COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

Application of Kentucky Utilities	**)**	
Company for an Adjustment of its Electric	**)**	**Case No. 2016-00370**
Rates and for Certificates of Public	**)**	
Convenience And Necessity	**)**	

DIRECT TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF THE

KENTUCKY OFFICE OF THE ATTORNEY

GENERAL

MARCH 3, 2017

PUBLIC REDACTED VERSION

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Appendix and Exhibits*

* Note: Exhibits RCS-2 and RCS-12 are not used for Kentucky Utilities Company. The other exhibit numbering is used for consistency with Case No. 2016-00371, the concurrent rate case for Louisville Gas & Electric Company.

I. INTRODUCTION AND STATEMENT OF QUALIFICATIONS

Q. Please state your name, position, and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Please describe Larkin & Associates.

A. Larkin & Associates, PLLC ("Larkin") is a Certified Public Accounting and Regulatory Consulting firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin has extensive experience in the utility regulatory field as expert witnesses in over 400 regulatory proceedings including numerous telephone, water and sewer, gas, and electric matters.

Q. Mr. Smith, please summarize your educational background.

A. I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan - Dearborn, in April 1979. I passed all parts of the Certified Public Accountant ("C.P.A.") examination in my first sitting in 1979, received my CPA license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. In addition, I have attended a variety of continuing education courses in conjunction with maintaining my accountancy license. I am a licensed C.P.A. and attorney in the State of Michigan.[1] I am also a Certified Financial Planner™ professional and a Certified Rate of Return Analyst

[1] My testimony in this proceeding is as a Senior Regulatory Consultant, and I am not offering any legal opinions.

("CRRA"). Since 1981, I have been a member of the Michigan Association of Certified Public Accountants. I am also a member of the Michigan Bar Association. I have been a member of the Society of Utility and Regulatory Financial Analysts ("SURFA"), and the American Bar Association (ABA), and the ABA sections on Public Utility Law and Taxation.

Q. Please summarize your professional experience.

A. Subsequent to graduation from the University of Michigan, and after a short period of installing a computerized accounting system for a Southfield, Michigan realty management firm, I accepted a position as an auditor with the predecessor CPA firm to Larkin & Associates in July 1979. Before becoming involved in utility regulation where the majority of my time for the past 37 years has been spent, I performed audit, accounting, and tax work for a wide variety of businesses that were clients of the firm.

During my service in the regulatory section of our firm, I have been involved in rate cases and other regulatory matters concerning electric, gas, telephone, water, and sewer utility companies. My present work consists primarily of analyzing rate case and regulatory filings of public utility companies before various regulatory commissions, and, where appropriate, preparing testimony and schedules relating to the issues for presentation before these regulatory agencies.

I have performed work in the field of utility regulation on behalf of industry, state attorneys general, consumer groups, municipalities, and public service commission staffs concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Indiana, Illinois, Kansas, Kentucky, Louisiana, Maine, Maryland, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, Washington D.C., West Virginia, and Canada as well as the Federal Energy Regulatory Commission and various state and federal courts of law.

Q. Have you previously testified before the Kentucky Public Service Commission ("PSC" or "Commission")?

A. Yes. For example, I testified in a Kentucky American Water Company rate case, Case No. 2010-00036 and in a Kentucky Power Company rate case, Case No. 2014-00396.

Q. Have you previously performed analysis on rate case issues where testimony was submitted by other members of Larkin before the Kentucky Public Service Commission?

A. Yes. Several years ago, I worked on various Kentucky rate cases as a regulatory analyst where testimony was submitted before the Commission by other Larkin professionals, such as Hugh Larkin, Jr.

Q. Have you previously testified before other state public utility regulatory commissions?

A. Yes, I have testified before other state public utility regulatory commissions on many occasions.

Q. Have you prepared an attachment summarizing your educational background and regulatory experience?

A. Yes. Appendix A provides details concerning my experience and qualifications.

II. LIST OF EXHIBITS

Q. Have you prepared any exhibits to accompany your testimony?

A. Yes. I have prepared Exhibits RCS-1, RCS-3 through RCS-11 and RCS-13 through RCS-16, which are attached to my testimony. Exhibit RCS-2 and Exhibit RCS-12, which were exhibits used in my testimony for Louisville Gas and Electric Company's ("LG&E" concurrent rate case (Case No. 2016-00371), are not being used for Kentucky Utilities. We have attempted to be as consistent as feasible with the numbering of my exhibits in the LG&E and KU rate cases, where the same exhibit number in each case contains similar information.

Q. Please briefly explain what is contained in each of those exhibits.

A. Exhibit RCS-1 presents Accounting and Revenue Requirement Schedules.

Exhibit RCS-3 presents the Company's responses to data requests referenced in testimony related to Construction Slippage.

Exhibit RCS-4 contains the Company's responses to data requests referenced in testimony related to Distribution Automation.

Exhibit RCS-5 contains the Company's responses to data requests referenced in testimony related to Cash Working Capital.

Exhibit RCS-6 contains the Company's responses to data requests referenced in testimony related to Advanced Metering Systems cost included in the forecasted test year.

Exhibit RCS-7 contains the Company's non-confidential responses to data requests referenced in testimony related to Incentive Compensation Expense.

Exhibit RCS-8 contains the Company's responses to data requests referenced in testimony related to Transmission Vegetation Management Expense.

Exhibit RCS-9 contains the Company's responses to data requests referenced in testimony related to Uncollectibles.

Exhibit RCS-10 contains the Company's responses to data requests referenced in testimony related to Vacant Positions and Salary Differentials for Replacing Employees.

Exhibit RCS-11 contains the Company's responses to data requests referenced in testimony related to Administrative Expense Charges from the affiliate, PPL Service Corporation.

Exhibit RCS-13 contains the Company's responses to data requests referenced in testimony related to Regulatory Asset Amortizations.

Exhibit RCS-14 contains the Company's responses to data requests referenced in testimony related to the Amortization Period for the Remaining Net Book Value of Retired Meters that Would Be Replaced with New AMS Meters.

Exhibit RCS-15 contains the Company's responses to data requests referenced in testimony related to Off-System Sales Margin Sharing.

Exhibit RCS-16 contains the Company's responses to data requests referenced in testimony related to affiliated charges from LG&E and KU Service Company.

III. SCOPE AND PURPOSE OF TESTIMONY

Q. What is the scope and purpose of your testimony?

A. Larkin was engaged by the Office of Rate Intervention of the Kentucky Office of Attorney General ("AG") to conduct a review and analysis and present testimony regarding rate base, operating income and revenue requirement aspects of the filing.

The purpose of my testimony is to present to the Commission the appropriate test period rate base, overall rate of return and utility operating income, as well as the appropriate overall revenue requirement and rate increase for the Company in this proceeding.

Q. Have you incorporated the recommendations of other AG witnesses?

A. Yes. In the determination of the AG's recommended overall revenue requirement and revenue increase, I have relied on and incorporated the recommendations of AG witness Dr. J. Randall Woolridge concerning the appropriate capital structure ratios, cost rates for short and long term debt, and common equity, and the resulting overall rate of return for the Company in this proceeding. I have also incorporated the recommendations of AG witness Larry Holloway and Paul Alvarez. Mr. Holloway is addressing some of the Company's projected construction projects for the electric utility, including Distribution Automation. Mr. Alvarez is addressing the Company's request for Advanced Metering Systems ("AMS").

Q. What information did you review in preparing your testimony?

A. In developing this testimony, I have reviewed and analyzed the Company's November 23, 2016 filing, supporting testimonies, exhibits, filing requirements and workpapers; the

Company's responses to initial and follow-up data requests by the PSC Staff, AG and other intervenors; selected case material; and other relevant financial documents and data, as well as the recommendations provided to me by other AG consultants.

IV. SUMMARY OF COMPANY'S REQUEST

Q. When were the Company's base rates last re-set?

A. Kentucky Utilities Company ("Kentucky Utilities", "KU", or "Company") filed its last rate case in 2014 in Case No. 2014-00371. KU's current base rates for electric service were approved by the Commission in its Order dated June 30, 2015, in that case.

Q. What base period and test period is the Company using?

A. KU's requested revenue increase is based on operating results for the base year ended February 28, 2017 and a test year that uses the forecasted 12-month period ended June 30, 2018.

Q. What amount of base rate revenue increase is the Company requesting for electric utility service?

A. KU is requesting an increase in its base rates for electric utility service of $103.098 million over the test year adjusted base rate revenues of $1.485 billion, resulting in total annual Company revenues of $1.588 billion, for an increase of approximately 6.94%.

Q. What cost of capital and return on equity is the Company requesting?

A. The Company is requesting a test year weighted cost of capital of 7.29% and a proposed return on equity ("ROE") of 10.23%. The capitalization that the Company has requested has been reproduced on Exhibit RCS-1, Schedule D.

V. SUMMARY OF FINDINGS AND CONCLUSIONS

Q. Please summarize your findings and conclusions for electric utility service in this case.

A. I have reached the following findings and conclusions in this case concerning KU's electric utility revenue requirement:

1. The appropriate jurisdictional capitalization for its electric operations in this proceeding amounts to $3.603 billion, which is approximately $35.496 million lower than the Company's proposed capitalization of $3.639 billion, as shown on Exhibit RCS-1, Schedule A, line 1 and on Schedule D.

2. The appropriate jurisdictional test period rate base for its electric operations amounts to approximately $3.770 billion, which is approximately $35.496 million lower than the Company's proposed test period rate base of $3.805 billion, as shown on Exhibit RCS-1, Schedule B, line 18.

3. The AG's expert rate of return witness, Dr. Woolridge, has recommended a return on equity of 8.75%, and an overall rate of return of 6.34% for its electric operations. In contrast, KU has requested an overall rate of return of 7.29%, including a return on equity of 10.23%, as shown on Exhibit RCS-1, Schedule A, line 2, and on Schedule D.

4. The appropriate test period utility operating income for its electric operations amounts to approximately $213.33 million, which is approximately $10.82 million higher

than the Company's proposed test period utility operating income of $202.51 million, as shown on Exhibit RCS-1, Schedule A, page 1, line 4 and on Schedule C.

5. To calculate the base rate revenue increase, I used a gross revenue conversion factor ("GRCF") of 1.641605, as shown on Exhibit RCS-1, Schedule A-1. This differs from the GRCF used by KU of 1.642132, due to my use of a more updated Uncollectibles factor.[2]

6. The application of the recommended overall rate of return of 6.34% to the recommended capitalization of approximately $3.603 billion produces a required return of approximately $228.61 million, as shown on Exhibit RCS-1, Schedule A, column B, line 3. Compared to the adjusted net operating income of approximately $213.33 million, this represents a deficiency of approximately $15.28 million, as shown on Exhibit RCS-1, Schedule A, page 1, column B, line 5. Applying the GRCF of 1.641605 indicates that the Company has an annual base rate revenue requirement excess of approximately $25.09 million, as shown on Exhibit RCS-1, Schedule A, column B, line 7. As shown on Exhibit RCS-1, Schedule A, page 1, column C, line 7, this represents a difference of approximately $78.01 million versus the Company's proposed annual base rate revenue deficiency of $103.098 million.

7. The total base rate revenue increase of approximately $25.09 million is an overall increase of 1.69 percent over adjusted revenue at current rates of approximately $1.485 billion, as shown on Exhibit RCS-1, Schedule A, line 11.

[2] As described in my testimony, and shown on Exhibit RCS-1, Schedule A-1 and Schedule C-5, the recommended Uncollectibles factor is based on a five-year average for 2012-2016, whereas the Uncollectibles factor used by the Company is based on a five-year average for 2011-2015.

VI. ORGANIZATION OF ACCOUNTING SCHEDULES FOR BASE RATE REVENUE REQUIREMENT (EXHIBIT RCS-1)

Q. How are the AG's accounting schedules organized?

A. The AG's accounting and revenue requirement schedules used to determine KU's electric utility base rate revenue requirement are presented in Exhibit RCS-1.

In that exhibit, the accounting schedules are organized into summary schedules and adjustment schedules.

For the electric utility revenue requirement, in Exhibit RCS-1, the summary schedules consist of Schedules A, A-1, B, B.1, C, C.1 and D. Exhibit RCS-1 also contains rate base adjustment Schedules B-1 through B-4 and net operating income adjustment Schedules C-1 through C-11.[3]

Q. What is shown on Schedule A, page 1, of Exhibit RCS-1?

A. As noted above, Exhibit RCS-1 presents the AG Accounting Schedules and revenue requirement determination for KU. Schedule A presents the overall financial summary, giving effect to all the adjustments I am recommending in my testimony, including the recommendations of the other AG witnesses that affect the determination of the utility base rate revenue requirement.

Schedule A presents the change in the Company's gross revenue requirement needed for the Company to have the opportunity to earn the AG's recommended rate of return on the adjusted rate base. The adjusted capitalization base and operating income amounts are taken from Schedules D and C, respectively. The overall rate of return on the

[3] Note that Schedule C-10 is not being used for KU. The schedule numbering in Exhibit RCS-1 is consistent with the numbering used in the concurrent LG&E rate case, Case No. 2016-00371.

adjusted capitalization is presented in the direct testimony of AG witness Woolridge, and is also summarized on Exhibit RCS-1, Schedule D.

Column A of Schedule A replicates KU's proposed calculations of its overall revenue deficiency. Column B of Schedule A presents the AG's determination of the base rate revenue deficiency. Column C shows the differences between KU's request and the AG's recommendation.

The operating income deficiency shown on line 5 of Schedule A is obtained by subtracting the adjusted operating income on line 4 (adjusted operating income) from the required operating income on line 3. Line 7 represents the gross revenue requirement deficiency, which is obtained by multiplying the income deficiency by the Gross Revenue Conversion Factor ("GRCF").

Q. What is shown on Exhibit RCS-1, Schedule A, page 2?

A. Exhibit RCS-1, Schedule A, page 2, presents a reconciliation of the base rate revenue requirement and shows the approximate impact on the utility's revenue requirement of each adjustment.

Q. What is shown on Schedule A-1 of Exhibit RCS-1?

A. Schedule A-1 shows the GRCF that I used to convert the net operating income deficiency into a revenue deficiency amount. For purposes of this case, I have used a different GRCF than was used in KU's filing. As noted above, this is due to my use of a more updated Uncollectibles factor.

Q. What is shown on Exhibit RCS-1, Schedule B?

A. Schedule B presents KU's proposed adjusted test year rate base and the AG's adjusted test year rate base. The beginning rate base amounts presented on Schedule B are taken from the Company's filing for the test year, specifically Schedule B-1.1, page 3 of 4. My recommended adjustments to rate base are summarized on Exhibit RCS-1, Schedule B.1, and are shown on Schedule B, page 1, column B. My adjusted rate base for KU is shown on Exhibit RCS-1, Schedule B, page 1, column C.

Q. What is shown on Exhibit RCS-1, Schedule B.1?

A. Exhibit RCS-1, Schedule B.1 presents a summary of my recommended rate base adjustments.

Q. What is shown on Exhibit RCS-1 on Schedules B-1 through B-4?

A. Schedules B-1 through B-4 provide further support and calculations for the rate base adjustments I and other AG witnesses are recommending.

Q. What is shown on Exhibit RCS-1, Schedule C?

A. The starting point on Exhibit RCS-1, Schedule C is KU's adjusted test year net operating income, as provided on Schedule C-1 from the Company's filing. The Company's proposed operating income for the test year is shown in column A of my Exhibit RCS-1, Schedule C. The AG's adjustments are shown in column B. The AG-adjusted results at current rates for the test year are shown in column C. The components of the revenue change are shown in column D, and the adjusted jurisdictional base rate revenue requirement is shown in column E.

Q. What is shown on Exhibit RCS-1, Schedule C.1?

A. Recommended adjustments to KU's adjusted test year revenues and expenses are summarized on Schedule C.1. These include my recommendations and recommendations of other AG witnesses. Each of the adjustments is discussed in my testimony.

Q. What is shown on Exhibit RCS-1 on Schedules C-1 through C-11?

A. Schedules C-1 through C-9 and C-11 provide further support and calculations for the net operating income adjustments I and other AG witnesses are recommending.[4] Each of the adjustments to operating revenues and expenses is discussed in my testimony and is shown on a separate "C" schedule.

Q. What is shown on Exhibit RCS-1, Schedule D?

A. Schedule D, page 1, summarizes the capital structure and cost of capital that is being proposed by KU and the AG-adjusted capital structure and cost of capital that is recommended by AG witness Woolridge.

Q. What is shown on Exhibit RCS-1, Schedule D, pages 2 and 3?

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[4] Schedule C-10 is not being used for KU.

A. Schedule D, page 2, of Exhibit RCS-1, in part I replicates the Company's calculation of its proposed jurisdictional capitalization.[5] Schedule D, page 2, in part II, shows the AG-adjusted capitalization, and applicable cost rates.

Schedule D, page 3, presents the derivation of the AG's adjusted capitalization showing the impact on capitalization of AG adjustments to rate base. Put another way, page 3 of Schedule D reflects the impacts of my recommended rate base adjustments on the Company's jurisdictional capitalization, as well as Dr. Woolridge's recommended reapportionment of the capitalization to reflect his recommended 50/50 debt/equity capital structure for the utility.

VII. RATE BASE

Q. What adjustments are you recommending to KU's requested rate base?

A. I am recommending each of the following adjustments to KU's rate base, as discussed below.

B-1, "Slippage Factor" Adjustment to Plant and CWIP

Q. Please explain the "Slippage Factor" Adjustment.

A. As part of the capital budgeting process, utilities will estimate the level of capital construction that will be undertaken during the year. Because of delays, weather conditions, or other events, the actual level of construction will often vary from the level budgeted. The difference between the actual and budgeted levels is reflected in the calculation of a "slippage factor," which serves as an indicator of the utility's accuracy in predicting the cost of its utility plant additions and when new plant will be placed into

[5] KU's proposed jurisdictional capitalization is reflected in Schedule J-1.1/J-2.2, page 1 from its filing.

service. The Commission has routinely applied a slippage factor in the forward-looking test period rate cases for the utilities it regulates.[6] The Commission has usually utilized a slippage factor calculated by determining the annual slippage during the most recent 10-year period and then calculating the mathematic average of the annual slippage factors. The slippage factor is normally applied to the utility plant in service balance and the construction work in progress ("CWIP") balance to determine the slippage adjustment.

In its application, the Company did not calculate a slippage factor or recognize a slippage adjustment in its determination of the jurisdictional rate base or the jurisdictional rate base ratio. In response to data requests, the Company did calculate 10-year slippage factors for its electric operations.[7]

The Company does not believe a slippage adjustment is appropriate in this case because it believes it has been reasonably accurate in predicting the cost of utility plant additions and when new plant will be placed into service.[8]

As shown on Schedule B-1 of Exhibit RCS-1, I recommended that a slippage factor adjustment should be made to the utility plant in service and CWIP based on the charges from the base period ending February 28, 2017 to the 13-month average balances reflecting in the Company's filing for the forecasted test year ending June 30, 2018. As shown on Schedule B-1, I have used a slippage factor of 97.204 percent, which is the 10-year period slippage factor for the Company's base rate capital construction projects, as provided in the response to Staff 1-13. The Commission has previously utilized a slippage factor reflecting a 10-year period. The use of a 10-year period lessens the impact of

[6] See, e.g., Case No. 2000-00120, The Application of Kentucky-American Water Company to Increase its Rates, final Order dated November 27, 2000 at 2-4 and Case No. 2004-00103, Adjustment of the Rates of Kentucky-American Water Company, final Order dated February 28, 2005 at 3, , and 10.
[7] Response to the Commission Staff's first Data Request, Q. 13.
[8] See, e.g., the Company's response to Staff 1-13(c).

extreme fluctuations in the annual variances. In some of the previous cases where the slippage factor adjustment has been made, the slippage factor has reflected the mathematical average. In the Company's response to Staff 1-13(b), the Company calculated the slippage factor based on a weighted average of base rate actual and budgeted capital cost, as well as the mathematical average of the yearly slippage factors for the ten years, 2006 through 2015. As explained in the Company's response to Staff 1-13(b):

> The Company recommends the weighted average, as opposed to the simple average, be used in the requested calculation to reflect the relationship of the size of the budget and associated variance.

I agree with the Company about the use of a weighted average and have applied the 97.204 percent factor to the increase in Plant in Service and CWIP, as shown on Schedule B-1 of Exhibit RCS-1.

Q. What adjustment does the "Slippage Factor" produce for the Company's electric utility operations?

A. As shown on Exhibit RCS-1, Schedule B-1, average electric Plant in Service and CWIP for the forecast test year ending June 30, 2018 are reduced by $7.143 million.

Q. Did the slippage adjustment also affect the Company's capitalization?

A. Yes. The slippage adjustment also impacted the Company's capitalization, as shown on Exhibit RCS-1, Schedule D, page 3, column B. In essence, the Company's proposed jurisdictional capitalization is reduced by the amount of the slippage for the forecast test year impacts on Plant and CWIP.

Q. Is there a related adjustment to depreciation expense?

A. Yes. Since the amount of forecast test year impacts on Plant is being reduced for the impact of slippage, an overall weighted average depreciation rate has been applied on Schedule C-6 of Exhibit RCS-1, in order to compute the estimated reduction to forecast test year depreciation expense. Depreciation expense is reduced by $167,559 on a Kentucky jurisdictional basis as shown on Exhibit RCS-1, Schedule C-6.

<u>B-2, Distribution Automation</u>

Q. Please discuss the adjustment for Distribution Automation.

A. AG witness Holloway is recommending that certain capital spending that the Company had projected for Distribution Automation ("DA") be deferred beyond the forecast test year ending June 30, 2018. The adjustment shown on Exhibit RCS-1, Schedule B-2, reflects the removal of that investment from the forecasted test year. Because an overall slippage factor had already been applied (in Exhibit RCS-1, Schedule B-1) the amounts of DA capital spending identified for removal by AG witness Holloway have been decreased for the impact of overall slippage, using the same slippage factor that was applied on Exhibit RCS-1, Schedule B-1. The deferral of the two projects reduces average forecasted test year plant in accounts 365 and 397 by $2.989 million on a Kentucky jurisdictional basis. After applying the slippage factor, the reduction to forecast jurisdictional test year electric plant is $2.905 million.

Q. Is there a related adjustment to depreciation expense?

A. Yes. As shown on Exhibit RCS-1, Schedule C-7, depreciation expense for the forecast test year is reduced by $65,929 on a Kentucky jurisdictional basis after applying the slippage factor.

B-3, Cash Working Capital

Q. What is Cash Working Capital ("CWC")?

A. Cash working capital is the cash needed by the Company to cover its day-to-day operations. If the Company's cash expenditures, on an aggregate basis, precede the cash recovery of expenses, investors must provide cash working capital. In that situation a positive cash working capital requirement exists. On the other hand, if revenues are typically received prior to when cash expenditures are made, on average, then ratepayers provide the cash working capital to the utility, and the negative cash working capital allowance is reflected as a reduction to rate base. In this case, the cash working capital requirement is an increase to rate base as ratepayers are essentially supplying these funds.

Q. How has KU determined CWC?

A. KU has determined its proposed test year CWC requirement of $106.349 million using the "1/8th formula" method. By using this method, the Company assumes that 1/8th of the going-level O&M expenses reflect a reasonable level of cash working capital.

Q. Do you agree with the Company's use of the "1/8th Formula" method in its determination of going-level CWC?

A. No, I do not. In my opinion, an accurate level of a utility's CWC can only be obtained through the use of a detailed lead-lag study. However, it is my understanding that the Commission has established a long-standing precedent whereby a utility's CWC can be calculated using the 1/8th formula. Therefore, I am not challenging the method by which the Company has calculated CWC in this proceeding.

Q. Although you are not challenging the Company's use of the 1/8th formula in its CWC determination, have you made any adjustments to KU's CWC requirement?

A. Yes. As shown on Exhibit RCS-1, Schedule B-3, I have reflected the impacts of my adjustments to O&M expenses to KU's CWC requirement. Specifically, reflecting the impact of my recommended adjustments to KU's operating expenses would reduce KU's CWC allowance by approximately $1.775 million.

Q. Have you adjusted KU's capitalization for the impact of the CWC adjustment?

A. Yes. As shown on Exhibit RCS-1, Schedule D, page 3, column D, I have adjusted the capitalization for the impact of the CWC adjustment.

Q. Do you have any other comments regarding the Company's CWC requirement?

A. Yes. If CWC is to be calculated using the 1/8th formula, then the proper level of CWC reflected for ratemaking purposes should ultimately be based on the pro forma O&M expenses allowed by the Commission versus the $106.349 million CWC amount proposed by the Company in this proceeding.

Q. Should the Company be required to file a Lead-lag study with its next rate case?

A. Yes. Having a Lead-lag study is a preferable method for determining a utility's cash working capital requirement. The Commission should require the Company to file a Lead-lag study in its next rate case.

B-4, Advanced Metering Systems

Q. Please explain the adjustment for Advanced Metering Systems ("AMS").

A. AG witness Alvarez is recommending that the Commission reject the Company's proposed AMS project. The adjustment shown on Exhibit RCS-1, Schedule B-4, therefore removes the rate base amounts related to the AMS project. Rate base for CWIP for this is decreased by $25.507 million. There is a related impact on Accumulated Deferred Income Taxes ("ADIT"). The rate base offset for ADIT is reduced by $1.834 million. The net rate base reduction is $23.673 million. The amounts are from the Company's response to KIUC 1-17.

Q. Does the adjustment to reflect AG witness Alvarez's recommendation for the AMS project affect the Company's capitalization?

A. Yes. As shown on Exhibit RCS-1, Schedule D, page 3, column E, the capitalization is reduced by $23.673 million.

Q. Are there some related adjustments to forecasted test year operating expenses relating to Mr. Alvarez's recommendation to reject the Company's AMS project?

A. Yes. The operating expenses that the Company identified in its response to KIUC 1-17 relating to AMS costs in the forecasted test period are being removed, as shown on

Schedule C-3 of Exhibit RCS-1. The operating expense adjustments are discussed in a subsequent section of my testimony that addresses Schedule C-3.

