: (1) customer-related costs: costs associated with connecting customers to the distribution system, metering usage and other customer support functions (i.e., meter reading, billing, postage and customer service expenses); (2) energy-related costs: costs that tend to change with the amount of electricity sold (i.e., fuel, fuel handling, and interchange power costs); and (3) demand-related costs: costs associated with meeting maximum electricity demands.[336]

It is well established that the electric industry is very capital intensive. The evidence indicates that KCPL has invested almost $8.7 billion in its various production, transmission and distribution facilities.[337] Of this, over 63%, approximately $5.5 billion, is associated with KCPL's investment in its various methods of generating electricity.[338] As such, the most significant issue underlying any class cost of service study concerns the method by which these generation fixed costs are allocated to the various customer classes.

While there are different methods utilized for allocating generation fixed costs, the difference in these methodologies generally concern the degree to the specific methodology considers generation plant to be an energy-related cost (focused on class energy usage) or a demand-related cost (focused on class peak demand). The evidence

[336] Exhibit 303, Dismukes Direct, pages 4-5.
[337] Exhibit 201, Accounting Schedules, Accounting Schedule 3, page 7.
[338] *Id.* at page 6 (line 226).

indicates that production plant is <u>both</u> an energy and demand related cost. In fact, the evidence indicates that the need to meet both class energy needs and 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, ***<u>giving consideration to fixed costs and variable costs</u>***, 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.[339]

2. <u>Average & Excess Production Allocator</u>

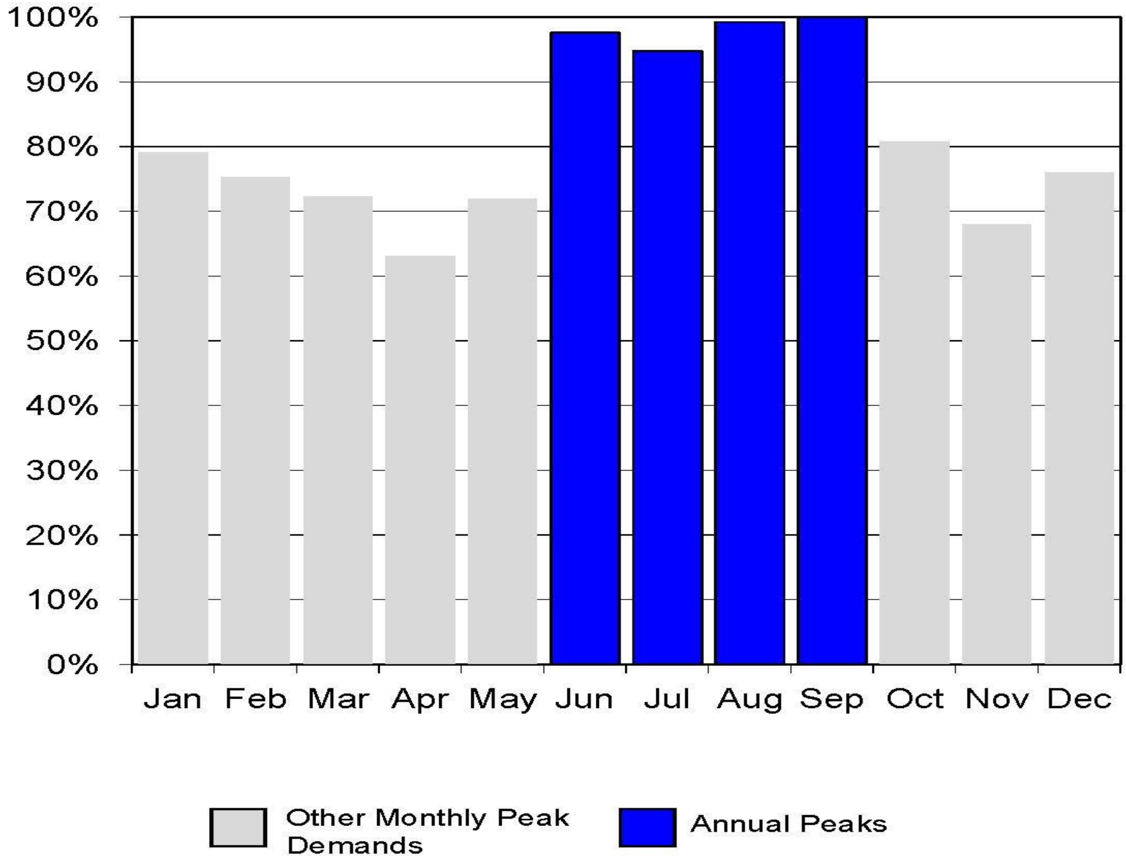
Recognizing that both class peak demand <u>and</u> energy usage are important to the utility's decision as to the amount and type of capacity to be added, MECG relies upon the Average & Excess ("A&E") production allocator methodology. As Mr. Brubaker points out, the A&E methodology relies upon both class energy and peak demand in its calculation of a production allocator.

