BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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

INITIAL POST-HEARING BRIEF OF
KANSAS CITY POWER & LIGHT COMPANY

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TABLE OF CONTENTS

Kansas City Power & Light Company ("KCP&L" or the "Company") submits this Initial Post-Hearing Brief ("Brief") in accord with the Missouri Public Service Commission's ("Commission" or "PSC") Order Setting Procedural Schedule issued August 10, 2017.

I. INTRODUCTION

1. The parties have worked diligently to resolve many issues in this case, as reflected by the three non-unanimous stipulation and agreements filed on February 10, 2017 and February 22, 2017, which were approved by the Commission on March 8, 2017. However, the issues remaining for decision by the Commission will have a large impact upon the Company and its customers. In particular, the Commission's findings regarding cost of capital, capital structure, the fuel adjustment clause ("FAC"), depreciation, and rate design will greatly affect the financial integrity of KCP&L and its ability to earn its authorized return on equity ("ROE").

II. COST OF CAPITAL

A. Return on Common Equity: What Return on Common Equity Should be Used for Determining Rate of Return?

2. As all major economic trends over the past six months show substantial improvement over the last time the Commission set KCP&L's rate of return, the Commission must determine what ROE will permit the Company to continue to attract investors while reflecting the concerns and interests of customers. The Commission must strike the appropriate balance among the recommendations presented to it by three experts in the context of economic data and trends. Its decision must be at a point within the zone of reasonableness that reflects the risks faced by the Company. Such a point should also be consistent with ROEs recently determined by other regulatory utility commissions for comparable companies.

3. In KCP&L's last rate case the Commission set the Company's ROE at 9.50%.[1] This figure was 50 basis points below the low-end of KCP&L's recommendation of 10.0%. It was 10 basis points above the high-end of the Midwest Energy Consumers Group ("MECG") recommendation (9.40%), and equal to the top of Staff's range (9.50%).[2] While the low end of the Company's recommendation and the high end of MECG and Staff's recommendations in that case were within a range of 60 basis points, in this proceeding that range has narrowed to 25 basis points between KCP&L (9.75%) and MECG (9.50%).[3] Staff is the clear outlier, with the high end of its range being 8.75%.[4]

4. In this case KCP&L recommends an ROE of 9.90%,[5] based on the analysis conducted by its expert Robert Hevert who testified that an ROE in the range of 9.75-10.50% "represents the range of equity investors' required return for investment in a vertically integrated company" like KCP&L "in today's capital markets." (Ex. 127 at 3, Hevert Direct).

5. MECG's expert Michael Gorman revised his initial ROE recommendation of 9.0% (based on a range of 8.80%-9.20%),[6] and in his rebuttal testimony boosted his recommendation to 9.20%, with a range of 8.90% to 9.50% (Ex. 651 at 2, 29, Gorman Rebuttal).

6. The lower range of Mr. Hevert (9.75%) and the upper range of Mr. Gorman (9.50%) are close to the average ROE authorized in 2016 by state utility commissions for all electric utilities of 9.77%, and, excluding limited issue rider cases, of 9.60%.[7] Given the positive

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[1] See Report and Order at 22, In re Kansas City Power & Light Co., No. ER-2014-0370 (Sept. 2, 2015).
[2] Id. at 15-16.
[3] Ex. 127 at 3, 63 (Hevert Direct); Ex. 129 at 28 (Hevert Surrebuttal); Ex. 651 at 2, 29 (Gorman Rebuttal).
[4] Ex. 200, Staff Report at 43.
[5] Ex. 106 at 3(Bryant Direct).
[6] Ex. 650 at 2 (Gorman Direct).
[7] Ex. 155, Regulatory Research Associates Regulatory Focus (Jan. 18, 2017) at 1, 6.

economic data presented to the Commission, a higher ROE for KCP&L would be consistent with the recent decision of the Maryland Public Service Commission which authorized an ROE of 9.60% for a distribution-only electric utility which, as Staff expert Dr. J. Randall Woolridge noted, is typically "about 20 basis points below those for integrated electric utilities." See Order No. 88033 at 20-21, In re Delmarva Power & Light Co., No. 9424 (Md. P.S.C., Feb. 15, 2017).[8] Given the evidence of growth in the economy, rising interest rates, and lower unemployment, a 9.80% ROE is clearly justified.

7. The ROE estimates at the low end of the recommendations provided by Staff and MECG demonstrate the flaws in both their analyses and their conclusions. Staff proposes a low-end recommendation of 7.90, far outside any zone of reasonableness and unlawfully confiscatory (Ex. 200, Staff Report at 43). While the low end of MECG's range is 100 basis points higher than Staff, at 8.90% it is still outside the mainstream (Ex. 651 at 29, Gorman Rebuttal).

1. Governing Legal Principles

8. The Supreme Court of the United States established requirements for determining the reasonable rate of return in Bluefield Waterworks & Improvement Co. v. Public Serv. Comm'n of West Virginia, 262 U.S. 679, 692 (1923) ("Bluefield") and Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944) ("Hope"). The fixing of "just and reasonable" rates involves a balancing of investor and consumer interests. Hope, 320 U.S. at 603. Accord, § 386.610 ("substantial justice between patrons and public utilities"). "What annual rate will constitute just compensation depends upon many circumstances, and must be

[8] Ex. 166 at 20-21.

determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts." Bluefield, 262 U.S. at 692.

9. A reasonable rate of return is one that closely approximates the profits upon capital invested in other undertakings where the risk involved and other conditions are similar. Bluefield, 262 U.S. at 689-90. "A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding, risks and uncertainties ...." Bluefield, 262 U.S. at 692.

10. A key concern in setting the appropriate return on common equity is that the return be reasonably sufficient to maintain the financial health of the utility. Bluefield, 262 U.S. at 693; Hope, 320 U.S. at 603. "The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties." Bluefield, 262 U.S. at 693. As the Hope Court explained:

> [T]he investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

Hope, 320 U.S. at 603.

The Bluefield Court stressed this point, declaring:

> Investors take into account the result of past operations, especially in recent years, when determining the terms upon which they will invest in such an undertaking. Low, uncertain, or irregular income makes for low prices for the securities of the utility and higher rates of interest to be demanded by investors.

Bluefield, 262 U.S. at 694.

11. In Bluefield, the West Virginia Commission ordered a rate of return of 6%. The Supreme Court found that while a 6% rate of return had been reasonable in the recent past, the record in that case showed that the utility's rate of return had been suffering long before that rate case was brought. 262 U.S. at 695. With investors in mind, the Court held that a 6% rate of return "is substantially too low to constitute just compensation for the use of the property employed to render the service." (Id.). The Supreme Court, therefore, reversed the state appellate court that had affirmed the decision of the West Virginia Commission.

12. While the Hope and Bluefield Courts require that investor and customer interests be balanced in setting a *reasonable* rate of return, which depends upon many factors to be considered by the Commission, neither Court enunciated a particular methodology to arrive at a reasonable rate of return. Conversely, "[u]nder the statutory standard of 'just and reasonable' it

is the result reached not the method employed which is controlling. It is not theory but the impact of the rate order which counts." Hope, 320 U.S. at 602 (citations omitted).

13. Following Bluefield and Hope, Missouri appellate courts agree that "the Commission is not bound to any set methodology in ensuring a just and reasonable return in setting rates." State ex rel. Praxair, Inc. v. PSC, 328 S.W.3d 329, 339 (Mo. App. W.D. 2010). See State ex rel. Noranda Aluminum, Inc. v. PSC, 356 S.W.3d 293, 311 (Mo. App. S.D. 2011).

14. In performing its duty, the Commission is bound to set a rate of return that falls within a zone of reasonableness: "Statutory reasonableness is an abstract quality represented by an area rather than a pinpoint. It allows substantial spread between what is unreasonable because too low and what is unreasonable because too high." Federal Power Comm'n v. Conway Corp., 426 U.S. 271, 278 (1976), quoting Montana-Dakota Util. Co. v. Northwestern Pub. Serv. Co., 341 U.S. 246, 251 (1951). Stated differently, the zone of reasonableness is "the zone between the lowest rate not confiscatory and the highest rate fair to the public." In re New Jersey Power & Light Co. v. State, 89 A.2d 26, 44 (N.J. 1952).

2. KCP&L's Recommendation: Mr. Hevert

15. Robert B. Hevert presented the Company's ROE recommendation. He is a partner at ScottMadden, Inc. and a Chartered Financial Analyst. He holds a bachelor's degree in business and economics from the University of Delaware, and a masters of business administration degree with a concentration in finance from the University of Massachusetts. Prior to becoming a private consultant, he was Vice President and Assistant Treasurer of Bay State Gas Company, at the time a publicly-traded natural gas company (Ex. 127 at 1-2 & Att. A, Hevert Direct). He has testified before this Commission on a number of occasions.

16. Mr. Hevert used a group of proxy companies to determine the cost of equity for KCP&L. He modified his original group of 16 companies, which he expanded to 18 in his rebuttal testimony (Ex. 127 at 14, Hevert Direct; Ex. 128 at 3, Hevert Rebuttal). Mr. Gorman generally used Mr. Hevert's proxy group, with the exception of Otter Tail Power Co. (Ex. 650 at 25, Gorman Direct). Staff used both Mr. Hevert's proxy group, as well as a broader group of 30 companies (Ex. 200, Staff Report at 22). As a result, there were no material disputes among the cost of capital witnesses regarding the selection of a proxy group, although Mr. Gorman's reasons for excluding Otter Tail Power are discussed below.

17. Mr. Hevert estimated KCP&L's cost of equity[9] by analyzing "market data to quantify a range of investor expectations of required equity returns." (Ex. 115, Hevert Direct at 14). He employed multiple methodologies to mitigate the effects of assumptions and inputs associated with any single approach. He utilized the DCF model in both its Constant Growth and Multi-Stage forms; the CAPM; and finally the Bond Yield Plus Risk Premium approach (Id. at 14-15).

18. The Constant Growth DCF model contains four assumptions: (1) a constant average annual growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings multiple; and (4) a discount rate greater than the expected growth (Id. at 15). This model is based on the theory that a stock's current price represents the present value of all expected future cash flows. In the standard formula, the first term is the expected dividend yield, and the second term is the expected long-term annual growth rate (Id.)

[9] The terms "cost of equity" and "return on equity" (ROE) are used interchangeably (Ex. 127, Hevert Direct at ii).

19. Utilizing earnings growth estimates provided by Zacks, First Call, and Value Line, Mr. Hevert employed an average earnings growth rate (mean and median) of 5.29% (Ex. 127 at 21, Hevert Direct & Sch. RBH-1). As a result of improved economic data reported since direct testimony was filed on July 1, 2016, he increased the mean growth rate to 5.57% and the median growth rate to 5.68% in his rebuttal testimony, filed on December 30, 2016 (Ex. 128 at Sch. RBH-13, Hevert Rebuttal). This analysis resulted in the following ROE estimates, as set forth in Schedule RBH-13 of Mr. Hevert's Rebuttal (Ex. 128):

Table 1: Constant Growth DCF Results

	Mean Low	***Mean***	***Mean High***
30-Day Average	8.35%	8.99%	9.65%
90-Day Average	8.30%	8.94%	9.60%
180-Day Average	8.31%	8.96%	9.61%

20. The Multi-Stage DCF model considers growth rates over three distinct stages. Although it defines the cost of equity as the discount rate that sets the current price equal to the discounted value of future cash flows, the Multi-Stage DCF model must be solved in an iterative or repetitive fashion, unlike the Constant Growth DCF model (Ex. 127 at 24-25, Hevert Direct). Mr. Hevert explained that the Multi-Stage model provides the ability to specify near, intermediate and long-term growth rates, which "avoids the sometimes limiting assumption that the subject company will grow at the same, constant rate in perpetuity." (Id. at 26). He chose a long-term growth rate of 5.28%, which was based on the real gross domestic product ("GDP") growth rate of 3.24% from 1929 through 2015, and an inflation rate of 1.98% (Id. at 28-29).

21. Mr. Hevert's Multi-Stage DCF analysis produced an ROE range of results from 8.97% to 10.74%. The table set forth below reflects an analysis in which the terminal value is based on the current P/E ratio (Schedule RBH-14 at pp. 11-20 Ex. 128, Hevert Rebuttal).

Table 2: Multi-Stage DCF Model Results[10]

	Mean Low	***Mean***	***Mean High***
30-Day Average	9.94%	10.34%	10.74%
90-Day Average	9.81%	10.20%	10.60%
180-Day Average	9.84%	10.24%	10.64%

22. Mr. Hevert also relied upon the CAPM which estimates the cost of equity for a company based on a risk-free return plus a risk premium. He measured the risk-free rate based upon the current 30-day average yield on 30-year Treasury Bonds, and the projected 30-year Treasury yield. He used a forward-looking approach to estimate a market risk premium based on data from Bloomberg and Value Line, applying beta coefficients that represented both relative volatility of returns, and the correlation in returns between the subject company and the market, from both Value Line and Bloomberg. The results suggested an ROE range of 8.77% to 11.29%, as set forth below (Sched. RBH-17, Ex. 128, Hevert Rebuttal):

[10] Using a terminal value based on the assumed long-term nominal GDP growth rate yields a lower range of 8.97% to 9.35% (Sched. RBH-14, pp. 1-10, Ex. 128, Hevert Rebuttal).

Table 3: Summary of CAPM Results

	Bloomberg Derived Market Risk Premium	***Value Line Derived Market Risk Premium***
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (2.75%)	8.77%	9.37%
Near Term Projected 30-Year Treasury (3.13%)	9.15%	9.75%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (2.75%)	10.17%	10.91%
Near Term Projected 30-Year Treasury (3.13%)	10.55%	11.29%

23. Finally, Mr. Hevert utilized a Bond Yield Plus Risk Premium approach, which is based on the principle that equity investors require a premium over the return they would have earned as a bond holder. Since equity holders owning stock are subject to returns that are more risky than returns to bond holders, equity investors must be compensated for that additional risk (Ex. 127 at 38, Hevert Direct). Mr. Hevert defined the risk premium as the difference between the authorized ROE and the prevailing level of the 30-year Treasury Yield. Utilizing a basic regression analysis, which accounted for high interest rates and authorized ROEs in the 1980's compared with very low numbers during the post-Lehman bankruptcy period, his analysis estimated ROEs between 10.01% and 10.34%, as depicted below and as found in Mr. Hevert's Rebuttal Testimony (Ex. 128) in Schedule RBH-18.

Table 4: Summary of Bond Yield Plus Risk Premium Results

	Return on Equity
Current 30-Year Treasury (2.75%)	10.01%
Near Term Projected 30-Year Treasury (3.13%)	10.03%
Long Term Projected 30-Year Treasury (4.35%)	10.34%

24. Based upon all of his analyses, Mr. Hevert recommends that the Commission award an ROE in the range of 9.75% to 10.50% (Ex. 127 at 63, Hevert Direct; Ex. 128 at 68, Hevert Rebuttal; Ex. 129 at 28, Hevert Surrebuttal). KCP&L requests that the Commission authorize an ROE of 9.90% (Ex. 106 at 3, Bryant Direct).

3. MECG's Recommendation: Mr. Gorman

25. Mr. Gorman conducted a DCF analysis, preparing a Constant Growth, Sustainable Growth and a Multi-Stage Growth analysis. Both Mr. Hevert for KCP&L and Dr. Woolridge for Staff did as well. However, only Mr. Gorman eliminated Otter Tail Corporation (and its wholly-owned public utility, Otter Tail Power Company) from his proxy group. In direct testimony he stated that he excluded Otter Tail "because it did not have analysts' growth rates from Zacks, SNL Financial or Reuters at the time I developed my studies." (Ex. 650 at 25, Gorman Direct). However, he conceded at the hearing that Value Line and Yahoo! Finance both report earnings growth rates for Otter Tail (Tr. 231). There was no reason for Mr. Gorman to exclude that company from his analysis, except for the fact that Otter Tail had the highest Dividend Yield and the highest Expected Dividend Yield of any company in the proxy group selected by Mr. Hevert (Ex. 127, Sched. RBH-1 at Col. 3-4, Hevert Direct).

26. The earnings growth estimates provided by Value Line and Yahoo! Finance were both 6.00% (Id., Col. 6-7). When these figures are compared with Mr. Gorman's earnings

growth estimates of the other 15 utilities which he used in Mr. Hevert's proxy group, the Otter Tail 6.00% growth rate would have been among the highest growth rates in Mr. Gorman's analysis (Ex. 651, Sched. MPG-5 at Col. (1), (3), and (5), Gorman Direct). Otter Tail would have also been among the companies with the highest analysts' growth rates in Mr. Gorman's revised analysis which he submitted in rebuttal (Ex. 651, Sched. MPG-R-5, Col. (1), (3), (5), Gorman Rebuttal).

27. The most significant aspect of Mr. Gorman's testimony is that he revised his recommendations in rebuttal, moving from a range of 8.80% to 9.20% in direct testimony, to 8.90% to 9.50% (Ex. 650 at 53; Ex. 651 at 29). The lower end of his range increased 10 basis points while the upper end of his range jumped 30 points.