VIII. ADJUSTMENTS TO OPERATING INCOME

Q. Please describe how you have summarized the AG's proposed adjustments to operating income.

A. Schedule C of Exhibit RCS-1 summarizes the AG's recommended net operating income. Schedule C.1 presents the AG's recommended adjustments to forecasted test year revenues and expenses. The impact on state and federal income taxes associated with each of the recommended adjustments to operating income is also reflected on Schedule C.1.

Q. How does the AG's adjusted net operating income compare with KU's request?

A. As shown on Exhibit RCS-1, Schedule C, column A, line 12, KU's proposed adjusted projected period net operating income is $202.51 million, whereas the AG's recommended adjusted net operating income is $213.33 million, as shown in column C, line 12 of that schedule.

Q. How is your discussion of the AG's recommended adjustments to net operating income organized?

A. The recommended adjustments to operating income are discussed below in the same order as they appear on Schedule C.1 of Exhibit RCS-1.

C-1, Interest Synchronization

Q. Please explain the adjustment on Schedule C-1 of Exhibit RCS-1.

A. The interest synchronization adjustment applies the weighted cost of debt to the adjusted capitalization to derive a pro forma interest expense deduction that is used in the calculation of test year income expense. After adjustments, the AG's recommended adjusted capitalization and weighted cost of debt differs from that of the Company. This results in an adjustment to the amount of synchronized interest included in the tax calculation. The calculation of the interest synchronization adjustment is shown on Schedule C-1 of Exhibit RCS-1.

As shown on Exhibit RCS-1, Schedule C-1, the adjustment decreases income tax expense by the amount shown on Schedule C-1, line 8 and increases the Company’s achieved operating income by a similar amount.

C-2, Incentive Compensation Expense

Q. Does the Company have an incentive compensation plan available to its employees?

A. Yes. The Company has what it refers to as the Team Incentive Award plan ("TIA") plan available to its employees.

Q. What is the stated purpose of the TIA?

A. KU provided a copy of its plan in response to AG 1-210. Page 1 of the TIA Plan states:

> The TIA focuses employee efforts on customer and business goals and rewards employees for achieving those goals. The TIA provides an opportunity for eligible employees to share in the added value they create through superior performance.

Page 2 of the TIA Plan states in part:

> The TIA was developed to motivate and direct employees toward the achievement of strategic goals. It also assists with attracting and retaining skilled personnel by providing competitive compensation commensurate with their talents, cooperation and contribution.

Page 2 of the TIA Plan lists the following basic concepts:

- There is a focus on the cooperative spirit of all employees working together as a team.
- Risk-taking, embodied in initiative, fresh perspectives and innovative solutions, is encouraged and rewarded.
- The plan is designed to motivate and improve the individual performance of all employees.
- Incentive award levels vary depending on the employee's base salary, position and performance. The TIA represents "pay at risk." The relationship of the target awards to salary reflects that employees who have increasing responsibility for customer and business performance, as reflected in higher salaries, generally have higher amounts of individual compensation tied to that performance.

The TIA Plan states that with those concepts in mind, the TIA is designed to (1) promote the achievement of the Company's objectives; and (2) attract, motivate and retain employees.

Q. Does the TIA plan state what the Company's objectives are?

A. Not explicitly. Page 2 lists key elements of the TIA Plan. The third key element that is listed states that the performance objectives are established annually to support the customer and business strategies and that the size of the awards depend on the degree to which these objectives are achieved. However, page 2 of an attachment to PSC 1-55, which relates to KU's compensation policy, states in part the following:

> The Company encourages the use of pay for performance variable compensation plans to emphasize and support the Company's strategic objectives. Where used, the short-term incentive plans are designed and administered to ensure that incentive compensation earned is directly related to performance against one or multiple predetermined objectives established by the Company. The predetermined incentive compensation objectives may be quantitative, qualitative, objective, subjective, financial, and/or operational and they may be linked to corporate, divisional, team, and/or individual performance.

Q. Are there different components to the TIA plan?

A. Yes. Page 1 of the TIA Plan lists the following components:

- Corporate Safety
- Customer Satisfaction
- Cost Control
- Customer Reliability
- Individual and Team Effectiveness

Q. Has the Company included incentive compensation expense in its test year cost of service?

A. Yes. The Company has included TIA expense totaling $11.506 million on a total Company basis and $10.420 million on a Kentucky jurisdictional basis in its test period cost of service. This includes amounts for Company employees, as well as for affiliate employees which charge or allocate cost to the Company.

Q. Has the Company's incentive compensation traditionally included a component related to Net Income?

A. Yes. Data request KIUC 1-18 requested that KU provide incentive compensation expense for (1) 2015, (2) 2016, (3) the base period, and (4) the test period. In its response, KU provided the requested information broken out between the five components listed above as well as a sixth component referred to as Net Income. The $11.506 million includes incentive compensation direct charged to KU employees as well as incentive compensation allocated to KU from LGE/KU Services and LG&E.[9]

Q. What does the Net Income component of incentive compensation expense relate to?

A. The Net Income component of incentive compensation expense is a financial target and reflects budgeted revenue less operating expense, interest expense and income tax expense. According to the response to AG 2-15, actual net income results are compared to budget to determine the achievement of the financial target.

Q. What percentage of incentive compensation expense was allocated to the Net Income component for 2015, 2016 and the base period?

A. As shown in the table below, the percentage of incentive compensation expense allocated to the Net Income component for 2015, 2016 and the base period was as follows:

Description	2015	2016	Base Period
Net Income Component	$ 7,297,430	$ 3,699,077	$ 2,817,851
Total Team Incentive Award Expense	$ 13,785,439	$12,301,629	$11,128,234
Percentage Allocated to Net Income	52.94%	30.07%	25.32%
Source: KIUC 1-18			

[9] See page 4 of the attachment KU provided in the response to AG 1-68.

Q. Does the $11.506 million of incentive compensation expense being requested by KU for the test period explicitly include a portion that is allocated to the Net Income component?

A. No. The response to KIUC 1-18 reflected Net Income components of $7.297 million, $3.699 million and $2.818 million for 2015, 2016 and the base period, respectively, but reflected $0 for the Net Income component for the test period.

Q. Did the Company provide an explanation of why $0 was allocated to the Net Income component for the test period?

A. No. The Company did not provide an explanation of why $0 was allocated to the Net Income component for the test period despite the fact that the projected test year total amounts noted above are comparable to the total amounts that the Company listed for 2015, 2016 and for the base period ending February 28, 2017. The Company's response to AG 2-15 merely states that the Net Income component is not included as a target for the forecasted test year. In addition, the Company's response to Kroger 2-3 states (without explanation) that the Net Income component was eliminated as a goal for 2017 and 2018.

Q. How does the amount being requested by the Company for incentive compensation in the forecast test year compare with the amount in the base period?

A. The $11.506 million of incentive compensation expense being requested by KU for the forecasted test period is $.377 million higher than the base period amount of $11.128 million. Moreover, that base period amount included $2.818 million related to the Net Income component.

Q. How does KU propose to allocate the $11.506 million of test period incentive compensation expense among the TIA Plan components?

A. According to the response to KIUC 1-18, KU proposes to allocate the $11.506 million of test period incentive compensation expense as follows:

Net Income:	$0
Cost Control:	$1,598,010
Customer Reliability:	$1,598,010
Customer Satisfaction	$1,598,010
Corporate Safety:	$1,598,010
Individual/Team Performance:	$5,113,633
Total	$11,505,675

According to an attachment provided in the Company's response to Kroger 2-3, the amounts above represent a weighted percentage for each target as shown in the following table:

Financial:	0%
Other Operating and Maintenance:	13.89%
Capital Spend:	13.89%
Customer Satisfaction:	13.89%
Safety:	13.89%
Individual/Team Effectiveness:	44.44%
Total	100.00%

Q. As noted above, the Kentucky jurisdictional amount of incentive compensation being requested by KU is $10,420,237. Do you agree with KU's proposal to charge ratepayers for $10,420,237 for incentive compensation in the projected test year?

A. No. I do not agree with KU's proposal to charge ratepayers for $10,420,237 for incentive compensation expense in the projected test year. It is inconsistent to not include an allocation of incentive compensation expense to the Net Income component for the test period when similar amounts were allocated in the three prior periods noted, especially when the overall TIA award payout is comparable to those prior periods, and is higher than the base period total.

Q. Do the incentive compensation targets and achieved results appear to warrant charging ratepayers for 100 percent of the forecast TIA plan-based incentive compensation?

A. No. The targets and achieved results appear to result in large TIA plan-based payouts, based on achievement of goals that are based on questionable metrics. For example, the 2015 payout percentages for the other TIA Plan components included a Customer Satisfaction target. The Company's response to AG 1-54 included a 2015 Customer Satisfaction Results Summary, which indicates that in each of the four quarters of 2015, KU had customer satisfaction results of 62.6%, 61.4%, 64.1% and $66.6%.[10] However, these percentages of customer satisfaction resulted in KU initiating an incentive compensation payout of 141.7%.

Other examples from 2015 that related to payouts of over 100% of target included a payout of 173.1% related to the Net Income target, 147.75% related to electric distribution operations, 102.5% related to information technology as well as payouts related to nine of the Company's plants which averaged to a payout percentage of 130%. In contrast, the payouts related to customer services, gas distribution services and operating services were 66.75%, 86.79% and 56.25%, respectively.

Charging ratepayers for incentive compensation payouts that are based on achievements that are of questionable benefit to customers or that are based upon

[10] The response to AG 2-16(d) stated that a 66.6% customer satisfaction measurement indicates that 66.6% of customers surveyed rated their overall satisfaction with KU a 9 or 10 on a 10-point scale, thus inferring that the remaining 33.4% gave ratings anywhere between 1 and 8.

achievement of over 100 percent of targets, especially during periods when the Company's base rates have been increasing in each successive rate case, appears to be questionable.

Q. Is there another reason you do not agree with KU's proposed allocation of test period incentive compensation expense among the TIA components?

A. Yes. The response to KIUC 1-18 states that KU assumed that the measures and weightings used for 2017 will apply in 2018 as well for purposes of categorizing the TIA for the forecast test year. The table below shows how KU allocated incentive compensation expense for the base period:

TIA Plan Component	Base Period Amount	Ratio
Net Income	$ 2,817,851	25.32%
Cost Control	$ 223,285	2.01%
Customer Reliability	$ 223,285	2.01%
Customer Satisfaction	$ 1,843,437	16.57%
Corporate Safety	$ 1,733,313	15.58%
Individual/Team Effectiveness	$ 4,287,063	38.52%
Total Team Incentive Award Expense	$ 11,128,234	100.00%
Source: KIUC 1-18		

As noted above, for the test period KU is proposing to allocate $1.598 million each to the (1) Cost Control component; (2) Customer Reliability component; (3) Customer Satisfaction component; and (4) Corporate Safety component. To allocate the exact same amount to each of those four TIA components seems inconsistent with the allocations to the TIA components shown in the table above for the base period.

Q. Has the Commission previously disallowed portions of utility incentive compensation expense that primarily benefits shareholders?

A. Yes. For example, in its Order dated December 14, 2010 in Case No. 2010-00036 in a proceeding involving Kentucky-American Water Company, the Commission stated in part the following with regard to incentive compensation:

> We remain unconvinced that Kentucky-American's ratepayers receive any benefit from the AIP program to support the recovery of AIP's costs through rates. While some consideration is given to non-financial criteria, the AIP appears weighted to financial goals that primarily benefit shareholders. If these goals are not met, the program is unfunded and no Kentucky-American employee receives an incentive award regardless of how well he or she meets the customer satisfaction or service quality goals. Accordingly, we find that forecasted labor expense should be decreased by an additional $349,529 to eliminate the ICP.

In addition, in its Order dated April 22, 2014 in Case No. 2013-00148 in a proceeding involving Atmos Energy Corporation, the Commission stated in part the following with regard to incentive compensation:

> Incentive criteria based on a measure of EPS, with no measure of improvement in areas such as safety, service quality, call-center response, or other customer-focused criteria, are clearly shareholder-oriented. As noted in the hearing on this matter, the Commission has long held that ratepayers receive little, if any, benefit from these types of incentive plans...It has been the Commission's practice to disallow recovery of the cost of employee incentive plans that are tied to EPS or other earnings measures and we find Atmos-Ky's argument to the contrary unpersuasive.

Q. Are you recommending an adjustment to the level of incentive compensation that is included in test year cost of service?

A. Yes. I recommend that one fourth (i.e., 25 percent) of the forecasted test period incentive compensation expense be charged to the Company's shareholders, rather than being borne by ratepayers. This percentage to be borne by shareholders is in line with the ratio of incentive compensation expense allocated to the Net Income component in the base period as shown in the table above.

Q. What is the basis for your recommendation?

A. The basis for my recommendation is that incentive compensation expense that primarily benefits shareholders by either being tied to a utility's financial performance and/or to questionable goals that do not appear to directly benefit customers should not be borne by ratepayers. For the Company to eliminate the Net Income component for the forecasted test year when it had included this financial target in prior years, including the base period, is not a good reason for charging ratepayers for 100 percent of the forecasted test period incentive compensation, especially when the incentive compensation expense payout for forecasted test year is higher than the level for the base period which did include a Net Income component.

Q. Please explain your recommended adjustment for KU's Incentive Compensation expense.

A. As shown on Schedule C-2 of Exhibit RCS-1, this adjustment decreases test year expense by $2.605 million on a Kentucky jurisdictional basis to reflect the removal of 25 percent of KU's requested jurisdictional incentive compensation expense of $10.420 million.

C-3, Advanced Metering Services Operating Expenses

Q. Please explain the adjustment to remove operating expenses that the Company has identified in its forecasted test year with its AMS project.

A. As described above, AG witness Alvarez has recommended that the Commission reject the Company's proposed AMS project. Accordingly, the amounts of operating expenses for the AMS project that the Company identified in its response to KIUC 1-17 are being removed on a Kentucky jurisdictional basis, as shown on Exhibit RCS-1, Schedule C-3.

C-4, Transmission Vegetation Management Expense

Q. Is the Company proposing a change to its transmission related vegetation management program?

A. Yes. As discussed on page 30 of the Direct Testimony of Company witness Paul Thompson, as part of its Transmission System Improvement Program, KU is proposing to transition from its current just-in-time tree trimming program to a five-year cycled growth approach. Specifically, the Company proposes to implement a five-year cycled approach to vegetation management and an identification and removal program for hazard trees.[11] Mr. Thompson states that the proposed five-year cycled approach will enable the Company to restore existing rights-of-way through a combination of tree trimming, herbicide application, hazard tree patrol and removal and an emerald ash borer mitigation program.

Q. When does the Company intend to implement the proposed five-year plan?

A. As discussed in Mr. Thompson's testimony at pages 30-31, the Company has already begun transitioning to the regular cycle for the 345kV and 500kV power lines in order to ensure compliance with mandatory NERC standards. Beginning in mid-2017, KU would

[11] Mr. Thompson defines hazard trees as those that are dead, dying or diseased, which includes trees infested by the emerald ash borer, an invasive insect.

establish an average five-year line clearance cycle for lines operating at less than 345kV, with the initial cycle completed by 2022.

Q. Please explain the Company's current transmission related vegetation management practices.

A. As discussed on page 20 of the Company's Transmission System Improvement Plan (2017-2021),[12] (Transmission Plan) the Company's current vegetation clearing practices uses a just-in-time approach whereby KU inspects transmission lines at least three times a year to identify areas where vegetation is encroaching upon the Company's conductors. These areas are then prioritized and maintained to reduce the risk of an outage.

Q. Did the Company provide a copy of any studies and/or analyses that it relied upon in order to justify the change in methodology it is proposing with respect to vegetation management?

A. Yes. The Company's Transmission Plan states at page 20 that its proposed program was developed with input from Environmental Consultants, Inc. ("ECI"). A copy of ECI's Louisville Gas & Electric and Kentucky Utilities Transmission Program Review ("ECI Report) was provided as an attachment to the response to KIUC 1-30.[13]

Q. What was ECI's stated purpose of its review of the Company's transmission program review?

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[12] The Transmission System Improvement Plan (2017-2021) was filed as Exhibit PWT-2 in conjunction with Mr. Thompson's Direct Testimony.

[13] ECI's report evaluated both KU's and LG&E's vegetation management programs.

A. In the executive summary of the ECI report, its states in part:

> The primary goal of the evaluation was to assess the vegetation workload on the LG&E and KU overhead transmission and develop a budget to support the vegetation management program. A secondary goal was to conduct a high-level assessment of the vegetation management program and identify general opportunities to enhance program management, reliability and cost effectiveness.

Q. What was ECI's general assessment of the Company's current methodology of vegetation management?

A. The ECI report listed the following items, which it indicated were key strengths of the Company's current vegetation management program:

- LG&E and KU management is supportive of program improvements.
- The program is focused on reliability and regulatory compliance.
- A centralized management structure is in place.
- Right-of-Way (ROW) conditions are inspected on a quarterly basis.
- 'Action Threshold Clearance' has been established to ensure minimum acceptable clearances are not encroached upon, providing increased margin of safety regarding reliability.
- Tree-caused outages are formally investigated and documented, with trained personnel.
- Aerial herbicide application are effectively used to control brush in rural ROW areas.

In addition, at page 12 of the ECI report, ECI stated that KU is doing an admirable job in managing transmission vegetation with a limited budget and that the size of the annual budget has necessitated a just-in-time approach to vegetation management. ECI also stated that the current just-in-time methodology herbicide treatment and edge pruning on non-NERC lines has resulted in a system that is a patchwork of various vegetation conditions on the ROW's.

Q. What were ECI recommendations?

A. On page 4 of the ECI report, ECI made the following recommendations:

- Transition maintenance program to cyclical maintenance.
- Continue to remove incompatible trees within the ROW and particularly under the conductors (within the wire zone corridor).
- Determine and document the ROW width for all LG&E and KU transmission circuits.
- Develop a hazard tree ground patrol to address potential risk from trees that may not be visible through normal routine aerial inspections.
- Establish a list or database of hazard tree location and develop a priority program to determine which trees should be removed first. This database may include ash trees that could be affected by the emerald ash borer (EAB).
- Continue to enforce vegetation maintenance clearance specifications for transmission voltages and the policies and standards specific to LG&E and KU needs and conditions. Current specifications appear adequate to maintain vegetation on the transmission system.
- Ensure that vegetation maintenance crews exhibit reasonable production levels by implementing a work reporting/measurement system and utilize the records to evaluate crews and compare contractor performance.
- Implement Integrated Vegetation Management (IVM) as the guiding maintenance principle on the LG&E and KU transmission system.
- Re-establish the transmission corridor ROW edges wherever practical to bring the corridors back to specification by voltage.
- Continue to maximize herbicide use where practical to minimize future vegetation management costs and better manage for compatible plant communities.
- Once established maintain consistent transmission vegetation maintenance program funding to maximize overall program effectiveness and ensure compliance with NERC Standards FAC-003.
- Consider increasing vegetation management oversight to address the addition of approximately 46 crews to meet workload requirement for a 5-year cycle.

Q. You indicated earlier that ECI stated that the primary goal of its review was to assess the vegetation workload and develop a budget to support the proposed vegetation management program. Did ECI develop a budget in its report?

A. Yes. However, as noted earlier, ECI's report evaluated both LG&E's and KU's vegetation management programs. Having said that, on pages 21-22 of the ECI report, it states the total budget to maintain the LG&E and KU transmission system for a targeted five-year cycle is estimated to be approximately $56.32 million, approximately $11.26 million annually over the five-year period.

Q. Does this amount agree with the five-year estimated cost of the program in the Company's Transmission Plan that was provided as Exhibit PWT-2?

A. No. On page 25 of the Transmission Plan, the Company states that the estimated cost of the proposed plan for both companies (LG&E and KU) over five years is $64 million as shown in the table below:

Description	2017 (Millions)	2018 (Millions)	2019 (Millions)	2020 (Millions)	2021 (Millions)	Total
Base VM Spend	$ 7.2	$ 7.8	$ 8.2	$ 9.7	$ 9.9	$ 42.8
Incremental VM Spend	$ 2.2	$ 5.1	$ 5.5	$ 4.2	$ 4.2	$ 21.2
Total VM Spend	$ 9.4	$ 12.9	$ 13.7	$ 13.9	$ 14.1	$ 64.0

Source: Exhibit PWT-2, page 25 of 52

Q. Has the Company provided an explanation for the $7.68 million difference ($64 million and $56.32 million) between the two reports?

A. No.

Q. How much transmission related vegetation cost has KU included in its test year cost of service?

A. According to the response to KIUC 2-12, KU has reflected transmission related vegetation management costs of $9.993 million in its test year cost of service. The table below provides a summary of KU's transmission vegetation management expense over the period 2007 through 2016 as well as the base period and the test period.

Year	Amount	Dollar Change Over Prior Year	Percentage Change Over Prior Year
2007	$ 2,851,413		
2008	$ 2,899,128	$ 47,715	1.67%
2009	$ 3,887,218	$ 988,090	34.08%
2010	$ 4,066,864	$ 179,646	4.62%
2011	$ 4,108,149	$ 41,285	1.02%
2012	$ 4,148,767	$ 40,618	0.99%
2013	$ 4,511,675	$ 362,908	8.75%
2014	$ 5,310,433	$ 798,758	17.70%
2015	$ 5,329,253	$ 18,820	0.35%
2016	$ 5,286,815	$ (42,438)	-0.80%
Base Year	$ 5,629,253	$ 342,438	6.48%
Test Year	$ 9,992,809	$ 4,363,556	77.52%

Source: KIUC 2-12

As shown in the table, the Company's costs for transmission vegetation management from 2007 through the base period has generally increased. However, the Company's forecasted amount for the test year of $9.993 million is nearly 78% higher than the base year amount of $5.629 million and 89% higher than the 2016 amount of $5.287 million.

Q. Has the Company stated whether the proposed five-year cycle approach will result in cost savings?

A. Yes. On page 31 of his testimony, Mr. Thompson stated that after completion of the first five-year cycle (i.e., starting in 2022) the proposed program is expected to reduce vegetation management costs and ROW maintenance.

Q. Did KU reflect any cost savings from the proposed program in its test year filing?

A. No. In fact, some of the Company's responses to discovery seem to contradict Mr. Thompson's assertion that the program will eventually result in reduced vegetation management costs. For example, in response to KIUC 1-30(b), which asked KU to quantify the expected annual benefits from reduced outage maintenance expense as a result of moving to a five-year cycle approach, KU stated in part:

> The Company expects some reduction in outage maintenance expense, but has not quantified the reduction.

In addition, in response to KIUC 1-30(c), which asked KU to confirm that the change to a five-year cycle approach should be expense neutral or result in savings due to more efficient trimming aside from any savings from reduced outage maintenance expense, the Company stated:

> The referenced increases include the cost to convert to a five-year maintenance cycle and implementation of a new hazard tree identification and removal program which are expected to reduce tree related customer outages but may not be expense neutral. The Company did not specifically perform detailed analysis to determine O&M costs beyond the conversion timeframe.

Q. Based on the foregoing information, in your opinion, has the Company demonstrated that its proposed test year transmission vegetation management expense of $9.993 million is reasonable?

A. No, I do not. In my opinion, the Company has not demonstrated that its proposed test year transmission vegetation management expense of $9.993 million is reasonable. Specifically, the ECI report listed what it considered the Company's key strengths with respect to its current just-in-time vegetation management program and that KU is doing an admirable job in its management of the current program. In addition, even the ECI recommendations stated that KU should continue doing things it is already doing, including, for example, (1) removing incompatible trees within the ROW, (2) enforcing vegetation management clearance specifications for transmission voltages and that the current specification appear adequate to maintain vegetation on the transmission system, and (3) maximizing herbicide use where practical to minimize future vegetation management costs and better manage for plant communities.

Q. Please continue.

A. There also seems to be a disconnect between the Company's Transmission Plan and the ECI report with respect to the estimated budget for the proposed program over the initial five-year cycle whereby the KU Transmission Plan indicates a budget of approximately $64 million over five years whereas ECI indicated a budget of $56.32 million over five years. In addition, based on the responses to discovery, there appears to be uncertainty as to whether and if there will eventually be cost savings resulting from efficiencies achieved through the proposed program.

Q. What is your recommendation?

A. As noted above, for the period 2007 through the base period, KU's transmission vegetation management expense has been fairly consistent with relatively modest increases. Therefore, I recommend that the base period amount of $5.629 million be reflected in KU's test year cost of service.

Q. Please explain your adjustment.

A. As shown on Exhibit RCS-1, Schedule C-4, my adjustment reduces test year operating expense by $3.937 million on a Kentucky jurisdictional basis.

C-5, Uncollectibles Expense

Q. What Uncollectibles factor has the Company used?

A. The Company has proposed an Uncollectibles factor of 0.352%, based on a five-year average of write-offs to revenues for the period 2011 through 2015, as shown in the Company's response to AG 1-25.

Q. Are you recommending an adjustment for Uncollectibles?

A. Yes. As shown on Exhibit RCS-1, on Schedule C-5, I recommend using a five-year average including 2016. The five-year average Uncollectibles factor for 2012 through 2016 is 0.320 percent. Applying that Uncollectibles factor to the forecasted test year revenue results in an adjustment to decrease uncollectibles expense by $0.937 million as shown on Exhibit RCS-1, Schedule C-5.

Q. Have you also incorporated the updated Uncollectibles factor into the Gross Revenue Conversion Factor?

A. Yes. As shown on Exhibit RCS-1 on Schedule A-1, I have incorporated the Uncollectibles factor into the GRCF.

C-6, Depreciation Expense Related to Plant Slippage

Q. Please explain the adjustment for Depreciation Expense related to the impact of slippage on average forecast test year Plant.