> As the name implies, A&E makes a conceptual split of the system into an "average" component and an "excess" component. The "average" demand is simply the total kWh usage divided by the total number of hours in the year. This is the amount of capacity that would be required to produce the energy if it were taken at the same demand rate each hour. The system "excess" demand is the difference between the system peak demand and the system average demand.[340]

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 <u>amount</u> of capacity to add and the <u>type</u> of capacity to add.

[339] Exhibit 555, Brubaker Rebuttal, page 14 (emphasis added).
[340] Exhibit 554, Brubaker Direct (Rate Design), pages 17-18.

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 554, Brubaker Direct (Rate Design), Schedule MEB-COS-1.

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 decision to add additional generation.[341] Given the definite summer peaking nature of KCPL, it is these summer peaks that drive generation additions. In a similar nature, it

[341] Exhibit 702, Schmidt Direct, page 7 ("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 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.").

should be these definite summer peaks that drive any allocation of fixed production costs among the customer classes.[342]

3. KCPL and OPC's Peak and Average Methodology

In contrast to the logic underlying MECG's use of the A&E production allocator methodology, KCPL and OPC[343] relied upon a production allocator that is inherently flawed because it double counts the average demand [energy] of customer classes.[344] Specifically, KCPL and OPC's preferred method of fixed production cost allocation is a peak and average methodology ("P&A") methodology.[345]

As the evidence indicates, the average component of both the A&E and P&A 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 all of the 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) contained in the P&A methodology.

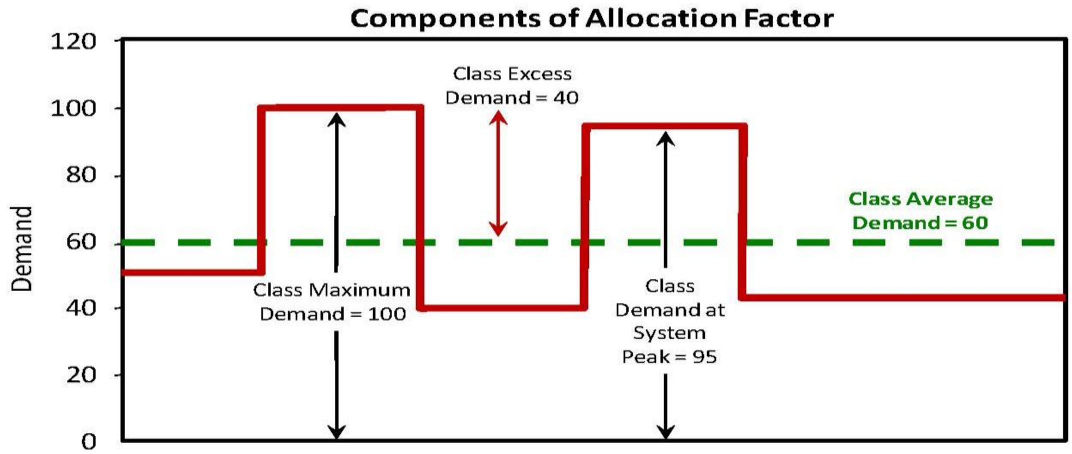
In his rebuttal testimony, Mr. Brubaker graphically illustrates the differences between the A&E method and the flawed P&A method.