28. These significant upward changes in Mr. Gorman's recommendations were based on (a) higher stock prices for the 13-week period ending December 16, 2016; (b) updated higher analysts' growth rates in December, (c) GDP (gross domestic product) growth, as well as (d) increases in utility and Treasury bond yields through December 16 (Ex. 651 at 29; Tr. 236-37). Mr. Gorman also considered the December 14, 2016 Federal Reserve interest rate increase to 0.75% (Tr. 237-38). He agreed with the Federal Reserve announcement of February 1, 2017 that the labor market has continued to strengthen, economic activity has continued to expand at a moderate pace, inflation has increased, and that job gains have been solid, while the unemployment rate is low (Tr. 240-41; Ex. 153, Federal Reserve Announcement (Feb. 1, 2017)).

29. Mr. Gorman agreed that the Bureau of Labor Statistics announced that non-foreign payroll employment had increased by $227,000 in January, and that the unemployment rate was little changed at 4.8% (Tr.241-42). He also agreed that since July 2016, Treasury yields

have increased by over 100 basis points, and that the Bureau of Economic Analysis (U.S. Department of Commerce) announced on December 22, 2016 that the third quarter gross domestic product rose by 3.50% (Tr. 242; Ex. 128 at 9-10, Hevert Rebuttal).

30. Mr. Gorman agreed that higher interest rates since July 2016 and GDP growth indicate that the financial community sees strong growth prospects in the economy and that, therefore, it is reasonable to expect higher dividend yields and higher growth rates. Accordingly, such data and trends indicate that increases to the cost of equity are appropriate. Mr. Gorman did not disagree (Tr. 243-44).

31. Mr. Gorman's updated analysis reflects these developments. In his DCF Constant Growth study, Mr. Gorman used a growth rate of 5.41% in direct testimony, which he revised upward to 5.52% in rebuttal (Ex. 650 at 29:6-10, Gorman Direct; Ex. 651 at 29, Gorman Rebuttal). In addition, Mr. Gorman increased the dividend yield in his rebuttal testimony, boosting it from 3.39% to 3.50% (Ex. 650, Sched. MPG-6 (Col. 4), Gorman Direct; Ex. 651, Sched. MPG-R-6, Col. 4, Gorman Rebuttal).

32. Although Mr. Gorman quibbled with Mr. Hevert's Alternative Bond Yield Plus ("BYP") Risk Premium analysis, his conclusion essentially ratified Mr. Hevert's conclusions. Mr. Hevert's Alternative BYP Risk Premium method concluded that KCP&L's expected ROE should fall "in the range of 9.74% to 10.04%." (Ex. 127 at 42). In reviewing the Hevert analysis, Mr. Gorman found it to be a "substantial improvement" over previous studies (Ex. 651 at 20:8, Gorman Rebuttal). Mr. Gorman then conducted his own analysis, although he removed Mr. Hevert's use of the CBOE Volatility Index as an independent variable to represent market

volatility (Ex. 651 at 21, Gorman Rebuttal). While Mr. Gorman agreed that a volatility factor was appropriate, he did not substitute his own volatility parameter for Mr. Hevert's (Tr. 247-48).

33. However, more significant is Mr. Gorman's conclusion that his version of Mr. Hevert's Alternative BYP Risk Premium analysis led him to conclude that a return on equity for KCP&L of "no higher than 9.75%" was supported by that analysis (Ex. 651 at 22:12-13). 9.75% is at the low end of Mr. Hevert's recommended ROE range (Ex. 127 at 3, Hevert Direct).

34. Mr. Gorman recognized that the average ROE's authorized by state utility commissions for vertically-integrated electric utilities in 2016 was 9.77% overall, and 9.60% when limited issue rider cases were excluded (Tr. 258-59; Ex. 155, RRA Regulatory Focus (Jan. 18, 2017) at 1, 6). However, Mr. Gorman encouraged the Commission to ignore decisions from the Indiana, Wisconsin and Michigan Commissions because he viewed them as too high, ranging from 9.85% to 10.30% (Ex. 650 at 8-9).

35. Ironically, Mr. Gorman made no effort to adjust the 9.30% ROE granted by the Kansas Corporation Commission, even though that decision was issued in the context of certain rate mechanisms that Kansas offers to electrical utilities, but Missouri does not. In affirming the decision of the KCC, the Kansas Court of Appeals found that the 9.30% ROE was reasonable in light of rate mechanisms known as the Energy Cost Adjustment, the Transmission Delivery Charge rider, and an energy efficiency rider. Kansas City Power & Light Co. v. KCC, 371 P. 3rd 923, 936 (Kan. App. 2016). The Court noted that the KCC's approval of the Transmission Delivery Charge rider alone had "an estimated annual value of over $33 million." (Id. at 940).

36. Mr. Gorman conceded that he did not take any of these factors into consideration in weighing the Kansas ROE of 9.30% (Tr. 253-54). He also did not acknowledge or consider a

Kansas statutory provision that permits surcharges reflecting increases or decreases in Kansas ad valorem taxes including property taxes. See K.S.A. § 66-117(f).

4. Staff's Recommendation: Dr. Woolridge

37. Staff's expert is Dr. J. Randall Woolridge, a professor of finance at Pennsylvania State University who has never testified in his long career on behalf of any public utility (Tr. 743-44). Unlike the other ROE experts in this case, he presented only two cost of capital studies: (1) a Constant Growth DCF with a recommended ROE range of 8.45% to 8.75%; and (2) a Capital Asset Pricing Model which recommended an ROE of 7.9% (Ex. 200, Staff Report at 43).

38. Dr. Woolridge's overall recommendation that KCP&L's ROE be set at 8.65% is clearly an "outlier," (Tr. 755) as suggested by Commissioner Kenney. It is 100 basis points below the 9.77% and 9.60% average national ROE's authorized by utility commissions in 2016 (Ex. 155, RRA Report).[11] Staff's recommendation should be given no serious consideration, given that it is either beyond or at the edge of the zone of reasonableness recognized by both federal and state appellate courts, as well as this Commission. In re Permian Basin Area Rate Cases, 390 U.S. 747, 767 (1968); State ex rel. Public Counsel v. PSC, 274 S.W.3d 569, 574 (Mo. App. W.D. 2009); Report and Order at 20-21, In re Kansas City Power & Light Co., No. ER-2006-0314 (Dec. 21, 2006).

39. During cross-examination Dr. Woolridge was presented with a variety of government reports that showed solid momentum in the U.S. economy. Real gross domestic product (GDP) increased at an annual rate of 1.9% for both the fourth quarter and for all of 2016, following a third quarter increase of 3.5%. (Ex. 159, Bureau of Economic Analysis, U.S.

[11] The average ROE that was authorized all electric utilities was 9.77% during 2016, with the average being 9.60% if limited issue rider cases are excluded (Ex. 155 at 1, 6 (Jan. 18, 2017)).

Department of Commerce). Retail and food services sales reported a January 2017 increase from December and were 5.6% above January 2016 (Ex. 160, U.S. Census Bureau). Inflation also increased in January, rising 2.5% over the past 12 months (Ex. 161, Bureau of Labor Statistics, U.S. Department of Labor). This rise in the Consumer Price Index for All Urban Consumers was "the largest 12-month increase since March 2012." (Id.).

40. Dr. Woolridge acknowledged that the Board of Governors of the Federal Reserve System recognized these developments, advising Congress that its Federal Open Market Committee "will evaluate whether employment and inflation are continuing to evolve in line with these expectations, in which case a further adjustment of the federal funds rate would likely be appropriate." (Ex. 162, Testimony of Chair Janet L. Yellen (Feb. 14, 2017)).

41. Dr. Woolridge agreed that if growth rates and dividend yields are going up, returns on equity should increase as well (Tr. 728). However, despite these recent increases, as well as a more than 50 basis point increase in the 30-year Treasury yield to over 3.0%,[12] Dr. Woolridge failed to make any adjustment or update to his recommendation. Explaining that "I was not asked to, and I didn't update it," (Tr. 729) Dr. Woolridge grudgingly conceded that his ROE recommendation of 8.65% might change "maybe ten basis points. But it's not going to be more than that." (Tr. 746). He later reduced his opinion to: "Maybe 5 to 10." (Tr. 750).

42. In response to Chairman Hall's questions regarding the effect of awarding KCP&L an ROE almost 100 basis points below the national average of ROE's, Dr. Woolridge advised "there could be some negative news effect." (Tr. 751). However, he adamantly denied that there would be any adverse result regarding access to capital if his recommendation were

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[12] Ex. 233 at 2 (Woolridge Surrebuttal); Tr. 726.

followed (Tr. 753). He seemed oblivious to the common sense notion that capital would flee from KCP&L to more positive financial environments such as Florida, where the Florida Commission approved a 10.55% ROE for Florida Power & Light, or to South Carolina and North Carolina where state commissions recently approved ROE's of 10.1% and 9.9%, respectively, to local utilities (Tr. 129, 140-41 [Hevert]).

43. Although Dr. Woolridge discounted predictions of future interest rate increases, he acknowledged that the market had predicted a 43% chance of a future Federal Reserve Board interest rate hike on February 22, 2017 (Tr. 718-19). This was consistent with the banner headline on the front page of The Wall Street Journal on February 23rd: "Fed Eyes Aggressive Rate Increases." Nonetheless, Dr. Woolridge urges the Commission to ignore not only recent historical data, but near-universal predictions of growth in the economy, higher inflation, and steady to rising Treasury yields. Dr. Woolridge's position is contradicted by long-standing Missouri law which requires the Commission to rely upon "all relevant factors" under Section 393.270.4, including trends and forecasts. See State ex rel. Missouri Water Co. v. PSC, 308 S.W.2d 704, 710, 719 (Mo. 1957) (use of "trending" principles and tables); State ex rel. Mo. Public Serv. Co. v. Fraas, 627 S.W.2d 882, 888 (Mo. App. W.D. 1981) ("the Commission must make an intelligent forecast with respect to the future period for which it is setting the rate").

44. Given Dr. Woolridge's recalcitrant attitude toward data that disagrees with his position, it is not surprising that when he appeared before this Commission on a previous KCP&L rate case, his ROE recommendation was found to be outside the zone of reasonableness and was discarded (Ex. 167, Report and Order at 21-22, In re Kansas City Power & Light Co.,

No. Er-2006-0314 (Dec. 21, 2006). The Commission should treat his opinion in this case similarly and give his recommendation little or no weight.

5. Improved Economic Growth

45. This Commission has always compared its ROE analysis with those of other commissions to make certain that its decision is not out of the mainstream. Although it does not "unthinkingly mirror the national average,"[13] the Commission has concluded that "the national average is an indicator of the capital market" in which a utility "will have to compete for necessary capital". See Report and Order at 122, In re Kansas City Power & Light Co., Case No. ER-2010-0355 (2011).

46. Although all three ROE experts agreed that recent economic trends were positive, only Mr. Hevert and Mr. Gorman updated their DCF, Risk Premium and Capital Asset Pricing Model results in rebuttal. Although Mr. Gorman continued to focus on authorized ROE's in "fully litigated cases," the evidence demonstrated that there is no factual basis to conclude that litigated cases result in lower ROE's than settled cases. In the past six years, settled cases produced *lower* ROE's in 2011, 2012 and 2014. In 2016 the results of settled and litigated cases were each within 3 basis points of the average (9.80% for settled cases; 9.74% for litigated cases) (Ex. 155 at 6, RRA Regulatory Focus Report (Jan. 18, 2017)).

47. The RRA Regulatory Focus Report (Ex. 155) summarized the authorized ROEs granted during 2016:

[13] Report and Order at 19, In re Missouri Gas Energy, Case No. GR-2004-0209 (2004).

1.	Vertically Integrated Electric Utility Rate Cases	9.77%
2.	Electric Utility Cases (without Limited Issue Rider Cases)	9.60%
3.	Natural Gas Utility Cases	9.50%

48. The experts' ROE recommendations and their ranges were:

Witness	**Recommendation**	**Range**
Hevert	9.90%	9.75 - 10.50%
Gorman	9.20%	8.90 - 9.50%
Woolridge	8.65%	7.90 - 8.85%

49. Based on this evidence, the Commission should find that KCP&L's requested 9.90% recommendation, based on Mr. Hevert's range of 9.75% to 10.50%, is a just and reasonable rate, reflective of improvements in the economy and higher interest rates, and one that will permit KCP&L to continue to attract investors and to be financially sound.

B. <u>Capital Structure</u>

50. KCP&L proposes to use its actual per book capital structure as of the true-up period ending December 31, 2016. This will reflect the actual cost of capital specific to the Company, rather than the consolidated capital structure of KCP&L's parent holding company Great Plains Energy Incorporated ("GPE") (Ex. 106 at 3-4, Bryant Direct). Based upon its actual per book capital structure as of the true-up, KCP&L's common equity is 49.72% and its long-term debt is 50.28% (Ex.174 at 2, Klote True-up Rebuttal).

51. These percentages are slightly different from Staff's recommendation of common equity at 49.20% and long-term debt at 50.80% (Ex. 242, Staff Accounting Sched. 12).

However, Staff's differences are not based on KCP&L's actual capital structure, but rather GPE's capital structure. And, instead of choosing GPE's capital structure as of December 31, 2016, Staff recommends it be set as of June 30, 2016, but with additional adjustments reflecting GPE's redemption of preferred stock in August 2016 (Ex. 200, Staff Report at 23; Ex. 221 at 11-12, Murray Surrebuttal).

52. The Office of the Public Counsel (OPC) also recommends the use of the GPE capital structure, but as of yet a different date: September 30, 2016. Like Staff, OPC proposes its own adjustments. The first relates to goodwill on GPE's books as a result of the acquisition of Aquila, Inc. (now KCP&L Greater Missouri Operations Company ["GMO"]), with the second proposing the exclusion of current maturities of long-term debt (Ex. 302 at 17, Hyneman Direct).

53. MECG's expert Mr. Gorman took no formal position on this issue, but agreed that KCP&L's recommendation was appropriate. He stated: "The proposed common equity ratio is in line with the common equity ratio for the electric utility industry as authorized by regulatory commissions in setting rates." (Ex. 650 at 23:4-6, Gorman Direct).

54. Using a capital structure and capital costs that are different from the actual capital structure and costs specific to a utility will result in earnings that are either higher or lower than that intended by the Commission when it determines the return on equity and other cost of capital issues (Ex. 106 at 4, Bryant Direct). Staff did not disagree, with its expert Mr. Murray stating: "I agree with Mr. Bryant that it is desirable to attempt to reconcile costs to each utility in setting the revenue requirement." (Ex. 220 at 3, Murray Rebuttal). Mr. Murray advised that it was important for costs to be consistent with the risk-profile of the utility's operations (Id.).

Given that Mr. Bryant testified that KCP&L is managed based upon its own individual financial interests, KCP&L agrees (Ex. 107 at 2-3, Bryant Rebuttal; Ex. 108 at 3-6, Bryant Surrebuttal).

55. However, Staff's position is based upon Mr. Murray's effort over the past eight years to convince the Commission to make hypothetical adjustments to KCP&L's capital structure (or that of its affiliate GMO) since GPE acquired GMO's predecessor Aquila, Inc. in 2008. For example, in GMO's 2009 and 2010 rate cases, Mr. Murray proposed that the Commission use the embedded cost of debt of Empire District Electric Co., instead of the actual debt issuances of GMO. The first case, No. ER-2009-0090, was settled, but in the 2010 rate case, the Commission found that Staff's recommendation "is not reasonable as Empire's debt does not reflect the debt of GMO." See Report and Order at 152 ¶ 419, In re KCP&L Greater Mo. Operations Co., No. ER-2016-0356 (May 4, 2011). The Commission rejected the use of a consolidated debt structure in that case (Id. at 153 ¶ 421).

56. Similarly, Mr. Murray recommended "a hypothetical assignment of $250 million of 2.75% Senior Notes" to KCP&L on the basis that GPE had issued those notes "solely for the benefit of GMO." See Report and Order at 125, ¶ 360, In re Kansas City Power & Light Co., No. ER-2010-0355 (Apr. 12, 2011). In its decision, the Commission rejected this argument, finding "no reason to engage in hypothetical debt assignment for KCP&L." (Id. at 126, ¶ 362). Mr. Murray made similar recommendations in the 2012 KCP&L and GMO rate cases, recommending that the actual interest rates on three GPE Senior Notes issued for the benefit of its utilities be arbitrarily reduced. The Commission found Staff's arguments "unpersuasive," concluding that arguments about what KCP&L or GMO "would look like if the past were different" was "speculation." See Report and Order at 27, In re Kansas City Power & Light Co.,

No. ER-2012-0174 and In re KCP&L Greater Mo. Operations Co., No. ER-2012-0175 (Jan. 9, 2013).