A. As discussed above, in conjunction with rate base adjustment B-1 ("Slippage Adjustment"), the amount of projected test year plant requested by the Company is being reduced. In order to compute the related impact on Depreciation Expense, I applied an overall composite depreciation rate to the amount of forecast test year Plant adjustment related to slippage. As shown on Exhibit RCS-1, Schedule C-6, this reduces Depreciation Expense by $167,559 on a Kentucky jurisdictional basis.

<u>C-7, Depreciation Expense Related to Distribution Automation</u>

Q. Please explain the adjustment for Depreciation Expense Related to Distribution Automation.

A. AG witness Holloway is recommending that certain components of the Company's requested Distribution Automation program be deferred to beyond June 30, 2018, i.e., and thus not included in the forecasted test year. Mr. Holloway's adjustment affects two Plant accounts. As shown on Exhibit RCS-1, Schedule C-7, applying the Company's requested depreciation rates to the impacted Plant adjustment amounts in each of those two Plant accounts (accounts 365 and 397) reduces Depreciation Expense by $76,480. The adjustment amount has also been reduced by the impact of the slippage adjustment. The net reduction to Depreciation Expense for the two accounts affected by Mr. Holloway's Distribution Automation recommendation is $74,342 on a total Company basis and by $65,929 on a Kentucky jurisdictional basis, as shown on Exhibit RCS-1, Schedule C-7.

<u>C-8, Payroll and Employee Benefits for Vacant Positions</u>

Q. Has the Company included cost in the forecasted test year for vacant positions?

A. Yes. As indicated in the Company's response to AG 2-8, cost for vacant positions at KU as well as at the affiliate, LG&E and KU Service Company, were included in the forecast test year in the Company's application. The projections include adding four positions at KU and 34 positions at the affiliate, LG&E and KU Service Company.

Q. Has the Company demonstrated that those additional positions are needed and/or would be filled for the full duration of the forecasted test year?

A. No. The Company has not demonstrated that those additional positions are needed and/or would be filled for the full duration of the forecasted test year.

Q. Is it typical for a utility (and its affiliated service company) to experience turnover in its work force?

A. Yes, it is common for a utility, as well as its affiliated service company, to experience turnover in the work force, as employees retire or change jobs, and are replaced by new employees.

Q. Has the Company provided responses to discovery which compare the salary cost for (1) retiring employees and (2) the new employees that have replaced them?

A. Yes. For example, the Company's responses to AG 1-67 contains a confidential listing of the salaries of (1) retiring employees and (2) the new employees that have replaced them. A copy of that confidential response is contained in Exhibit RCS-10. An analysis of that information indicates that the average salary cost of the replacement employees is approximately **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]**

Q. Have you based your recommended adjustment on the historic differential between the salaries of (1) retiring employees and (2) the new employees that have replaced them?

A. No, not in this case. That would be one way of addressing the impact of work force turnover and could be appropriate in circumstances where the forecasted work force additions have been justified by the utility. However, in the current case, the Company has failed to justify the substantial work force additions at the Company or at the affiliated service company. Nor has the Company adequately shown that the requested new positions would be filled for the entire forecasted test period. Thus, a different approach is needed.

Q. What adjustment do you recommend?

A. As shown on Exhibit RCS-1, Schedule C-8, I recommend that the payroll, employee benefits and payroll tax expense for the additional positions be eliminated. This adjustment reduces O&M expense by $1.774 million and payroll taxes by $0.107 million on a Kentucky jurisdictional basis.

Q. Is there another concern that you have identified with the Company's four projected staffing levels in the forecasted test year?

A. Yes. The Company based its forecasted staffing levels on budgets and projections for the test year. However, the experience reflected in the response to Staff 1-33 shows that actual staffing has been less than the budgeted staffing. Additionally, the Company's response to AG 1-43 identified actual versus budget variances for December 2015 and December 2016, and indicates reasons for such variances, including plant closure, transfers and normal attrition. The Company's response to AG 1-38, parts a and b, provided monthly information on actual and budgeted employee headcount. Actual and budgeted employee headcount for KU and for LG&E and KU Service Company are summarized in the following tables:

KU Employee Headcount Budget/Actual Differences				
Month	Actual Employee Headcount	Budgeted Employee Headcount	Actual Under Budget	Actual Under Budget Percent
December 2014	957	975	-18	-1.8%
December 2015	940	984	-44	-4.5%
December 2016	937	963	-26	-2.7%
Source: Company's response to AG 1-38(a-b)				

LG&E and KU Services Company Budget/Actual Differences				
Month	Actual Employee Headcount	Budgeted Employee Headcount	Actual Under Budget	Actual Under Budget Percent
December 2014	1571	1558	13	0.8%
December 2015	1600	1617	-17	-1.1%
December 2016	1631	1681	-50	-3.0%
Source: Company's response to AG 1-38(a-b)				

At December 2015 and December 2016 actual headcount has been below the budgeted level for KU and for the affiliate, LG&E and KU Services Company.

Q. If the Commission determines that some of the additional positions projected by the Company should be allowed, do you have an alternative recommendation?

A. Yes. I recommend that the Commission disallow the payroll and related expenses for the positions that the Companies' actual experience indicates will not be filled due to normal work force turnover, i.e., apply a vacancy rate adjustment. If the positions are not filled, then the Company will not incur the expenses.

<u>C-9, Administrative Charges from PPL Services - Affiliated Service Company</u>

Q. How many service companies are there within in the PPL Corporation system?

A. According to the Company's response to AG 1-51, there are three service companies within the PPL Corporation system.

LG&E and KU Services Company is a subsidiary of LKE that provides services to LG&E and KU Energy LLC, and its subsidiaries, including LG&E and KU.

PPL EU Services Corporation is a subsidiary of PPL Corporation that provides support services and corporate functions such as financial, supply chain, human resources and facilities management services primarily to PPL Electric and its affiliates.

PPL Services Corporation is a subsidiary of PPL that provides administrative, management and support services to PPL and its subsidiaries.

Q. How much cost has KU reflected for charges from LG&E and KU Services Company for the projected test year?

A. The Company's response to AG 1-50(e) includes a listing of projected test year charges to KU from LG&E and KU Services Company for the projected test year. The total amount is approximately $319.751 million.

Q. How much affiliated charge expense from LG&E and KU Services Company is included in Administrative and General expense accounts, such as accounts 920, 921 and 926 for KY?

A. According to the Company's response to AG 1-50(e), the following amounts of administrative expenses in each of those accounts was reflected by KY for the projected test year:

- $36.890 million for account 920, Administrative and General Salaries
- $6.771 million for account 921, Office Supplies and Expenses
- $22.423 million for account 926, Employee Benefits

Q. Do some of those administrative expense charges from the affiliate, LG&E and KU Services Company, also include charges from another affiliate, PPL Services Corporation?

A. Yes. According to the Company's response to AG 1-50(d), the administrative expenses include the following charges from PPL Services Corporation for the forecasted test period:

- $139,317 for account 920, Administrative and General Salaries
- $1,426,120 for account 921, Office Supplies and Expenses
- $100,896 million for account 926, Employee Benefits

Q. Why does the projected test year include administrative expense charges to the Company from LG&E and KU Services Company and from the other affiliated service company, PPL Services Corporation?

A. The question: "Why is PPL Services Corporation allocating cost to LG&E and KU Services Company?" was asked in AG 1-50(c). The following response was provided by the Company:

> PPL Services Corporation is a subsidiary of PPL that provides direct administrative, management and support services to PPL and its subsidiaries including acting as a billing agent and providing administrative, technical, management, and other services to its affiliates. Coordination of procurement and provision of certain limited goods and services within the PPL family of companies, including with LG&E and KU Services Company, may mitigate cost increases in the future. In addition, PPL Services Corporation allocates a portion of its indirect general and administrative costs to LG&E and KU Services Company. These costs are not charged to KU.

Q. Please explain your adjustment on Schedule C-9 of Exhibits RCS-1.

A. As stated in the Company's response to AG 2-11, the Company has included in the forecasted test year amounts related to administrative expenses from PPL Service Corporation that were charged to KU.

Q. Why should the administrative expenses charged to the Company from PPL Service Company be removed?

A. The Company has not justified the forecast test year administrative expenses from multiple service companies. The response to AG-50 indicates that for the forecast test year, there are charges to the Company of approximately $319.751 million from LG&E and KU Service Company to KU. LG&E and KU Service Company is the service company that was established to provide shared services to LG&E and Kentucky Utilities. PPL Service Company is another affiliated service company that was established to provide shared services to the PPL operations in Pennsylvania. Affiliated charges for the same types of general and administrative expenses are being allocated and charged to the Company from LG&E and KU Service Company.

Q. What is the impact of your adjustment to remove affiliated charges for administrative expenses from PPL Services Corporation?

A. As shown on Exhibit RCS-1, Schedule C-9, PPL Services Corporation charges for administrative expenses in accounts 920, 921 and 926 are being removed in the amount of $1.505 million on a Kentucky jurisdictional basis.

<u>C-11, Rescheduling of Expiring Regulatory Asset Amortizations</u>

Q. Please explain the adjustment for expiring regulatory asset amortizations.

A. The Company's response to KIUC 2-8 listed amortizations of various regulatory assets. As shown on Exhibits RCS-1, Schedule C-11, in the situations where the amortization would expire during the forecasted test year, or within 12 months after the end of the forecasted test year (i.e., by June 30, 2019), I have correspondingly updated the scheduled amortization to reflect full amortization by June 30, 2019.

Q. What is your recommendation to address this problem and the over-recovery that would occur either during the test year or within twelve months after the end of the forecasted test year?

A. I recommend that the Commission reset the amortization period to two years for each of the deferred cost and regulatory asset balances listed on Exhibit RCS-1, Schedule C-11. Put another way, for amortizations that would otherwise be expiring either during or within 12 months after the forecast test year (i.e., for each amortization that would be expiring prior to June 30, 2019), the test year balances should be amortized over two years. This will allow for recovery by the Company of the costs that have been deferred while minimizing the risk of over-recovery.

Q. Please discuss the components of the electric utility regulatory asset amortizations for which you recommend a re-scheduled amortization period.

A. As shown on Exhibit RCS-1, Schedule C-11, for the electric utility, I recommend re-scheduling the remaining amortization period for the following items:

- Mountain Storm - Electric
- Rate Case Expenses
- Green River Retirement

Q. What is the impact of your recommended adjustment?

A. As shown on Exhibit RCS-1, Schedule C-11, the amortization expense for the forecast test year is reduced by $0.253 million.

IX. AMORTIZATION PERIOD FOR REMAINING NET BOOK VALUE OF RETIRED METERS THAT ARE BEING REPLACED WITH NEW ELECTRIC UTILITY AMS METERS

Q. Does the Company anticipate having a remaining un-depreciated net book value associated with the retirement of its existing meters that it proposes to be replaced with new electric utility AMS meters?

A. Yes.

Q. How does the Company propose to account for and amortize that remaining un-depreciated net book value of its existing meters when they are retired and replaced with new AMS meters?

A. As explained in its response to AG 2-79, the Company states that it is seeking Regulatory Asset treatment of the retired meters, with the remaining value to be amortized over five years. A copy of this response is provided in Exhibit RCS-14.

Q. Do you agree with that Company proposal?

A. No. The remaining net book value of the retired currently existing meters that would be replaced with new AMS meters should be amortized over a longer period than five years. I would recommend, consistent with Commission precedent, that the amortization occur over the same period that the Commission determines for the average service life for the new AMS meters. Moreover, unless the Company can demonstrate that there have been net customer savings, the amortization associated with the Regulatory Asset for the existing meters that are being retired and replaced with AMS meters should not be charged to ratepayers. As noted previously in my testimony, AG witness Alvarez is recommending against Commission approval of the Company's AMS project. The creation of a Regulatory Asset for the un-depreciated book value of existing meters and the related amortization period and who should bear the related cost would not be an issue if the Commission rejects the Company's AMS project.

X. OFF-SYSTEM SALES MARGIN SHARING

Q. What Off-System Sales margin sharing is the Company currently applying?

A. Currently, the Company is applying 75/25 sharing of Off-System Sales margins, with 75 percent going to customers, and the Company retaining the remaining 25 percent. See, e.g., the Company's response to Staff 1-54, which included an Excel file, [Att_KU_PSC_1-54_Sch_C_and_D_Electric.xlsx] that showed base year and projected year information for Off-System Sales at tab "OSS" (a copy of that portion of the response is presented in Exhibit RCS-15).

Q. What do you recommend prospectively for Off-System Sales margins sharing?

A. I recommend that a 90/10 sharing of Off-System Sales margins, with 90 percent going to customers, and the Company retaining the remaining 10 percent be applied prospectively. Customers are paying for the fixed costs and operating expenses for the Company's generating plant, and for the dispatch organization, including affiliate charges, and related overheads. OSS margins can be subject to greater volatility and variability than fuel and purchased power expenses. OSS margins are related to fuel and purchase power expense and could thus be allocated entirely to customers in the same manner that fuel and purchased power expenses are allocated to customers. The Company should be making Off-System Sales when it is economical and beneficial to do so. All of these factors support that a higher customer sharing percentage is warranted. Allowing the Company to retain 10 percent should be sufficient incentive for the Company to continue making beneficial Off-System Sales.

Q. Does this recommendation affect the Company's base rate revenue requirement for the current case?

A. No, not directly. Because the sharing of Off-System Sales margins occurs via the tracker, the 90/10 sharing to be applied prospectively would not affect the Company's base rate revenue requirement for the current case.

Q. Does this conclude your testimony?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	))))	CASE NO. 2016-00370

AFFIDAVIT OF Ralph Smith

State of Michigan)
)
)

Ralph Smith, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony and the Schedules attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

Ralph C Smith

Ralph Smith

SUBSCRIBED AND SWORN to before me this 3rd day of March, 2017.

Christine Miller

NOTARY PUBLIC

My Commission Expires: 11/8/2021

CHRISTINE MILLER
NOTARY PUBLIC, STATE OF MI
COUNTY OF WAYNE
MY COMMISSION EXPIRES Nov 8, 2021
ACTING IN COUNTY OF Wayne

APPENDIX A

Appendix A

QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a Certified Rate of Return Analyst, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Oregon, Pennsylvania, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, Washington DC, West Virginia, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed were the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

<u>Partial list of utility cases participated in</u>:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933*	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)
U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)

U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA &76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA & 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001 & ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)
R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU & 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102 T E-1032-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546*	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628*	Duquesne Light Company, et al, plaintiffs, against Gulf+ Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)

R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102 & U-1551-89-103	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona Corporation Commission)
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and TC-91-040B	Intrastate Access Charge Methodology, Pool and Rates Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS & 911-67-WS	General Development Utilities - Port Malabar and West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)
R-00922314 & M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 & U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 & U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission)
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/ E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR*	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)

Non-Docketed Staff Investigation	Citizens Utility Company - Arizona Telephone Operations (Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)
GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non-Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
R-00973953	Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power &Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed Staff Investigation	Delaware - Estimate Impact of Universal Services Issues (Delaware PSC)
PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60, U-98-65, U-98-67	Investigation of 1998 Intrastate Access charge filings (Alaska PUC)
(U-99-66, U-99-65, U-99-56, U-99-52)	Investigation of 1999 Intrastate Access Charge filing (Alaska PUC)
Phase II of 97-SCCC-149-GIT	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed Assistance	Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed Project	Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)

E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)
Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No. 98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)
Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No. 99-01-016, Phase I	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)

97-12-020 Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)
Docket No. E-01345A-06-009	Arizona Public Service Company (Arizona Corporation Commission)
Case No. 05-1278-E-PC-PW-42T	Appalachian Power Company and Wheeling Power Company both d/b/a American Electric Power (West Virginia PSC)
Docket No. 04-0113	Hawaiian Electric Company (Hawaii PUC)
Case No. U-14347	Consumers Energy Company (Michigan PSC)
Case No. 05-725-EL-UNC	Cincinnati Gas & Electric Company (PUC of Ohio)
Docket No. 21229-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 19142-U	Georgia Power Company (Georgia PSC)
Docket No. 03-07-01RE01	Connecticut Light & Power Company (CT DPUC)
Docket No. 19042-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 2004-178-E	South Carolina Electric & Gas Company (South Carolina PSC)
Docket No. 03-07-02	Connecticut Light & Power Company (CT DPUC)
Docket No. EX02060363, Phases I&II	Rockland Electric Company (NJ BPU)
Docket No. U-00-88	ENSTAR Natural Gas Company and Alaska Pipeline Company (Regulatory Commission of Alaska)
Phase 1-2002 IERM, Docket No. U-02-075	Interior Telephone Company, Inc. (Regulatory Commission of Alaska)
Docket No. 05-SCNT- 1048-AUD	South Central Telephone Company (Kansas CC)
Docket No. 05-TRCT- 607-KSF	Tri-County Telephone Company (Kansas CC)
Docket No. 05-KOKT- 060-AUD	Kan Okla Telephone Company (Kansas CC)
Docket No. 2002-747	Northland Telephone Company of Maine (Maine PUC)

Docket No. 2003-34	Sidney Telephone Company (Maine PUC)
Docket No. 2003-35	Maine Telephone Company (Maine PUC)
Docket No. 2003-36	China Telephone Company (Maine PUC)
Docket No. 2003-37	Standish Telephone Company (Maine PUC)
Docket Nos. U-04-022, U-04-023	Anchorage Water and Wastewater Utility (Regulatory Commission of Alaska)
Case 05-116-U/06-055-U	Entergy Arkansas, Inc. EFC (Arkansas Public Service Commission)
Case 04-137-U	Southwest Power Pool RTO (Arkansas Public Service Commission)
Case No. 7109/7160	Vermont Gas Systems (Department of Public Service)
Case No. ER-2006-0315	Empire District Electric Company (Missouri PSC)
Case No. ER-2006-0314	Kansas City Power & Light Company (Missouri PSC)
Docket No. U-05-043,44	Golden Heart Utilities/College Park Utilities (Regulatory Commission of Alaska)
A-122250F5000	Equitable Resources, Inc. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
E-01345A-05-0816	Arizona Public Service Company (Arizona CC)
Docket No. 05-304	Delmarva Power & Light Company (Delaware PSC)
05-806-EL-UNC	Cincinnati Gas & Electric Company (Ohio PUC)
U-06-45	Anchorage Water Utility (Regulatory Commission of Alaska)
03-93-EL-ATA, 06-1068-EL-UNC	Duke Energy Ohio (Ohio PUC)
PUE-2006-00065	Appalachian Power Company (Virginia Corporation Commission)
G-04204A-06-0463 et. al	UNS Gas, Inc. (Arizona CC)
U-06-134	Chugach Electric Association, Inc. (Regulatory Commission of Alaska)
Docket No. 2006-0386	Hawaiian Electric Company, Inc (Hawaii PUC)
E-01933A-07-0402	Tucson Electric Power Company (Arizona CC)
G-01551A-07-0504	Southwest Gas Corporation (Arizona CC)
Docket No.UE-072300	Puget Sound Energy, Inc. (Washington UTC)
PUE-2008-00009	Virginia-American Water Company (Virginia SCC)
PUE-2008-00046	Appalachian Power Company (Virginia SCC)
E-01345A-08-0172	Arizona Public Service Company (Arizona CC)
A-2008-2063737	Babcock & Brown Infrastructure Fund North America, LP. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
08-1783-G-42T	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
08-1761-G-PC	Hope Gas, Inc., dba Dominion Hope, Dominion Resources, Inc., and Peoples Hope Gas Companies (West Virginia PSC)
Docket No. 2008-0083	Hawaiian Electric Company, Inc. (Hawaii PUC)
Docket No. 2008-0266	Young Brothers, Limited (Hawaii PUC)
G-04024A-08-0571	UNS Gas, Inc. (Arizona CC)
Docket No. 09-29	Tidewater Utilities, Inc. (Delaware PSC)
Docket No. UE-090704	Puget Sound Energy, Inc. (Washington UTC)
09-0878-G-42T	Mountaineer Gas Company (West Virginia PSC)
2009-UA-0014	Mississippi Power Company (Mississippi PSC)
Docket No. 09-0319	Illinois-American Water Company (Illinois CC)
Docket No. 09-414	Delmarva Power & Light Company (Delaware PSC)
R-2009-2132019	Aqua Pennsylvania, Inc. (Pennsylvania PUC)
Docket Nos. U-09-069, U-09-070	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
Docket Nos. U-04-023, U-04-024	Anchorage Water and Wastewater Utility - Remand (Regulatory Commission of Alaska)
W-01303A-09-0343 & SW-01303A-09-0343	Arizona-American Water Company (Arizona CC)
09-872-EL-FAC & 09-873-EL-FAC	Financial Audits of the FAC of the Columbus Southern Power Company and the Ohio Power Company - Audit I (Ohio PUC)

2010-00036	Kentucky-American Water Company (Kentucky PSC)
E-04100A-09-0496	Southwest Transmission Cooperative, IHnc. (Arizona CC)
E-01773A-09-0472	Arizona Electric Power Cooperative, Inc. (Arizona CC)
R-2010-2166208, R-2010-2166210, R-2010-2166212, & R-2010-2166214	Pennsylvania-American Water Company (Pennsylvania PUC)
PSC Docket No. 09-0602	Central Illinois Light Company D/B/A AmerenCILCO; Central Illinois Public Service Company D/B/A AmerenCIPS; Illinois Power Company D/B/A AmerenIP (Illinois CC)
10-0713-E-PC	Allegheny Power and FirstEnergy Corp. (West Virginia PSC)
Docket No. 31958	Georgia Power Company (Georgia PSC)
Docket No. 10-0467	Commonwealth Edison Company (Illinois CC)
PSC Docket No. 10-237	Delmarva Power & Light Company (Delaware PSC)
U-10-51	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
10-0699-E-42T	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
10-0920-W-42T	West Virginia-American Water Company (West Virginia PSC)
A.10-07-007	California-American Water Company (California PUC)
A-2010-2210326	TWP Acquisition (Pennsylvania PUC)
09-1012-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 1 (Ohio PUC)
10-268-EL FAC et al.	Financial Audit of the FAC of the Columbus Southern Power Company and the Ohio Power Company – Audit II (Ohio PUC)
Docket No. 2010-0080	Hawaiian Electric Company, Inc. (Hawaii PUC)
G-01551A-10-0458	Southwest Gas Corporation (Arizona CC)
10-KCPE-415-RTS	Kansas City Power & Light Company – Remand (Kansas CC)
PUE-2011-00037	Virginia Appalachian Power Company (Commonwealth of Virginia SCC)
R-2011-2232243	Pennsylvania-American Water (Pennsylvania PUC)
U-11-100	Power Purchase Agreement between Chugach Association, Inc. and Fire Island Wind, LLC (Regulatory Commission of Alaska)
A.10-12-005	San Diego Gas & Electric Company (California PUC)
PSC Docket No. 11-207	Artesian Water Company, Inc. (Delaware PSC)
Cause No. 44022	Indiana-American Water Company, Inc. (Indiana Utility Regulatory Commission)
PSC Docket No. 10-247	Management Audit of Tidewater Utilities, Inc. Affiliate Transactions (Delaware Public Service Commission)
G-04204A-11-0158	UNS Gas, Inc. (Arizona Corporation Commission)
E-01345A-11-0224	Arizona Public Service Company (Arizona CC)
UE-111048 & UE-111049	Puget Sound Energy, Inc. (Washington Utilities and Transportation Commission)
Docket No. 11-0721	Commonwealth Edison Company (Illinois CC)
11AL-947E	Public Service Company of Colorado (Colorado PSC)
U-11-77 & U-11-78	Golden Heart Utilities, Inc. and College Utilities Corporation (The Regulatory Commission of Alaska)
Docket No. 11-0767	Illinois-American Water Company (Illinois CC)
PSC Docket No. 11-397	Tidewater Utilities, Inc. (Delaware PSC)
Cause No. 44075	Indiana Michigan Power Company (Indiana Utility Regulatory Commission)
Docket No. 12-0001	Ameren Illinois Company (Illinois CC)
11-5730-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 2 (Ohio PUC)
PSC Docket No. 11-528	Delmarva Power & Light Company (Delaware PSC)
11-281-EL-FAC et al.	Financial Audit of the FAC of the Columbus Southern Power Company and the Ohio Power Company – Audit III (Ohio PUC)

Cause No. 43114-IGCC-4S1	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
Docket No. 12-0293	Ameren Illinois Company (Illinois CC)
Docket No. 12-0321	Commonwealth Edison Company (Illinois CC)
12-02019 & 12-04005	Southwest Gas Corporation (Public Utilities Commission of Nevada)
Docket No. 2012-218-E	South Carolina Electric & Gas (South Carolina PSC)
Docket No. E-72, Sub 479	Dominion North Carolina Power (North Carolina Utilities Commission)
12-0511 & 12-0512	North Shore Gas Company and The Peoples Gas Light and Coke Company (Illinois CC)
E-01933A-12-0291	Tucson Electric Power Company (Arizona CC)
Case No. 9311	Potomac Electric Power Company (Maryland PSC)
Cause No. 43114-IGCC-10	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
Docket No. 36498	Georgia Power Company (Georgia PSC)
Case No. 9316	Columbia Gas of Maryland, Inc. (Maryland PSC)
Docket No. 13-0192	Ameren Illinois Company (Illinois CC)
12-1649-W-42T	West Virginia-American Water Company (West Virginia PSC)
E-04204A-12-0504	UNS Electric, Inc. (Arizona CC)
PUE-2013-00020	Virginia and Electric Power Company (Virginia SCC)
R-2013-2355276	Pennsylvania-American Water Company (Pennsylvania PUC)
Formal Case No. 1103	Potomac Electric Power Company (District of Columbia PSC)
U-13-007	Chugach Electric Association, Inc. (The Regulatory Commission of Alaska)
12-2881-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 3 (Ohio PUC)
Docket No. 36989	Georgia Power Company (Georgia PSC)
Cause No. 43114-IGCC-11	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
UM 1633	Investigation into Treatment of Pension Costs in Utility Rates (Oregon PUC)
13-1892-EL FAC	Financial Audit of the FAC and AER of the Ohio Power Company – Audit I (Ohio PUC)
14-255-EL RDR	Regulatory Compliance Audit of the 2013 DIR of Ohio Power Company (Ohio PUC)
U-14-001	Chugach Electric Association, Inc. (The Regulatory Commission of Alaska)
U-14-002	Alaska Power Company (The Regulatory Commission of Alaska)
PUE-2014-00026	Virginia Appalachian Power Company (Commonwealth of Virginia SCC)
14-0117-EL-FAC	Financial, Management, and Performance Audit of the FAC and Purchased Power Rider for Dayton Power and Light – Audit 1 (Ohio PUC)
14-0702-E-42T	Monongahela Power Company and The Potomac Edison Company (West Virginia PSC)
Formal Case No. 1119	Merger of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, Exelon Energy Delivery Company, LLC, and New Special Purpose Entity, LLC (District of Columbia PSC)
R-2014-2428742	West Penn Power Company (Pennsylvania PUC)
R-2014-2428743	Pennsylvania Electric Company (Pennsylvania PUC)
R-2014-2428744	Pennsylvania Power Company (Pennsylvania PUC)
R-2014-2428745	Metropolitan Edison Company (Pennsylvania PUC)
Cause No. 43114-IGCC-12/13	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
14-1152-E-42T	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
WS-01303A-14-0010	EPCOR Water Arizona, Inc. (Arizona CC)
2014-000396	Kentucky Power Company (Kentucky PSC)
15-03-45^	Iberdrola, S.A. Et Al, and UIL Holdings Corporation merger (Connecticut PURA)
A.14-11-003	San Diego Gas & Electric Company (California PUC)
U-14-111	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
2015-UN-049	Atmos Energy Corporation (Mississippi PSC)
15-0003-G-42T	Mountaineer Gas Company (West Virginia PSC)