[342] The reasonableness of the A&E approach is also recognized by the fact that Public Counsel provided results for an A&E approach as an alternative to its "preferred" Peak & Average approach. See, Exhibit 303, Dismukes Direct, page 10 and Schedule DED-1.

[343] Undoubtedly recognizing the flawed nature of the Peak & Average approach, as well as the Commission's stated preference for the A&E methodology, Public Counsel presented an alternative class cost of service study that relied upon the A&E production allocator. (See Exhibit 303, Dismukes Direct, page 10 and Schedule DED-1).

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

[345] Exhibit 134, Rush Direct, page 53; Exhibit 303, Dismukes Direct, page 10.



Source: Exhibit 555, Brubaker Rebuttal, page 6.

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, "[T]he 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."[346]

Unlike the A&E method which combines the average demand with the excess (40), the KCPL and OPC Peak & Average method "combines the average demand (60) with the class monthly peak demand (100)."[347] Recognizing that "the average peak demand (60) is a component or sub-set of the class peak demand (100) and the class load coincident with the system peak (95)," "the average demand is double-counted."[348]

[346] Exhibit 555, Brubaker Rebuttal, at page 6.
[347] *Id.* at page 7.
[348] *Id.*

The practical result of OPC'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 its most recent 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***.[349]

Further evidence of the unreliability of the Peak and Average methodology is found in the fact that 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.[350]

[349] Case No. ER-2010-0036, *Report and Order*, issued May 28, 2010, at page 85.
[350] Exhibit 555, Brubaker Rebuttal, at page 4.

4. Staff's Base / Intermediate / Peak Methodology

Similar to KCPL / OPC, Staff also disregarded the logic inherent in the A&E methodology in favor of its flawed Base / Intermediate / Peak ("BIP") method. Under this methodology, Staff attempts to categorize KCPL's production capacity 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 is allocated on the basis of the class 4 CP demand, less the previously allocated base and intermediate components.[351] The evidence, however, demonstrates that Staff's BIP study is inherently flawed.

First, as Mr. Brubaker points out, the BIP methodology is not widely accepted. "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."[352]

Second, while Staff claims that "KCPL's generation facilities are predominantly considered fixed assets, and so the costs of these are assets are considered to be demand-related,"[353] Staff ignores class demand and inexplicably allocates 82.9% of these fixed

[351] Exhibit 201, Staff's Class Cost of Service / Rate Design Report, page 20.
[352] Exhibit 555, Brubaker Rebuttal, page 17.
[353] Exhibit 202, Staff Class Cost of Service / Rate Design Report, page 15.

costs (the baseload units)[354] on the basis of class energy.[355] Effectively, Staff's BIP method falsely assumes that all base load plant investment is utilized simply for providing energy. Implicit in this assumption is the mistaken belief that base load investment does not provide any capacity value.

> By effectively choosing to allocate 100% of the investment (fixed costs) associated with base load plants essentially on the basis of class energy, Staff effectively is assuming that investment in base load plants is not driven by total system demands but rather by a component of class profiles. 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.[356]

As previously mentioned, the Commission has rejected methodologies, like the Peak & Average and Base / Intermediate / Peak methodology that rely heavily on class energy usage.[357] In the previous Ameren case, in which it expressly adopted the use of the A&E methodology, the Commission rejected OPC fixed production cost allocation methodologies that were weighted 55% on the basis of class energy.[358] As Mr. Brubaker demonstrates, in this case, Staff's BIP model weights class energy usage as 50% in its