57. In this case Mr. Murray agrees that KCP&L issues its own debt, and that GMO has issued its own debt since 2013 (Tr. 182). He confirmed that in 2013 GMO issued three series of Senior Notes amounting to $350 million (Id. at 183; Ex. 149, 2012 GPE Annual Report at 88-90). Mr. Murray confirmed that Standard & Poor's issues separate financial reports for KCP&L and GMO, which contained separate assessments of each company despite their common ownership (Ex. 150, S&P Global Research Report on KCP&L (June 17, 2016); Ex. 151, S&P Global Research Report on GMO (June 17, 2016)). He confirmed that KCP&L had a higher stand-alone credit profile of "a-minus" and an anchor credit rating of "a-minus" while GMO was assigned a "bbb" rating for both (Tr. 184-86). S&P also assigned each company a different business risk rating (KCP&L: "excellent"; GMO: "strong"), and a different competitive position rating (KCP&L: "strong"; GMO: "satisfactory") (Ex. 150 at 3, 5; Ex. 151 at 3, 5).

58. Mr. Murray corrected his rebuttal testimony to indicate that GPE does not guarantee GMO's "credit facilities," but guarantees only some of GPE's debt and its commercial paper program (Tr. 178, 186-87). GPE does not guarantee the Series A, B and C notes issued by GMO in the amount of $350 million (Ex. 152 at 85, 87).

59. Based on the foregoing, there is no reason why the Commission should not set KCP&L's capital structure based upon its own cost structure. Staff's proposal to use GPE's 2d quarter capital structure, with adjustments, and OPC's proposal to use GPE's 3d quarter capital structure, also with adjustments, should be rejected as they are hypothetical capital structures that do not correspond with KCP&L's actual capital structure and costs.

60. Moreover, utilizing KCP&L's specific capital structure, rather than GPE's consolidated capital structure, will insulate the Company's utility operations and customers from activities occurring only at the holding company level. Adopting KCP&L's actual per book capital structure will reflect its revenues and expenses for ratemaking purposes

C. Cost of Debt

61. KCP&L proposes that the Commission use the Company's actual cost of debt, which is 5.51% using KCP&L's yield-to-maturity calculation (Ex. 108 at 5). However, given Staff's apparent preference to use the simple interest/amortization method, KCP&L has no objection to the Commission setting the cost of debt two basis points lower at 5.49% (Id. at 7-8).

62. Staff's lower recommendation of 5.42% results from using the GPE consolidated cost of debt based on the yield-to-maturity method adjusted for debt issuance expenses and discounts. It is also the GPE cost of debt as of June 30, 2016 using the simple interest/amortization method. (Ex. 220 at 14-15, Murray Rebuttal).

63. OPC provides no recommendation. Although MECG takes no position, its expert Mr. Gorman uses KCP&L's 5.51% cost of debt in his calculation of the overall weighted cost of capital (Ex. 650 at 23, Gorman Direct).

64. As discussed at length above, Mr. Murray's position is based on his long-held views regarding how KCP&L and GMO have been operated within the Great Plains Energy holding company structure. The numerous adjustments that Mr. Murray has proposed over the past nine years have never been adopted by the Commission, which has found them to be either "not reasonable," "unpersuasive," or "speculative."

65. There is no reason for the Commission to adopt a different position in this case. The Company's recommendation that its cost of debt be set at 5.51% (or at 5.49% under the simple interest/amortization method) should be authorized by the Commission.

III. FUEL ADJUSTMENT CLAUSE

66. The Commission approved KCP&L's first Fuel Adjustment Clause ("FAC") in its previous rate case (ER-2014-0370) and the FAC went into effect on September 29, 2015. The Company is seeking re-authorization of the FAC which is an important part of KCP&L ability to earn its authorized return. Staff supports the reauthorization of the FAC. KCP&L's FAC is similar to KCP&L Greater Missouri Operations Company's ('GMO") FAC which has had an FAC for many years. The Company believes that the FAC changes proposed by Public Counsel are not appropriate, especially since the changes would make KCP&L's FAC dramatically different than GMO's FAC.

A. Issues Resolved

67. The Commission's March 8, 2017 Order Approving Stipulation and Agreement Regarding Certain Issues regarding the Non-Unanimous Partial Stipulation and Agreement submitted to the Commission on February 10, 2017 resolved a number of issues related to the Company's "FAC". KCP&L believes that there is no longer an issue whether KCP&L met the criteria for the Commission to authorize it to continue to have an FAC under Issue III(A), or whether the Commission should authorize KCP&L to continue to have an FAC under Issue III(B).

68. Regarding Issue III(C) on what costs should flow through the FAC, KCP&L has agreed that it will not request recovery of any administration charges (such as those assessed by

Southwest Power Pool), or any FERC or NERC assessment charges. It has agreed that its FAC shall only recover SPP transmission expenses and any non-SPP transmission expenses calculated in the manner that was ordered in the Company's last rate case, which were termed "true purchased power costs." See Report and Order at 32-35, In re Kansas City Power & Light Co., No. ER-2014-0370 (Sept. 2, 2015).

Finally, KCP&L's request to recover fuel handling costs has been withdrawn.

B. Has KCP&L Met the Criteria for the Commission to Authorize It to Continue its FAC?

69. Yes. The requirements for continuing an FAC are found in Commission rules 4 CSR 240-20.090 and 4 CSR 240-3.161(3)(A) through (T). The supporting information showing that KCP&L meets the requirements is summarized in Schedules TMR-1 through TMR-4 of Ex. 142HC (Rush Direct). Staff agrees that the Company has met the criteria (Staff's Statement of Position at 1).

C. Should the Commission Authorize KCP&L to Have a FAC?

70. Yes. The Company is requesting to continue the FAC to address continuing uncertainty and volatility in fuel, purchased power and transmission costs offset by revenues as well as increases in costs that are expected to continue. The volatility and uncertainty in the Company's net fuel costs were demonstrated by KCP&L witness Wm. Edward Blunk (Ex. 103HC, at 21-24, Blunk Direct).

71. The FAC is a balanced recovery mechanism which provides the Company with recovery of the majority of its fuel, purchased power and transportation costs with off system sales above a base amount that is included in base rates. The FAC provides customers assurance that KCP&L is not over-recovering net-fuel and purchased power costs, and to ensure the

Company has an opportunity to earn a fair return in order to generally preserve the financial health of the Company (Ex. 142HC, at 6, Rush Direct). The Staff agrees that KCP&L's FAC should continue to be authorized by the Commission (Ex. 200 at 162. Staff Report, Revenue Requirement Cost of Service).

D. <u>There Should be No Changes in the FAC's Definition of "Fuel"</u>

72. OPC advocates a change in the definition of "fuel" that would be contrary to FERC's Uniform System of Accounts ("USoA") 501 ("Fuel") and the five subaccounts currently contained in KCP&L's FAC definition of fuel costs (Ex. 142, Sched. TMR-3 at 2, Rush Direct). The FAC also includes fuel costs relating to nuclear fuel in USoA Account 518, as well as natural gas and oil costs in USoA Account 547. KCP&L proposes no change in the existing definitions.

73. However, OPC seeks to change the definitions so that only the costs of the literal fuel commodity, such as coal, would be included, and not essential additives that are used to assist the combustion process (such as ammonia, lime, activated carbon and sulfur). These "fuel additives and consumable costs" are used in the operation of KCP&L's air quality control systems, and are currently included in the FAC as part of Subaccount 501300 (<u>Id</u>.).

74. Although OPC has not proposed any specific tariff sheets or even redlined the KCP&L tariff with revisions or changes, OPC argues for "the purest definition of fuel and transportation costs" that would exclude a variety of essential elements to KCP&L's FAC (Ex. 305 at 6, Mantle Direct). OPC would exclude fuel adders, start-up costs, fuel handling costs, as well as the cost of essential components of IM revenues and costs.

75. It also appears that OPC's re-definition of Fuel would mean that KCP&L would be required to stop using the inventory cost of fuel system, which is how KCP&L and all other utilities subject to the USoA currently keep track of fuel costs (Ex. 126 at 8-9, Herrington Surrebuttal). Rather than simplify the FAC or reduce the likelihood of errors, such a change would increase the complexity of FAC accounting and require deviations from standard USoA procedures (Id. at 9-10). There is no basis for such a radical change, either based upon the law, the Commission's regulations, or common sense.

76. Section 386.266.1 allows the recovery in an FAC of "prudently incurred fuel and purchased power costs, including transportation." The statute does not define fuel costs, nor do the Commission's FAC regulations in either 4 CSR 240-3.161 (filing and submission requirements) or in 4 CSR 240-20.090. It is clear that both the legislature and this Commission have allowed the parties to establish what should and should not flow through an FAC, reserving disputes for decisions by the Commission or the appellate courts. When disputes have arisen, as OPC has noted, the courts have resolved the dispute. The Court of Appeals determined that the costs of electric transmission are included in the statute's term "transportation," even though not specifically stated in the FAC statute. Union Elec. Co. v. PSC, 422 S.W.3d 358, 367 (Mo. App. W.D. 2013).

77. One of the FERC cases that Ms. Mantle cited in surrebuttal actually supports the Company's position that unduly restrictive interpretations of the USoA language should be rejected by regulatory commissions. In a 1989 Missouri Public Service Company ("MoPub") case, FERC rejected its Division of Audit's narrow interpretation of "deficient tonnage payments," holding that they were properly recorded in USoA Asset Account 151, which defined

"Fuel stock." FERC held that "deficient tonnage payments … are a component of the cost of fuel consumed and are among those costs listed [by the utility] in Account 151, making them appropriate for fuel adjustment clause recovery." Missouri Pub. Serv. Co., 46 FERC ¶ 61,011 at 61,078 (1989) (Ex. 307, Sched. LM-S-2, Mantle Surrebuttal). MoPub argued that Account 151 expressly permitted the recovery of contract costs related to deficient tonnage because Account 151's Item 3 defined "Fuel" to include expenses "directly assignable to [the] cost of fuel."[14] (Id. at 4). FERC agreed, stating: "Because we find deficient tonnage payments to be costs of fossil fuel consumed in a utility's own plants and among those items listed in Account 151, [MoPub's] recovery of deficient tonnage payments through its fuel adjustment clause was proper." (Id. at 6, 46 FERC ¶ 61,011 at 61,079).

78. One absurd result of OPC's argument would be the exclusion of essential costs and revenues that KCP&L incurs as a member of Southwest Power Pool's Integrated Marketplace ("IM"). Ms. Mantle argues for the exclusion of "most" SPP costs as not related to either fuel or purchased power (Ex. 306 at 4, Mantle Rebuttal). However, as KCP&L's Jessica Tucker stated in surrebuttal, all of the costs and revenues shown on Ms. Mantle's Sched. LM-D-1 as "SPP Integrated Market Costs" are components of Integrated Marketplace Revenues or Integrated Marketplace Costs (Ex. 148 at 6, Tucker Surrebuttal). These costs and revenues are all a part of making purchased power possible. For example, the majority of costs listed under SPP Integrated Marketplace Costs are directly attributable to Operating Reserves (such as Spinning Reserves and Regulation that are used to ensure that demand continues to be served in the event of a system contingency) that are necessary to support purchased power in the

[14] Item 3 of Account 151 currently contains this language.

Integrated Marketplace. Id. As Ms. Tucker testified, such products "ensure that power is available to be purchased for load regardless of system operating conditions." (Id. at 6). These are essential ancillary services that support KCP&L's purchases of power, and must remain in the FAC.

79. Another SPP IM product that OPC's proposal would eliminate from the FAC is the Auction Revenue Rights/ Transmission Congestion Rights ("ARR/TCR") mechanism. The purpose of the ARR/TCR is to protect the utility's load from the cost of congestion by offsetting the higher congestion paid as a part of the price of purchased power (Ex. 143, at 30, Rush Rebuttal). Ms. Mantle's proposal would eliminate TCR charge codes from the FAC and would expose KCP&L's customers to higher purchased power prices. Id. OPC's simplistic attempt to redefine fuel fails to recognize the interrelationship of costs and revenues in the IM so that the market can be co-optimized for minimal total cost. Id.

80. There is simply no basis to mandate that KCP&L create an entirely different, more complex and overly prescriptive FAC that would exclude legitimate fuel and purchased power costs, including transportation and transmission. No other party has filed testimony supporting OPC's proposal to eliminate from the FAC essential regional transmission organization costs and revenues which the Commission has never adopted for any other Missouri electric utility. OPC's recommendations should be rejected in their entirety.

E. KCP&L Should Not be Required to Revise its FAC to Report Net Sales and Purchases pursuant to FERC Order 668

81. In the Rebuttal Testimony of John Riley, OPC proposed for the first time that the Commission require KCP&L to report purchased power expenses and off-system sales revenues in the FAC on a netted basis (Ex. 317 at 2-5, Riley Rebuttal). Although no other Missouri

electric utility reports its purchases and sales on a net basis, and no other party to this case filed testimony advocating that KCP&L begin to do so, OPC recommends that the Commission require such reporting on the basis of FERC Order No. 668 (Id. at 2-3).

82. In that order FERC revised the USoA "to accommodate the restructuring changes that are occurring in the electric industry due to the availability of open-access transmission service and increasing competition in wholesale power markets." See Final Rule at 1, Order No. 668, Accounting and Financial Reports for Public Utilities Including RTOs, No. RM04-12-000 (Dec. 16, 2005).[15] KCP&L complies with Order 668 by netting all of its day-ahead purchases and sales from Southwest Power Pool on an hourly basis, and all real-time purchases and sales on a five minutes basis (Ex. 126 at 2, 7, Herrington Surrebuttal).

83. However, Order 668 does not prescribe how any public utility should prepare or present retail ratemaking schedules or tariffs, especially those that set forth the provisions of an FAC (Id. at 2-3). Mr. Riley conceded that Order 668 sets forth no requirements regarding fuel adjustment clauses and contains no guidance on how a state utility commission should engage in ratemaking (Tr. 610). He admitted that this Commission has never ordered any electric utility in Missouri to net purchases and sales in their fuel adjustment clause, pursuant to Order 668 (Tr. 616).

84. If KCP&L's FAC were re-written so that purchases and sales were netted, it would actually hide the information currently disclosed with regard to specific sales and transactions (Ex. 126 at 3-4, Herrington Surrebuttal). Adopting OPC's proposal would actually

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[15] The Commission took official notice of Order 668 (Tr. 613). An excerpt of Order 668 was admitted into evidence as Exhibit 158 (Tr. 612).

conceal the actual transactions that are occurring and eliminate the transparency that the FAC provides today (Id.).

85. It is also clear that FERC Order 668 was not designed to be used in retail ratemaking. Order 668 recognizes the distinction between reporting financial information on a wholesale basis, and how electric utilities should otherwise maintain their records regarding specific transactions. "The Commission does expect public utilities, however, to maintain detailed records for audited purposes of the gross sale and purchase transactions that support the net energy market amounts reported on their books." See Order 668, ¶ 80 at p. 39 (Ex. 158). It is this gross or individual sale and purchase information that is currently reported in KCP&L's FAC (Ex. 126 at 4-7, Herrington Surrebuttal).

86. FERC recognized that reports with gross information, such as in the Electric Quarterly Reports ("EQR"), "provide the Commission and the public with a more complete picture of wholesale market activities …." See Order 668 at ¶ 84, p. 40 (Ex. 158). The purpose of reporting such information in EQRs is "not necessarily the same criteria and principles" that FERC used in establishing uniform accounting requirements in Order 668 (Id.). This same reasoning applies to KCP&L's FAC where it is important to present both energy purchases and sales as separate transactions in USoA Account 447 (sales for resale) and Account 555 (purchased power).

87. MECG witness James Dauphinais agreed that nothing in Order 668 requires a utility like KCP&L to report sales and purchases on a netted basis as part of its FAC (Tr. 800-01). He acknowledged that Order 668 does not even mention fuel adjustment clauses (Tr. 800).

He also agreed that this Commission has never required any Missouri electric utility to net purchases and sales in a fuel adjustment clause based on Order 668 (Tr. 802).

88. Because Order 668 was not intended to address retail ratemaking issues and was certainly not intended to address fuel adjustment clauses or how state commissions should structure them, OPC's recommendation that Order 668 be imposed upon KCP&L's FAC should be rejected.

F. There Should be No Changes to the FAC's Current Sharing Mechanism

89. OPC proposes that the sharing mechanism in KCP&L's FAC should be changed from its current 95%/5% allocation method to a 90%/10% method (Ex. 305 at 25-26, Mantle Direct). No other party filed testimony proposing an adjustment to the current 95/5 ratio.

90. Under the current system, customers are permitted to keep only 95% of any decreases in fuel costs, while the Company's recovery of additional costs is limited to 95%. No other electric utility in Missouri operates under OPC's proposed 90/10 FAC formula (Ex. 143 at 44-45, Rush Rebuttal).

91. The vast majority of electric utilities in the United States are permitted to reconcile recoveries within their FACs at the 100% level (Id. at 45). Given that KCP&L, like these other utilities, has limited means to control its FAC-related costs, there is no good reason to change the sharing mechanism to forbid FAC recovery of an additional 5% more of prudently incurred costs to the Company, or an additional 5% less of benefits in terms of lower costs to customers. Moreover, because such a change would raise questions by KCP&L's current investors and lenders, asking why KCP&L is being treated differently from other Missouri utilities, there is no sound basis to adopt OPC's recommendation.