PUE-2015-00027	Virginia Electric and Power Company (Commonwealth of Virginia SCC)
Docket No. 2015-0022	Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., Maui Electric Company Limited, and NextEra Energy, Inc. (Hawaii PUC)
15-0676-W-42T	West Virginia-American Water Company (West Virginia PSC)
15-07-38^^	Iberdrola, S.A. Et Al, and UIL Holdings Corporation merger (Connecticut PURA)
15-26^^	Iberdrola, S.A. Et Al, and UIL Holdings Corporation merger (Massachusetts DPU)
15-042-EL-FAC	Management/Performance and Financial Audit of the FAC and Purchased Power Rider for Dayton Power and Light (Ohio PUC)
2015-UN-0080	Mississippi Power Company (Mississippi PSC)
Docket No. 15-00042	B&W Pipeline, LLC (Tennessee Regulatory Authority)
WR-2015-0301/SR-2015-0302	Missouri American Water Company (Missouri PSC)
U-15-089, U-15-091, & U-15-092	Golden Heart Utilities, Inc. and College Utilities Corporation (The Regulatory Commission of Alaska)
Docket No. 16-00001	Kingsport Power Company d/b/a AEP Appalachian Power (Tennessee Regulatory Authority)
PUE-2015-00097	Virginia-American Water Company (Commonwealth of Virginia SCC)
15-1854-EL-RDR	Management/Performance and Financial Audit of the Alternative Energy Recovery Rider of Duke Energy Ohio, Inc. (Ohio PUC)
Docket No. 40161	Georgia Power Company – Integrated Resource Plan (Georgia PSC)
Formal Case No. 1137	Washington Gas Light Company (District of Columbia PSC)
160021-EI, et al.	Florida Power Company (Florida PSC)
R-2016-2537349	Metropolitan Edison Company (Pennsylvania PUC)
R-2016-2537352	Pennsylvania Electric Company (Pennsylvania PUC)
R-2016-2537355	Pennsylvania Power Company (Pennsylvania PUC)
R-2016-2537359	West Penn Power Company (Pennsylvania PUC)
16-0717-G-390P	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
15-1256-G-390P (Reopening)/16-0922-G-390P	Mountaineer Gas Company (West Virginia PSC)
16-0550-W-P	West Virginia-American Water Company (West Virginia PSC)
CEPR-AP-2015-0001	Puerto Rico Electric Power Authority (Puerto Rico Energy Commission)

* Testimony filed, examination not completed
** Issues stipulated
*** Company withdrew case
^ Testimony filed, case withdrawn after proposed decision issued
^^ Issues stipulated before testimony was filed

EXHIBIT RCS-1

Kentucky Utilities Company
Case No. 2016-00370
Exhibit RCS-1
Accompanying the Direct Testimony of Ralph Smith

Kentucky Utilities Company
Calculation of Revenue Deficiency (Sufficiency)

Forecasted Test Period Ended June 30, 2018

Line No.	Description	Reference	Per Company (A)	Per AG (B)	Difference (C)
1	Adjusted Capitalization	Sch D	$ 3,638,800,730	$ 3,603,304,645	$ (35,496,085)
2	Rate of return	Sch D	7.29%	6.34%	
3	Net operating income required		$ 265,293,552	$ 228,614,766	$ (36,678,787)
4	Adjusted net operating income	Sch C	$ 202,510,540	$ 213,333,236	$ 10,822,696
5	Net operating income deficiency (Sufficiency)		$ 62,783,012	$ 15,281,530	$ (47,501,482)
6	Gross revenue conversion factor	Sch A-1	1.642132	1.641605	
7	Revenue deficiency (Sufficiency)		$ 103,098,006	$ 25,086,238	$ (78,011,768)
8	Change in Revenue		$ 103,098,006	$ 25,086,238	$ (78,011,768)
9	Adjusted operating revenues	Sch C	$ 1,485,327,442	$ 1,485,327,442	$ -
10	Revenue requirement	Sch C	$ 1,588,425,448	$ 1,510,413,680	$ (78,011,768)
11	Revenue increase, percent		6.94%	1.69%	

Notes and Source

Col.A: Schedule A from Company filing
Col.B: See referenced schedules
Col.C: Col B - Col. A

Kentucky Utilities Company
Revenue Requirement Reconciliation

Forecasted Test Period Ended June 30, 2018

Line No.	Description	Exhibit RCS-1 Schedule Reference	Component	AG Adjustments (A)	AG Multiplier (B)	AG Revenue Requirement Amount (C)
1		D	ROR Difference		-0.95%	
2	**Jurisdictional Capitalization**	A-1	GRCF	x	1.6416	
3	Capitalization per KU's Filing	B		$ 3,638,800,730	-1.553%	$ (56,515,059)
4		D	Rate of Return		6.34%	
5	**Effect of AG Adjustments to Capitalization**	A-1	GRCF	x	1.6416	
				Sch B.1		
6	Slippage Adjustment	B-1		$ (7,142,892)	10.42%	$ (743,954)
7	Distribution Automation	B-2		$ (2,905,008)	10.42%	$ (302,565)
8	Cash Working Capital	B-3		$ (1,774,884)	10.42%	$ (184,860)
9	Advanced Metering Systems	B-4		$ (23,673,302)	10.42%	$ (2,465,647)
10	Total AG Capitalization Adjustments			$ (35,496,085)		
11	**AG Adjusted Capitalization**	B&D		$ 3,603,304,645		
12	**Net Operating Income**		Pre-Tax		AG	
			Operating Income	NOI Amount	GRCF	
	Effect of AG Adjustments on NOI		Amount	Sch C.1	Sch. A-1	
13	Interest Synchronization	C-1	$ -	$ 1,550,105	1.6416	$ (2,544,660)
14	Incentive Compensation Expense	C-2	$ (2,605,059)	$ 1,595,597	1.6416	$ (2,619,340)
15	Advanced Metering Services	C-3	$ (3,789,059)	$ 2,320,797	1.6416	$ (3,809,832)
16	Transmission Vegetation Management Expense	C-4	$ (3,936,758)	$ 2,411,262	1.6416	$ (3,958,340)
17	Uncollectibles Expense	C-5	$ (936,649)	$ 573,697	1.6416	$ (941,785)
18	Depreciation Expense - Impacts of Slippage	C-6	$ (167,559)	$ 102,630	1.6416	$ (168,478)
19	Depreciation Expense Related to Distribution Automation	C-7	$ (65,929)	$ 40,381	1.6416	$ (66,290)
20	Payroll and Employee Benefits Expense - Remove Vacant Positions	C-8	$ (1,880,656)	$ 1,151,901	1.6416	$ (1,890,967)
21	Affiliate Charges From PPL Services Corporation to LG&E	C-9	$ (1,504,533)	$ 921,526	1.6416	$ (1,512,782)
22	Not Used for KU	C-10	$ -	$ -	1.6416	$ -
23	Rescheduling of Expiring Regulatory Asset Amortizations	C-11	$ (252,734)	$ 154,799	1.6416	$ (254,119)
24	Total AG Adjustments to Operating Income	C.1	$ (15,138,937)	$ 10,822,696		
25	Net Operating Income per Company Filing	C		$ 202,510,540		
26	**AG Adjusted Net Operating Income**	C		$ 213,333,236		
	Gross Revenue Conversion Factor Difference:					
27	Per AG	A-1			1.6416	
28	Per Company	A-1			1.6421	
29	Difference				-0.000527	
30	Company Adjusted NOI Deficiency	A			$ 62,783,012	
31	GRCF Difference					$ (33,091)
32	AG REVENUE REQUIREMENT ADJUSTMENTS ABOVE					$ (78,011,769)
33	Company Requested Base Rate Revenue Increase (Decrease)	A				$ 103,098,006
34	Reconciled Revenue Deficiency					$ 25,086,237
35	Revenue Requirement Deficiency Calculated on Schedule A	A				$ 25,086,238
36	Difference Not Accounted for Above	A				$ (1)

Notes and Source

Pre-tax return computed using Gross Revenue Conversion Factor

Kentucky Utilities Company
Gross Revenue Conversion Factor

Forecasted Test Period Ended June 30, 2018

Line No.	Description	Reference	Tax Rates	Per Company State (A)	Per Company Federal (B)	Per AG State (C)	Per AG Federal (D)
1	Operating Revenues			100.000000%	100.000000%	100.000000%	100.000000%
2	Less: Uncollectible Accounts Expense	Notes A&B		0.352000%	0.352000%	0.320000% [B]	0.320000% [B]
3	Less: PSC Fees	Note A		0.194100%	0.194100%	0.194100%	0.194100%
4	Less: Production Activities Deduction - State			3.336000%		3.336000%	
5	Income Before State Taxes			96.117900%	99.453900%	96.149900%	99.485900%
6	Less: State Income Taxes	Note A	6.0000%	5.767074%	5.767074%	5.768994%	5.768994%
7	Less: Production Activities Deduction - Federal						
8	Income Before Federal Income Taxes				93.686826%		93.716906%
9	Less: Federal Income Taxes	Note A	35.00%		32.790389%		32.800917%
10	Operating Income Percentage				60.896437%		60.915989%
11	Gross Revenue Conversion Factor	Note A			1.642132		1.641605

Notes and Source
[A] KU Schedule H-1
[B] See Schedule C-5

12	Combined state and federal income tax rate	38.7501%	Company Schedule WPH-1.B, line 7

Components of Base Rate Revenue Change

Line No.	Description	Percent	Per AG
13	Revenue Change		$ 25,086,238
	Change in Expenses and Net Operating Income:		
14	Less: Uncollectible Accounts Expense	0.3200%	$ 80,276
15	PSC Fees	0.1941%	$ 48,692
16	State Income Taxes	5.7690%	$ 1,447,224
17	Federal Income Taxes	32.8009%	$ 8,228,516
18	Net Operating Income	60.9160%	$ 15,281,530
19	Total Revenue Change	100.0000%	$ 25,086,238

Kentucky Utilities Company
Adjusted Rate Base

Forecasted Test Period Ended June 30, 2018

Exhibit RCS-1
Schedule B
Case No. 2016-00370
Page 1 of 1

Line No.	Description	Company Proposed (A)	AG Adjustments (B)	AG Proposed (C)
	RATE BASE			
	Electric Utility Plant			
1	Utility Plant - Original Cost	$ 6,970,753,239	$ (10,047,900)	$ 6,960,705,339
	Deduct			
2	Reserve for Depreciation	$ 2,699,542,764	$ -	$ 2,699,542,764
3	Net Electric Utility Plant	$ 4,271,210,475	$ (10,047,900)	$ 4,261,162,575
4	Construction Work in Progress	$ 118,703,941	$ (25,507,302)	$ 93,196,639
	Deduct:			
5	Customer Advances for Construction	$ 1,549,704	$ -	$ 1,549,704
6	Accumulated Deferred Income taxes	$ 910,427,698	$ (1,834,000)	$ 908,593,698
7	Income Tax Credit	$ 81,185,411	$ -	$ 81,185,411
8	Total Deductions	$ 993,162,813	$ (1,834,000)	$ 991,328,813
9	Net Plant Deductions	$ 3,396,751,603	$ (33,721,201)	$ 3,363,030,402
	Add:			
10	Materials and Supplies	$ 119,808,344	$ -	$ 119,808,344
11	Prepayments	$ 16,171,254	$ -	$ 16,171,254
12	Emmission Allowances	$ -	$ -	$ -
13	Cash Working Capital	$ 106,348,560	$ (1,774,884)	$ 104,573,676
14	Unamortized Closure Costs	$ -	$ -	$ -
15	Total Additions	$ 242,328,158	$ (1,774,884)	$ 240,553,274
16	Total Net Original Cost Rate Base	$ 3,639,079,761	$ (35,496,085)	$ 3,603,583,676
17	ARO Balance Offset	$ 166,187,055	$ -	$ 166,187,055
18	Total Net Original Cost Rate Base for Capital Allocation	$ 3,805,266,816	$ (35,496,085)	$ 3,769,770,731
19	Jurisdictional Capitalization	$ 3,638,800,730	$ (35,496,085)	$ 3,603,304,645

Notes and Source
Col. A: Amounts from Supporting Schedule B-1.1, Page 3 of 4 of KU's filing
Col. B: See Schedule B.1

Kentucky Utilities Company
Summary of Adjustments to Rate Base

Forecasted Test Period Ended June 30, 2018

Line No.	Description	AG Adjustments	Slippage	Distribution Automation	Cash Working Capital	Advanced Metering Systems
			B-1	B-2	B-3	B-4
				Holloway		Alvarez
	RATE BASE					
	Electric Utility Plant					
1	Utility Plant - Original Cost	$ (10,047,900)	$ (7,142,892)	$ (2,905,008)		
2	Deduct					
3	Reserve for Depreciation	$ -				
4	Net Electric Utility Plant	$ (10,047,900)	$ (7,142,892)	$ (2,905,008)	$ -	$ -
5	Construction Work in Progress	$ (25,507,302)				$ (25,507,302)
	Deduct:					
6	Customer Advances for Construction	$ -				
7	Accumulated Deferred Income taxes	$ (1,834,000)				$ (1,834,000)
8	Income Tax Credit	$ -				
9	Total Deductions	$ (1,834,000)	$ -	$ -	$ -	$ (1,834,000)
10	Net Plant Deductions	$ (33,721,201)	$ (7,142,892)	$ (2,905,008)	$ -	$ (23,673,302)
	Add:					
11	Materials and Supplies	$ -				
12	Prepayments	$ -				
13	Emmission Allowances	$ -				
14	Cash Working Capital	$ (1,774,884)			$ (1,774,884)	
15	Unamortized Closure Costs	$ -				
16	Total Additions	$ (1,774,884)	$ -	$ -	$ (1,774,884)	$ -
17	Total Net Original Cost Rate Base	$ (35,496,085)	$ (7,142,892)	$ (2,905,008)	$ (1,774,884)	$ (23,673,302)
18	ARO Balance Offset	$ -				
19	Total Net Original Cost Rate Base for Capital Allocation	$ (35,496,085)	$ (7,142,892)	$ (2,905,008)	$ (1,774,884)	$ (23,673,302)

Notes and Source
See referenced schedule for each adjustment

Kentucky Utilities Company
Adjusted Net Operating Income

Forecasted Test Period Ended June 30, 2018

Exhibit RCS-1
Schedule C
Case No. 2016-00370
Page 1 of 1

			Per AG			
Line No.	Description	Per Company (A)	AG Adjustments (B)	Per AG (C)	Components of Revenue Change (D)	Revenue Requirement Impact (E)
	Operating Revenue					
1	Electric Sales Revenues	$ 1,453,880,950	$ -	$ 1,453,880,950	$ 25,086,238	$ 1,478,967,188
2	Other Operating Revenues	$ 31,446,492	$ -	$ 31,446,492		$ 31,446,492
3	**Total Operating Revenues**	$ 1,485,327,442	$ -	$ 1,485,327,442	$ 25,086,238	$ 1,510,413,680
	Operating Expenses			$ -		
4	Operations & Maintenance Expense	$ 932,936,123	$ (14,199,071)	$ 918,737,052	$ 128,968	$ 918,866,020
5	Depreciation and Amortization	$ 228,062,837	$ (832,990)	$ 227,229,847		$ 227,229,847
6	Regulatory Debits	$ -	$ -	$ -		$ -
7	Taxes Other Than Income Taxes	$ 37,820,875	$ (106,876)	$ 37,713,999		$ 37,713,999
8	Total Income Taxes	$ 83,997,067	$ 4,316,241	$ 88,313,308	$ 9,675,740	$ 97,989,048
9	Investment Tax Credit	$ -	$ -	$ -		$ -
10	Losses/(Gains) from Deposition of Allowances	$ -	$ -	$ -		$ -
11	**Total Operating Expenses**	$ 1,282,816,902	$ (10,822,696)	$ 1,271,994,206	$ 9,804,708	$ 1,281,798,914
12	**Net Electric Operating Income**	$ 202,510,540	$ 10,822,696	$ 213,333,236	$ 15,281,530	$ 228,614,766
13	**Capitalization Allocated to Kentucky Jurisdiction**	$ 3,638,800,730	$ (35,496,085)	$ 3,603,304,645		$ 3,603,304,645
14	**Rate of Return on Capitalization**	5.57%		5.92%		6.34%
15	**Kentucky Jurisdiction Rate Base**	$ 3,639,079,760	$ (35,496,085)	$ 3,603,583,675		$ 3,603,583,675
16	**Earned Rate of Return**	5.56%		5.92%		6.34%

Notes and Source
Col.A: KU Schedule C-1, Column 3
Col.B: Schedule C.1
Col.C: Col.A + Col.B
Col.D: Schedule A-1
Col.E: Col. C + Col. D

Kentucky Utilities Company
Summary of Net Operating Income Adjustments

Forecasted Test Period Ended June 30, 2018

Line No.	Description	AG Adjustments	Interest Synchronization	Incentive Compensation Expense	Advanced Metering Services
			C-1	C-2	C-3
					Alvarez
	Operating Revenue				
1	Electric Sales Revenues	$ -			
2	Other Operating Revenues	$ -			
3	**Total Operating Revenues**	$ -	$ -	$ -	$ -
	Operating Expenses				
4	Operations & Maintenance Expense	$ (14,199,071)		$ (2,605,059)	$ (3,189,557)
5	Depreciation and Amortization	$ (832,990)			$ (599,502)
6	Regulatory Debits	$ -			
7	Taxes Other Than Income Taxes	$ (106,876)			
8	Total Income Taxes	$ 4,316,241	(1,550,105)	$ 1,009,462	$ 1,468,262
9	Investment Tax Credit	$ -			
10	Losses/(Gains) from Deposition of Allowances	$ -			
11	**Total Operating Expenses**	$ (10,822,696)	$ (1,550,105)	$ (1,595,597)	$ (2,320,797)
12	**Net Electric Operating Income**	$ 10,822,696	$ 1,550,105	$ 1,595,597	$ 2,320,797

Notes and Source

Line 8: Composite Income Tax Rate 38.7501%

Kentucky Utilities Company
Summary of Net Operating Income Adjustments

Forecasted Test Period Ended June 30, 2018

Line No.	Description	Transmission Vegetation Management	Uncollectibles Expense	Depreciation Expense - Impacts of Slippage	Depreciation Expense Related to Distribution Automation	Payroll and Employee Benefits - Remove Vacant Positions
		C-4	C-5	C-6	C-7	C-8
	Operating Revenue					
1	Electric Sales Revenues					
2	Other Operating Revenues					
3	**Total Operating Revenues**	$ -	$ -	$ -	$ -	$ -
	Operating Expenses					
4	Operations & Maintenance Expense	$ (3,936,758)	$ (936,649)			$ (1,773,780)
5	Depreciation and Amortization			$ (167,559)	$ (65,929)	
6	Regulatory Debits					
7	Taxes Other Than Income Taxes					$ (106,876)
8	Total Income Taxes	$ 1,525,496	$ 362,952	$ 64,929	$ 25,548	$ 728,755
9	Investment Tax Credit					
10	Losses/(Gains) from Deposition of Allowances					
11	**Total Operating Expenses**	$ (2,411,262)	$ (573,697)	$ (102,630)	$ (40,381)	$ (1,151,901)
12	**Net Electric Operating Income**	$ 2,411,262	$ 573,697	$ 102,630	$ 40,381	$ 1,151,901

Notes and Source
Line 8: Composite Income Tax Rate 38.7501%

Kentucky Utilities Company
Summary of Net Operating Income Adjustments

Forecasted Test Period Ended June 30, 2018

Line No.	Description	PPL Services Corporation Affiliate Charges to LG&E	Gas Line Tracker Mechanism	Rescheduling of Expiring Regulatory Asset Amortizations
		C-9	C-10	C-11
			N/A	
	Operating Revenue			
1	Electric Sales Revenues			
2	Other Operating Revenues			
3	**Total Operating Revenues**	$ -	$ -	$ -
	Operating Expenses			
4	Operations & Maintenance Expense	$ (1,504,533)		$ (252,734)
5	Depreciation and Amortization			
6	Regulatory Debits			
7	Taxes Other Than Income Taxes			
8	Total Income Taxes	$ 583,007		$ 97,935
9	Investment Tax Credit			
10	Losses/(Gains) from Deposition of Allowances			
11	**Total Operating Expenses**	$ (921,526)	$ -	$ (154,799)
12	**Net Electric Operating Income**	$ 921,526	$ -	$ 154,799

Notes and Source
Line 8: Composite Income Tax Rate 38.7501%

Kentucky Utilities Company
Capital Structure and Cost Rates

Forecasted Test Period Ended June 30, 2018

Line No.	Description	Adjusted Capitalization Amount	Capital Structure Ratio	Cost Rate	Weighted Cost	GCRF	WACC (Pre-Tax)
		(A)	(B)	(C)	(D)	(E)	(F) = D x E
	I. Per Company						
1	Long Term Debt	$ 1,610,324,675	44.25%	4.12%	1.82%	1.0050	1.83%
2	Short Term Debt	$ 89,828,656	2.47%	0.74%	0.02%	1.0050	0.02%
3	Common Equity	$ 1,938,647,399	53.28%	10.23%	5.45%	1.6421	8.95%
4	Total	$ 3,638,800,730	100.00%		**7.29%**		**10.80%**
	II. Per AG						
5	Long Term Debt	$ 1,706,525,080	47.36%	4.12%	1.95%	1.0050	1.96%
6	Short Term Debt	$ 95,127,243	2.64%	0.74%	0.02%	1.0050	0.02%
7	Common Equity	$ 1,801,652,323	50.00%	8.75%	4.38%	1.6416	7.18%
8	Total	$ 3,603,304,645	100.00%		**6.34%**		**9.16%**
9	Difference		L.8- L.4		-0.95%		-1.64%
10	Weighted Cost of Debt per AG		Sum of Lines 6, 7 & 8		1.970%		

Notes

Cols. A-D (Lines 1-3): Schedule J-1.1/J-2.2, Page 1 of KU's filing
Cols. B, C and D (lines 5-8): Cost rates and Return on Equity as recommended by AG witness J. Randall Woolridge
Cols. A-D (Lines 5-8): Also see pages 2 and 3 of this schedule

Kentucky Utilities Company
Capital Structure and Cost Rates - Capitalization

Forecasted Test Period Ended June 30, 2018

Line No.	Description	PER BOOK BALANCE (A)	Adjustment Amount (B)	Adjusted Capital (C=A+B)	Jurisdictional Rate Base Percentage (D)	Jurisdictional Capital (E=CxD)	Jurisdictional Adjustments (F)	Jurisdictional Adjusted Capital (G=E+F)	Reapportioned Jurisdictional Capital (H)	Percent of Total (I)	Cost Rate (J)	13 Month Average Weighted Cost (K)=IxJ
	I. Per Company											
1	Long Term Debt	$ 2,315,890,751	$ (540,431)	$ 2,315,350,320	89.28%	$ 2,067,144,766	$ (456,820,091)	$ 1,610,324,675		44.25%	4.12%	1.82%
2	Short Term Debt	$ 129,187,211	$ (30,147)	$ 129,157,064	89.28%	$ 115,311,426	$ (25,482,771)	$ 89,828,656		2.47%	0.74%	0.02%
3	Common Equity	$ 2,788,572,734	$ (1,154,801)	$ 2,787,417,933	89.28%	$ 2,488,606,730	$ (549,959,331)	$ 1,938,647,399		53.28%	10.23%	5.45%
4	Total	$ 5,233,650,696	$ (1,725,379)	$ 5,231,925,317		$ 4,671,062,923	$ (1,032,262,193)	$ 3,638,800,730		100.00%		7.29%
	II. Per AG								AG Adjusted			
5	Long Term Debt	$ 2,315,890,751	$ (540,431)	$ 2,315,350,320	89.28%	$ 2,067,144,766	$ (456,820,091)	$ 1,610,324,675	$ 1,706,525,080	47.36%	4.12%	1.95%
6	Short Term Debt	$ 129,187,211	$ (30,147)	$ 129,157,064	89.28%	$ 115,311,426	$ (25,482,771)	$ 89,828,656	$ 95,127,243	2.64%	0.74%	0.02%
7	Common Equity	$ 2,788,572,734	$ (1,154,801)	$ 2,787,417,933	89.28%	$ 2,488,606,730	$ (549,959,331)	$ 1,938,647,399	$ 1,801,652,323	50.00%	8.75%	4.38%
8	Total	$ 5,233,650,696	$ (1,725,379)	$ 5,231,925,317		$ 4,671,062,923	$ (1,032,262,193)	$ 3,638,800,730	$ 3,603,304,645	100.00%		6.34%