[354] Staff notes that Wolf Creek, Iatan 1 and 2, Hawthorn 5 and La Cygne Units 1 and 2 are all baseload units. (Exhibit 202, Staff Class Cost of Service / Rate Design Report, page 16). The cost of these units (Wolf Creek = $1,666,084,730; Iatan 1 = $508,176,917; Iatan 2 = $1,008,160,404; Iatan common = $344,799,192; Hawthorn 5 = $518,291,219; La Cygne 1 = $303,464,364; La Cygne 2 = $186,017,964; La Cygne common = $29,159,209) represent a total of $4,564,153,999 of KCPL's total production plant investment of $5,504,952,361. (Exhibit 201, Accounting Schedules, Accounting Schedule 3, pages 1-6).
[355] Staff states that the "relative expensive capacity costs of base generation" is allocated on "each class' base level of demand." (Exhibit 202, Staff Class Cost of Service / Rate Design Report, page 20). 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 555, pages 13-14).
[356] Exhibit 555, Brubaker Rebuttal, pages 12 and 14.
[357] See, Exhibit 555, Brubaker Rebuttal, page 15 (citing to Case No. ER-2010-0036, *Report and Order*, issued May 28, 2010, at page 85.
[358] *Id.* at page 15.

allocation methodology.[359] As such, Staff's methodology is equally as flawed as those previously rejected by the Commission.

Much like the OPC Peak and Average methodology, the Staff's BIP methodology has been demonstrated to be flawed. As such, the Commission should disregard this methodology for purposes of allocation fixed production costs. Instead, as the following section demonstrates, the Commission should continue to utilize the A&E methodology for allocating fixed production plant costs.

5. Previous Commission Decision

As previously indicated, in its 2010 Ameren decision, the Commission expressly found that the Peak & Average methodology, advocated by Public Counsel, was "unreliable." In that same decision, the Commission relied upon the A&E method for allocating production plant.[360] While this Commission is not bound by that 2010 decision, there are important policy reasons for the Commission to maintain its reliance on the A&E methodology.

> It would be desirable to continue use of the A&E 4 NCP method in this case as well because there has been no material change in the Company's load characteristics, the relative short time period between cases, and also because such consistency affords all parties the ability to rely upon a standardized method whose results can be reasonably predicted. These considerations promote CCOSS stability in that they contributed to the prevention of material case-to-case swings in class revenue responsibility for the most significant portion of the Company's investment in rate base.

For this reason, as well as recognizing the flaws inherent in the methods advanced by KCPL / OPC and Staff, the Commission should again adopt the A&E methodology as recommended by MECG.

[359] *Id.* at pages 15-16.
[360] Exhibit 50, Amended Warwick Rebuttal, page 7.

C. <u>WHAT METHODOLOGY IS MOST REASONABLE FOR ALLOCATING NET COST OF SERVICE AMONG THE CUSTOMER CLASSES IN THIS CASE?</u>

<u>HOW SHOULD ANY REVENUE INCREASE BE ALLOCATED AMONG RATE SCHEDULES?</u>

<u>WHAT, IF ANY, INTERCLASS SHIFT IN REVENUE RESPONSIBILITIES SHOULD THE COMMISSION MAKE?</u>

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

As previously indicated, there were five class cost of service provided in this case: (1) KCPL's study relying on Peak & Average production allocator; (2) OPC study relying on Peak & Average production allocator; (3) Staff study relying on BIP production allocator; (4) MECG / MIEC study relying on A&E (4CP) production allocator; and (5) DOE study relying on A&E (4CP) production allocator). As pointed out, and the Commission has previously found, production allocators that rely heavily on class energy usage, to the detriment of class peak demand, are inherently flawed. As such, the Commission should reject the KCPL, OPC and Staff's methodologies. In contrast, the Commission has previously found that the A&E methodology is reasonable. Given this, the Commission should rely on the MECG / 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 energy intensive approach advocated by KCPL / OPC and the demand intensive (4CP) approach recommended by DOE. Specifically, for the residential class, the A&E methodology provides for a revenue neutral increase of 11.2% which fits neatly between the 8.95% revenue neutral increase under the energy weighted Peak & Average methodology and the 20.15% revenue neutral increase under the demand weighted 4 CP methodology. Similarly, for the large industrial class, the A&E methodology provides for a revenue neutral decrease of 4.8% as compared to the 5.05% increase provided under the energy weighted Peak & Average approach and the 8.45% revenue neutral decrease provided by the demand weighted 4CP approach.