G. **<u>The FAC Should Continue to Require Reporting of Expenses and Revenues by USoA Account and Subaccount, but No Additional Reporting by KCP&L Resource Codes and Specific Descriptions should be Required</u>**

92. KCP&L's current FAC tariff requires that fuel, purchased power and transmission costs, as well as net emission costs, revenue from off-system sales, and renewable energy credit revenue be identified by FERC USoA account (a 3-digit number sometimes referred to as a "prime account") and by a 6-digit USoA subaccount. This system was established in 2015 when the Commission ordered that the FAC tariffs "should identify costs and revenues by FERC account and subaccount." <u>See</u> Report and Order at 31-32, <u>In re Kansas City Power & Light Co.</u>, No. ER-2014-0370 (Sept. 2, 2015). The Commission rejected OPC's recommendation that the use of KCP&L's internal corporate resource codes also be utilized, finding that this was "not necessary." (<u>Id</u>. at 32).

93. In this case OPC not only reasserts its view that KCP&L's tariff sheets be dramatically expanded to identify costs and revenues by corporate resources codes, but also to incorporate detailed cost descriptions. (Ex. 305 at 13-16 (Mantle Direct); Tr. 663-65). Schedules attached to Ms. Mantle's direct testimony included the subaccounts, resource codes, and specific descriptions that OPC requests be included in KCP&L's FAC (<u>Id</u>., Sched. LM-D-2 & LM-D-3). Ms. Mantle testified that such an expansion of the FAC would include over 200 resource codes and descriptions (Tr. 664). No other party has filed testimony proposing such an extraordinary expansion in the FAC tariff.

94. OPC has offered the Commission no proposed tariff sheets on how such an expansion in reporting would be presented. It has provided no redline or tracked changes version to any of the tariffs attached to Mr. Rush's direct testimony to reflect OPC's recommendations.

Indeed, OPC has not actually proposed any specific language to be included in the hypothetical FAC that it recommends (Tr. 659 (Mantle); Ex. 142, Sched. TMR-3 (Rush Direct)).

95. Ms. Mantle conceded that when Public Counsel, Staff or another party has asked KCP&L to provide further details regarding the costs and revenues included in its FAC, such information has always been provided (Tr. 663). Although Ms. Mantle complains that KCP&L's current FAC tariff is unduly complex (Ex. 305, Mantle Direct at 22-23), her argument in favor of adding internal resource codes and descriptions of costs to the FAC would impose a level of detail that is both unnecessary and unreasonable (Ex. 143 at 38-40, Rush Rebuttal). Indeed, it is ironic that Ms. Mantle complains that the FAC tariffs are too complex because they contain too much information, but now recommends that the Commission impose a level of specificity that would overcomplicate both the reporting process, as well as the audit process that necessarily follows (Id. at 42-43, Rush Rebuttal).

96. Throughout OPC's arguments in favor of more and significantly detailed reporting, neither Ms. Mantle nor Mr. Riley identify even one cost item that flowed through the FAC as an imprudent expense. Perhaps this relates to OPC's misunderstanding of the benchmark by which costs are evaluated, which is the standard prudence test. Ms. Mantle's testimony that a standard of "beyond doubt" is the "practice" applied at the Commission finds no support in the record (Tr. 666-67). Neither Staff nor any other party filed testimony advocating such a level of detail in the FAC. Given the lack of any imprudent costs having been identified during this case or any other reason for such an expansion of the current reporting requirements, OPC's recommendation should be rejected.

H. **<u>The FAC should Continue to Allow KCP&L to Add Changes in SPP Cost and Revenue Types, as Currently Permitted by the FAC</u>**

97. Finally, OPC proposes that KCP&L's current ability to add cost and revenue types to the FAC between rate cases that reflect changes in Southwest Power Pool cost categories be eliminated (Ex. 305 at 23). OPC appears to suggest that this is a new process that KCP&L has submitted in its proposed tariff sheets 50.14-50.16 (<u>Id</u>.). However, the identical process is contained in KCP&L's current FAC.

98. Schedule 3 to Ms. Rush's Direct Testimony sets forth both the existing ability and the proposed continuing ability of KCP&L to propose a new schedule or charge "should the SPP or another centrally administered market (e.g. PJM or MISO) implement a new market settlement charge type not listed below or a new schedule not listed in TC [transmission costs]." (Ex. 142, Sched. TMR-3 at p. 5 (existing Tariff Sheet No. 50.4) & p. 15 (proposed Tariff Sheet No. 50.15), Rush Direct). Both the existing and proposed FAC tariff sheets allow for a challenge to such proposals by any party, including OPC (<u>Id</u>. at 6, 16).

99. As KCP&L explained, it is not unusual for SPP to change a schedule or charge code by giving it a new name or by simply reclassifying it. Such changes do not relate to new costs (Ex. 143 at 43, Rush Rebuttal). The Company has no control over changes made by SPP or another RTO, so the existing process, which KCP&L proposes to continue in the new FAC tariff, simply allows it to continue to recover such existing costs.

100. It is also important to note that the current practice which KCP&L proposes to continue allows OPC, Staff or any "party other than the Company" to include a new schedule or charge type (Ex. 142, Sched. TMR-3 at 6, 16, Rush Direct).

101. As with OPC's other proposals, neither Staff nor any other party has filed testimony advocating such a change. Given OPC's failure to cite any problems or concerns with the current practice regarding the submission of changes when SPP revises its cost schedules or charge codes, it should be continued and OPC's recommendations rejected.

I. <u>What FAC-related reporting requirements should the Commission impose?</u>

102. The Company agrees to submit the nine additional reporting requirements presented in the rebuttal testimony of Staff witness Roos. The Company believes that it is already providing much of this information (Ex. 144, at. 4, Rush Surrebuttal).

IV. <u>DEPRECIATION</u>

A. <u>Should the Commission allow terminal net salvage in the calculation of KCP&L's depreciation rates?</u>

1. The Commission Should Allow Terminal Net Salvage In The Calculation of KCP&L's Depreciation Rates.

103. From a public policy perspective, the issue to be determined by the Commission in this case is whether current customers who receive the benefit of using the Company's power plants should pay for the cost of retiring those plants while they are being used, or whether those retirement costs should be pushed off on future generations who did not receive benefits from the power plants.

104. In this proceeding, KCP&L retained the firm Sega, Inc. to perform a detailed study of the expected retirement and dismantlement costs for the Company's power plants. The results of this Sega report are set forth in Ex No. 140, Rogers Direct Testimony, Schedule CRR-2. The Sega report determined that the total retirement and dismantlement costs for KCP&L's power plants are $235,915,903, and $263,012,214, respectively (<u>Id</u>. Schedule CRR-2, page 1-7; Tr. 323). These costs were based on a thorough review of the activities associated with the

terminal net salvage for these facilities, and the Staff and Public Counsel witnesses have not challenged the results of the Sega Study (Tr. 350).

105. The terminal net salvage used for KCP&L's depreciation study, however, are based only on the retirement components of the Sega report, and do not include other costs for site remediation or dismantlement that may potentially occur. In other words, the depreciation rates that KCP&L is proposing in this case include the cost of shutting the doors to the power plants upon retirement and ensuring the safety of the site, but not the full cost of dismantling the power plants. The terminal net salvage costs used for KCP&L's depreciation study in this case (i.e. retirement costs only) are therefore conservative estimates of the terminal net salvage costs. According to the Sega report, the retirement costs represent less than one-half of the total terminal net salvage expected for the power plants if dismantlement costs are considered.

106. In this proceeding, KCP&L is requesting that the Commission join the overwhelming majority of states that include a portion of the terminal net salvage costs (i.e. retirement costs of power plants) in the depreciation rates so that current customers that receive the benefit of the energy and power from those plants will pay those retirement costs through depreciation expense as the power plants are used. In the past, the Commission has not included the retirement costs in depreciation rates since there were few, if any, power plants that were being retired.[16] However, the uncontroverted evidence in this proceeding demonstrates that such retirements of power plants are occurring in Missouri and elsewhere, and are expected to continue in the future (Ex. No. 146, Spanos Rebuttal, pp. 9-14; Tr. 325-346).

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[16] See *Report And Order*, Re Empire District Electric Company, Case No. ER-2004-0570, p. 53 (March 10, 2005)(hereinafter "*Empire* case").

107. In addition, since the Commission last considered this issue in the *Empire* case in 2005, the Commission has changed its overall approach to depreciation rates for power plants. In its *Report And Order* in Re Union Electric Company, ER-2010-0036, p. 30 (May 28, 2010), the Commission decided to adopt the "life span" method for depreciation rates rather than the previously used "mass accounting" method. This change of depreciation policy to adopt the life span method also suggests that it is now appropriate to include terminal net salvage in the Company's depreciation rates.

108. By including the cost of retirements in the current depreciation rates, the Commission will ensure that the current generation of customers that receive the benefit of the power plants will also have the retirement costs of those power plants reflected in their electric rates. Otherwise, these retirement costs will be left for future generations to pay, even though future customers may not have received any benefit from the retired power plants.

2. Retirement of Power Plants Are Occurring in Missouri and Elsewhere.

109. The competent and substantial evidence in the record demonstrates that the retirements of power plants are occurring in Missouri and throughout the country (Ex. No. 146, Spanos, pp. 9-14; Tr. 325-346). Given the circumstances today with regard to plant retirements, as well as more recent Commission decisions regarding the use of the life span method, the *Empire* decision for terminal net salvage is no longer applicable and should not apply to KCP&L's instant case.

110. Specifically, the Commission's logic in the *Empire* case was based on an expectation that power plants would be unlikely to be fully retired, much less experience terminal net salvage upon retirement. However, experience over the past decade has

demonstrated that power plants are eventually retired and experience terminal net salvage costs upon retirement. Indeed, KCP&L has experienced terminal net salvage costs at Montrose Unit 1 and Ameren has retired its Venice Plant (Tr. 303, 345; Ex. No. 146, Spanos Rebuttal, pp. 9-14).

111. The record reflects that there are many recent examples of plants throughout the country that either have been or will be decommissioned and dismantled. Some examples include:

- Black Hills Power will decommission its Ben French, Osage and Neil Simpson I plants.
- Black Hills Colorado Electric is in the process of decommissioning its Canon City (W.N. Clark) plant and units 5 and 6 at its Pueblo plant.
- Duke Energy is in the process of decommissioning a number of sites in the Carolinas, and activities related to the retirements of these sites include asbestos removal, demolition and the closure of ash ponds.
- Dominion Virginia Power is in the process of decommissioning coal units at its Chesapeake Energy Center, North Branch and Yorktown sites.
- PacifiCorp is in the process of decommissioning its Carbon coal power plant.
- Florida Power and Light has decommissioned a number of retired oil and gas fired steam power plants, including Cape Canaveral, Riviera, Cutler and Pt. Everglades.

112. It is undisputed that power plants are being retired in Missouri and across the country, and such retirements are expected to occur in the future (Tr. 346). As a result, these

power plants will experience terminal net salvage costs that need to be reflected in depreciation rates.

3. The Commission Has Adopted the Life Span Method For Depreciation Since the *Empire* Decision.

113. The Commission's depreciation practices have evolved over the years. The Commission addressed the issue of net salvage in its *Third Report and Order* in Re Laclede Gas Company, Case No. GR-99-315, pages 9 and 14 ("*Laclede Order*"), and ruled that net salvage should be included in depreciation rates, and the Staff's position in that proceeding to exclude net salvage costs from depreciation rates should be rejected:

> The Commission finds that the fundamental goal of depreciation accounting is to allocate the full cost of an asset, including its net salvage cost, over its economic or service life so that utility customers will be charged for the cost of the asset in proportion to the benefit they receive from its consumption.
>
> * * *
>
> The Commission also finds that Staff's method significantly decreases the cash flows available to utilities to meet their infrastructure and other public service obligations. This, in turn, has a negative financial impact on both the utility and its customers by requiring that such obligations be met with more expensive sources of external financings and by driving up the cost generally of obtaining money in the capital markets. The Commission finds that Staff has not shown that the adoption of its method would justify these increased costs for utility consumers (*footnotes omitted*).

Ten years later, in Re Union Electric Company, ER-2010-0036, p. 30 (May 28, 2010), the Commission decided to adopt the "life span" method for depreciation rates rather than the previously used "mass asset accounting" method:

> Public Utility Depreciation Practices, published in 1996 by the National Association of Regulatory Utility Commissioners (NARUC), specifically states that electric power plants are to be

> treated as life span property. Similarly, the leading textbook on depreciation accounting Depreciation Systems, written by Dr. Frank Wolf and Dr. Chester Finch, clearly indicates that electric generating equipment is to be depreciated using a life span approach instead of a mass property approach. Even Staff's own depreciation manual, which Staff's witness relied upon in preparing his depreciation study, indicates the life span approach is appropriately used to determine depreciation for electric power plants.

114. The Commission has also adopted the life span method for KCP&L in Case Nos. ER-2010-0355 and ER-2014-0370 (Ex. No. 146, Spanos Rebuttal, pp. 2-3). Staff has agreed with this life span method in both KCP&L cases. In the instant case, Staff stated that "[t]he projected retirement dates for production plants relied on for depreciation purposes by KCP&L were used by Staff during the last KCP&L rate case, Case No. ER-2014-0370, and have not changed for this rate case." (Ex. No. 200, Staff Report, p. 147, lines 5-7). This change of policy to adopt the life span method also suggests that it is now appropriate to include terminal net salvage in the Company's depreciation rates.

115. While Staff and Public Counsel accept the concept that net salvage should be included in depreciation rates, neither Staff nor Public Counsel included <u>terminal net salvage</u> in their proposed depreciation rates. As KCP&L witness John Spanos explains, Staff and Public Counsel's recommendations for terminal net salvage are not consistent with the USOA, nor are they consistent with the Commission's *Laclede Order* (Ex. No. 146, Spanos Rebuttal, pp. 4-5). In addition, as explained below, the Staff and Public Counsel recommendations are not consistent with the *NARUC Depreciation Manual* when the life span method is utilized (Tr. 330-31).

116. Under the previously adopted mass asset accounting method, there was a component of retirement costs of power plants were reflected in rates (Tr. 372-74). As Public Counsel witness John Robinett testified, typically under mass asset accounting, the retirement costs were "usually built in." (Tr. 374). As a result, the record demonstrates that if the Commission had continued the mass asset accounting method, then customers would be paying for plant retirement costs through depreciation rates (Tr. 374). However, as the Commission's practices have evolved to the life span method, and with the recognition of net salvage in depreciation rates, the Commission's practices also should evolve to specify that the retirement costs (one component of terminal net salvage) should be included in depreciation rates under the life span method (Tr. 330-31).

117. For the life span method, service life estimates are made for the final retirement of a facility as well as for the interim retirements expected to occur throughout the life of the facility. Logic and fairness dictates that since the life span method is now used in Missouri, terminal net salvage must also be included in depreciation in order to be consistent with the USOA and the Commission's decision in *Laclede* on net salvage recovery (Ex. No. 146, Spanos, p. 8).

4. The *NARUC Depreciation Manual* Supports The Inclusion of Net Terminal Salvage In Depreciation Rates.

118. As explained by Mr. Spanos, the *NARUC Depreciation Manual* which the Commission relied upon to make its decision to adopt the life span method in the *Union Electric* case also strongly suggests that terminal net salvage costs (including retirement costs), should be reflected in depreciation rates (Tr. 331-32; 339-42; Ex. 156, *NARUC Depreciation Manual* at page 161).

119. The NARUC Depreciation Manual states at page 161:

> Net salvage associated with final retirements must be composited with interim net salvage resulting from expected piecemeal retirements in order to develop an estimate of future net salvage. Therefore, in order for the life span method to be applied properly, individual records of additions and retirements associated with each building and large installation must be maintained. Such records allow for data on interim and final retirements, gross salvage, and the cost of removal to be separately identified. This facilitates their analysis in the process of estimating future interim and final net salvage.

120. During cross-examination, Staff witness Keenan Patterson also agreed that the *NARUC Depreciation Manual* suggests that it is appropriate to include net salvage costs associated with retirement in depreciation rates under the Life Span Method (Tr. 341-42; 351):

> [Fischer]: Q. Mr. Patterson, wouldn't you agree that the NARUC depreciation manual suggests that net salvage associated with final retirement must be included with the interim net salvage?
>
> [Patterson]: A. That is what this passage would indicate.

121. Mr. Patterson re-iterated this position when he was questioned by Chairman Hall (Tr. 351):

[Chairman Hall]: Q. Do you believe that KCP&L's position is supported by the NARUC depreciation manual?

[Patterson]: A. The NARUC depreciation manual does refer to final net salvage as a component when using this [life span] method.

[Chairman Hall]: Q. So it does support KCP&L's position on this issue?

[Patterson]: A. Yes.