Notes and Source

Part I: Amounts above from Schedule J-1.1/J-2.2, Page 1 from the Company's filing
Part II: Lines 8-14, column H: See page 3, column H

The long term debt cost rate has been updated by AG witness Woolridge

Kentucky Utilities Company
Capital Structure and Cost Rates

Forecasted Test Period Ended June 30, 2018

Line No.	Description	Company Proposed Jurisdictional Adjusted Capitalization	Slippage B-1	Distribution Automation B-2	Cash Working Capital B-3	Advanced Metering Systems B-4	Total AG Adjustments	AG Adjusted Capitalization Before Reapportionment	Reapportioned Kentucky Jurisdictional Capitalization Per AG
		(A)	(B)	(C)	(D)	(E)	(F)	(G)=A+F	(H) =P
1	Long Term Debt	$ 1,610,324,675	$ (3,382,874)	$ (1,375,812)	$ (840,585)	$ (11,211,676)	$ (16,810,946)	$ 1,593,513,729	$ 1,706,525,080
2	Short Term Debt	$ 89,828,656	$ (188,572)	$ (76,692)	$ (46,857)	$ (624,975)	$ (937,097)	$ 88,891,559	$ 95,127,243
3	Common Equity	$ 1,938,647,399	$ (3,571,446)	$ (1,452,504)	$ (887,442)	$ (11,836,651)	$ (17,748,043)	$ 1,920,899,357	$ 1,801,652,323
4	Total	$ 3,638,800,730	$ (7,142,892)	$ (2,905,008)	$ (1,774,884)	$ (23,673,302)	$ (35,496,085)	$ 3,603,304,645	$ 3,603,304,645

Notes and Source
Col.A: Page 2, column G, lines 1-4

Capitalization Reapportionment Adjustment:

Line No.	Description	AG (Woolridge) Recommended	Per Company Before Adjustment: Page 2, Col. G Capitalization	Per Company Before Adjustment: Page 2, Col. G Ratios	AG Capitalization Reapportionment: Ratios	AG Capitalization Reapportionment: Capitalization	Capitilization Reapportionment Adjustment on Company Amount	AG Adjusted Capitalization Before Reapportionment	Capitilization Reapportionment Adjustment on AG Adjusted Amt.	Jurisdictional Capitalization Reapportion Adjustment
		(I)	(J)	(K)	(L)=I	(M)	(N)	(O)=G	(P)	(Q) = P-O
5	Long Term Debt	47.36%	$ 1,610,324,675	44.25%	47.36%	$ 1,723,336,026	$ 113,011,351	$ 1,593,513,729	$ 1,706,525,080	$ 113,011,351
6	Short Term Debt	2.64%	$ 89,828,656	2.47%	2.64%	$ 96,064,339	$ 6,235,684	$ 88,891,559	$ 95,127,243	$ 6,235,684
7	Total Debt	50.00%								
8	Common Equity	50.00%	$ 1,938,647,399	53.28%	50.00%	$ 1,819,400,365	$ (119,247,034)	$ 1,920,899,357	$ 1,801,652,323	$ (119,247,034)
9	Total	100.00%	$ 3,638,800,730	100.00%	100.00%	$ 3,638,800,730	$ -	$ 3,603,304,645	$ 3,603,304,645	$ -

Cols. I and L: AG witness Woolridge recommended capital structure ratios. See Exhibits JRW-1 and JRW-5

Kentucky Utilities Company
Slippage Adjustment

Forecasted Test Period Ended June 30, 2018

Exhibit RCS-1
Schedule B-1
Case No. 2016-00370
Page 1 of 1

Line No.	Rate Base Component	Base Period (A)	13 Month Avg Forecast Period (B)	Plant & CWIP Increase From Base Period (C)	Slippage Factor (D)	Slippage Adjusted (E)=C x D	Slippage Adjustment (F) = E-C
	ELECTRIC:						
1	Plant in Service	$ 6,763,836,329	$ 6,970,368,268	206,531,939	97.204%	$ 200,757,306	$ (5,774,633)
2	Property Held for Future Use	$ 384,971	$ 384,971				
3	Accumulated Depreciation and Amortization	$ (2,573,686,914)	$ (2,699,542,764)				
4	Net Plant in Service (Lines 1+2+3)	$ 4,190,534,386	$ 4,271,210,475	$ 206,531,939		$ 200,757,306	$ (5,774,633)
5	Construction Work in Progress	$ 69,767,636	$ 118,703,941	$ 48,936,305	97.204%	$ 47,568,046	$ (1,368,259)
6	Net Plant (Lines 4+5)	$ 4,260,302,022	$ 4,389,914,416	$ 255,468,244		$ 248,325,352	$ (7,142,892)
7	Cash Working Capital Allowance	$ 101,002,227	$ 106,348,560				
8	Other Working Capital Allowances	$ 150,181,362	$ 135,979,598				
9	Customer Advances for Construction	$ (1,549,704)	$ (1,549,704)				
10	Deferred Income Taxes	$ (819,583,394)	$ (910,427,698)				
11	Investment Tax Credits	$ (82,538,337)	$ (81,185,411)				
12	Other Items	$ -	$ -				
13	Rate Base (Lines 6 through 12)	$ 3,607,814,177	$ 3,639,079,760	$ 255,468,244		$ 248,325,352	$ (7,142,892)

Notes and Source
Cols. A and B: Company Schedule B-1
Col.C: Col. B - Col.A
Col. D: Company response to Staff 1-13

Kentucky Utilities Company
Distribution Automation

Forecasted Test Period Ended June 30, 2018

Line No.	Description	Kentucky Jurisdictional Amount (A)	Reference
1	AG Jurisdictional Adjustment to Plant in Service Related to Distribution Automation	$ (2,905,008)	A

Notes and Source

A: This adjustment is being sponsored by AG witness Larry Holloway and calculated below:

	Description	Plant Account	Total Companny Amount	Half of Plant Amount	Kentucky Jurisdictional Allocation Factor	Kentucky Jurisdictional Amount
2	OH Conductors and Devices	365	$ 5,758,000	$ 2,879,000	100.00%	$ 2,879,000
3	Communication Equipment	397	$ 238,000	$ 119,000	92.074%	$ 109,568
4	Total Adjustment		$ 5,996,000	$ 2,998,000		$ 2,988,568
5	Amount Reflected in Slippage Adjustment on Schedule B-1					$ (83,560)
6	Net Adjustment to Plant in Service Related to Distribution Automation					$ 2,905,008

B: The amount reflected in Overall Slippage Adjustment calculated as follows

		Amount	Reference
7	Total Distribution Automation Adjustment - Line 4	$ 2,988,568	Line 4
8	Slippage Factor on Schedule B-1	97.204%	Sch. B-1
9	Slippage Adjusted Distribution Automation Adjustment	$ 2,905,008	L7 x L8
10	Amount to Reflect in Overall Slippage Adjustment on Schedule B-1	$ (83,560)	L9 - L7

Kentucky Utilities Company
Cash Working Capital

Forecasted Test Period Ended June 30, 2018

Line No.	Description	Base Electric Amount	AG Adjustments	AG Adjusted Amount
		(A)	(B)	(C)
1	Electric O&M Expenses	$ 901,541,819	$ (14,199,071)	$ 887,342,748
	Less:			
2	Electric Power Purchased	$ (50,753,339)		$ (50,753,339)
3	Gas Supply Expenses			
4	Subtotal	$ 850,788,480	$ (14,199,071)	$ 836,589,409
5	1/8 Formula Percentage	12.5%	12.5%	12.5%
6	Cash Working Capital	$ 106,348,560	$ (1,774,884)	$ 104,573,676

Notes and Source
Col. A: Amounts from Company's application, Supporting Schedule B-1.1, page 4 of 4
Col. B: See page 2

Kentucky Utilities Company
Cash Working Capital - AG Adjustments to Expenses

Forecasted Test Period Ended June 30, 2018

Exhibit RCS-1
Schedule B-3
Case No. 2016-00370
Page 2 of 2

Line No.	Description	Adjustment No.	Expense Adjustments (A)	O&M Expense in CWC (B)
1	Interest Synchronization	C-1	$ (1,550,105)	
2	Incentive Compensation Expense	C-2	$ (1,595,597)	$ (2,605,059)
3	Advanced Metering Services	C-3	$ (2,320,797)	$ (3,189,557)
4	Transmission Vegetation Management Expense	C-4	$ (2,411,262)	$ (3,936,758)
5	Uncollectibles Expense	C-5	$ (573,697)	$ (936,649)
6	Depreciation Expense - Impacts of Slippage	C-6	$ (102,630)	
7	Depreciation Expense Related to Distribution Automation	C-7	$ (40,381)	
8	Payroll and Employee Benefits Expense - Remove Vacant Positions	C-8	$ (1,151,901)	$ (1,773,780)
9	Affliliate Charges From PPL Services Corporation to LG&E	C-9	$ (921,526)	$ (1,504,533)
10	Not Used for KU	C-10	$ -	$ -
11	Rescheduling of Expiring Regulatory Asset Amortizations	C-11	$ (154,799)	$ (252,734)
12	TOTAL		$ (10,822,696)	$ (14,199,071)
13	Total per Schedule C.1, line 11		$ (10,822,696)	
14	Difference		$ -	
15	Total O&M Expense per Schedule C, column B, line 4			$ (14,199,071)
16	Difference			$ -

This schedule shows how the AG adjustments to operating expenses from Schedule C.1 are posted for CWC purposes.

Kentucky Utilities Company
Advanced Metering Systems

Forecasted Test Period Ended June 30, 2018

Line No.	Description	Kentucky Jurisdictional Amount (A)	Reference
1	Adjustment to Remove AMS Related Costs from CWIP	$ (25,507,302)	A
2	Adjustment to Remove AMS Related ADIT	$ 1,834,000	B
3	Net Adjustment to 13-Month Average Rate Base	$ (23,673,302)	

Notes and Source

A: Adjustment calculated using information from the response to KIUC 1-17 and shown below:

	Description	Total Company Test Year Amount	Kentucky Jurisdictional Factor*	Kentucky Jurisdictional Test Year Amount
4	13-Month Average CWIP Related to AMS	$ 26,241,000	100.00%	$ 26,241,000
5	Amount Reflected in Slippage Adjustment on Schedule B-1	$ (733,698)		$ (733,698)
6	Net Adjustment to CWIP Related to AMS	$ 25,507,302		$ 25,507,302
7	13-Month Average ADIT Related to AMS	$ 1,834,000	100.00%	$ 1,834,000

* Kentucky jurisdictional allocation factor for Distribution plant from KU Schedule B-7

Kentucky Utilities Company
Interest Synchronization

Forecasted Test Period Ended June 30, 2018

Exhibit RCS-1
Schedule C-1
Case No. 2016-00370
Page 1 of 1

Line No.	Description	KU Amount (A)	AG Amount (B)	AG Adjustment (C)
1	Adjusted Jurisdictional Capitalization	$ 3,638,800,730	$ 3,603,304,645	
2	Weighted Cost of Debt	1.840%	1.970%	
3	Synchornized Interest Deduction	$ 66,969,923	$ 70,970,188	
4	Composite Federal and State Income Tax Rate	38.7501%	38.7501%	
5	Income Tax Adjustment (Ln 3 X Ln 4)	$ (25,950,881)	$ (27,500,985)	$ (1,550,105)

Notes and Source:
Col. A: Amounts from WPD-2, Sheet 3 of 3 from Company's filing
Col. B: Debt capitalization amounts and cost rates are from Schedule D

Kentucky Utilities Company
Incentive Compensation Expense

Forecasted Test Period Ended June 30, 2018

Line No.	Description	Kentucky Jurisdictional Amount	Reference
1	AG Jurisdictional Adjustment to Test Year Incentive Compensation Expense	$ (2,605,059)	A

Notes and Source

A: Adjustment to incentive compensation expense calculated as follows:

	Description	Kentucky Jurisdictional Amount	Reference
2	KU Employees	$ 3,627,330	see page 2
3	LGE-KU Services	$ 6,146,612	see page 2
4	LG&E	$ 646,295	see page 2
5	Total Test Period Team Incentive Award Expense	$ 10,420,237	
6	Percentage of Base Period Team Incentive Award Expense Recommended for Disallowance	25.00%	
7	AG Adjustment to Test Year Team Incentive Award Expense	$ 2,605,059	

Kentucky Utilities Company
Incentive Compensation Expense

Forecasted Test Period Ended June 30, 2018

Exhibit RCS-1
Schedule C-2
Case No. 2016-00370
Page 2 of 3

Line No.	FERC Account	Total Company Amount	Kentucky Jurisdicitional Allocation Factor	Kentucky Jurisdictional Amount
		(A)	(B)	(C)
1	500	$ 675,798	0.870121	$ 588,026
2	501	$ 229,157	0.879382	$ 201,517
3	502	$ 748,037	0.870121	$ 650,883
4	505	$ 466,584	0.870121	$ 405,985
5	506	$ 125,197	0.870121	$ 108,937
6	510	$ 594,275	0.879382	$ 522,595
7	511	$ 92,214	0.870121	$ 80,238
8	512	$ 552,109	0.879382	$ 485,515
9	513	$ 124,110	0.879382	$ 109,140
10	514	$ 24,243	0.870121	$ 21,095
11	541	$ 12,881	0.870121	$ 11,208
12	542	$ 3,650	0.870121	$ 3,176
13	546	$ 26,959	0.870121	$ 23,457
14	551	$ 9,705	0.870121	$ 8,445
15	553	$ 67,506	0.870121	$ 58,738
16	554	$ 2,767	0.870121	$ 2,408
17	556	$ 200,329	0.870121	$ 174,311
18	560	$ 234,471	0.901548	$ 211,387
19	561	$ 323,853	0.901548	$ 291,969
20	562	$ 37,146	0.901548	$ 33,489
21	566	$ 10,323	0.901548	$ 9,307
22	570	$ 88,899	0.901548	$ 80,147
23	571	$ 9,082	0.901548	$ 8,188
24	580	$ 110,542	0.944360	$ 104,391
25	581	$ 34,498	0.944360	$ 32,579
26	582	$ 60,397	0.944360	$ 57,036
27	583	$ 191,016	0.944360	$ 180,388
28	586	$ 454,173	0.944360	$ 428,903
29	588	$ 268,452	0.944360	$ 253,516
30	592	$ 43,127	0.944360	$ 40,727
31	593	$ 461,407	0.944360	$ 435,735
32	594	$ 30,798	0.944360	$ 29,084
33	595	$ 3,836	0.944360	$ 3,623
34	901	$ 318,088	0.948783	$ 301,796
35	902	$ 59,057	0.948783	$ 56,032
36	903	$ 1,125,367	0.948783	$ 1,067,729
37	907	$ 57,922	0.997250	$ 57,762
38	908	$ 25,509	0.997250	$ 25,439
39	920	$ 3,556,333	0.903711	$ 3,213,896
40	935	$ 45,857	0.903711	$ 41,442
41	Total	$ 11,505,675		$ 10,420,237

Notes and Source
Cols. A-C: Amounts from the response to Kroger 2-3

	Description	Total Company Amounts*	Ratio	Kentucky Jurisdictional Amounts
42	KU Employees	$ 4,005,176	34.81%	$ 3,627,330
43	LGE-KU Services	$ 6,786,882	58.99%	$ 6,146,612
44	LG&E	$ 713,617	6.20%	$ 646,295
45	Total Test Period	$ 11,505,675	100.00%	$10,420,237

* Total Company amounts from the response to AG 1-68

Kentucky Utilities Company
Incentive Compensation Expense

Forecasted Test Period Ended June 30, 2018

Line No.	Team Incentive Award Description	2015 Jurisdictional Amount	2015 Ratio	2016 Jurisdictional Amount	2016 Ratio	Base Period Jurisdictional Amount	Base Period Ratio
		(A)	(B)	(C)	(D)	(E)	(F)
1	Net Income	$ 6,584,295	52.94%	$ 3,342,481	30.07%	$ 2,545,288	25.32%
2	Cost Control	$ -	0.00%	$ -	0.00%	$ 201,687	2.01%
3	Customer Reliability	$ -	0.00%	$ -	0.00%	$ 201,687	2.01%
4	Customer Satisfaction	$ 1,796,639	14.44%	$ 1,822,208	16.39%	$ 1,665,126	16.57%
5	Corporate Safety	$ -	0.00%	$ 1,713,353	15.41%	$ 1,565,655	15.58%
6	Individual/Team Effectiveness	$ 4,057,335	32.62%	$ 4,237,694	38.12%	$ 3,872,387	38.52%
7	Total Team Incentive Award Expense	$ 12,438,269	100.00%	$11,115,736	100.00%	$10,051,830	100.00%

Notes and Source

Jurisdictional amounts above from the response to Kroger 2-3

Cols E&F: The Base Period in the Company's filing is the 12 months ending February 28, 2017

Kentucky Utilities Company
Advanced Metering Services

Forecasted Test Period Ended June 30, 2018

Line No.	Description	Kentucky Jurisdictional Amount (A)	Reference
1	Adjustment to Remove AMS Costs from Operating Expenses	$ (3,189,557)	A
2	Adjustment to Remove AMS Costs from Depreciation Expense	$ (599,502)	B

Notes and Source

A: Adjustment calculated using information from the response to KIUC 1-13 and shown below:

Line No.	Description	FERC Account (B)	Total Company Test Year Amount (C)	Kentucky Jurisdictional Factor* (D)	Kentucky Jurisdictional Test Year Amount (E)
3	Meter Expense	586	$ 1,173,875	95.070%	$ 1,116,000
4	Maintenance of Meters	597	$ 1,443,099	95.070%	$ 1,371,950
5	Customer Records and Collection Services	903	$ 640,773	94.878%	$ 607,955
6	Miscellaneous Customer Service and Information Expense	910	$ 93,745	99.901%	$ 93,652
7	Total AMS Related Operating Expenses		$ 3,351,492		$ 3,189,557

B: Adjustment calculated using information from the response to KIUC 1-17 and shown below:

Line No.	Description	FERC Account (B)	Total Company Test Year Amount (C)	Kentucky Jurisdictional Factor* (D)	Kentucky Jurisdictional Test Year Amount (E)
8	AMS Related Depreciation Expense	403	$ 676,000	88.684%	$ 599,502

* Kentucky jurisdictional allocation factors from KU Schedule C-2.1

Kentucky Utilities Company
Transmission Vegetation Management Expense

Forecasted Test Period Ended June 30, 2018

Exhibit RCS-1
Schedule C-4
Case No. 2016-00370
Page 1 of 1

Line No.	Description	Kentucky Jurisdictional Amount (A)	Reference
1	Test Period Transmission Vegetation Management Expense Per KU	$ 9,992,809	A
2	AG Recommended Transmission Vegetation Management Expense	$ 5,629,253	A
3	AG Adjustment to Transmission Vegetation Management Expense	$(4,363,556)	L2 - L1
4	Kentucky Jurisdictional Allocation Factor	90.219%	
5	AG Jurisdictional Adjustment to Transmission Vegetation Management Expense	$(3,936,758)	

Notes and Source

A: Amounts from the response to KIUC 2-12

Kentucky Utilities Company
Uncollectibles Expense

Forecasted Test Period Ended June 30, 2018

Exhibit RCS-1
Schedule C-5
Case No. 2016-00370
Page 1 of 1

Line No.	Description	Per Company	Per AG	AG Adjusted
		(A)	(B)	(C) =(B) - (A)
1	Uncollectibles Expense	5,566,157	4,629,508	(936,649)

Notes and Source:
Col (A): From Schedule C-2.1, Pages 7-12 of Company's Filing

Line No.	Year	Five-Year Avg Per Company	Five-Year Avg Per AG
		A	B
2	2011	0.43%	
3	2012	0.29%	0.29%
4	2013	0.23%	0.23%
5	2014	0.48%	0.48%
6	2015	0.33%	0.34% [A]
7	2016		0.26%
8	Uncollectible Accounts Expense Factor (5-Year Average)	0.352%	0.320%

Col A: From KU's Attachment to Response to AG-1 Question No. 25(a)
Col B, Line 5-6: From KU's Resposne to AG-1 Question No. 85

[A] Difference is noted between the percentage given in KU's Attachment to Response to AG-1 Question No. 25(a) and KU's Response to AG-1 Question No. 85

Additional Calculations:

From Schedule C-2.1, Pages 7-12 of Company's Filing:

		Total Unadjusted	Jurisdictional Adjusted
9	Uncollectible Accounts	$ 5,866,627	$ 5,566,157
10	Total Sales to Ultimate Consumers	$ 1,672,099,144	$ 1,446,721,110
11	Uncollectible Accounts Expense Factor (Line 9/Line 10)	0.3509%	0.3847%

	Per AG:	
12	Total Sales Revenue to Ultimate Consumers	$ 1,446,721,110 [B]
13	Uncollectible Expense Factor	0.320%
14	Uncollectibles Expense	$ 4,629,508

[B] Using Adjusted Jurisdictional amount from Schedule C-2.1 of Company's filing

Kentucky Utilities Company
Depreciation Expense - Impacts of Slippage

Forecasted Test Period Ended June 30, 2018

Exhibit RCS-1
Schedule C-6
Case No. 2016-00370
Page 1 of 1

Line No.	Description		Amount (A)	Reference
1	AG Adjustment to Depreciation Expense to Reflect the Impact of Slippage	$	(188,940)	A
2	Kentucky Jurisdictional Allocation Factor		88.684%	
3	AG Jurisdictional Adjustment to Depreciation Expense to Reflect the Impact of Slippage	$	(167,559)	

Notes and Source

A: AG recommended adjustment to reflect the impact of slippage on depreciation expense calculated below:

	Description		Amount	Reference
4	Depreciation and Amortization Expense Per LG&E	$	228,062,837	LG&E Sch. C-1
5	13-Month Average Plant in Service per LG&E	$	6,970,368,268	LG&E Sch. B-1
6	Composite Depreciation Expense Rate		3.27%	L2 / L3
7	AG Adjustment to Plant in Service to Reflect the Impact of Slippage	$	(5,774,633)	Sch. B-1
8	Slippage Factor for Depreciation Expense		3.27%	Line 4
9	Adjustment to Depreciation Expense to Reflect the Impact of Slippage	$	(188,940)	L5 x L6

Kentucky Utilities Company
Depreciation Expense Related to Distribution Automation

Forecasted Test Period Ended June 30, 2018

Exhibit RCS-1
Schedule C-7
Case No. 2016-00370
Page 1 of 1

Line No.	Description	Amount (A)	Reference
1	AG Jurisdictional Adjustment to Depreciation Expense Related to Distribution Automation	$ (76,480)	A
2	Adjusted for Impact of Slippage	97.204%	
3	AG Adjustment to Depreciation Expense Related to Distribution Automation - Adjusted for Slippage	$ (74,342)	
4	Kentucky Jurisdictional Allocation Factor	88.684%	
5	AG Jurisdictional Adjustment to Depreciation Expense Related to Distribution Automation - Adjusted for Slippage	$ (65,929)	

Notes and Source

A: This amount is a fallout adjustment related to AG witness Holloway's Distribution Automation related adjustment

	Description	Plant Account	AG Jurisdictional Adjustment (Sch. B-2) (B)	KU Proposed Depreciation Rate*	Jurisdictional Depreciation Expense
6	OH Conductors and Devices	365	$ 2,879,000	2.47%	$ 71,111
7	Communication Equipment	397	$ 109,568	4.90%	$ 5,369
8	Depreciation Expense Related to Adjustment to Distribution Automation		$ 2,988,568		$ 76,480

* Depreciation rates from the attachment provided in response to PSC 1-66

Kentucky Utilities Company
Payroll and Employee Benefits Expense - Remove Vacant Positions

Forecasted Test Period Ended June 30, 2018

Line No.	Description	Kentucky Jurisdictional KU Amount (A)	Kentucky Jurisdictional LKE Amount (B)	Total Adjustment (C)
1	AG Adjustment to Payroll Expense for Vacant Positions	$ (194,442)	$ (1,254,202)	$ (1,448,644)
2	AG Adjustment to Employee Benefits Expense for Vacant Positions	$ (53,386)	$ (271,750)	$ (325,136)
3	Total Adjustment	$ (247,828)	$ (1,525,952)	$ (1,773,780)
4	AG Adjustment to Payroll Tax Expense for Vacant Positions	$ (14,461)	$ (92,415)	$ (106,876)

Notes and Source
Col. A: see page 2
Col. B: see page 3

Kentucky Utilities Company
Payroll and Employee Benefits Expense - Remove Vacant Positions

Exhibit RCS-1
Schedule C-8
Case No. 2016-00370
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Forecasted Test Period Ended June 30, 2018

Kentucky Utilities

Line No.	Description	Total Company KU Amount (A)	Kentucky Jurisdictional Factor (B)	Kentucky Jurisdictional KU Amount (C)
1	Number of Vacant Positions	4		4
2	Salaries	$ 280,561	90.37%	$ 253,546
3	Team Incentive Award*	$ 18,938	90.37%	$ 17,114
4	Total Payroll	$ 299,499		$ 270,660
5	O&M Percentage	71.84%		71.84%
6	O&M Payroll	$ 215,160		$ 194,442
	Employee Benefits			
7	401(k) Match	$ 11,784	90.37%	$ 10,649
8	Retirement Income	$ 8,417	89.03%	$ 7,494
9	Group Life Insurance	$ 1,367	89.03%	$ 1,217
10	Long Term Disability	$ 1,473	89.03%	$ 1,311
11	Post Retirement Benefits	$ 7,738	89.03%	$ 6,889
12	Worker's Compensation	$ 2,426	90.37%	$ 2,192
13	Dental	$ 2,213	89.03%	$ 1,970
14	Medical	$ 44,388	89.03%	$ 39,520
15	Other Miscellaneous	$ 1,200	89.03%	$ 1,068
16	Total Benefits	$ 81,006		$ 72,310
17	O&M Percentage	73.83%		73.83%
18	O&M Employee Benefits	$ 59,807		$ 53,386
19	Payroll Taxes	$ 22,175	90.27%	$ 20,018
20	O&M Percentage	72.24%		72.24%
21	O&M Payroll Taxes	$ 16,019		$ 14,461
22	Total KU O&M Payroll, Employee Benefits and Payroll Taxes	$ 290,986		$ 262,289