	KCPL / OPC[361]	**MECG / MIEC**[362]	**DOE**[363]
	Revenue Neutral Change	Revenue Neutral Change	Revenue Neutral Change
Residential	+8.95%	+11.2%	+20.15%
Small Gen. Svc.	-11.95%	-5.8%	-7.35%
Med. Gen. Svc.	-7.35%	-4.2%	-7.55%
Large Gen. Svc.	-9.05%	-8.3%	-15.75%
Large Power	+5.05%	-4.8%	-8.45%
Total Lighting	-2.55%	-1.3%	-26.35%

Another consideration to the Commission's determination of an appropriate revenue neutral shift in this case is the fact that the residential subsidy has grown significantly since the last case. As Public Counsel readily admits, while residential rates did not fully meet cost of service in the last case, those rates are now significantly below

[361] See, Exhibit 134, Rush Direct, page 57. (Mr. Rush's results include KCPL's proposed 15.75% rate increase. As such, in order to arrive at revenue neutral results, this 15.75% rate increase was removed from Mr. Rush's results).
[362] See, Exhibit 554, Brubaker Direct (Rate Design), Schedule MEB-COS-5. The reasonableness of Mr. Brubaker's results are confirmed by those provided by Public Counsel in its A&E study. (See, Exhibit 303, Dismukes Direct, Schedule DED-1).
[363] See, Exhibit 702, Schmidt Direct, page 11 (Dr. Schmidt's results include KCPL's proposed 15.75% rate increase. As such, in order to arrive at revenue neutral results, this 15.75% rate increase was removed from Dr. Schmidt's results).

cost of service. Therefore, the residential subsidy has grown significantly since the last case.[364]

Given the significant and long-standing nature of the current residential subsidy, MECG asks the Commission to take definitive steps to address the rapidly increasing 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.[365] 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 17 months, the current subsidy would continue for almost 5 more years.[366]

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 the residential subsidy.[367] Similarly, in a recent American Electric Power decision, the West Virginia Commission decided to eliminate 33% of the residential subsidy.[368]

Given MECG's recommendation to eliminate 25% of class subsidies, the Commission should order the following revenue neutral shifts[369]:

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[364] Exhibit 303, Dismukes Direct, page 28 and Schedule DED-5.
[365] Exhibit 554, Brubaker Direct (Rate Design), page 27,
[366] Exhibit 200, Staff Cost Service Report, page 12 (KCPL will have had 6 rate increases in the 8 ½ years between January 1, 2007 and September 30, 2015. Therefore, KCPL has had a rate increase every 17 months.).
[367] See, Case No. ER-2014-0258, *Report and Order,* issued June 24, 2015, page 20.
[368] 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.
[369] See, Exhibit 554, Brubaker Direct (Rate Design), Schedule MEB-COS-6.

Residential:	2.8% Increase
Small General Service:	1.5% Decrease
Medium General Service:	1.0% Decrease
Large General Service:	2.1% Decrease
Large Power:	1.2% Decrease
Total Lighting:	0.3% Decrease

D. SHOULD THE COMMISSION ADOPT MIEC / MECG'S RATE DESIGN PROPOSAL FOR THE LGS / LP RATE CLASSES, OR SOME VARIANT OF IT?

As designed, the Large General Service and Large Power Service rate schedule "consist of a series of charges differentiated by voltage level."[370] Specifically, KCPL collects revenues from LGS and LP customers upon 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.[371] In each case, the demand and energy charges are seasonally differentiated.[372] 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.[373]

Of particular importance to the issue presented, the demand charges for each voltage service level decrease 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

[370] *Id.* at page 2.
[371] *Id.*
[372] *Id.*
[373] *Id.*

> 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.[374]

The need to account for the decreased costs associated with serving customers with increased load factors is a long standing regulatory concept. The lower cost of serving such customers is well established and was recognized in the 1964 treatise entitled *Public Utility Economics*.