5. Missouri Should Move Into the Mainstream On This Issue.

122. In addition to the authoritative *NARUC Depreciation Manual* which is used by the Staff (Tr. 339), the Commission should also consider the practices of other state commissions with regard to including terminal net salvage in depreciation rates. Mr. Spanos has appeared in approximately 20-25 states on this terminal net salvage issue (Tr. 320). According to Mr. Spanos, "Most states are including some component of terminal net salvage in their depreciation rates." (Id.) In fact, he estimated that 50-75 percent of the states include both the dismantlement component as well as the retirement component. About 90 percent of the states include some component of those costs (Tr. 327).

123. In answer to questions posed by Chairman Hall, Mr. Spanos also clarified that many states will include both retirement and dismantlement costs in terminal net salvage (Tr. 321):

[Chairman Hall]: Q. So most states are including the retirement component—maybe not the demolition, but the retirement component?

[Spanos]: A. I'll add a slight distinction is that not all states segregate the two components of terminal net salvage; they will just include a

> dismantlement component, and then a portion of that is considered a terminal net salvage part. . . But to answer your question, most have a portion of the dismantlement, which can be associated with the retirement costs.

Based upon Mr. Spanos' experience in approximately 25 states, it is clear that a decision to accept the approach recommended by KCP&L and the *NARUC Depreciation Manual* would put Missouri in the mainstream of the states with regard to the terminal net salvage issue.

6. All Depreciation Studies Use Estimates of Costs That Are Periodically Updated.

124. During the hearings, some concerns were raised about the use of estimated retirement costs for terminal net salvage in depreciation studies. As Mr. Spanos explained and Staff witness Patterson confirmed, all depreciation studies are based upon estimates and estimated lives of the plants (Tr. 356-57). Mr. Spanos also made the point that retirement costs are less speculative today than dismantlement costs since "many, many, many units have been retired since 2005. . . Today we know that generating facilities are being retired; we know that there are many more planned to be retired in the next five years. . . So because of the fact that you have these retirements and expectations for them to retire, they're no longer speculative." (Tr. 326).

125. In any event, the Commission rules require that KCP&L and other electrical corporations file with the Commission periodic deprecation studies at least every five years. <u>See</u> 4 CSR 240-3.175(1)(B) (Tr. 330). As a result of these periodic depreciation study filings, the estimated retirement costs as well as the other components of the depreciation study will be

updated as time goes by. The Commission should not be concerned that retirement costs are estimated. This is true for many, if not all, components of a depreciation study.

7. There Is A Long Lag In Recovery of Retirement Costs Under the Current System.

126. Under the Commission's current practice of excluding retirement costs from depreciation rates until the plant is actually retired, there is a long delay in final recovery of the retirement costs. This long delay occurs because these retirement costs are not reflected in rates until the plant is retired, and then those costs are again deferred and recovered over the remaining life of the remaining generating units on the electric system (Tr. 328).

127. As a hypothetical example, if a customer received service from the Montrose plant in the 1950s and the plant was retired this year, all the retirement costs associated with the customer's service would not be finally recovered until the year 2070 (i.e. the remaining life of all existing power plants). In other words, the retirement costs would not be fully recovered until 120 years after the customer actually received the benefit of the plant in the 1950s (Tr. 328-29).

128. As a result, the current depreciation practice related to the recovery of retirement costs promotes intergenerational inequities since the customers that are currently receiving the benefits of the power plants are most likely not going to be paying for the full retirement costs of the plant unless they have a very extended life span themselves and remain a customer of KCP&L long after the plant is retired.

129. For all of the foregoing reasons, the Commission should adopt KCP&L's position that the retirement cost component of terminal net salvage should be reflected in KCP&L's depreciation rates in this case. It is fair and equitable for customers who receive the benefit of the Company's power plants to pay the cost of retiring those power plants as they are being used.

Otherwise, future generations of KCP&L's customers will be required to pay for the retirement costs of the power plants, even though they will not receive the benefit of those retired plants.

B. <u>What depreciation rates should the Commission order KCPL to use?</u>

130. The depreciation rates set forth in the Depreciation Update Study (Ex. No. 145, Spanos Direct, Exhibit JJS-1) filed by KCP&L in the Direct Testimony of John Spanos are the most appropriate. These rates reflect the combined analyses of all KCP&L assets through 2013 and include the most appropriate recovery methods and service value of all assets. Only depreciation rates for the Electric Generating Plant accounts were updated. In addition, a proposed rate is being requested for a new plant sub-account for Electric Vehicle Charging Stations. The depreciation rates for all other plant accounts are those authorized in the 2014 KCP&L case (Ex. No. 145, Spanos Direct, pp. 5).

131. The Commission should include estimates of terminal net salvage that the Company will incur upon the retirement of its generating facilities in the depreciation rate, as recommended by KCP&L witness John Spanos.

132. The difference between Staff and OPC's proposed depreciation rates and the depreciation rates KCP&L has proposed is that KCP&L has included estimates of terminal net salvage that the Company will incur upon the retirement of its generating facilities. Thus, the primary area of disagreement for production plant assets is the inclusion of terminal net salvage in the depreciation rates. The Company contends that the depreciation rates set forth in the Depreciation Update Study (Exhibit JJS-1) filed by KCP&L in the Direct Testimony of John Spanos are the most appropriate. These rates reflect the combined analyses of all KCP&L assets through 2013 and include the most appropriate recovery methods and service value of all assets.

V. CLEAN CHARGE NETWORK

133. From the Company's perspective, the Clean Charge Network ("CCN") is an extremely important issue because it will largely determine if KCP&L makes further investments into the electric vehicle ("EV") market, and as a result, may substantially impact the pace of development of the EV market.

A. Is the Clean Charge Network a regulated public utility service?

134. The Commission has jurisdiction to regulate utility-owned and operated electric vehicle charging stations operated in a utility's service area. Section 386.020(43) RSMo. defines a "public utility" as any "electrical corporation" "owning, operating or controlling or managing any electric plant. . ."[17] KCP&L and GMO are both "electrical corporation[s],"[18] owning, operating, controlling and managing the electric vehicle charging stations. The electric vehicle charging stations are "electric plant" under Section 386.020(14)[19] which facilitates the distribution, sale or furnishing of electricity for power.

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[17] Section 386.020(43) RSMo. states: "Public utility" includes every pipeline corporation, gas corporation, electrical corporation, telecommunications company, water corporation, heat or refrigerating corporation, and sewer corporation, as these terms are defined in this section, and each thereof is hereby declared to be a public utility and to be subject to the jurisdiction, control and regulation of the commission and to the provisions of this chapter." (emphasis added)

[18] Section 386.020(15) RSMo. defines electrical corporation as: "Electrical corporation" includes every corporation, company, association, joint stock company or association, partnership and person, their lessees, trustees or receivers appointed by any court whatsoever, other than a railroad, light rail or street railroad corporation generating electricity solely for railroad, light rail or street railroad purposes or for the use of its tenants and not for sale to others, owning, operating, controlling or managing any electric plant except where electricity is generated or distributed by the producer solely on or through private property for railroad, light rail or street railroad purposes or for its own use or the use of its tenants and not for sale to others (emphasis added).

[19] Section 386.020(14) RSMo. states: "Electric plant" includes all real estate, fixtures and personal property operated, controlled, owned, used or to be used for or in connection with or to facilitate the generation, transmission, distribution, sale or furnishing of electricity for light, heat or power; and any conduits, ducts or other devices, materials, apparatus or property for containing, holding or carrying conductors used or to be used for the transmission of electricity for light, heat or power; (emphasis added)

135. Missouri case law has imposed the further requirement that such service must be offered "for public use." See *State ex rel. Danciger and Co. v. Public Service Commission of Missouri*, 275 Mo. 483, 205 S.W. 36 (1918). Relying on *Danciger*, the federal court in *City of St. Louis v. Mississippi River Fuel Corporation*, 97 F.2d 726 (8^{th} Cir. 1938), stated that the public use of a service is the deciding factor in determining whether an operation is a "public utility" under Missouri law. It concluded that "under Missouri law the term 'for public use' . . . means the sale . . . to the public generally and indiscriminately, and not to particular persons upon special contract." (Id. at 730). The *City of St. Louis* court cited with favor the following definition:

> To constitute a public use all persons must have an equal right to the use, and it must be in common, upon the same terms, however few the number who avail themselves of it (Id.)

136. The Commission should conclude that KCP&L is providing electrical service through the electric vehicle charging stations as a public utility. The service will be available to any electrical vehicle driver that wishes to avail themselves of the electric service. The Commission should conclude that the electric vehicle charging stations are part of the public utility's regulated local distribution network which is necessary to provide electricity to the electric vehicles. As such, KCP&L's CCN facilities should be treated as electric plant needed to provide electric service through electric vehicle charging stations to electric vehicle drivers as a public utility service.

B. Should capital and O&M expenses associated with the Clean Charge Network be recovered from ratepayers?

137. Yes. As a regulated public utility service, all prudently incurred capital and operations and maintenance costs associated the CCN should be recovered from ratepayers. All

customers will derive some benefits from the program in the form of cleaner air, state economic development and increased electric usage over which KCP&L's fixed costs are spread. In the future, there may be some subsidy required for KCP&L's CCN, but the amount of that subsidy is unknown at this time. It is important to note that some degree of subsidy is inherent in the provision of almost all utility services. For example, residential customers who live close to electric generating plants subsidize those who live farther away. Higher load factor industrial customers may subsidize lower load factor customers in the same rate class. Higher income customers subsidize lower income customers who take advantage of programs such as KCP&L's low income weatherization program, ERPP and other programs. In fact, many new customers receive some subsidy when there is an extension of the distribution plant into a new subdivision. There is nothing wrong with some degree of subsidization in support of a program that provides public benefits. In this case, there is no subsidy at all since tax benefits related to the EV Charging Stations make the service profitable. In fact, the Company's revenue requirement is lowered by approximately $400,000 as a result of the CCN (Ex No. 144, Rush Surrebuttal p. 18, Schedule TMR-12, p.1; Tr. 1568).

138. Staff witness Natelle Dietrich testified that the Staff has modified its position on cost recovery of investments in EV charging stations for public utilities. According to her testimony, Staff is now asserting that EV charging station investments should be considered a regulated service and booked above-the-line (Ex. No. 208, Dietrich Surrebuttal p. 2; Tr. 1553). However, Staff apparently intends to make revenue imputation adjustments in future rate cases in the event the revenues from such EV charging stations do not recover their costs (Id.). Staff's position on revenue imputation is short-sighted and should not be adopted by the Commission.

139. As Mr. Rush explained, there are five areas of customer and public benefit that KCP&L believes the EV charging station pilot projects can provide many benefits to consumers and society as a whole. These benefits include:

- Beneficial Electrification: More efficient use of the electrical grid through increased electrical sales during off-peak times. As more drivers adopt electric vehicles, not only will vehicle emissions be reduced, but the cost of operating and maintaining the electrical grid will be spread over more kilowatt-hours without causing increased investment in additional generation and grid upgrades.
- Environmental Benefits: Environmental and health benefits through reducing tailpipe emissions—in particular regional ozone emissions and compliance, carbon dioxide reduction, and reductions in other EPA categorized pollutants.
- Economic Development: Regional economic development through increased attraction of auto industry, electric vehicle industry, battery and charging station companies to the KCP&L service territory; local job creation through increased household spending on local goods and services rather than at the gas pump; direct and indirect job creation from electric vehicle charging station deployment, electric vehicles sales and servicing; and increased talent recruitment in competitive job categories such as STEM (Science, Technology, Engineering, Math) and IT jobs.
- Customer Programs: Network enabled customer programs for cost-effective demand side management, time of use incentives/rates, and vehicle to grid battery storage and discharge.

- Cost and Efficiency Benefits: Installation and operation of EV charging stations as part of the utility's electric distribution system should reduce the cost of equipment and installation while use of the utility as a standard payment platform should also reduce cost; such efficiencies should ease expansion of the system if deemed appropriate (Ex. No. 143, Rush Rebuttal, pp. 54-55).

140. The Commission should not expect public utility shareholders to bear the burden of the cost of providing a new technology and service to an emerging market when that service is expected to produce substantial benefits to all ratepayers in the future. The Staff seems to want the benefits of the service when it is profitable (i.e. profits will be included in rates), but not the initial start-up costs of producing those benefits (Tr. 1553-54). Such a position is not fair and reasonable, and is not lawful.

C. Should KCPL develop a PEV-TOU rate to be considered in its next general rate case?

141. No. The Company is actively engaged in studying TOU rates, and the Company cannot currently implement TOU rates with its current billing system. Ex. 144, (Rush Surrebuttal) at 19. It would be premature to develop a PEV-TOU rate to be considered in the next general rate case.

D. Should the session charge be removed from the tariff?

142. During the hearings, KCP&L witness Tim Rush stated that KCP&L was no longer requesting that a session charge should be included in the tariff (Tr. 1352-53). As a result, this is no longer an issue to be resolved by the Commission.

E. Should Chairman Hall's "Make Ready" Model Be Adopted in Missouri?

143. During the hearings, Chairman Hall questioned several of the witnesses about a potential model that would have the public utility provide the distribution plant necessary to provide service to the EV charging station towers, and the public utility (or its unregulated operation or unregulated subsidiary) and unregulated third-party providers would own and install the charging station tower itself (Tr. 1508-19).

144. KCP&L has provided a quantification of the investment in the distribution plant and the EV charging station tower capital and O&M costs (Late-filed Ex. No. 169). Based upon the breakdown of the costs which are considered Highly Confidential, a very small portion of the $4.9 million CCN investment is related to distribution costs associated with serving the EV charging stations themselves. The tax benefits that accrue from the CCN, and thereby reduce the cost of the overall CCN, are also directly associated with the EV charging stations themselves.

145. KCP&L estimates that the approximate cost of its EV charging station investment, if it were included in rates and without tax benefits, is approximately $0.10 per month for an average residential customer. This calculation is made by adding the total return on the CCN rate base ($303,002), total Missouri jurisdiction O&M ($179,833) and total depreciation expense ($497,818) found on Schedule TMR-12 of Ex. 144(Rush Surrebuttal). These amounts total $980,653 and is the total estimated CCN revenue requirement. This amount ($980,653) is then divided by the total kWh usage for all classes. That usage amount is calculated by taking Staff's Missouri retail kWh sales of 8,412,099,098[20] minus 100,662,532

[20] See line 3 of Staff's Executive Case Summary, Ex. 242

KWHs of reduced usage associated with MEEIA Cycle 1 programs[21] which equals 8,311,436,566 This number is multiplied by the average Missouri residential usage amount of 871 kWh[22] to arrive at the $0.10 per month figure ($980,653/8,311,436,566 x 871=.10). However, as mentioned earlier, the average residential customer will benefit by the approximately $400,000 revenue requirement reduction due to the tax benefits associated with the CCN and the Company estimates that the average residential customer will get a credit of approximately $0.04 per month under the rates set in this case.[23]

146. KCP&L believes that if the charging stations are unregulated and any entity can own and charge for the electric vehicle charging stations, these tax benefits and other benefits to the non-EV customers on the KCP&L system would be eliminated or substantially reduced. An unregulated entity would not take into consideration the grid optimization aspects of having a grid enabled network of charging stations. Therefore, an unregulated entity would most likely not opt for a tower that would allow for demand response control, negating any demand response capabilities. In addition, under the unregulated model, the Commission will no longer have access to the data that can be derived from the network assess understand the impact on grid operations.

147. KCP&L also believes that the typical unregulated private entity is installing charging stations for a separate set of benefits outside of revenue from charging stations. Workplaces install stations to attract employees. Retailers install charging stations because attracting EV drivers positively impact their bottom line when EV drivers by more product in

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[21] See Ex No. 143, Rush Rebuttal, Schedule No. TMR-7)
[22] See Ex. No. 100, Schedule ARB-5 (2015 average usage of 10,452 KWH/12)
[23] $400,000 / 8,311,436,566 kWh sales x 871 kWh (average usage).

their store. As a unregulated operation, KCP&L does not have the access to these other benefits derived from charging stations and would reply only upon the incremental revenue obtained to offset the cost. Under the unregulated model, KCP&L rate-paying customers would still receive all of the benefits derived from kWh sales both at the public charging stations and as a result of the increase at home charging.

148. As a regulated service, KCP&L's position is to provide the best service in the public interest. This positions KCP&L to ensure that stations will be deployed in underserved areas. There are also a number of technical variables that need to be evaluated should the charging stations be unregulated. Guidelines and standards need to be put in place for installation.

149. As part of the CCN network, KCP&L has established an installation process including the evaluation of the charging stations to meet our safety standards and regulated requirements including the measurement technology to bill customers. Not all charging stations are created equal. There are non-networked stations and networked stations. Within that networked stations have different capabilities. There should be an evaluation process to identify the requirements a charging station does or does not need to meet in order to operate under this model.

150. For all of the reasons described above, KCP&L would urge the Commission that at this point in time, to allow the charging stations included in this rate case be regulated while KCP&L and other stakeholders continue to evaluate other potential models and the implications.