Notes and Source

A: Adjustment calculated using information from the response to AG 2-8 and shown below:

* AG recommended removing 25% of TIA expense on Schedule C-2 - see calculation below:

23	Team Incentive Award Expense	$ 25,250
24	AG recommended percentage of Team Incentive Award in Cost of Service	75.00%
25	Net Team Incentive Award Expense	$ 18,938

^ O&M percentages from 807 KAR 5:001 Section 16(8)(g), page 2

Kentucky Utilities Company
Payroll and Employee Benefits Expense - Remove Vacant Positions

Forecasted Test Period Ended June 30, 2018

Line No.	Description	LKE Amount	Kentucky Jurisdictional Factor*	Kentucky Jurisdictional LKE Amount
	LG&E and KU Services Company	(A)	(B)	(C)
1	Number of Vacant Positions	34		34
2	Salaries	$3,348,176	90.37%	$ 3,025,782
3	Team Incentive Award*	$ 226,002	90.37%	$ 204,240
4	Total Payroll	$3,574,178		$ 3,230,022
5	O&M Percentage^	71.84%		71.84%
6	O&M Payroll	$2,567,689		$ 2,320,448
7	Percentage to Allocate to KU	54.05%		54.05%
8	LKE O&M Payroll Allocated to KU	$1,387,836		$ 1,254,202
	Employee Benefits			
9	401(k) Match	$ 140,623	90.37%	$ 127,082
10	Retirement Income	$ 100,445	89.03%	$ 89,429
11	Group Life Insurance	$ 16,312	89.03%	$ 14,523
12	Long Term Disability	$ 17,578	89.03%	$ 15,650
13	Post Retirement Benefits	$ 59,806	89.03%	$ 53,247
14	Post Employment Benefits	$ 19,075	89.03%	$ 16,983
15	Worker's Compensation	$ 2,579	90.37%	$ 2,331
16	Dental	$ 18,809	89.03%	$ 16,746
17	Medical	$ 377,298	89.03%	$ 335,920
18	Other Miscellaneous	$ 10,200	89.03%	$ 9,081
19	Total Benefits	$ 762,725		$ 680,992
20	O&M Percentage^	73.83%		73.83%
21	O&M Employee Benefits	$ 563,120		$ 502,776
22	Percentage to Allocate to KU	54.05%		54.05%
23	LKE O&M Employee Benefits Allocated to KU	$ 304,366		$ 271,750
24	Payroll Taxes	$ 262,187	90.27%	$ 236,685
25	O&M Percentage^	72.24%		72.24%
26	O&M Payroll Taxes	$ 189,404		$ 170,981
27	Percentage to Allocate to KU	54.05%		54.05%
28	LKE O&M Payroll Taxes Allocated to KU	$ 102,373		$ 92,415
29	Total LKE O&M Payroll, Employee Benefits and Payroll Taxes	$1,794,575		$ 1,618,367

Notes and Source

A: Amounts above from the response to AG 2-8

* AG recommended removing 25% of TIA expense on Schedule C-2. The amount above reflects this adjustment

30	Team Incentive Award Expense	$ 301,336
31	AG recommended percentage of Team Incentive Award in Cost of Service	75.00%
32	Net Team Incentive Award Expense	$ 226,002

^ O&M percentages from 807 KAR 5:001 Section 16(8)(g), page 2

Kentucky Utilities Company
Afflliliate Charges From PPL Services Corporation to LG&E

Forecasted Test Period Ended June 30, 2018

Exhibit RCS-1
Schedule C-9
Case No. 2016-00370
Page 1 of 1

Line No.	Description	Amount (A)	Reference
1	Jurisdictional Adjustment to Remove Affiliate Charges from PPL Services Corporation	$ (1,504,533)	A

Notes and Source
A: Adjustment calculated from information provided in response to AG 2-11 and calculated below:

	Description	FERC Account	Amount
2	IT Joint Initiatives	920	$ 139,317
3	Kentucky Jurisdictional Allocation Factor		90.371%
4	Kentucky Jurisdictional Amount		$ 125,902
5	Audit - PCAOB Fees	921	$ 37,118
6	Office of Compliance	921	$ 58,208
7	Credit Services	921	$ 7,891
8	Financial Statement Reporting Software	921	$ 3,514
9	Hyperion Financial Management Software	921	$ 9,676
10	Insurance Services	921	$ 77,465
11	Internal Reporting	921	$ 172,549
12	Investor Relations	921	$ 210,283
13	IT Joint Initiatives	921	$ 78,947
14	Office of General Counsel	921	$ 470,722
15	Pension/Investments	921	$ 251,821
16	UI Planner Software	921	$ 10,486
17	Wall Street Software	921	$ 37,440
18	Total Account 921		$ 1,426,120
19	Kentucky Jurisdictional Allocation Factor		90.371%
20	Kentucky Jurisdictional Amount		$ 1,288,800
21	IT Joint Initiatives	926	$ 100,896
22	Kentucky Jurisdictional Allocation Factor		89.033%
23	Kentucky Jurisdictional Amount		$ 89,831
24	Kentucky Jurisdictional PPL Services Corporation Affiliate Charges to KU		$ 1,504,533

Kentucky Utilities Company
Rescheduling of Expiring Regulatory Asset Amortizations

Forecasted Test Period Ended June 30, 2018

Line No.	Description	Amount (A)	Reference
1	AG Jurisdictional Adjustment to Reduce Amortization of Rate Case Expenses	$ (252,734)	A

Notes and Source

A: Adjustment calculated below using information from the response to KIUC 2-8

	Description	Amount	Kentucky Jurisdictional Factor	Kentucky Jurisdictional Amount
2	Mountain Storm - Electric Beginning Balance	$ 236,413		
3	Amortization of 2 Years	2		
4	Annual Amortization of Mountain Storm - Electric	$ 118,207		
5	Annual Amortization of Mountain Storm - Electric Per KU	$ 236,413		
6	AG Adjustment to Reduce Amortization of Mountain Storm - Electric	$ (118,207)	93.359%	$ (110,356)
7	Rate Case Expenses Beginning Balance	$ 2,463,414		
8	Amortization of 2 Years	2		
9	Annual Amortization of Rate Case Expenses	$ 1,231,707		
10	Annual Amortization of Rate Case Expenses Per LG&E	$ 1,272,256		
11	AG Adjustment to Reduce Amortization of Rate Case Expenses	$ (40,549)	97.146%	$ (39,392)
12	Green River Retirement Beginning Balance	$ 2,583,039		
13	Amortization of 2 Years	2		
14	Annual Amortization of Green River Retirement	$ 1,291,520		
15	Annual Amortization of Green River Retirement Per KU	$ 1,408,926		
16	AG Adjustment to Reduce Amortization of Green River Retirement	$ (117,406)	87.717%	$ (102,986)
17	Total AG Adjustment Related to Expiring Regulatory Asset Amortizations	$ (276,162)		$ (252,734)

EXHIBIT RCS-3

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's First Request for Information
Dated November 10, 2016

Case No. 2016-00370

Question No. 13

Responding Witness: Kent W. Blake / Paul W. Thompson

Q-13. Concerning the utility's construction projects:

a. For each project started during the last ten calendar years, provide the information requested in the format contained in Schedule 13a. For each project, include the amount of any cost variance and delay encountered, and explain in detail the reasons for such variances and delays.

b. Using the data included in Schedule 13a, calculate the annual "Slippage Factor" associated with those construction projects. The Slippage Factor should be calculated as shown in Schedule 13b.

c. In determining the capital additions reflected in the base period and forecasted test period, explain whether the utility recognized a Slippage Factor.

A-13. a. See attached. The Company has provided the requested data for both Mechanism Capital Construction Projects and Non-Mechanism Capital Construction Projects. Due to the voluminous number of projects over a 10-year period (over 12,000 individual projects), the Company has provided the variance explanations included in the last rate case for portions of the ten year period included therein and have added explanations for variances greater than $500,000 for the additional two periods.

b. See attached for the requested calculations of the Slippage Factor. The Company recommends the weighted average, as opposed to the simple average, be used in the requested calculation to reflect the relationship of the size of the budget and associated variance.

c. No. KU did not recognize a Slippage Factor for capital additions in either the base period or the forecasted test period. The requested calculations of the slippage factors (97.204% for KU and 98.111% for LG&E) on capital projects that are recovered in base rates demonstrate the reasonableness of KU and LG&E's accuracy in predicting the cost of its utility plant additions and when new plant will be placed into service. Given the reasonable accuracy demonstrated, the need to apply a Slippage Factor does not exist and the Commission should decline to do so.

The Slippage Factors for the mechanism capital (90.383% for KU and 87.631% for LG&E) are different than base rate capital because mechanism projects are typically larger projects that are subject to delays caused by environmental permitting; ongoing, frequent, and contentious environmental regulation; and greater exposure to commodity and skilled labor availability variables. The projects to be included in base rates, with the exception of new base load generation, are typically smaller in size and are not subject to the same exposure by such variables. In addition, mechanism projects are explicitly reviewed and approved as part of the operation of the respective mechanism. To the extent there are delays or the Company is able to complete those projects at costs less than original estimates, that unexpected available capital is not redeployed to other prudent projects as the Company may do with respect to base rate capital projects.

Finally, mechanism capital slippage is irrelevant for ratemaking in a base rate case. The cost of base rate capital projects is recovered through forecasted amounts in future test period rate cases. In contrast, the cost of mechanism capital projects (e.g., KU and LG&E's Environmental Cost Recovery mechanism) is recovered based on actual amounts spent. Therefore, any consideration of a slippage factor, if any, should be limited to capital projects to be recovered in base rates. For the reasons previously stated, the Company believes the need to apply a Slippage Factor does not exist and the Commission should decline to do so.

Kentucky Utilities Company
Case No. 2016-00370
Calculation of Capital Construction Project Slippage Factor -Non-Mechanism Construction Projects

Schedule 13b(1)

Source: Schedule 13a - Construction Projects

Years	Base Rate Capital Actual Cost	Base Rate Capital Budget Cost	Variance in Dollars	Variance as a percent	Slippage Factor
2015	240,247,704	254,705,926	(14,458,222)	-5.676%	94.324%
2014	258,672,601	285,655,724	(26,983,123)	-9.446%	90.554%
2013	467,930,147	442,723,204	25,206,943	5.694%	105.694%
2012 [1]	250,621,314	298,013,293	(47,391,979)	-15.90%	84.097%
2011	203,042,999	215,256,373	(12,213,373)	-5.674%	94.326%
2010	209,036,428	183,198,611	25,837,818	14.10%	114.104%
2009	247,393,650	254,530,196	(7,136,546)	-2.804%	97.196%
2008	299,810,659	364,973,077	(65,162,418)	-17.85%	82.146%
2007	365,638,569	341,423,721	24,214,848	7.092%	107.092%
2006	190,920,150	171,459,091	19,461,060	11.35%	111.350%
Totals	**2,733,314,222**	**2,811,939,216**	**(78,624,994)**	**-2.796%**	**97.204%**

10 Year Average Slippage Factor (Mathematic Average of the Yearly Slippage Factors / 10 Years)	**98.088%**

The Base Rate Capital Actual Cost is the Annual Actual Cost per Schedule 13(a)Non-Mechanism Construction Projects . The Base Rate Capital Budget Cost is the Annual Original Budget per Schedule 13(a)Non-Mechanism Construction Projects .

The Slippage Factor is calculated by dividing the Base Rate Capital Actual Cost by the Base Rate Capital Budget Cost. Calculate a Slippage Factor for each year and the Totals line. Carry Slippage Factor percentages to 3 decimal places

2012 [1] = Removed the budgeted amount related to the acquisition of the Bluegrass CTs. Based on the mitigation measures required by FERC for approval LG&E and KU determined that the options were not commercially justifiable. In June 2012, LG&E and KU terminated the asset purchase agreement for the Bluegrass CTs in accordance with its terms and made applicable filings with the KPSC and FERC.

Kentucky Utilities Company
Case No. 2016-00370
Calculation of Capital Construction Project Slippage Factor - Mechanisms Construction Projects Only

Schedule 13b (2)

Source: Schedule 13a - Construction Projects

	A	B	C=A+B	D	E	F=D+E	G=C-F	H=G/F	I=C/F
Years	**Actual ECR**	**Actual DSM**	**Mechanism Capital Actual Total**	**Budget ECR**	**Budget DSM**	**Mechanism Capital Budget Total**	**Variance in Dollars**	**Variance as a percent**	**Slippage Factor**
2015	202,607,589	3,226,169	205,833,758	221,828,814	1,546,665	223,375,478	(17,541,720)	-7.85%	92.147%
2014	325,250,119	1,235,843	326,485,962	311,941,339	2,102,322	314,043,661	12,442,301	3.96%	103.962%
2013	357,471,329	1,808,343	359,279,672	331,193,876	1,307,386	332,501,262	26,778,410	8.05%	108.054%
2012	249,935,786	304,046	250,239,832	319,312,275	1,604,339	320,916,614	(70,676,782)	-22.02%	77.977%
2011	122,599,687	-	122,599,687	222,559,895	1,853,002	224,412,896	(101,813,209)	-45.37%	54.631%
2010	136,407,834	-	136,407,834	232,331,970	-	232,331,970	(95,924,136)	-41.29%	58.712%
2009	227,067,458	-	227,067,458	260,647,784	-	260,647,784	(33,580,326)	-12.88%	87.117%
2008	381,490,690	-	381,490,690	441,357,545	-	441,357,545	(59,866,855)	-13.56%	86.436%
2007	441,727,604	-	441,727,604	391,730,183	-	391,730,183	49,997,421	12.76%	112.763%
2006	180,024,677	-	180,024,677	169,793,002	-	169,793,002	10,231,675	6.03%	106.026%
Totals	**2,624,582,774**	**6,574,401**	**2,631,157,175**	**2,902,696,682**	**8,413,712**	**2,911,110,394**	**(279,953,219)**	**-9.617%**	**90.383%**

10 Year Average Slippage Factor (Mathematic Average of the Yearly Slippage Factors / 10 Years)	**88.782%**

The Mechanism Capital Actual Total, Mechanism Capital Budget Total, Variance in Dollars, and Variance as Percent are to be taken from Schedule 13a Mechanism Construction Projects. Total all projects for a given year.

The Slippage Factor is calculated by dividing the Mechanism Capital Actual Total by the Mechanism Capital Budget Total. Calculate a Slippage Factor for each year and the Totals line. Carry Slippage Factor percentages to 3 decimal places.

Explanation for significant variances from budget:
2015 – Lower costs on the Trimble landfill due to delays in the permitting process.

2014 – The Ghent Environmental Air project was above budget due to change orders with the primary contractor KBR primarily related to the unit 3 and 4 economizers, partially offset by lower costs on the Brown landfill due to the shifting of milestones on the transport system from 2014 to 2015.

2013 – Better than expected customer engagement in the DSM Direct Load Control program.

2012 – Continued permitting delays on the Trimble County landfill and a later start to the Environmental Air projects under the 2011 ECR plan than had been expected in the budget.
With regards to DSM, lower costs were the result of the approval of Case No. 2011-00134 being later than originally expected. The original budget assumed capitalizing the expenses starting in January but the Company had existing expensed inventory that had to be used before starting to use the newly approved DSM Rate of Return for capital projects within the DSM mechanism.

2011 – Permanent savings on the Brown 3 SCR, a later start to the Environmental Air projects under the 2011 ECR plan than had been expected in the budget, and permitting delays on the Trimble County landfill.
With regards to DSM, lower costs were the result of the approval of Case No. 2011-00134 being later than originally expected.

2010 – Permanent savings toward the end of the KU FGD installations, a delay in the start of the Brown ash pond/landfill due to the shift from an ash pond to a landfill under the 2011 ECR plan.

2007 – Cost escalations on the KU FGD's driven by much higher commodity and labor costs being incurred throughout the industry prior to the recession of 2008/2009.

Schedule 13b(3)

Kentucky Utilities Company
Case No. 2016-00370
Calculation of Capital Construction Project Slippage Factor - Includes Mechanism Construction Projects

Source: Schedule 13a - Construction Projects

Years	Annual Actual Cost	Annual Original Budget	Variance in Dollars	Variance as a percent	Slippage Factor
2015	446,081,462	478,081,404	(31,999,942)	-6.69%	93.307%
2014	585,158,563	599,699,385	(14,540,822)	-2.42%	97.575%
2013	827,209,819	775,224,466	51,985,353	6.71%	106.706%
2012 [1]	500,861,146	618,929,907	(118,068,761)	-19.08%	80.924%
2011	325,642,687	439,669,269	(114,026,583)	-25.93%	74.065%
2010	345,444,263	415,530,581	(70,086,318)	-16.87%	83.133%
2009	474,461,108	515,177,980	(40,716,872)	-7.90%	92.097%
2008	681,301,349	806,330,622	(125,029,273)	-15.51%	84.494%
2007	807,366,173	733,153,904	74,212,269	10.12%	110.122%
2006	370,944,827	341,252,092	29,692,735	8.70%	108.701%
Totals	**5,364,471,397**	**5,723,049,610**	**(358,578,213)**	**-6.266%**	**93.734%**

10 Year Average Slippage Factor (Mathematic Average of the Yearly Slippage Factors / 10 Years)	**93.112%**

The Annual Actual Cost, Annual Original Budget, Variance in Dollars, and Variance as Percent are the sum of the projects from Schedule 13a Non-Mechanism Construction Projects and Schedule 13a Mechanism Construction Projects. Total all projects for a given year.

The Slippage Factor is calculated by dividing the Annual Actual Cost by the Annual Original Budget. Calculate a Slippage Factor for each year and the Totals line. Carry Slippage Factor percentages to 3 decimal places.

2012 [1] = Removed the budgeted amount related to the acquisition of the Bluegrass CTs. Based on the mitigation measures required by FERC for approval LG&E and KU determined that the options were not commercially justifiable. In June 2012, LG&E and KU terminated the asset purchase agreement for the Bluegrass CTs in accordance with its terms and made applicable filings with the KPSC and FERC.

EXHIBIT RCS-4

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 392

Responding Witness: John K. Wolfe

Q-392. Regarding Table 3 of Exhibit PWT-5 provide annual 5-year historic data for each of the listed categories (from 2012-2016).

A-392. The Distribution Automation Program was initiated in 2016. There were no Distribution Automation Program investments prior to 2016.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

**Response to the Attorney General's Supplemental Data Requests
Dated February 7, 2017**

Question No. 101

Responding Witness: John K. Wolfe

Q-101. Regarding the response to AG1 – 11, describe in detail how the DA initiative will be used to improve reliability on each of the worst performing circuits.

A-101. The DA initiative will improve reliability on worst performing circuits where it is implemented by sectionalizing and isolating faults to minimize sections of impacted customers, thus reducing reliability impacts of mainline outages. This capability maintains service to customers outside of the isolated section of the distribution circuit. Speed of service restoration to impacted customers will be improved due to immediate availability of fault location information from the DA reclosers.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's First Request for Information
Dated November 10, 2016

Case No. 2016-00370

Question No. 66

Responding Witness: Christopher M. Garrett / Daniel K. Arbough

Q-66. To the extent not included in other responses, provide all work papers, calculations, and assumptions the utility used to develop its forecasted test period financial information.

A-66. See Tab 16 of the Filing Requirements for the assumptions used to develop the forecasted test period financial information. See attachment being provided in Excel format for the depreciation reconciliation.

Kentucky Utilities Company
Depreciation Calculation

Description	Current Rate	Proposed Rate	Jul-17 Depreciation_base_Forecast	Aug-17 Depreciation_base_Forecast	Sep-17 Depreciation_base_Forecast	Oct-17 Depreciation_base_Forecast	Nov-17 Depreciation_base_Forecast	Dec-17 Depreciation_base_Forecast	Jan-18 Depreciation_base_Forecast	Feb-18 Depreciation_base_Forecast	Mar-18 Depreciation_base_Forecast	Apr-18 Depreciation_base_Forecast	May-18 Depreciation_base_Forecast	Jun-18 Depreciation_base_Forecast	YE Jun-18 Depreciation_base_Forecast
KU-136500- KY Overhead Conductor	3.23%	2.47%	349,943,204.81	351,491,236.51	353,081,099.24	354,489,338.54	355,878,260.26	357,689,857.54	359,680,391.96	361,298,882.06	362,868,130.00	364,533,376.46	366,285,105.68	367,899,000.28	4,305,137,883.33
KU-139700-KY Microwave,Fiber,Other	5.70%	4.90%	26,858,318.25	27,023,688.30	27,172,613.30	28,865,382.47	30,915,801.09	31,325,315.50	31,345,900.52	31,345,900.52	31,345,900.52	31,345,900.52	31,345,900.52	31,345,900.52	360,236,522.02

Description	Current Rate	Proposed Rate	Jul-17 Calculated depr exp	Aug-17 Calculated depr exp	Sep-17 Calculated depr exp	Oct-17 Calculated depr exp	Nov-17 Calculated depr exp	Dec-17 Calculated depr exp	Jan-18 Calculated depr exp	Feb-18 Calculated depr ex	Mar-18 Calculated depr exp	Apr-18 Calculated depr exp	May-18 Calculated depr exp	Jun-18 Calculated depr exp	YE Jun-18 Calculated depr exp
KU-136500- KY Overhead Conductor	3.23%	2.47%	$ 720,299.76	$ 723,486.13	$ 726,758.60	$ 729,657.22	$ 732,516.09	$ 736,244.96	$ 740,342.14	$ 743,673.53	$ 746,903.57	$ 750,331.20	$ 753,936.84	$ 757,258.78	$ 8,861,408.82
KU-139700-KY Microwave,Fiber,Other	5.70%	4.90%	$ 109,671.47	$ 110,346.73	$ 110,954.84	$ 117,866.98	$ 126,239.52	$ 127,911.70	$ 127,995.76	$ 127,995.76	$ 127,995.76	$ 127,995.76	$ 127,995.76	$ 127,995.76	$ 1,470,965.80

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 44

Responding Witness: John K. Wolfe

Q-44. Refer to the Thompson Testimony, page 38, lines 23-24. State whether this statement indicates that only 50 percent of KU's customers will benefit from the Distribution Automation ("DA") program.

A-44. Fifty percent of the combination of LG&E and KU customers will benefit directly from the Distribution Automation program. Thirty-nine percent of KU customers will benefit directly from the program.

EXHIBIT RCS-5

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

**Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017**

Question No. 18

Responding Witness: Christopher M. Garrett

Q-18. Reference the Company's lead-lag study. Provide the electronic Excel files, with formulas and calculations intact, which were used to produce the lead-lag study that was used for the current rate case.

A-18. The Company did not perform a lead-lag study but instead used the 45 day or 1/8th formula method to determine its cash working capital allowance. The Kentucky Public Service Commission has consistently found that the use of the 1/8th formula is appropriate and reasonable and is an acceptable alternative to a lead-lag study. *See Application of Water Service Corporation of Kentucky for An Adjustment of Rates*, Case No. 2008-00563 (Ky. PSC Nov. 9, 2009) at 8 (finding that the 45 day approach "is reasonable and should be permitted"); *The Application of Kentucky Power Company D/B/A American Electric Power For Approval of An Amended Compliance Plan for Purposes of Recovering the Costs of New and Additional Pollution Control Facilities and to Amend Its Environmental Cost Recovery Surcharge Tariff*, Case No. 2002-00169 at 28 (Ky. PSC Mar. 31, 2003) ("the Commission has found the use of the 1/8 formula approach to be reasonable in previous base rate cases and environmental surcharge proceedings"); *An Adjustment of General Rates of Delta Natural Gas Company, Inc.*, Case No. 97-066 (Ky. PSC Dec. 8, 1997) at 4 ('in the absence of any lead-lag study, the 1/8th formula method should be used to determine the level of cash working capital"); *The Application of The Union Light, Heat, and Power Company for An Adjustment of Rates*, Case No. 92-346 (Ky. PSC July 23, 1993) at 5-6 (finding that the 1/8 formula methodology "has been used in its past rate cases and continues to produce a just and reasonable result."); *Application of The Union Light, Heat and Power Company to Adjust Electric Rates*, Case No. 91-370 (Ky. PSC May 5, 1992) at 6 ("The Commission has traditionally used the 1/8 formula approach in electric utility rate cases and find[s] no basis to now depart from that practice."); *Adjustment of Rates of the Salem Telephone Company, Inc.*, Case No. 91-217 (Ky. PSC Feb. 28, 1992) at 3 ("In lieu of a lead-lag study, this and many other commissions have used the 1/8 formula method. This method is based on 45 days of operating and maintenance expenses and is a widely accepted surrogate for a lead-lag study.")

EXHIBIT RCS-6

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 13

Responding Witness: John P. Malloy

Q.1-13. Refer to page 17, lines 1-16, of Mr. Malloy's Direct Testimony wherein he describes the deployment related capital and O&M costs for implementation of the AMS meter deployment as well as the projected savings. The Kentucky jurisdictional O&M expenses for KU were estimated on line 7 to be $13.7 million.

a. Please provide the estimated deployment-related O&M expense by FERC account number included in the (a) base year, (b) test year, and (c) 12 months immediately succeeding the test year.

b. Please provide the estimated O&M expense savings by FERC account number, such as meter reading expense, that serve to offset the deployment-related O&M expenses included in the (a) base year, (b) test year, and (c) 12 months immediately succeeding the test year.