> The *load factor* shows the average use of facilities as a percentage of the maximum use. It is defined as the ratio of the average load over a designated period of time to the peak load occurring in that period. . . . In a public utility enterprise characterized by high fixed costs, the importance of the load factor may be assessed in cost terms. **The higher the system load factor, the lower the average unit of cost of service.** . . . High load-factor usage means relatively continuous use, which is apt to contribute both to the peak and the off-peak demands alike.[375]

As applied to KCPL's current LGS / LP rate schedules, the specific energy charges to be applied to a particular customer's usage decrease as the customer's load factor increases. Specifically, energy usage (on a kWh basis) is charged in a sequential fashion. Energy is first billed at the initial 180 hour energy block rate; any usage in excess of this is billed at the second 180 hour energy block and finally, any remaining usage is billed at the tail block rate.[376] 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

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[374] *Id.* at page 4.
[375] *Public Utility Economics*, Garfield and Lovejoy, Prentice-Hall, Inc. (1964) at page 153. (Italics part of original, boldface added).
[376] Exhibit 554, Brubaker Direct (Rate Design), page 29.

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.[377] 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.[378] 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.

> Because the Hopkinson rate schedule contains a demand element, it is sometimes termed a "load factor" rate. . . . Studies of Hopkinson rate schedules show that, as the customer increases his use without any increase in maximum demand, or with a less than proportionate increase in maximum demand, his load factor will increase and his average rate will decrease. If a customer decreases his use without any decrease in maximum demand, or with a less than proportional decrease in his maximum demand, his load factor will decrease and his average rate will increase.[379]

As can be seen, the KCPL LGS / LP 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 MECG'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,

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[377] *Id.*
[378] *Id.*
[379] *Public Utility Economics* at page 157.

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.[380]

After analyzing KCPL's filed revenue requirement request, including the breakdown of fixed and variable costs, it became apparent that KCPL is collecting a large portion of its fixed costs through LGS and LP energy charges. Specifically, while the LPS energy blocks range from 2.4¢/kWh to 2.6¢/kWh,[381] KCPL's average variable cost is less than 1.7¢/kWh.[382] Therefore, the LGS and LP 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."[383] 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.

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

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380 *Public Utility Economics* at page 154 and 158.
381 Exhibit 554, Brubaker Direct (Rate Design), page 30. Mr. Brubaker also notes that the LGS energy blocks ranges from 3.1¢/kWh to 4.3¢/kWh.
382 *Id.*
383 *Id.* at page 32.

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 recent Atmos decision, the Commission adopted the use of a "straight fixed variable" rate design.[384] 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."[385] 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."[386] 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)."[387] The same logic was relied upon when the Commission adopted the straight fixed variable rate design for Missouri Gas Energy.[388]

Interestingly, KCPL does not dispute any of the benefits asserted by Mr. Brubaker in his testimony. For instance, KCPL does not refute: (1) that its average variable cost is

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[384] *In re: Atmos Energy Corporation*, Case No. GR-2006-0387, issued February 22, 2007, at pages 13-25.
[385] *Id.* at page 14.
[386] *Id.*
[387] *Id.* at page 20.
[388] *In re: Missouri Gas Energy*, Case No. GR-2006-0422, issued March 22, 2007, at pages 9-13.

approximately 1.7¢ / kWh;[389] (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.

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

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[389] KCPL, in fact, admits that its "average fuel and purchased power costs among LPS customers" is "approximately 1.4¢ per kWh annually." Exhibit 20, page 3.

Respectfully submitted,

WOODSMALL LAW OFFICE

David L. Woodsmall
Woodsmall Law Office
308 E. High Street, Suite 204
Jefferson City, MO 65101
Phone: 573-636-6006
Fax: 573-636-6007
david.woodsmall@woodsmalllaw.com

ATTORNEYS FOR MIDWEST ENERGY CONSUMERS GROUP

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: July 22, 2015