151. KCP&L will provide ongoing information to the Commission so that at right time and under the right conditions, entities other than regulated utilities should be permitted to

provide and charge for electric vehicle charging station service. The data gathered from the CCN project can also be used by the Commission and legislature in making more informed decisions on the future of EV in the State of Missouri. KCP&L is willing to provide periodic reports to the Commission on data gathered from the CCN project.

152. KCP&L also believes that further study of an unregulated model is necessary to determine its long term feasibility to provide sufficient incentives to unregulated providers to own and install the EV charging stations themselves. Additional workshops could be convened to allow all stakeholders the opportunity to discuss and explore the desirability of the "make ready" model described by Chairman Hall during the hearings. In the meantime, KCP&L respectfully requests that it adopt its EV tariffs proposals in this case to include the costs and revenues associated with the CCN in its rate base and rates.

VI. CLASS COST OF SERVICE, RATE DESIGN

153. From a policy perspective, the most important rate design issue to be resolved is the Inclining Block Rate ("IBR") Structure issue. For the reasons stated below, both Company and Staff are opposed to abandoning the time-tested rate structures of the Company in favor of the IBR at this time. KCP&L is particularly concerned that the premature adoption of an IBR will introduce volatility into its cost recovery and earnings levels without any tracker to recover lost margins. If an IBR were adopted for space heating and large summer air conditioning customers, it would adversely affect the bills of such customers. Other states have experienced negative reactions from many customers when IBR proposals have been adopted without careful study. The adoption of an IBR in the winter months will also have an adverse impact upon the Company's ability to compete in the space heating market.

154. KCP&L believes that the IBR and its impact upon customers has not been adequately reviewed in Missouri, and therefore its adoption in this case is premature. As explained below, KCP&L and GMO have numerous rate studies underway, and it is clearly premature to make a significant change in rate design policy before these studies have been completed. Therefore, KCP&L, with the support of the Staff, requests that the Commission decline to adopt IBR proposals of the Division of Energy and other intervenors in this case.

A. What interclass shifts in revenue responsibility, if any should the Commission order in this case?

155. As explained below, the Company is proposing that the requested increase be applied to all metered retail classes on an equal percentage basis, with the exception of the Lighting class (Ex No. 136, Miller Direct, p. 16).

B. How should any increase ordered in this case be applied to each class?

156. The Company is proposing that the requested increase be applied to all metered retail classes on an equal percentage basis, with the exception of the Lighting class (Ex No. 136, Miller Direct, p. 16).

157. As explained by KCP&L witness Marisol Miller (Ex. No. 136, Miller Direct pp. 5-15 and Ex No. 137, pp. 5-10), the Company prepared a Class Cost of Service ("CCOS") Study based on the Average & Peak production allocation method[24]. The CCOS is used to directly

[24] Production plant is the single, largest component cost to allocate to the classes within the study. As such, the production allocator has the most impact on the outcome of the CCOS study. In 2012, the Company reviewed industry data and information available within the public domain, including the National Association of Regulatory Utility Commissioners' ("NARUC's") "Electric Utility Cost Allocation Manual" published in January 1992 with the objective of validation of the production plant allocation method being used or exploring other possible alternatives. The Company reviewed an informal survey performed by the Edison Electric Institute on plant allocation methods. Finally, KCP&L looked at testimony from recent Missouri and Kansas rate proceedings, exploring the positions offered by parties on the topic. The evaluation considered the three main categories of

assign or allocate each relevant component of cost on an appropriate basis in order determine the contribution that each customer class makes toward the Company's overall rate of return. The CCOS analysis strives to attribute costs in relationship to the cost-causing factors of demand, energy and customers.

158. KCP&L's CCOS showed the following: The jurisdictional rate of return was calculated to be 5.5%. Individual classes' rates of return at current rates vary, and based on the current costs, are shown in the following table.

Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Other Lighting
4.0%	8.2%	7.0	7.2%	4.9%	9.4%

159. Based on the results of the KCP&L CCOS study, the Company made three proposals for this case:

1.) No class revenue shifts based on the rate of return results;

2.) Apply the increase equally to the remaining classes (adjusted for pre-MEEIA opt-out revenues) across bill components; and

3.) Apply no increase to the Lighting Class (unmetered).

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production allocation defined in the NARUC materials; Peak Demand, Energy Weighted, and Time Differentiated methods.

After considering all allocation theories and ensuring that the selected method aligned with the principles of reflecting actual planning and operating characteristics, cost causation, recognizing the broad set of customer class characteristics and their usage, and producing stable results on a year to year basis, the Company selected the utilization of the Energy Weighted approach, specifically the Average & Peak Production Plant Allocation method, incorporating a four (4) Coincident Peak (CP) component. An Energy Weighted approach was viewed to be cost effective, balanced through its incorporation of energy, and less subjective than other methods. Utilization of the Average & Peak method is an energy-weighted method of production plant allocation that gives classes recognition or both usage and contribution to peak load (Ex. No. 136, Miller Direct, pp. 9-10). If the Commission adopts a specific production allocation method in this proceeding, the Company recommends the Average and Peak Production Plant Allocation method.

160. Other parties also submitted CCOS studies, including Staff, MIEC, and the US DOE. The following identifies the relative rates of return for the provided studies. Rates below 1.0 indicate the class is not providing revenues to cover its costs. Rates greater than 1.0 indicate the class is providing more revenue than is needed to cover its costs.

Comparison of Class Cost of Service Studies - Relative Rate of Return								
Party	**Production Allocation**	**Total**	**RES**	**SGS**	**MGS**	**LGS**	**LPS**	**Lighting**
KCP&L	Ave. & Peak	1.00	0.72	1.48	1.26	1.30	0.88	1.70
Staff	BIP	1.00	1.02	1.25	1.24	1.03	0.65	1.32
MIEC	Ave. & Excess (4NCP)	1.00	0.45	1.38	1.30	1.58	1.46	1.70
US- DOE	4CP	1.00	0.50	1.34	1.25	1.54	1.27	3.85

161. As pointed out by KCP&L witness Miller, review of these results reveals some consistent themes. The Residential rates provide results at or below their relative rate of return. The Small, Medium, and Large General Service rates are consistently shown to provide a higher relative rate of return than the average. The Large Power relative rates of return are less consistent across the studies. Further, the relationship between the residential relative rate of return and the Large Power relative rate of return varies based on the method used to allocate production plant. Production allocation methods that rely more heavily on peak demands allocate more cost to the residential class while methods that rely more heavily on energy allocate more cost to the Large Power class. The Lighting class shows extreme variation in results which has been common in previous cases and is likely due to the unique characteristics of lighting (Ex No. 137, Miller Rebuttal, p. 6).

162. From KCP&L's perspective, each CCOS study holds value and that some collective view might be warranted. Regardless, the CCOS results should only be used as a

guide and that bill impacts, revenue stability, rate stability and public acceptance must be considered. In making KCP&L's proposal, the Company considered the rates of return between the classes and determined the KCP&L study would support some opportunity for a class shift from the General Service Classes to the Residential and Large Power classes. However, in reviewing the magnitude of change needed to move the residential and Large Power rates of return and the potential impact of those shifts combined with the proposed revenue increase, the Company recommends no shift in revenues to classes based on the outcome of KCP&L's class cost of service study at this time (Id. at 10).

C. **Should KCPL be permitted to increase the fixed customer charge on residential customers?**

163. There should be an across the board percentage increase to all rate elements, including the customer service charge. If the Commission approved the requested increase, then the Company's recommended residential customer charge would be $13.18 per month (Tr. 942; 959). However, as explained below, the Company would also support an increase to the level supported by the Company and/or Staff cost of service study, even if the full increase is not granted.

164. Several witnesses including Mr. Doug Jester representing Renew MO and the Sierra Club recommended denial of any increase or a desire to keep customer charges artificially low, perhaps irrespective of associated customer related costs, largely ignore the latest CCOS study completed by the Company that supports an increase. The Company's current CCOS supports an increase to the monthly Residential Customer Charge to $16.68, significantly more than the charge proposed by the Company. (Ex. No. 135, Miller Direct, p. 14). However, if the MEEIA and RESRAM costs are removed from the cost study, then the Company's customer

charge would be approximately $13.18, at a level similar to Staff's calculation of the customer-related costs of $12.62 per month (Tr. 941-42).

165. The Company believes that knee-jerk opposition from consumer representatives to any increase in the customer charge is short-sighted and not consistent with the principles of "cost causer-ratepayer." In the Company's last rate case, the Commission explained the basis for establishing a customer service charge as follows:

> The residential customer charge is designed to include those costs necessary to make electric service available to the customer, regardless of the level of electric service utilized. Examples of such costs include monthly meter reading, billing, postage, customer accounting service expenses, a portion of costs associated with meter investment, and the service line.
>
> ***
>
> Customer-related costs are generally recovered through the customer charge, which serves to prevent higher usage customers from subsidizing lower usage customers, sends all customers more accurate energy pricing signals, and provides more stable and predictable funding for utilities' fixed costs. Other costs are recovered through volumetric rates that vary with the amount of electricity used.[25]

166. The Commission should rely heavily upon the cost causation principles of rate design, including establishing the customer service charge at a level to recover customer-related costs, as established by the competent and substantial evidence in the record. Based upon the record, KCP&L believes it would be appropriate to spread any increase to the customer service charge on an equal percentage basis. Alternatively, the Commission could reasonably accept the

[25] *Report And Order*, Re Kansas City Power & Light Company, File No. ER-2014-0370, pp.88- 89 (September 2, 2015).

results of the Company and/or Staff cost of service study for the customer charge and establish the customer charge in the range of $12.62 to $13.18 per month (Tr. 830, 890, 1050, 1068).

D. <u>Should KCPL be required to implement the block rate structure proposed by the Division of Energy for residential customers?</u>

167. The Company is opposed to proposals to take steps toward adopting an inclining block rate ("IBR") structure for the residential class in the summer and winter periods at this time. Staff is also opposed to this proposal (Ex No. 210, R. Kliethermes Rebuttal, pp. 3-5). There are numerous rate design studies underway that will address the residential rate structures, including IBR rates, and time-of-use rates, and the Company believes that it would be inappropriate to make significant policy decisions or changes in its rate design before those studies are completed and the customer impacts are fully considered.

168. More specifically, multiple studies are underway within the KCP&L and GMO companies to explore dynamic rates and demand side efforts. As these studies have not been completed, it is unclear if inclining block rates or time-of-use rates are the best means to address peak load issues. In File No. ER-2014-0370, the Commission ordered KCP&L to complete a study regarding the redesign of its time-of-use rates within two years of the effective date of that order. That study will be complete on September 15, 2017. Similarly, in File No. ER-2016-0156, the Commission ordered GMO to study time-of-use rates for GMO including time-of-use residential and SGS rates, critical peak rates, Electric Vehicle time-of-use rates for stand-alone charging stations, time-of-use rates applicable to Electric Vehicle charging associated with an existing account, Real Time Pricing, Peak Time Rebates, and other rate types which could encourage load shifting/efficiency. GMO will propose rates based on this study no later than its next rate case or rate design case. These studies will provide more understanding of

the role of various residential rate structures, dynamic rates and help determine an appropriate path forward for these rates. Finally, other work is being done within the Integrated Resource Planning process to examine demand side rates. This effort includes review of time-of-use as well as other rate designs that could be used by the Company in assessing the propriety of taking steps toward flat and/or inclining block rates in the future (Ex No. 137, Miller Rebuttal, pp. 16-17).

E. <u>What are the dangers of implementing an IBR immediately?</u>

169. **Lack Customer Understanding-**An IBR structure would be a significant change for the typical residential customer. Despite customer bill detail and available information explaining bill components to customers and other Company efforts to educate the customer on their bills, many customers may still grapple with understanding existing rates. So a dramatic change, e.g. moving from declining to inclining, even with existing block structures will likely be difficult to understand from a customer's perspective.

170. **Customer usage may not change-**If a goal of implementing IBR is to send a price signal to customers to modify/decrease their energy usage, absent an elasticity study to assist in determining targeted pricing that is specific to the KCP&L service territory, there is a very good chance that no change in customer usage may result. No elasticity study was performed by any party in this case.

171. **Customers may be negatively impacted by IBR-**Absent the right price signal and no change in usage, a typical customer may only experience bill instability and even significant swings in their monthly bills, when one factors in the probability of extreme weather.

172. **Unintended consequences may resu**lt-The adoption of an IBR structure may have substantial unintended consequences, particularly if an inclining block rate structure was applied in the future to high usage electric space heating customers in the winter, or high usage residential customers in the summer (Tr. 824, 1027). Witnesses for Staff (Tr. 1047), Public Counsel (Tr.1179), DE (Tr. 1237) as well KCP&L all recognized the need for careful study to ensure there were no unintended consequences related to the widespread adoption of a IBRs for electric spacing heating and large air-conditioning customers during the summer months. At the request of Chairman Hall, KCP&L witness Tim Rush also relayed to the Commission the negatives experiences of other public utilities in Illinois and Colorado with the initial introduction of IBR structures (Tr. 1386-89). The impacts upon all customers should be carefully studied before IBR rates are introduced, even on a limited scale.

173. KCP&L also has a significant concern that the adoption of an IBR rate structure may introduce volatility into the recovery of the Company's revenue requirement, and the inability to recover the substantial fixed costs of providing electric service to our customers. KCP&L's witness Marisol Miller estimated that the fixed costs of generation, transmission and distribution are approximately $86 per month for residential customers (Tr. 960). However, under the current rate structure, these costs are recovered in variable per KWH charges, largely in the first two blocks of the declining block rate structure (Tr. 960-61).   To the extent that cost recovery is moved from the initial blocks of the declining block rate structure to the tail block rates to create an IBR, there is the potential for the introduction of volatility into the recovery of the Company's revenue requirement (Tr. 961-64).

174. Staff witness Robin Kliethermes also expressed concerns related to revenue volatility and cost recovery with the adoption of IBR recommendations made by other intervenors in this case. Using the Company's normalized bill frequency information, she performed an analysis of the Residential Spacing Heating and Residential General Use customers, calculating average use per customer in the test year.

175. Based upon this analysis, Ms. Kliethermes concluded that overall revenue stability for the Company as well as customer impacts will be a significant issue if IBR is adopted, particularly in the winter months (Ex. No. 201, Kliethermes Rebuttal, pp. 3-5):

> It is important to note that the average usage per customer for a general use customer for the months of April, May, and November, which are designated as winter months, does not exceed the first 600 kWh, or first block, of KCPL's residential rate design. Shifting revenue recovery from the first block (declining block rate) to the tail block (inclining block rate) of over 1,000 kWh in these months can decrease the amount of overall revenue recovered by the utility. Additionally, cumulative frequency distribution data provided by KCPL shows that 68% of general use customers in April and May and 66% of general use customers in November show usage of under 600 kWh. Also, the average usage per customer in the months of December, January, February, and March for a general use customer is drastically different from that of a space heating customer in those same months. For example, a general use customer's average use only exceeds 1,000 kWh in the summer months, while the average use of space heating customer is above 1,000 kWh in only December, January, February, and March. Currently, the rate design for the Residential General Use and Residential Space Heating classes share the same flat rate in the summer but have different declining rates in the winter months.

176. The Company agrees with Ms. Kliethermes[26] that given the current billed usage data in the test year, and the number of residential customers whose energy falls at or below the first energy block, moving costs, particularly non-energy costs, to the second and third block to create an IBR will result in greater volatility in both revenue recovery, and may adversely affect customers in years with abnormal weather (Ex No. 136, Miller Rebuttal, p. 9).

177. According the DE witness Martin Hyman, DE is supporting the adoption of the following rate proposal:

Table 2. DE's proposed residential general use rate design.