A.1-13.

a. O&M Expenses	**Base Year**	**Test Year**	**12-mos Succeeding**
586: Meter Expense	$ -	$ 1,173,875	$ 795,785
597: Maintenance of Meters	-	1,443,099	2,107,102
903: Customer Records and Collection Exp	-	640,773	794,787
910: Miscellaneous Customer Service Exp	-	93,745	120,020
	$ -	**$ 3,351,492**	**$ 3,817,693**

b. O&M Savings	**Base Year**	**Test Year**	**12-mos Succeeding**
586: Meter Expense	$ -	$ -	$ (395,500)
902: Meter Reading Expenses	-	-	(547,000)
	$ -	**$ -**	**$ (942,500)**

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 17

Responding Witness: Christopher M. Garrett

Q.1-17. Please provide a quantification of the revenue requirement included for the AMS initiative in the test year, including all rate base/capitalization components and all operating expenses on a total Company and jurisdictional basis. The quantification should include all reductions in rate base/capitalization and operating expenses from savings due to the proposed transition to AMS. Provide all assumptions, data, and calculations.

A.1-17. See attached for an estimate of the AMS revenue requirement for the test year.

2017 Business Plan
LG&E and KU Key Business Unit Projects
Dollars in 000's

	Capital Including 108					Test Year Ended June 30, 2018			
Project	Total Project	2017-2021	Through TYE 6/30/18	Avg. Capital TYE 6/30/18	Avg. Def. Tax Bal. TYE 6/30/18	Cost of Capital	Depreciation	O&M	Total Rev. Reqts.
Advanced Metering Systems (AMS)	$ 319,610	$ 319,610	$ 120,220	$ 52,481	$ 3,668	$ 5,200	$ 1,352	$ 6,703	$ 13,255

2017 Business Plan
LG&E Key Business Unit Projects
Dollars in 000's

Project	Capital Including 108					Test Year Ended June 30, 2018			
Project	Total Project	2017-2021	Through TYE 6/30/18	Avg. Capital TYE 6/30/18	Avg. Def. Tax Bal. TYE 6/30/18	Cost of Capital	Depreciation	O&M	Total LGE Rev. Reqts.
Advanced Metering Systems (AMS)	$ 159,805	$ 159,805	$ 60,110	$ 26,241	$ 1,834	$ 2,633	$ 676	$ 3,352	$ 6,660
									Total Elec.
									$ 5,343
									Total Gas
									$ 1,317
						Elec. Split	Elec. Cap/Dep	Elec. O&M	
						0.7	$ 2,316	$ 3,027	
						Gas Split	Gas Cap/Dep	Gas O&M	
						0.3	$ 993	$ 324	

2017 Business Plan
KU Key Business Unit Projects
Dollars in 000's

Project	Capital Including 108: Total Project	2017-2021	Through TYE 6/30/18	Avg. Capital TYE 6/30/18	Avg. Def. Tax Bal. TYE 6/30/18	Test Year Ended June 30, 2018: Cost of Capital	Depreciation	O&M	Total KU Rev. Reqts.
Advanced Metering Systems (AMS)	$ 159,805	$ 159,805	$ 60,110	$ 26,241	$ 1,834	$ 2,567	$ 676	$ 3,352	$ $\boxed{6,595}$
							KU KY Juris. Cap & Depr.	KU KY Juris. O&M	KU KY Juris. $\boxed{\$ 6,066}$
							$ 2,895	$ 3,171	
							KU Juris. Cap.		
							89.28%		

2017 Business Plan
LG&E and KU Key Business Unit Projects
Dollars in 000's

CS Projects
LG&E

Project	O&M	Total Rev. Reqts.		Electric	Gas
	Test Year Ended June 30, 2018				
Advanced Metering Systems (AMS)	$ 3,351	$ 3,351		3,027	324
AMS by FERC Account :	3351.49252	Electric	Gas	Electric	Gas
F586-METER EXPENSE	1167.42148	100%		1,167	-
F597-MTCE OF METERS	1427.89998	100%		1,428	-
F878-METER AND HOUSE REGULATOR EXPENSE	6.45402		100%	-	6
F893-MTCE OF METERS AND HOUSE REGULATORS	15.19902		100%	-	15
F903-CUSTOMER RECORDS AND COLLECTION EXPENSES	640.77306	56%	44%	359	282
F910-MISC CUSTOMER SERVICE AND INFORMATION EXPENSE	93.74496	78%	22%	73	21

Key Business Unit Projects
Plant In-Service Amounts by Project
Cumulative In-Service

	6/30/17	7/31/17	8/31/17	9/30/17	10/31/17	11/30/17	12/31/17	1/31/18	2/28/18	3/31/18	4/30/18	5/31/18	6/30/18	13 Month Average
LG&E Projects														
Advanced Metering Systems	$ -	$ -	$ -	$ -	$ 3,240	$ 6,480	$ 9,720	$ 13,409	$ 17,098	$ 20,787	$ 24,476	$ 28,165	$ 31,854	$ 11,941
KU Projects														
Advanced Metering Systems	$ -	$ -	$ -	$ -	$ 3,240	$ 6,480	$ 9,720	$ 13,409	$ 17,098	$ 20,787	$ 24,476	$ 28,165	$ 31,854	$ 11,941
Total LG&E and KU														
Advanced Metering Systems	$ -	$ -	$ -	$ -	$ 6,480	$ 12,960	$ 19,440	$ 26,818	$ 34,196	$ 41,574	$ 48,952	$ 56,330	$ 63,708	$ 23,881

Key Business Unit Projects
Plant In-Service Amounts by Project
Cumulative In-Service

		6/30/17	7/31/17	8/31/17	9/30/17	10/31/17	11/30/17	12/31/17	1/31/18	2/28/18	3/31/18	4/30/18	5/31/18	6/30/18	13 Month Average
Plant In Service															
LG&E Projects															
Advanced Metering Systems		$ -	$ -	$ -	$ -	$ 3,240	$ 6,480	$ 9,720	$ 13,409	$ 17,098	$ 20,787	$ 24,476	$ 28,165	$ 31,854	$ 11,941
Book Depreciation															
LG&E Projects															
Advanced Metering Systems		$ -	$ -	$ -	$ -	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 676
Tax Depreciation															
LG&E Projects	MACRS														
Advanced Metering Systems	10	$ -	$ -	$ -	$ -	$ 1,674	$ 1,755	$ 1,917	$ 1,011	$ 1,029	$ 1,052	$ 1,083	$ 1,129	$ 1,221	$ 913
Book/Tax Difference															
LG&E Projects															
Advanced Metering Systems		$ -	$ -	$ -	$ -	$ 1,599	$ 1,680	$ 1,842	$ 935	$ 954	$ 977	$ 1,008	$ 1,054	$ 1,146	$ 861
Deferred Tax Expense															
LG&E Projects															
Advanced Metering Systems		$ -	$ -	$ -	$ -	$ 622	$ 653	$ 716	$ 364	$ 371	$ 380	$ 392	$ 410	$ 446	$ 335

Accumulated Deferred Taxes	6/30/17	7/31/17	8/31/17	9/30/17	10/31/17	11/30/17	12/31/17	1/31/18	2/28/18	3/31/18	4/30/18	5/31/18	6/30/18	13 Month Average
LG&E Projects														
Advanced Metering Systems	$ -	$ -	$ -	$ -	$ 622	$ 1,275	$ 1,992	$ 2,356	$ 2,727	$ 3,107	$ 3,499	$ 3,909	$ 4,355	$ 1,834

Key Business Unit Projects
Plant In-Service Amounts by Project
Cumulative In-Service

		6/30/17	7/31/17	8/31/17	9/30/17	10/31/17	11/30/17	12/31/17	1/31/18	2/28/18	3/31/18	4/30/18	5/31/18	6/30/18	13 Month Average
Plant In Service															
KU Projects															
Advanced Metering Systems		$ -	$ -	$ -	$ -	$ 3,240	$ 6,480	$ 9,720	$ 13,409	$ 17,098	$ 20,787	$ 24,476	$ 28,165	$ 31,854	$ 11,941
Book Depreciation															
KU Projects															
Advanced Metering Systems		$ -	$ -	$ -	$ -	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 676
Tax Depreciation															
KU Projects	MACRS														
Advanced Metering Systems	10	$ -	$ -	$ -	$ -	$ 1,674	$ 1,755	$ 1,917	$ 1,011	$ 1,029	$ 1,052	$ 1,083	$ 1,129	$ 1,221	$ 913
Book/Tax Difference															
KU Projects															
Advanced Metering Systems		$ -	$ -	$ -	$ -	$ 1,599	$ 1,680	$ 1,842	$ 935	$ 954	$ 977	$ 1,008	$ 1,054	$ 1,146	$ 861
Deferred Tax Expense															
KU Projects															
Advanced Metering Systems		$ -	$ -	$ -	$ -	$ 622	$ 653	$ 716	$ 364	$ 371	$ 380	$ 392	$ 410	$ 446	$ 335

Accumulated Deferred Taxes	6/30/17	7/31/17	8/31/17	9/30/17	10/31/17	11/30/17	12/31/17	1/31/18	2/28/18	3/31/18	4/30/18	5/31/18	6/30/18	13 Month Average
KU Projects														
Advanced Metering Systems	$ -	$ -	$ -	$ -	$ 622	$ 1,275	$ 1,992	$ 2,356	$ 2,727	$ 3,107	$ 3,499	$ 3,909	$ 4,355	$ 1,834

EXHIBIT RCS-7

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Attorney General's Initial Data Requests for Information Dated January 11, 2017

Question No. 54

Responding Witness: Gregory J. Meiman

Q-54. Explain how the Company determines that the achievements of any incentive compensation goals are reached as a result of the incentive compensation plan, as opposed to other reasons. Provide all supporting empirical data.

A-54. There are no other reasons, other than achievements compared to goals that would result in payment from the incentive compensation plan.

The Company determines achievements of the incentive compensation plan based on actual results as reported by the respective department, line of business or plant. Actual results are compared to target and the payout percentage is determined. The results and payout percentage are then reviewed and approved by the officer responsible for the applicable measure.

Payments from the incentive compensation plan are not paid until approvals are secured. Attached are the incentive compensation goal achievements for the 2015 performance year.

LKE 2015 Incentive Measures and Results

Financial Performance Results

($ Millions)	Target	Actual	Payout %
LKE Net Income	$353,400	$376,351	173.1%
LKE EBIT	$754,200	$783,957	157.9%

Customer Satisfaction and Team Effectiveness Results

	Payout %	
Customer Satisfaction	141.70%	Approved by Paul Thompson
Union and Hourly		
Customer Services	66.75%	Approved by Paul Thompson
Electric Distribution Operations	147.75%	
Gas Distribution Operations	86.79%	
Operating Services	56.25%	
Plants		
Cane Run	145.21%	Approved by Paul Thompson
EWB CT's	126.40%	
EWB/Tyrone Steam	146.00%	
Ghent	123.08%	
Green River	144.07%	
Mill Creek	119.18%	
Ohio Falls	139.32%	
Paddy's Run	137.07%	
Trimble County	89.57%	
Information Technology		
IT Telecommunications	102.50%	Approved by Eric Slavinsky

Approved:

Vic Staffieri - Chief Executive Officer

2/18/16
Date

L:\Incentives\2015\2015 Final TIA Results for VAS Signature.xlsx

2015 Customer Satisfaction Results Summary

	Peer Average	LG&E	KU	LG&E/KU	Quarterly Points	YTD Points
Quarter 1	50.1%	43.0%	62.6%	54.0%	7	7
Quarter 2	51.4%	48.7%	61.4%	55.9%	6	13
Quarter 3	47.2%	47.7%	64.1%	56.9%	7	20
Quarter 4	48.7%	50.2%	66.6%	59.4%	8	28

Customer Satisfaction Payout Matrix - 32 Points Available

Points Earned	Payout %		
6	50.0	Diff	No payout for < 6 points ("floor")
7	54.2	4.17	
8	58.3	4.17	
9	62.5	4.17	
10	66.7	4.17	
11	70.8	4.17	
12	75.0	4.17	
13	79.2	4.17	
14	83.3	4.17	
15	87.5	4.17	
16	91.7	4.17	
17	95.9	4.17	
18	100.0	4.17	**Target**
19	104.2	4.17	
20	108.4	4.17	
21	112.5	4.17	
22	116.7	4.17	
23	120.9	4.17	
24	125.0	4.17	
25	129.2	4.17	
26	133.4	4.17	
27	137.6	4.17	
28	141.7	4.17	
29	145.9	4.17	
30	150.0	4.11	

Based on the Payout Matrix Above, 28 YTD Points = Customer Satisfaction Payout of 141.7%

Prepared by:	Martha Jessee Martha Jessee - Manager Compensation	2/3/2016 Date
Approved:	Gregory Meiman Greg Meiman - VP Human Resources	2/3/2016 Date
Approved:	John P. Malloy - VP Customer Services	03 Feb 2016 Date
Approved:	Paul Thompson - Chief Operating Officer	2/5/16 Date

2015 Customer Services Hourly and Union TIA Results and Payout

Team Effectiveness 40%

Measure	Measure Weighting	Weighting of Team Rating	Targets	Range		Actual Results	TIA % Payout	Weighted TIA Payout
SAFETY: TRR	20%	50%	0.71	0.91	0.61	1.10	0.00	0.00%
Field Services Work Orders Completed per Hour	12%	30%	3.01	2.41	3.61	3.55	145.00	43.50%
Meter Reading Accuracy	2%	5%	99.9	99.0	100	99.9	100.00	5.00%
Meter Assets Average Days to Complete Service Orders	6%	15%	7.00	11.0	1.0	4.4	121.67	18.25%
								66.75%

HR Manager Renea McClure Date: February 15, 2016

Director HR Shannon M Johnson Date: 2-15-16

VP Customer Services Date: 15 Feb 2016

COO Date: 2/16/16

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2015 Electric Distribution Operations Hourly and Union TIA Results & Payout

Team Effectiveness 40%

Measure	Measure Weighting	Weighting of Team Rating	Targets	Range		Actual Results	TIA % Payout	Weighted TIA Payout
Safety (Total Recordable Rate)	20.00%	50.0%	2.11	3.11	1.11	1.20	145.50	72.75%
Electric Reliability CAIDI	20.00%	50.0%	97	106.7	92.5	92.21	150.00	75.00%
								147.75%

HR Manager Renea M McClure Date: February 15, 2016

Director HR Sharon M. Johnson Date: 2-15-16

VP - Electric Distribution John Wolfe Date: 2-15-16

COO Date: 2/16/16

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2015 Gas Distribution Operations Hourly and Union TIA Results & Payout

Team Effectiveness 40%

Measure	Measure Weighting	Weighting of Team Rating	Targets	Range		Actual Results	TIA % Payout	Weighted TIA Payout
Safety (Total Recordable Rate)	20.00%	50.0%	2.11	3.11	1.11	3.10	50.50	25.25%
Gas Response (Response to Priority 1 Calls - Minutes)	20.00%	50.0%	42	48.5	35.5	39.0	123.08	61.54%
								86.79%

HR Manager Renea McClure Date: February 15, 2016

Director HR Sharon M Johnson Date: 2-15-16

VP - Gas Distribution Ronn E Bellar Date: 2/15/16

COO Date: 2/10/16

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2015 Operating Services Hourly and Union TIA Results and Payout

Team Effectiveness 40%

Measure	Measure Weighting	Weighting of Team Rating	Targets	Ranges		Actual Results	TIA % Payout	Weighted TIA Payout
Safety (TRR) Customer Services	10.00%	25%	0.71	0.91	0.61	1.10	0	0.00%
Work Order Notification "alert" Management	15.00%	37.5%	99%	98%	100%	96.7%	0	0.00%
Preventive Maintenance Inspections	15.00%	37.5%	93%	85%	100%	100%	150.00	56.25%
								56.25%

HR Manager Date: February 15, 2016

Director HR Date: 2-15-16

VP Customer Services Date: 15 Feb 2016

COO Date: 2/16/16

KU PLANTS - 2015 TIA TEAM EFFECTIVENESS - YEAR END

Rev: 1/21/2016

Ghent

Weighting	Topic	MIN - TARGET - MAX	Actual	TARGET % Payout	Weighted TE % Payout
40%	Safety - Recordable Incidents (Plant)	5 - **3** - 1	3	100.00	40.00
15%	Cont. Budget Variance - Plant	3.00 - 1.00 - (-2.00)	0.77	103.83	15.58
15%	Cont. Budget Variance - Combined	3.00 - 1.00 - (-2.00)	-3.65	150.00	22.50
30%	Availability - EFOR Plant	8.5 - **5.0** - 3.5	3.45	150.00	45.00
					123.08

EWB/Tyrone Steam

Weighting	Topic	MIN - TARGET - MAX	Actual	TARGET % Payout	Weighted TE % Payout
40%	Safety - Recordable Incidents (Plant)	5 - 3 - 1	1	140.00	56.00
15%	Cont. Budget Variance - Plant	3.00 - 1.00 - (-2.00)	-4.29	150.00	22.50
15%	Cont. Budget Variance - Combined	3.00 - 1.00 - (-2.00)	-3.65	150.00	22.50
30%	Availability - EFOR Plant	9.5 - **5.6** - 3.9	2.27	150.00	45.00
					146.00

EWB CT's

Weighting	Topic	MIN - TARGET - MAX	Actual	TARGET % Payout	Weighted TE % Payout
40%	Safety - Recordable Incidents (Plant)	5 - 3 - 1	1	140.00	56.00
15%	Cont. Budget Variance - Plant	3.00 - 1.00 - (-2.00)	-4.29	150.00	22.50
15%	Cont. Budget Variance - Combined	3.00 - 1.00 - (-2.00)	-3.65	150.00	22.50
30%	Starting Reliability - Plant	92.00 - **96.50** - 98.50	95.12	84.67	25.40
					126.40

Green River

Weighting	Topic	MIN - TARGET - MAX	Actual	TARGET % Payout	Weighted TE % Payout
40%	Safety - Recordable Incidents (Plant)	4 - **2** - 1	0	150.00	60.00
15%	Cont. Budget Variance - Plant	3.00 - 1.00 - (-2.00)	-15.19	150.00	22.50
15%	Cont. Budget Variance - Combined	3.00 - 1.00 - (-2.00)	-3.65	150.00	22.50
30%	Availability - EFOR Plant	11.9 - **7.0** - 4.9	5.73	130.24	39.07
					144.07

Safety Payout: Maximum Target Stated = 140% Payout. Zero Recordables = 150% Payout.

Approval Signatures:

Ralph Bowling / Date
VP Power Production

Paul W. Thompson / Date
Chief Operating Officer

1/22/2016
Loren Hincker / Date
Director Human Resources

2015 IT Telecommunications Department Hourly Targets and Performance Results
Performance Measures for BU Technicians - 40% Team Effectiveness

Measure	Weighting	Target	Ranges	Actual Results	Payout Results	Weighted Results
Safety	20.0%	1	0 - 3+	1	100.00%	50.00%
Average Team Competency	10.0%	3	0 - 5	3.48	110.00%	27.50%
Internal Customer Satisfaction	10.0%	3 - 10	0 - 19+	7	100.00%	25.00%
					Payout	102.50%

Approved

See attached emailed approval
Steve Schaub Date

See attached emailed approval
Dan Reffett Date

2/16/2016
Todd Dierksheide Date

See attached email
Eric Slavinsky Date

2015 IT Telecommunications Department Hourly Targets and Performance Results
Performance Measures for BU Technicians - 40% Team Effectiveness

Measure	Weighting	Target	Ranges	Actual Results	Payout Results	Weighted Results
Safety	20.0%	1	0 - 3+	1	100.00%	50.00%
Average Team Competency	10.0%	3	0 - 5	3.48	110.00%	27.50%
Internal Customer Satisfaction	10.0%	3 - 10	0 - 19+	7	100.00%	25.00%
					Payout	**102.50%**

Approved

Steve Schaub 02-15-2016
Steve Schaub — Date

Daniel T. Reffett 2/16/16
Dan Reffett — Date

Todd Dierksheide — Date

Eric Slavinsky — Date

I:\Admin\MGMT\BU TIA\2015\2015 Telecom BU TIA Measures-HR Form.xlsx Summary

Jessee, Martha

From: Slavinsky, Eric
Sent: Tuesday, February 16, 2016 9:21 AM
To: Jessee, Martha; Dierksheide, Todd D [PPL]; Schaub, Steve; Reffett, Dan
Cc: Denham, Melinda
Subject: RE: Action Required - 2015 Telecom Results - Please Approve

I approve

-----Original Message-----
From: Jessee, Martha
Sent: Tuesday, February 16, 2016 9:11 AM
To: Dierksheide, Todd D [PPL]; Slavinsky, Eric; Schaub, Steve; Reffett, Dan
Cc: Denham, Melinda
Subject: Action Required - 2015 Telecom Results - Please Approve

Todd and Eric - Steve and Dan have prepared/reviewed the attached and I am routing to you now for approval. Could each of you review and sign today and pdf back to me.

Steve and Dan - Please sign and pdf your documents to me as well.

Thanks.
Martha

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Attorney General's Initial Data Requests for Information Dated January 11, 2017

Question No. 68

Responding Witness: Gregory J. Meiman

Q-68. Provide a description of each employee benefit program or plan.

a. Also show the related test year cost.

b. Provide this information:

i. For KU employees
ii. For affiliate employees that had charged or allocated cost to KU during the test year.

A-68. a –b See attached.

Kentucky Utilities Company
Case No. 2016-00370

Benefit Plan	Description
Medical	Employees are eligible for medical coverage upon date of hire which includes both medical and perscription drug coverage. Anthem is the claims administrator for our medical options and Express Scripts is the claims administrator for our prescription drug coverage. There are four medical options: • EPO • PPO Low Deductible (90/10) • PPO Standard (80/20) • High Deductible Health Plan with Health Savings Account (HSA)
Health Care Reimbursement Account (cost included with Medical)	Employees are eligible to participate in the Health Care Reimbursement Account upon date of hire. The Health Care Reimbursement Account is a health care flexible spending account which allows employees to pay certain health care expenses for themselves and eligible dependents with pre-tax money. The company will make an annual contribution to the Health Care Reimbursement Account for people actively employed on December 31 of the prior year.
Dependent Care Reimbursement Account	Employees are eligible to participate in the Dependent Care Reimbursement Account upon date of hire. The Dependent Care Reimbursement Account is a dependent care flexible spending account which gives employees the opportunity to pay for certain child and elder care expenses with pre-tax money.
Dental	Employees are eligible for dental coverage upon date of hire. There are two dental plans administered by Delta Dental: • High Option • Basic Option
Vision	Employees are eligible to participant in the vision benefit plan upon date of hire. Vision benefits are offered as a separate, voluntary, employee paid option. The voluntary vision plan is administered by Vision Service Plan (VSP).
Basic Life and AD&D Insurance	The company provides Basic Life and Accidental Death and Dismemberment insurance in the amount of two times annua salary; maximum benefit of $300,000.

Kentucky Utilities Company
Case No. 2016-00370

Benefit Plan	Description
Employee and Dependent Supplemental Life Insurance	Regular, full-time employees may purchase additional life insurance in the amount of one, two, or three times annual base salary; maximum of $300,000. Supplemental life insurance is a voluntary benefit, and is 100% paid by the employee. Regular, full-time employees may purchase dependent supplement life insurance on eligible dependents. There are 4 dependent supplement coverage options: • $5,000 – spouse / $2,500 – child(ren) • $10,000 – spouse / $5,000 – child(ren) • $25,000 – spouse / $10,000 – child(ren) • $50,000 – spouse / $20,000 – child(ren) Dependent supplemental life insurance is a voluntary benefit, and is 100% paid by the employee.
Business Travel Accident Plan (included in other benfits)	The Business Travel Accident Plan provided eligible employees on business-related travel (excluding travel to and from work) with accidental death and dismemberment insurance coverage.
Long-term disability	After an employee is disabled for at least six months and the plan has approved the employee's application for Long-Term Disability, an employee is eligible to receive monthly benefits — equivalent to 60 percent of base monthly rate of pay, reduced by an amount reflecting certain income from other sources.
Short-term disability (Charged to Sick time)	The Short- Term Disability program provides varying levels of wage protection for up to 1,000 hours depending on your service with the company. Coverage begins after 40 consecutive work-hours of medically certified absence or upon admission to a hospital requiring overnight stay or upon admission to an outpatient care facility for procedures or treatment
Retirement Plan	Employee hired prior to 1/1/06 are eligible for the retirement pension plan. The retirement plan benefit is calculated based on years of service and eligible earnings. The benefit is payable upon date of retirement in monthly installments or a one-time lump sum.

Kentucky Utilities Company
Case No. 2016-00370

Benefit Plan	Description
Savings Plan	Employees are eligible to participate in the savings plan upon date of hire. Employees can contribute between 0% and 75% of eligible pay on a traditional pretax or Roth after tax basis. The company will match $.70 for every $1.00 contributed to the savings plan, up to the first 6% of pay. Employees hired after 1/1/06 are eligible for the Retirement Income Account (RIA). The company will contribute between 3% and 7% of eligible pay to the Retirement Income Account on an annual basis.
Group legal	Employees are eligible for a voluntary group legal program administered by ARAG insurance company. ARAG contracts with local attorney for the ARAG network. Employee paid
Family Assistance Program (included in other)	The Family Assistance Program (FAP) provides professional help to employees and their immediate family members who have personal problem. The Family Assistance Program is administered by Wayne Corporation.
Tuition Reimbursement	Regular, full-time employees are eligible for tuition remibursement, which pays 100% of tuition up to an annual calendar year maximum of $7,000 for undergraduate degrees and $9,000 for graduate degrees and doctoral programs. Participation is based on individual approval of an employee's request and the relationship of courses to job assignment or career development.
Post-retirement Medical	Employees are eligible for post-retirement medical benefits if they retire at age 55 or older and have at least 10 years of service. Retirees and eligible dependents are offered retiree medical coverage. Employees hired before 1/1/06 are eligible for a monthly Retiree Medical Credit. The Retiree Medical Credit is what the company contributes toward the cost of medical coverage, and is based on teh retiree's age. Employees hired on or after Jan. 1, 2006 are eligible to participate in the Retiree Medical Account. The company will make a notional contribution to the Retiree Medical Account upon date of retirement.
Post-Retirement Life Insurance	Employees are eligible for post-retirement life insurance if they retire at age 55 or older and have at least 10 years of service. The company provides post-retirement life insurance, at no cost to the employee, based on the following level of benefits at the time of death: •Before age 65 — 100% of final base pay (maximum $100,000). •Age 65 to age 70 — 50% of final base pay (maximum $50,000). •Age 70 and above — $10,000.
Adoption Assistance Program (included in other)	The company supports employees who adopt children by providing the employees up to $2,500 of financial assistance.