<table>
<tr><th>Rate Component</th><th>Season</th><th>Block</th><th>Current</th><th>DE Proposal</th><th>Change</th></tr>
<tr><td colspan="3">Customer Charge</td><td>$11.88</td><td>$11.88</td><td>0.00%</td></tr>
<tr><td rowspan="5">Energy Charge</td><td rowspan="2">Summer</td><td>First 600 kWh</td><td rowspan="2">$0.13328</td><td>$0.12521</td><td>-6.05%</td></tr>
<tr><td>Over 600 kWh</td><td>$0.14485</td><td>8.68%</td></tr>
<tr><td rowspan="3">Winter</td><td>First 600 kWh</td><td>$0.11982</td><td>$0.11878</td><td>-0.87%</td></tr>
<tr><td>Next 400 kWh</td><td>$0.07183</td><td>$0.07183</td><td>0.00%</td></tr>
<tr><td>Over 1000 kWh</td><td>$0.06003</td><td>$0.06372</td><td>6.14%</td></tr>
</table>

178. Under DE's proposal, there would be an inclining block rate structure in the summer, and a flattening of the residential general use rates in the winter for KCP&L general use class of residential customers. According to DE, this proposal is designed in part to create incentives for customers for high usage customers to conserve on their electricity usage (DE Position Statement, p. 6). However, the Company questions whether an IBR will provide a realistic price signal to most residential customers to conserve since the evidence in this case supports the premise that the most residential customers are not aware of the Company's block

[26] Ms. Kliethermes testified: "If the majority of revenue recovery not directly related to energy occurs in the first block, there is less volatility in revenue recovery – positive or negative – associated with weather variations. Moving revenue recovery to the second and third block will result in a greater level of volatility in revenue recovery and customer bills than is currently experienced due to weather." (Ex No. 201, Kliethermes Rebuttal, p. 5)

structure at all. Dr. Geoff Marke, Regulatory Economist for the Office of the Public Counsel, testified:

> I would venture to say that most Kansas City Power & Light customers have no clue how their blocks are set or how they're being charged for electricity. . . What they won't be surprised by and what will have an impact on their elasticity is an increase to the overall bill." (Tr. 1166)(emphasis added)

179. Mr. Hyman suggested that reasonable minds could differ on whether customers would respond to changes in the block rate structure (Tr. 1255-56). He acknowledged there is a view that they do respond to the total bill as well as average price (Tr. 1256). Given such uncertainties on how customers would react to an IBR structure, the Company would request that the Commission decline to implement an IBR at this time. KCP&L believes additional study is needed before the Commission departs from the traditional declining block rate structure that has existed in various forms for many years (Tr. 827).

180. From the Company's perspective there are various ways to address the IBR proposals in a way that would be collaborative, comprehensive and with more thorough consideration of issues. More information, research, and due diligence is needed. Currently, in the GMO jurisdiction, there are studies underway that are evaluating various rate designs to encourage responsible energy use including IBR, TOU, and other rate designs. The results of these studies could be used to inform possible changes in rate designs in the KCPL-MO jurisdiction that would better explore the impacts of IBR and also review other rate design possibilities that would meet similar goals while still minimizing customer impact and the Company's revenue requirement. The Company would propose the opportunity to fully study this in a similar fashion that is being done in the GMO jurisdiction. This could also be done in

the context of workshop, where all stakeholders could contribute to the discussion to help ensure full consideration of the issues and risks.

181. Given the rate design provisions of the Integrated Resource Plan, Chapter 22 rules and inclusion of these considerations in the DSM Market Potential Study requirement in the MEEIA rules, an IBR proposal could be handled as a MEEIA program, where there's a clear framework for revenue losses that could be addressed through a DSIM or like mechanism. Under this approach, IBR proposals would be something that could be further explored and solidified via a workshop, so all stakeholders could participate and could weigh in on the various ways that such a program could work.

1. Chairman Hall's Tracker Proposal For IBR Structures

182. In his Direct Testimony, Mr. Hyman testified: "The Company would need to use reasonable estimates of the price elasticity of demand for residential customers to adjust the residential general use rates such that they collect revenues at a level of consumption reflecting changes in demand (Ex No. 800, Hyman Direct, p. 22). During cross-examination, Mr. Hyman confirmed that if an IBR was adopted in this proceeding, it would be appropriate to attempt to factor into the ratemaking process the effect of price elasticity on the billing determinants so that the Company could achieve its authorized revenue requirement (Tr. 1245-46). However, he also acknowledged that his IBR structure proposal had not attempted to factor in the price elasticity effects to ensure the Company would recover its revenue requirement if his IBR proposal was adopted by the Commission (Tr. 1246). "And that's why I put in my testimony that we're open to suggestions on that." (Id.).

183. During the hearings, Chairman Hall suggested the possibility that some of the price elastic effects, the Company's concerns about revenue volatility, and the effect of an IBR on earnings might be mitigated by the adoption of a tracker (Tr. 1056-57; 1066; 1253-54; 1261-62; 1268). The Company believes that this is an intriguing proposal that should be explored in the future. The price elastic effect of an IBR may be captured by a tracker that ensures that if there were a shortfall in revenues due to the adoption of the IBR, it would not prevent the Company from recovering the authorized revenues and therefore having a reasonable opportunity to earn its authorized rate of return.

F. Should KCPL be required to propose time-varying rate offerings for residential customers in future cases?

184. For the reasons stated above, KCP&L believes it is premature to require KCP&L to propose time-varying rate offerings for residential customers in future cases. With regard to time-of-use rates, multiple studies are underway within KCP&L and GMO to explore these rates. It is unclear at this time if time-of-use rates are the best way to address peak load issues. KCP&L believes that the Commission should allow these studies to be completed before requiring the Company to offer time-varying rates.

G. How should any increase to Rates LGS and LPS be distributed?

185. With regard to the LGS and LPS rates, MIEC recommended: "Given that the energy charges collect a large amount of fixed costs, the Commission should seek to reduce the energy charges and increase those charges (i.e., customer and demand charges) used to collect fixed costs. As such, MIEC recommends that the Commission maintain the energy charges for the high load factor (over 360 hours use per month, or over a 50% load factor) block at their current levels, increase the middle blocks (hours use from 181 to 360) 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. This includes the customer charge, the reactive demand charge, the facilities charges, the demand charges and the initial block energy charges. (Brubaker Direct, pages 32-33 and Schedules MEB- COS-7 and 8)." (MIEC Position Statement, p. 9)

186. As explained above, KCP&L believes there should be an across the board percentage increase to all rate elements, including the rates of the LGS and LPS class. The Commission should reject the proposals of MIEC to increase the LGS rates and LPS in the manner suggested by MIEC. In recent KCP&L rate cases, the Company settled rate design issues and adopted similar proposals to MIEC's proposal. Unfortunately, it has also experienced significant rate switching by other commercial and industrial customers. MIEC's testimony or rate proposal does not explore the disruption of the relationship between the Large General Service and the Large Power rate groups, leading to the potential rate switching impact of its proposal. In effect, MIEC's proposal recommends increasing the rates of lower load factor customers in Large General Service and Large Power classes, while moderating the increases of the largest high load factor LGS and LPS customers. As a result, if the MIEC proposal were adopted in this case, revenue adjustments would be necessary to take into account the expected rate switching, and otherwise ensure that the Company's rates are properly designed to achieve the authorized revenue requirement. In this case, no such revenue adjustments have been proposed, and KCP&L believes it is inappropriate and unreasonable to adopt MIEC's proposal in this case.

VII. REVENUES

187. This issue sets the foundation for unit sales and sales revenues to be used for setting the Company's rates. Chairman Hall recognized in the hearing on this issue that the Company "is trying to set accurate billing determinants going forward." (Tr. 1708).

A. Should KCP&L be permitted to make an adjustment to annualize kWh sales in this rate case as a result of KCP&L's Missouri Energy Efficiency Investment Act ("MEEIA") Cycle 1 demand-side programs?

1. Proper Ratemaking Requires The Billing Determinants To Be An Accurate Reflection of the Expected Usage in the Year Following The Conclusion of the Rate Case.

188. This issue involves ensuring that the billing determinants are correct and produce the revenues to meet the Company's authorized revenue requirement (Tr. 1661). The Company made an adjustment in its direct filing in this case to reflect the energy efficiency (e.g. MEEIA Cycle 1 and 2 programs) impact on normalized and annualized sales. The Staff has made an annualization adjustment for Cycle 2 energy savings (Tr. 1651), but Staff has not made a similar adjustment in this case to reflect the impact of the MEEIA Cycle 1 programs (Ex No. 143, Rush Rebuttal, p. 12). As a result, Staff is recommending that the Commission overstate the number of KWHs and KWs in the billing determinants in setting rates in this case (Tr. 1704, 1710-11). The Commission should reject Staff's recommendation.

189. KCP&L had twelve active MEEIA Cycle 1 programs which generated energy and demand savings for customers throughout the test period ending December 31, 2015. In addition, pursuant to the MEEIA Cycle 2 Stipulation discussed below, the Company was authorized to extend C&I (Commercial and Industrial) Custom Rebate program for projects that were approved under Cycle 1 through June 30, 2016. This program generated significant

additional customer energy and demand savings during the period between January 1, 2016 and June 30, 2016. Lastly, the Company's MEEIA Cycle 2 programs were approved effective April 1, 2016 and generated energy and demand savings for customers through December 31, 2016 (Ex No. 136, Rush Rebuttal, p. 13). The MEEIA Cycle 1 and 2 both generated permanent energy and demand savings that must be reflected in the billing determinants (Tr. 1652).

190. The specific issue to be resolved by the Commission is: "Whether the reduction in KWH sales that occurred as a result of the MEEIA Cycle I programs should be recognized, and adjusted for in the Company's rates?" (Tr. 1679). Staff has reflected the energy efficiency savings from the MEEIA Cycle 2 programs in its revenue annualization adjustment, but it has not included the MEEIA Cycle 1 programs.

191. For the billing determinants to be accurate and produce the necessary revenues for the Company to have the opportunity to earn its authorized rate of return, it is necessary for both Cycle 1 and Cycle 2 energy and demand savings to be reflected in the billing determinants through the revenue annualization adjustment. Mr. Rush explained at length the reasons the energy efficiency annualization adjustment to test period kWh sales in his rebuttal testimony and during the hearings (Ex No. 143, Rush Rebuttal, p. 14; Tr. 1648-49).

192. In summary, the Company's sales, sales revenues and net system input must be adjusted to reflect actual conditions faced by the Company in the test year and true up period. Adjustments are made to reflect normal weather, customer annualizations (e.g. establish customer levels at a time closer to when rates go into effect) and adjustments for known and measurable changes from the test period, such as customer usage changes not reflected in the weather normalization process. (Tr. 1741) This can include anything from specific customers

whose usage has specifically increased or decreased from the test period to where a new customer was added and the respective changes in load, to an adjustment for energy efficiency. Without this adjustment, the Commission is setting rates based on a level of revenues that is not achievable by the Company. Rates must be set on a level of achievable revenues.

193. These MEEIA energy efficiency programs have been successful. As a result, there has been a permanent reduction in KWH sales which will continue in the future (Tr. 1600). This permanent reduction in energy and demand requires an adjustment to the test year sales because the test year sales do not reflect the expected sales in the year following the effective date of the new rates. In other words, the billing determinants need to reflect the reductions in usage brought about by the MEEIA energy efficiency programs.

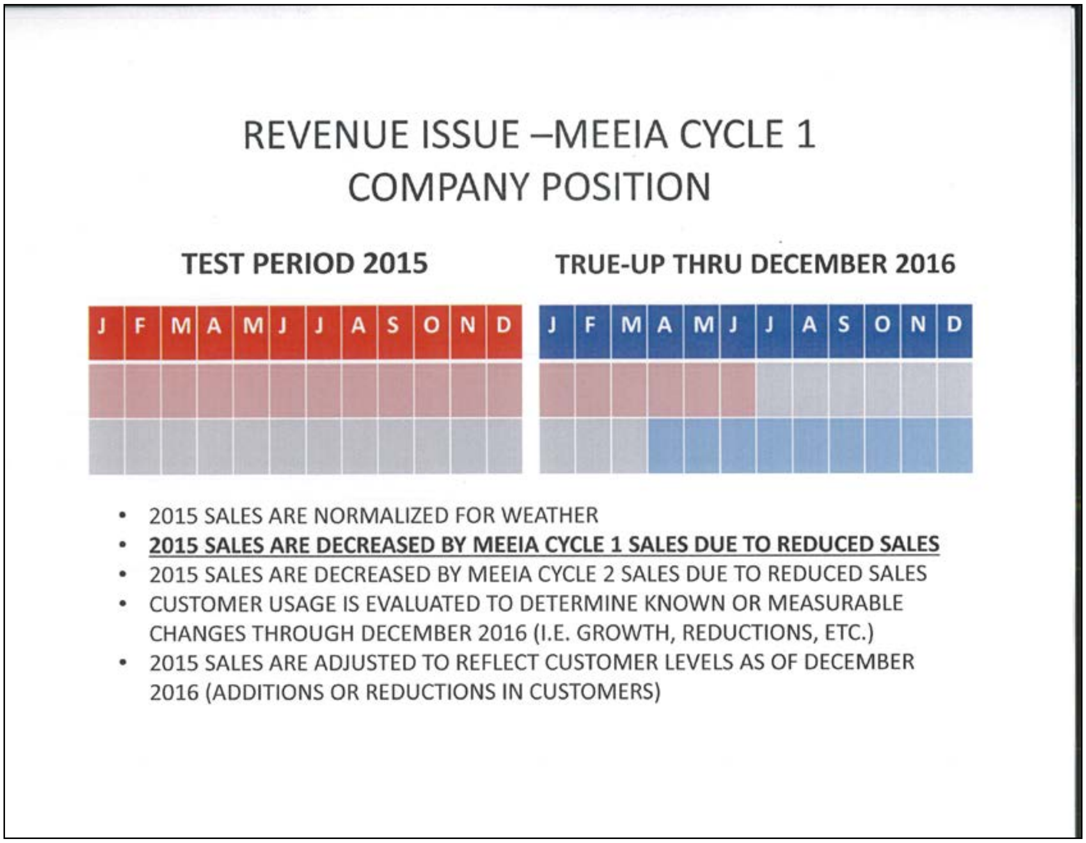
194. As an example, assume that a consumer purchased a high efficiency air-conditioner under the MEEIA Program which reduced the amount of KWHs used by the customer during the test year. This reduced usage as a result of the more efficient air-conditioner is a permanent reduction in load that will continue into the future. A revenue annualization adjustment should recognize that the amount of KWHs in the test year will be reduced in the future by the installation of this high efficiency air conditioner (Tr. 1653).

195. It is no different than making an adjustment because an industrial customer has left the system or making a weather normalization adjustment to reflect the fact that the test year had abnormal weather, either hotter than normal or colder than normal. An adjustment needs to be made to the test year to take such events into account. Otherwise, the Company's rates won't produce the approved revenue requirement.

196. It is also similar to what is discussed above on the inclining block rate design issue. If an inclining block rate is approved, it may produce conservation or reduced usage on KCP&L's system, at least according to the proponents of the inclining block rate structure. If such a reduction in usage would occur, it will need to be accounted for in a tracker mechanism consistent with what is being done under the MEEIA program, and a revenue annualization in the next rate case. Otherwise, the Company's new rates will not produce the expected revenues on a going forward basis (Tr. 1663-65).

197. The point of the revenue annualization adjustment is to develop billing determinants for customer usage levels that adjust the test period for the loss of sales due to the success of the MEEIA programs.

198. In this case, Staff is proposing to annualize the revenues associated with the MEEIA Cycle 2 programs (Tr.1664, 1679), but not the revenues associated with the MEEIA cycle 1 programs (Tr. 1610-13, 1711). As illustrated by a slide used during the Company's opening statement (Tr. 1601-05), the test year in this case is the 12 months ending December 31, 2015 (shown in red), with known and measurable changes projected through and update true-up period of December 31, 2016 (shown in blue). The MEEIA Cycle 1 covered the period of January 2015 through June 2016 (shown in light red). Cycle 2 covered the period of April 2016 through December 2016 (shown in light blue).



199. Staff has taken the 2015 test period revenues and normalized them for weather. Staff also decreased the 2015 test year sales for the MEEIA Cycle 2 savings due to the reduced sales that resulted from the MEEIA Cycle 2 programs. Customer usage is evaluated to determine known and measurable changes through the true-up period of December 2016. Finally, the 2015 Sales are adjusted to reflect customer levels as of December 2016. This is an appropriate adjustment for the MEEIA Cycle 2 programs.

200. However, Staff's approach is incomplete because it ignores the MEEIA Cycle 1 program savings. Under the air-conditioning example, if the customer purchased a high efficiency air conditioner during the MEEIA Cycle 2 period, Staff's adjustment would recognize this permanent reduction in usage. However, if the customer purchased the exact same high

efficiency air-conditioner during the MEEIA Cycle 1 program period, then Staff would not annualize the reduced sales associated with the purchase of this air-conditioner (Tr. 1652-53).

201. The Company's approach is the same as the Staff's approach, except that the Company's adjustment also recognizes that the MEEIA Cycle 1 programs were producing savings during the test period and true-up period. Under the Company's approach, the 2015 sales are decreased for MEEIA Cycle 1 savings as well as the MEEIA Cycle 2 savings. From the Company's perspective, this is the correct, fair and reasonable method of annualizing the MEEIA program savings to capture, on a going forward basis, all of the energy efficiency savings:

> [Fischer] Q: From a public policy standpoint, is there any reason why Cycle 1 and Cycle 2 would be treated differently, putting aside our disagreements about the stipulation?
>
> [Rush]: A: <u>From a policy perspective, I see no difference</u>….

202. The evidence demonstrates that the test year and the true-up period include both MEEIA Cycle 1 and Cycle 2 program savings. From the Company's perspective, it is important to reflect energy efficiency savings from both Cycle 1 and Cycle 2 programs in the billing determinants. Staff apparently does not disagree with the overall theory that the test year revenues should be adjusted for the loss of revenues related to energy efficiency programs. However, Staff is ignoring the MEEIA Cycle 1 program savings in its revenue annualization adjustment in this case. Under Staff's approach, the MEEIA Cycle 1 savings shown in the light red row on the above table would be excluded from the revenue annualization adjustment. Company disagrees with this treatment of the MEEIA Cycle 1 savings, and strongly recommends

that all energy and demand savings, including both MEEIA Cycle 1 and MEEIA Cycle 2 programs, be reflected in the adjustment to the billing determinants.

203. Even Staff witness Rogers candidly admitted during cross-examination that if the Staff's position is adopted, the billing determinants will not be correct or accurate:

> [Woodsmall]: Q. And if Staff's adjustment is accepted, will billing determinants be accurate going forward?
>
> [Rogers]: A. <u>They'll actually be a little bit higher than they should be</u>. But again, that is an outcome of the Cycle 1, the MEEIA Cycle 1 Stipulation & Agreements and the MEEIA Cycle 2 Stipulation & Agreements (<u>emphasis added</u>).

204. If Staff's position is adopted by the Commission, the billing determinants will be more than "a little bit higher than they should be." In fact, if the Staff's position is adopted, then 100,662,532 KWHs of reduced usage associated with MEEIA Cycle 1 programs will not be annualized, and as a result this permanent reduction in usage will not be reflected in the billing determinants and the new rates (Ex No. 143, Rush Rebuttal, Schedule No. TMR-7; Tr. 1635-37). This is the equivalent of about 1% of the Company's total Missouri sales. It will mean a loss of approximately $6.6 million in revenues to KCP&L on an ongoing basis (<u>Id</u>.).

205. For the reasons stated herein, the Commission should adopt the Company's revenue annualization approach which includes both Cycle 1 and Cycle 2 programs in the billing determinants.

2. The Non-Unanimous Stipulation and Agreement In Case No. EO-2015-0240 ("MEEIA Cycle 2 Stipulation") Requires A Revenue Annualization of All Active MEEIA Programs, Including Both Cycle 1 and Cycle 2 Programs.

206. Staff's opposition to the Company's MEEIA Cycle 1 annualization adjustment does not rest on traditional ratemaking principles since such revenue annualization adjustments have long been the standard practice in the Missouri (Tr. 1662-63). Instead, Staff's position in this case is based upon an incorrect interpretation of the stipulations in Case Nos. EO-2015-0240, EO-2014-0095 and two related KCP&L tariffs which defined the annualization process in detail (Ex. No. 225, Rogers Surrebuttal, pp. 2-11). This section of KCP&L's brief will review the legal arguments brought forth by Staff in opposition to KCP&L's inclusion of both Cycle 1 and Cycle 2 programs in the billing determinants and demonstrate that Staff's interpretation is flawed.

(a) <u>MEEIA Cycle 2 Stipulation</u>

207. On November 23, 2015, the Staff, KCP&L, GMO, Public Counsel, the Missouri Division of Energy, Renew Missouri, Natural Resources Defense Council, National Housing Trust, and West Side Housing Organization, filed a *Non-Unanimous Stipulation And Agreement Resolving MEEIA Filings ("Cycle 2 Stipulation")* in which those signatory parties reached agreement on all issues related to the Company's Cycle 2 MEEIA programs and the associated demand-side programs investment mechanism. The Commission approved the MEEIA Cycle 2 Stipulation, after hearing, on March 2, 2016, and ordered the signatory parties to comply with the terms of the stipulation (*Report And Order*, pp. 16-17, Re: Kansas City Power & Light Company, Case No. EO-2015-0240 (March 2, 2016)).

208. Under the Cycle 2 Stipulation, the Company was entitled to recover its program costs, its Throughput Disincentive (a/k/a lost margins), and an Earnings Opportunity Award (See Cycle 2 Stipulation, pp. 10-11).

209. Paragraph 10 of the Cycle 2 Stipulation also requires a revenue annualization adjustment for all active MEEIA programs, excluding Home Energy Reports and Income-Eligible Home Energy Reports, determined using the same methodology as set forth in KCP&L's tariffs:

> 10. Annualizations. Upon filing a rate case, the cumulative, annualized, normalized kWh and kW savings will be included in the unit sales and sales revenues used in setting rates as of an appropriate time (most likely two months prior to the true-up date) where actual results are known prior to the true-up period, to reflect energy and demand savings in the billing determinants and sales revenues used in setting the revenue requirements and tariffed rates in the case. Upon the adjustment for kWh and kW savings in a rate case, the collection of TD will be re-based.
>
> * * *
>
> b. The Adjusted test period sales from above will be annualized for customers and additionally be adjusted further by:
>
> (i) Subtracting the cumulative annual kWh energy savings from the first month of the test period through the month ending where actual results are available (most likely two months prior to the true-up date) by customer class from <u>all active MEEIA programs</u>, excluding Home Energy Reports and Income-Eligible Home Energy Reports, determined <u>using the same methodology as described in Tariff Sheet 49K and 49L (KCP&L)</u> . . . except that calendar month load shape percentages by program by month are converted to reflect billing month load shape percentages by program by computing a weighted average of the current and succeeding month percentages (Cycle 2 Stipulation, pp. 13-14)(<u>emphasis added</u>).

210. During the hearings, Mr. Rush explained the purpose of Paragraph 10 in more detail as follows:

> Paragraph [10]…is designed to simply say, when we file a rate case, we are to deal with a cumulative, annualized, normalized kilowatt hours in kW savings will be included in the unit sales and sales revenues used in setting rates. So it is telling us that we're going to make an adjustment to reflect the cumulative, annualized, normalized sales for that -- for the setting of rates.

211. In this rate case proceeding, KCP&L has made the annualization adjustment for <u>all active MEEIA programs</u>, including both Cycle 1 and Cycle 2, using the same methodology for all active MEEIA programs in the test period and true-up update period as required by the Cycle 2 Stipulation (Tr. 1700-01).

212. Staff witness John Rogers attempted to justify Staff's interpretation of the Cycle 2 Stipulation provisions (Ex No. 225, pp. 2-11; Tr. 1683-1713). However, it was apparent that there is no logical foundation for Staff's interpretation, and it improperly and unfairly ignores 100 million kwhs of savings that resulted from the MEEIA Cycle 1 programs during the test year and true-up period in the Staff's determination of the billing determinants in the case.

213. During cross-examination, Staff witness John Rogers confirmed that Staff agrees that both Cycle 1 and Cycle 2 programs were active and ongoing MEEIA programs during the test year and update period of this case (Tr. 1689):

> [Fischer}: Q. Is it correct that there would be both MEEIA Cycle 1 and MEEIA Cycle 2 program savings during the period of January 2015 through the true-up ending December 31st, 2016?
>
> [Rogers]: A. Yes.

[Fischer]: Q. And there's no question in your mind that MEEIA Cycle 1 programs were ongoing during that test year period, right?

[Rogers]: A. Correct.

[Fischer]: Q. And the MEEIA Cycle 2 programs were also active in the test year and the update period that ended December 31st, 2016, correct?

[Rogers]: A. Only for the update period.

214. Notwithstanding the fact that Staff agreed that both Cycle 1 and Cycle 2 Programs were <u>all active MEEIA programs</u> during the test year and update period, Staff excluded the Cycle 1 savings from the Staff's annualization adjustment. Staff witness Rogers asserted that the term "all active programs" is limited to MEEIA Cycle 2 programs, and does not include MEEIA Cycle 1 programs (Ex No. 225 Rogers Rebuttal, pp. 2-3). However, Staff is incorrect in its assertion.

215. First, Staff asserted that "The language 'all active MEEIA programs' occurs exactly four (4) times in the Cycle 2 Stipulation and all four (4) occurrences are in paragraph 10: <u>Annualizations</u> of the Cycle 2 Stipulation." (<u>Id</u>. at 2). However, the fact that the term "all active MEEIA programs" appears four times in the Annualization paragraph does nothing to indicate that "all active MEEIA programs" does not include all active MEEIA programs including those in Cycle 1.

216. According to Mr. Roger's interpretation, "all active programs" means only Cycle 2 active programs (Tr. 1696-97). However, during cross-examination, he was unable to point to any provision in the Cycle 2 Stipulation that states that "all active programs" does not include the active MEEIA Cycle 1 programs (Tr. 1697). In fact, he agreed with Chairman Hall that "You

have to admit, if you could do this over, you would put all active MEEIA 2 programs instead of just all active programs" (Tr. 1712) in paragraph 10 of the Cycle 2 Stipulation. Rogers' agreement with the Chairman's question shows that Staff's interpretation of the meaning of "all active programs" is strained.

217. Second, Mr. Rogers notes that Paragraph 10(a)(i) of the Cycle 2 Stipulation clearly specifies that the various steps to annualize kWh sales for "all active MEEIA programs" is the methodology in KCPL's Tariff Sheets 49K and 49L (Ex No. 225 Rogers Rebuttal, p. 2). KCP&L agrees that this provision of the Cycle 2 Stipulation specifies the methodology that is to be used for the annualization of "all active MEEIA programs." This is the same methodology that KCP&L used for the active MEEIA programs, including both Cycle 1 and Cycle 2 MEEIA programs, and Staff has not disputed the accuracy of KCP&L's annualization methodology. This provision, however, does nothing to limit the term "all active programs" to mean only "all active Cycle 2 MEEIA programs".

218. Third, Mr. Rogers points to Tariff Sheets 49K and 49L and notes that these tariff sheets refer to "programs", "all programs" or "Cycle 2 programs" and does not use the phrase "all active programs," "all active MEEIA programs" or "Cycle 1 programs." While Mr. Rogers may be correct, this fact does not in any way limit the term "all active MEEIA programs" in Paragraph 10 of the Cycle 2 Stipulation to mean only "all active MEEIA Cycle 2 programs" as Mr. Rogers suggests.

219. Fourth, Mr. Rogers notes that KCP&L's Tariff Sheet 49L which describes the calculation of KCP&L's Cycle 2 Throughput Disincentive defines the programs are applicable to the Cycle 2 Throughput Disincentive calculation as "MEEIA Cycle 2 programs listed in Tariff

Sheet No. 1.04C." Again, this is quite logical since only MEEIA Cycle 2 programs are included in the calculation of the Cycle 2 Throughput Disincentive calculation. As Mr. Rogers has pointed out, the calculation of the Cycle 2 Throughput Disincentive is somewhat different that the Cycle 1 Stipulation's calculation of the TD-NSB (Throughput Disincentive-Net Shared Benefits). However, this provision again does not define the term "all active MEEIA programs" contained in Paragraph 10 of the Cycle 2 Stipulation to mean only "all active MEEIA Cycle 2 programs".

220. Finally, Mr. Rogers points to the KCP&L Tariff Sheet No. 1.04C where there is a listing of the MEEIA Cycle 2 programs. However, this tariff sheet does not define "all active MEEIA programs in Paragraph 10 to mean these MEEIA Cycle 2 programs. It only identifies what programs are considered MEEIA Cycle 2 Programs.

221. None of the provisions in the Cycle 2 Stipulation, or KCP&L tariffs that Staff is relying upon in any way indicate that the term "all active MEEIA programs" in Paragraph 10 of the Cycle 2 Stipulation means that the annualization required by the paragraph is applicable to only Cycle 2 MEEIA programs, as asserted by Staff.

(b) MEEIA Cycle 1 Stipulation

222. Staff also discusses provisions from the *Non-Unanimous Stipulation and Agreement* in Re: Kansas City Power & Light Company's MEEIA Filing, Case No. EO-2014-0095 (filed on May 27, 2014)("Cycle 1 Stipulation") to support its position on this issue (Ex No. 225, Rogers Surrebuttal, pp.5-9). According to Staff, "KCPL's Cycle 1 TD-NSB Share was agreed to as a part of the Cycle 1 Stipulation and is designed to compensate KCPL for the entire

amount of KCP&L's throughput disincentive due to Cycle 1's deemed measures without any annualization of kWh sales in its general rate cases." (Id. at 9).

223. Fundamentally, Staff is conflating or confusing the recovery of MEEIA-related costs (i.e. program costs, throughput disincentive, and earnings opportunity) with a proper annualization of energy and demand savings from all active MEEIA programs in the test year and true-up update period to ensure the billing determinants in this case are accurate and will produce the revenues authorized in this case on a going forward basis. The calculation of the TD-NSB Share is not the same as determining the appropriate billing determinants for establishing new rates in this case.

224. As Chairman Hall accurately observed in the hearing (Tr. 1707), KCP&L is not trying to recover its MEEIA-related costs through the proposed revenue annualization adjustment. Instead, KCP&L is attempting to develop accurate billing determinants for establishing rates to ensure that the expected revenues will be produced from the new rates.

225. In any event, the Cycle 1 Stipulation at page 2 specifically stated: "This Stipulation is solely the result of compromise in the settlement process and does not serve as precedent beyond this particular 18-month Plan." While Staff may certainly describe the differences between the Cycle 1 and Cycle 2 stipulations, it is improper to rely upon any provisions of the Cycle 1 Stipulation as precedent for restricting the development of appropriate billing determinants for setting rates in this case.

226. In conclusion, if the Staff position is adopted by the Commission, more than half of the energy efficiency savings from the Company's MEEIA programs will be excluded, and the billing determinants will not produce the revenue requirement that will be authorized by the

Commission in its final order. For all of the foregoing reasons, the Commission should adopt the Company's revenue annualization adjustment which annualizes "all active MEEIA programs" including both Cycle 1 and Cycle 2 MEEIA programs using the same methodology described in KCP&L tariffs.

B. How should the Large Power class kW demand billing units be adjusted when a customer leaves the Large Power class?

227. The Company believes that this issue is no longer a contested issue with Staff, and therefore is not be an issue that needs to be resolved by the Commission.

C. How should customers who left the Large Power class and switched into the Large General Service and Medium General Service classes be annualized?

228. The Company believes that this issue is no longer a contested issue with Staff, and therefore is not be an issue that needs to be resolved by the Commission.

D. What methodology should be utilized to measure customer growth?

229. The Company believes this issue is no longer a contested issue with Staff, and therefore is not be an issue that needs to be resolved by the Commission.

VIII. CUSTOMER EXPERIENCE—IS KCP&L'S STRATEGY WITH RESPECT TO CUSTOMER SERVICE, CUSTOMER EXPERIENCE AND COMMUNITY INVOLVEMENT IN THE INTEREST OF ITS CUSTOMERS?

230. KCP&L's customer service and its commitment to its customers are addressed at length in the Direct and Surrebuttal Testimony of Charles A. Caisley (Ex Nos. 111HC and 112HC). No specific revenue requirement issues were raised by Public Counsel related to this testimony. However, during opening statements, the Public Counsel recommended that the Company refrain from asking "political" questions on its surveys of its customers, or alternatively, that the non-regulated operations benefiting from the poll answers should compensate the utility, which can be used as revenues to benefit the customers." (Tr. 1576).

During the hearing, Public Counsel's witness also raised objections about the specific polling firms utilized by KCP&L (Tr. 1595).

231. Such suggestions are beyond of the statutory authority of the Commission to adopt. The Commission should not attempt to regulate the free speech of regulated public utilities with their customers, or of third-party polling firms which are hired to assess the concerns of KCP&L's customers. Certainly, any order attempting to dictate what polling firms may or may not be utilized for such customer surveys would also improperly cross the line into the management of the public utility. *See State ex rel. Harline v. Public Service Commission*, 343 S.W.2d 177, 181 (Mo. App. 1960).[27]

232. The Company believes that the approach suggested by Chairman Hall is an acceptable resolution of this issue. Chairman Hall indicated that he believed that customer surveys are a responsible way for utilities to better understand customers on issues related to service issues but also felt that a very small number of the survey questions were not related to customer service and therefore the cost of those questions should not be paid by ratepayers. (Tr. 1504). The Company agrees with this approach and will make such an adjustment in future rate cases (Tr. 1505).

[27] In the *Harline* decision, the Missouri Court of Appeals explained this important principle: The utility's ownership of its business and property includes the right to control and management, subject, necessarily to state regulation through the Public Service Commission. The powers of regulation delegated to the Commission are comprehensive and extend to every conceivable source of corporate malfeasance. Those powers do not, however, clothe the Commission with the general power of management incident to ownership. The utility retains the lawful right to manage its affairs and conduct its business as it may choose, as long as it performs its legal duty, complies with lawful regulation and does no harm to the public welfare. Id. at 181.

IX. CONCLUSION

233. The issues that remain in these cases to be resolved by the Commission will have a large impact upon the Company and their customers. As discussed above, cost of capital, FAC, depreciation, rate design and revenues are issues that will have a substantial impact upon the financial health of the Company. The EV charging station issue may largely determine if KCP&L makes further investments into the EV market, and as a result, may substantially impact the pace of development of that EV market.

234. The Companies believe that competent and substantial evidence on the record as a whole supports their position on the issues as described above. Resolution of these issues as the Company proposes will lead to just and reasonable rates that properly balance the interests of shareholders and customers, and that give the Companies an opportunity to earn a reasonable rate of return following the conclusion of the case.

Respectfully submitted,

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CERTIFICATE OF SERVICE

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

/s/ Roger W. Steiner

Roger W. Steiner

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