Kentucky Utilities Company
Case No. 2016-00370

			From Affiliates	
	Test Year	KU Employees	LGE-KU Services	LGE
Pension	14,272,779	4,767,004	8,497,152	1,008,623
Post Retirement - SFAS 106 (ASC 715)	2,457,284	1,373,319	535,410	548,555
Post Employment - SFAS 112 (ASC 712)	207,223	(16,172)	172,596	50,799
401(k)	4,924,615	1,786,920	2,635,584	502,111
Retirement Income	1,573,540	479,451	936,636	157,453
Medical Insurance	14,888,936	5,974,611	7,309,068	1,605,257
Dental Insurance	769,286	304,914	384,606	79,766
Workers Compensation	547,999	454,899	24,180	68,920
Group Life Insurance	647,723	235,864	345,978	65,880
Long Term Disability Insurance	655,393	238,247	350,406	66,741
Other Benefits	1,833,860	957,179	706,554	170,128
Team Incentive Award	11,505,675	4,005,176	6,786,882	713,617
Tuition Reimbursement	462,979	41,100	421,879	-
	$54,747,292	$20,602,511	$29,106,931	$5,037,850

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 210

Responding Witness: Gregory J. Meiman

Q-210. Provide a copy of all incentive compensation/bonus plans and provide the level of related bonus payments included in cost of service.

A-210. See attached. See also the response to KIUC 1-18.

TEAM INCENTIVE AWARD (TIA) PLAN

- Corporate Safety
- Customer Satisfaction
- Cost Control
- Customer Reliability
- Individual and Team Effectiveness

TIA

Eligible employees participate in the LG&E and KU Team Incentive Award ("TIA"). The TIA focuses employee efforts on customer and business goals and rewards employees for achieving those goals. The TIA provides an opportunity for eligible employees to share in the added value they create through superior performance.

TIA AND BUSINESS STRATEGY

The company realizes the wealth that exists in the abilities of its people. The challenge is to become the best in our competitive market through each individual using his or her talents combined with other team members to make it happen. The TIA Plan plays a key role in assisting the company in focusing employees on customer and business goals as well as providing employees with a program that can increase their individual compensation.

The TIA was developed to motivate and direct employees toward the achievement of strategic goals. It also assists with attracting and retaining skilled personnel by providing competitive compensation commensurate with their talents, cooperation and contribution.

There are several basic TIA concepts:

- There is a focus on the cooperative spirit of all employees working together as a team.
- Risk-taking, embodied in initiative, fresh perspectives and innovative solutions, is encouraged and rewarded.
- The plan is designed to motivate and improve the individual performance of all employees.
- Incentive award levels vary depending on the employee's base salary, position and performance. The TIA represents "pay at risk." The relationship of the target awards to salary reflects that employees who have increasing responsibility for customer and business performance, as reflected in higher salaries, generally have higher amounts of individual compensation tied to that performance.

With these concepts in mind, the TIA was designed:

- To promote the achievement of the company's objectives.
- To attract, motivate and retain employees.

TIA PLAN

Key elements of the TIA are as follows:

1. Participants include all active full-time and regular, part-time salaried employees, IBEW 2100 employees and KU hourly and bargaining unit employees.

2. All TIA participants have Target Awards based on the following:

Target Award Participation

Non-Exempt & Hourly	6% of annual earnings
Exempt Individual Contributors	9% of base salary
Managers	14% of base salary
Senior Managers	25% of base salary

3. Performance objectives are established annually to support the customer and business strategies. The size of the awards depend upon the degree to which these objectives are achieved.

4. Exempt employees with salary changes during the year will have their awards calculated in accordance with the amount of time they work under each respective base salary.

5. Total annual earnings, including overtime, are used in calculating the earned awards for all regular non-exempt and hourly full- and part-time employees. Prior TIA awards are excluded from total annual earnings to calculate earned awards.

6. Earned TIA Awards will be paid in cash within 90 days of the completion of the calendar-based annual performance period.

7. Compensation from the TIA is included in calculating benefits under the Company's Retirement (except for the KU Retirement Plan) and 401(k) Savings Plan.

8. This plan in no way creates a contract of employment for any duration. The company has full and final discretion with respect to the interpretation and application of this plan. The Company reserves the right to modify or terminate this plan in its sole discretion. This plan document supersedes any prior plan document relating to the TIA.

ELIGIBILITY

All active, regular full- and part-time salaried employees, IBEW 2100 employees and KU hourly and bargaining unit employees, who have at least one month continuous service and are on the payroll on December 31 of the performance year, are eligible for a TIA. Employees who become disabled, die or retire during the performance year will be eligible for a prorated award. Disability, for purpose of this plan, means that the employee is eligible for the receipt of benefits under the Long Term Disability Plan. Retire means that the employee is eligible to retire under the terms of a company sponsored retirement plan. Employees who join the company during the performance year, who have at least one month continuous service, and are on the payroll on December 31 will also be eligible for a prorated award. Employees incurring unpaid work days during the performance year may experience a proportionate reduction in their TIA.

INDIVIDUAL PERFORMANCE OBJECTIVES

The individual performance objective links individual performance to the TIA award. The individual performance objective can be combined with performance objectives for small teams as well as with key objectives from the Performance Excellence Process. Individual performance objectives should align with, and support, strategic customer and business goals to drive performance.

TIA COMMUNICATION

TIA performance results for customer, business and operational performance measures are communicated through the Company's internal communications to provide information concerning performance. Final TIA performance results are approved following the completion of the performance period and are communicated through the Company's internal communications.

CONCLUSION

The Team Incentive Award Plan is designed to strengthen the connection between pay and performance. It will direct a portion of total pay to awards based on customer, business, operational and individual achievements. The TIA focuses eligible salaried and hourly employees' attention on the company's business goals.

TIA FORMULA

The TIA calculation formula is shown below, along with an example of a potential award. In this example, note the participant's salary is $40,000 and the target award is 9%.

TIA CALCULATION

Step 1: Target Award % x Annual Base Pay Earnings = Target Award

Step 2: Target Award x Corporate Safety Weighting x Performance % = Corporate Safety Award

Step 3: Target Award x Customer Satisfaction Weighting x Performance % = Customer Satisfaction Award

Step 4: Target Award x Cost Control Weighting x Performance % = Cost Control Award

Step 5: Target Award x Customer Reliability Weighting x Performance % = Customer Reliability Award

Step 6: Target Award x Individual or Team Weighting x Performance % = Individual or Team Award

Step 7: Corporate Safety Award + Customer Satisfaction Award + Cost Control Award
+ Customer Reliability Award + Individual or Team Award = Total TIA Award

TIA CALCULATION EXAMPLE

Annual Base Pay Earnings = $40,000
Target Award Percent = 9%
Corporate Safety Performance % = 105%
Customer Satisfaction Performance % = 110%
Cost Control Performance % = 100%
Customer Reliability Performance = 110%
Individual or Team Performance % = 105%

Step 1: 9% x $40,000 = $3,600 Total Award

Step 2: $3,600 x 15% x 105% = $567 Corporate Safety Award

Step 3: $3,600 x 15% x 110% = $594 Customer Satisfaction Award

Step 4: $3,600 x 15% x 100% = $540 Cost Control Award

Step 5: $3,600 x 15% x 110% = $594 Customer Reliability Award

Step 6: $3,600 x 40% x 105% = $1,512 Individual or Team Award

Step 7: $567 + $594 + $540 + $594 + 1,512 = $3,807 Total TIA Award

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to the Attorney General's Supplemental Data Requests
Dated February 7, 2017

Question No. 15

Responding Witness: Gregory J. Meiman

Q-15. Refer to the response to AG-1-54. For each of the following, show in detail how the target amounts were developed and also show in detail how actual achieved results were calculated:

a. LKE Net Income Target and Actual

b. LKE EBIT Target and Actual

c. Customer Satisfaction payout percentage

d. Electric Distribution Operations payout percentage

e. Payout percentage for each Plant

f. Information Technology payout percentage

A-15.

a. The LKE Net Income target was developed during the 2015 business planning and budgeting process and reflects budgeted revenue less operating, interest and income tax expenses. Actual net income results for 2015 were compared to budget to determine the achievement. The budget for 2015 assumed a payout based on 100% achievement of the target. See attachment being provided in Excel format. For the forecasted year, the net income target is no longer included as a measure.

b. For 2015, the EBIT incentive measure was not included in the calculation of revenue requirement; however, the calculation is provided in the attachment to the response to part a.

c. The Customer Satisfaction target of 18 points requires the company's customer satisfaction score to be above the peer group competitive range for 3 of the 4 quarters, earning six points per quarter.

In 2015 the company was above the peer group competitive range all 4 quarters, earning 24 points. In quarter 1 and quarter 3, the company earned one point for ranking second within the peer group and in quarter 4, the company earned two points for ranking first within the peer group.

d. The Electric Distribution Operations safety target was developed during the 2015 business planning process and is based on historical recordable incidents, projected performance and industry trending. The OSHA formula (# of recordable incidents x 200,000 / # of hours worked) is used to calculate actual results which reflect incidents that require medical treatment beyond first aid, days away from work, restricted work, transfer to another job, or loss of consciousness. See attached.

   The Electric Distribution Operations electric reliability measure was based on a Customer Average Interruption Duration Index (CAIDI) which is the sum of customer minutes interrupted divided by the total number of customers whose service was interrupted. It is calculated by dividing SAIDI (System Average Interruption Duration Index) by SAIFI (System Average Interruption Frequency Index). The 2015 target was based on 2015 business plan target values for SAIDI and SAIFI combined with historic CAIDI performance. Electric Distribution's 2015 actual CAIDI result of 92.21 was calculated based on 2015 outage data in the Outage Management System. See attachment being provided in Excel format.

e. The Plant budget and KPI targets were developed through the 2015 budget and business planning processes, respectively. The fleet safety (recordable incident rate) target is established and then allocated based on plant headcount. Availability targets are established at the fleet level and then allocated based on capacity. Targets are determined based on historical performance. Actual results are compared to target to determine achievement for each measure. See attachment being provided in Excel format.

f. Information Technology Telecommunications targets are based on historical performance relative to safety, internal customer satisfaction, and average team competency. Actual results are compared to target to determine achievement for each measure. See attachment being provided in Excel format.

2015 LKE Financial Results

Measures	Payout %	Results	50% TARGET	75% TARGET	100% TARGET	125% TARGE T	150% TARGET	200% TARGET	If < 75%	If < 50%	50%-75% Calc	75%-100% Calc	If > 100%	100%-125% Calc	If > 150%	125%-150% Calc	150% - 200% Calc
LKE Net Income	173.1%	**376.351**	339.100	346.250	353.400	361.250	369.100	384.800	180.2%	180.2%	180.2%	180.2%	173.1%	173.1%	173.1%	173.1%	173.1%
LKE EBIT	157.9%	**783.957**	730.900	742.550	754.200	767.050	779.900	805.600	163.9%	163.9%	163.9%	163.9%	157.9%	157.9%	157.9%	157.9%	157.9%

2015 Electric Distribution Operations Hourly and Union TIA Results & Payout

Team Effectiveness 40%

Measure	Measure Weighting	Weighting of Team Rating	Targets	Range		Actual Results	TIA % Payout	Weighted TIA Payout
Safety (Total Recordable Rate)	20.00%	50.0%	2.11	3.11	1.11	1.20	145.50	72.75%
Electric Reliability CAIDI	20.00%	50.0%	97	106.7	92.5	92.21	150.00	75.00%
								147.75%

2015 Electric Distribution Operations Team Effectiveness Payout Calculation

						ACTUAL RESULTS ARE							
						Below Target			Above Target				
Weight (% of TIA)	Weight (% of TE)	Measure	Min	Target	Max	Enter Results Here	Calc		Enter Results Here	Calc	Weighted Payout %	For Calc only	
20.00	50.00%	SAFETY: TRR	3.11	2.11	1.11		0		1.20	145.50	72.750%	205.5	145.5
20.00	50.00%	CAIDI	106.7	97	92.5		0		92.21	150	75.000%	600	153.22
40.00	100.0%										**147.75%**		

2015 TIA TEAM EFFECTIVENESS
KU PLANTS (Rev 1/21/2016)

GHENT

Weighting	Topic	MIN - TARGET - MAX	Actual (< Target)	TIA % Payout	Actual (> Target)	TIA % Payout	Weighted TIA % Payout		Below Target Formula	Above Target Formula
40%	Safety: Recordable Injuries (Plant)	5 - **3** - 1	*	0	3	100	40.00			
15%	Cont. Budget Variance (%) - Plant	3.0 - **1.0** - (-2.0)	*	0	0.77	103.83	15.58		#VALUE!	103.8333333
15%	Cont. Budget Variance (%) - Combined	3.0 - **1.0** - (-2.0)	*	0	-3.65	150	22.50		#VALUE!	177.5
30%	Availability - EFOR Plant	8.5 - **5.0** - 3.5	*	0	3.45	150	45.00		#VALUE!	151.6666667
							123.08			

EWB STEAM*

Weighting	Topic	MIN - TARGET - MAX	Actual (< Target)	TIA % Payout	Actual (> Target)	TIA % Payout	Weighted TIA % Payout		Below Target Formula	Above Target Formula
40%	Safety: Recordable Injuries (Plant)	5 - 3 - 1	*	0	1	140	56.00		#VALUE!	100
15%	Cont. Budget Variance (%) - Plant	3.0 - **1.0** - (-2.0)	*	0	-4.29	150	22.50		#VALUE!	188.1666667
15%	Cont. Budget Variance (%) - Combined	3.0 - **1.0** - (-2.0)	*	0	-3.65	150	22.50		#VALUE!	177.5
30%	Availability - EFOR Plant	9.5 - **5.6** - 3.9	*	0	2.27	150	45.00		#VALUE!	197.9411765
							146.00			

GREEN RIVER

Weighting	Topic	MIN - TARGET - MAX	Actual (< Target)	TIA % Payout	Actual (> Target)	TIA % Payout	Weighted TIA % Payout		Below Target Formula	Above Target Formula
40%	Safety: Recordable Injuries (Plant)	4 - **2** - 1	*	0	0	150	60.00		#VALUE!	200
15%	Cont. Budget Variance (%) - Plant	3.0 - **1.0** - (-2.0)	*	0	-15.19	150	22.50		#VALUE!	369.8333333
15%	Cont. Budget Variance (%) - Combined	3.0 - **1.0** - (-2.0)	*	0	-3.65	150	22.50		#VALUE!	177.5
30%	Availability - EFOR Plant	11.9 - **7.0** - 4.9	*	0	5.73	130.24	39.07		#VALUE!	130.2380952
							144.07			

EWB CT's*

Weighting	Topic	MIN - TARGET - MAX	Actual (< Target)	TIA % Payout	Actual (> Target)	TIA % Payout	Weighted TIA % Payout		Below Target Formula	Above Target Formula
40%	Safety: Recordable Injuries (Plant)	5 - **3** - 1	*	0	1	140	56.00		#VALUE!	100
15%	Cont. Budget Variance - Plant	3.0 - **1.0** - (-2.0)	*	0	-4.29	150	22.50		#VALUE!	188.1666667
15%	Cont. Budget Variance - Combined	3.0 - **1.0** - (-2.0)	*	0	-3.65	150	22.50		#VALUE!	177.5
30%	Starting Reliability - Plant	92.0 - **96.5** - 98.5	95.12	84.67		0	25.40		84.66666667	-2312.5
							126.40			

Safety Rec Inj Payout: Maximum Target Stated = 140% Payout. Zero Recordables = 150% Payout.

* EWB/TYRONE WEIGHTINGS
BUDGET = EWB STEAM + EWB CT's
SAFETY RECORDABLE INJ INCIDENTS = EWB + CT's

2015 IT Telecommunications Department Hourly Targets and Performance Results
Performance Measures for BU Technicians - 40% Team Effectiveness

Measure	Weighting	Target	Ranges	Actual Results	Payout Results	Weighted Results
Safety	20.0%	1	0 - 3+	1	100.00%	50.00%
Average Team Competency	10.0%	3	0 - 5	3.48	110.00%	27.50%
Internal Customer Satisfaction	10.0%	3 - 10	0 - 19+	7	100.00%	25.00%
					Payout	**102.50%**

2015 IT Telecom Team Effectiveness Payout Calculation

Weight (% of TIA)	Weight (% of TE)	Measure	Min	Target	Max	ACTUAL RESULTS ARE Below Target: Enter Results Here	Below Target: Calc		Above Target: Enter Results Here	Above Target: Calc	Weighted Payout %	For Calc only	
20.00	50.00%	Safety	3	1	0		0		1	100.00	50.000%	125	100
10.00	25.00%	Average Team Competency	0	3	5		0		3.4	110.00	27.500%	50	110
10.00	25.00%	Internal Customer Satisfaction	0	3-10	19		0		7	100.00	25.000%	n/a	n/a
40.00	100.00%										102.500%		

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to the Attorney General's Supplemental Data Requests
Dated February 7, 2017

Question No. 16

Responding Witness: Gregory J. Meiman

Q-16. Refer to the response to AG-1-54. Refer to the 2015 Customer Satisfaction Results Summary.

a. What does a 50 percent customer satisfaction measurement indicate?

b. Does a 50 percent customer satisfaction measurement indicate that half of the customers are satisfied and the other half are not? If not, explain fully.

c. What does a 43 percent customer satisfaction measurement indicate?

d. What does a 66.6 percent customer satisfaction measurement indicate? Does this mean that two-thirds of the customer are satisfied and one-third are not? If not, explain fully.

e. Which companies are in the "Peer Average" for 2015 Customer Satisfaction?

f. How were the companies in the "Peer Average" selected?

A-16.

a. A 50 percent customer satisfaction measurement indicates that 50 percent of customers surveyed rated their overall satisfaction with the company a 9 or 10 on a 10 point scale.

b. No. It means that the balance of customers (50 percent) surveyed rated their overall satisfaction with the company an 8, 7, 6, 5, 4, 3, 2, or 1.

c. A 43 percent customer satisfaction measurement indicates that 43 percent of customers surveyed rated their overall satisfaction with the company a 9 or 10 on a 10 point scale.

d. A 66.6 percent customer satisfaction measurement indicates that 66.6 percent of customers surveyed rated their overall satisfaction with the company a 9 or 10 on a 10 point scale and 33.4% gave a rating of 8, 7, 6, 5, 4, 3, 2, or 1.

e. AEP Midwest, Duke Carolinas, Georgia Power, Duke Midwest, MidAmerican, South Carolina Electric and Gas.

f. Peer utilities were selected based on characteristics similar to LG&E and KU.
   - Type of services provided (Electric or Electric and Gas)
   - Size of service area and number of customer's served
   - Performance in syndicated studies (e.g. top ranking in JD Power studies)
   - Customer demographic profiles

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to the Attorney General's Supplemental Data Requests
Dated February 7, 2017

Question No. 17

Responding Witness: Gregory J. Meiman

Q-17. Refer to the response to AG-1-68.

a. How much of the $11.506 million Team Incentive Award was reflected as expense by KU electric utility operations in the test year? Show the amounts by account.

b. What is the comparable total amount of Team Incentive Award for the forecasted period?

c. How much of the total forecasted period Team Incentive Award was reflected as expense by KU electric utility operations in the forecasted period? Show the amounts by account.

d. Identify each item and the related dollar amount that is included in the $1.8 million of Other Benefits.

e. How much of the $1.8 million Other Benefits were expensed by KU electric utility operations in the test year? Show the amounts by account.

f. What is the comparable total amount of Other Benefits Expense for the forecasted period? Show a breakout of KU electric utility operations and show the amounts by account.

g. What calendar period are the "Test Year" amounts in the Attachment to the response to AG-1-68 for?

A-17.

a. The $11.506 million Team Incentive Award shown in AG-1-68 is the total company amount included in expense for KU electric utility operations for the forecasted test period. See attachment for the amounts by account. The Kentucky jurisdictional amount included in the forecasted test year is $10.42 million. See response to Kroger 2-3 for the details.

b. The amount shown in AG-1-68 for Team Incentive Award is for the total company for the forecasted test period. See attachment to the response to part a. As stated in response a, the Kentucky Jurisdictional amount is $10.42 million included in expense.

c. See the response to parts a. and b.

d. See attached for each item and the related dollar amount that is included in the $1.8 million of Other Benefits.

e. The $1.8 million Other Benefits is the amount included in expensed by KU electric utility operations in the forecasted test year. The expense amounts are charged to FERC account 926.

f. The amount included in AG-1-68 for Other Benefits is for the forecasted test period. See attachment to the response to part d.

g. "Test Year" amounts in the Attachment to the response to AG-1-68 for is the Forecasted Test Year ending 6-30-18.

Attachment to Response to AG-2 Question No. 17(a)
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Meiman

Kentucky Utilities Company
Case No. 2016-00370

Construction-Other	Total
107	2,435,235
108	103,496
163	157,070
184	976,269
426	42,755
512	57,862
908	89,005
Total Construction-Other	**3,861,692**

Operating	Total
500	675,798
501	229,157
502	748,037
505	466,584
506	125,197
510	594,275
511	92,214
512	552,109
513	124,110
514	24,243
541	12,882
542	3,650
546	26,959
551	9,705
553	67,506
554	2,767
556	200,329
560	234,471
561	323,853
562	37,146
566	10,323
570	88,899
571	9,082
580	110,542
581	34,498
582	60,397
583	191,016
584	-
586	454,173
587	-
588	268,452

Operating	Total
590	-
592	43,127
593	461,407
594	30,798
595	3,836
598	-
901	318,088
902	59,057
903	1,125,367
907	57,922
908	25,509
920	3,556,333
935	45,857
Total Operating	**11,505,675**
Total TIA	**15,367,367**

Attachment to Response to AG-2 Question No. 17(d)
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Kentucky Utilities Company
Case No. 2016-00370

Other Benefits by Component

	Total Expensed to FERC 926
PBGC Premium	516,372
Wellness Programs	482,322
Consulting, primarily Actuarial Services	421,311
Administrative fees and Other miscellaneous benefits	195,771
Medical Fees (ACA)	177,421
Family Assistance Program	40,663
Total	**1,833,860**

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 18

Responding Witness: Gregory J. Meiman

Q.1-18. Please provide the incentive compensation expense for (a) 2015, (b) 2016, (c) the base year, and (U) the test year by incentive compensation plan and by goal or target for each plan. This includes incentive compensation expense incurred directly by the Company and the expense assigned and allocated to the Company from the Service Company.

A.1-18. The Company has one incentive compensation plan, the Team Incentive Award (TIA) that is charged to KU and included in its revenue requirement. The incentive measures are re-evaluated annually. However, for the sake of completeness, the table below assumes the measures and weightings used for 2017 will apply in 2018 as well for purposes of categorizing the TIA for the forecast test year. See the response to AG 1-210 for a copy of the plan.

	2015	2016	Base Period	Test Period
Total Team Incentive Award				
Net Income	7,297,430	3,699,077	2,817,851	-
Cost Control	-	-	223,285	1,598,010
Customer Reliability	-	-	223,285	1,598,010
Customer Satisfaction	1,991,230	2,016,612	1,843,437	1,598,010
Corporate Safety	-	1,896,143	1,733,313	1,598,010
Individual / Team Effectiveness	4,496,779	4,689,796	4,287,063	5,113,633
Total	13,785,439	12,301,629	11,128,234	11,505,675

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Supplemental Requests for Information of Kroger
Dated February 7, 2017

Question No. 3

Responding Witness: Gregory J. Meiman

Q-3. Please refer to KU's response to KIUC's First Set of Data Requests, Nos. 1-18.

a. Has KU eliminated the Net Income goal in its incentive compensation plan effective in 2017? If not, please provide the percentage weighting applicable to the Net Income goal in 2017.

b. Does KU anticipate including a Net Income goal in its incentive compensation plan in 2018? If so, please provide the percentage weighting that KU anticipates applying to the Net Income goal in 2018.

c. Are the amounts provided in response to KIUC's First Set of Data Requests Nos. 1-18 Total Company or Kentucky Jurisdictional amounts? If the former, please provide the Kentucky Jurisdictional Amounts for each goal. If the latter, please provide the Total Company amounts for each goal.

d. Please provide the workpapers, in Excel format with formulas intact, that derive KU's Test Period incentive compensation expense as presented in KU's response to KIUC's First Set of Data Requests, Nos. 1-18, including the derivation of the expense applicable to each goal.

A-3.

a. Yes, it is eliminated.

b. No.

c. The amounts in KIUC 1-18 were Total Company. The amounts shown below are Kentucky Jurisdictional amounts.

Total Team Incentive Award	**2015**	**2016**	**Base Period**	**Test Period**
Net Income	6,584,295	3,342,481	2,545,288	-
Cost Control	-	-	201,687	1,447,255
Customer Reliability	-	-	201,687	1,447,255
Customer Satisfaction	1,796,639	1,822,208	1,665,126	1,447,255
Safety	-	1,713,353	1,565,655	1,447,255
Individual / Team Effectiveness	4,057,335	4,237,694	3,872,387	4,631,216
Total	**12,438,269**	**11,115,736**	**10,051,830**	**10,420,237**

d. See attachment being provided in Excel format.

Incentive Compensation
Opex only

	KU Test Period
Total Team Incentive Award	
Jurisdictionalized Total	**10,420,237**
Weighted Percentage for each Goal/Target	
Financial	0%
Other Operating and Maintenance	14%
Capital Spend	14%
Customer Satisfaction	14%
Safety	14%
Individual / Team Effectiveness	44%
Total (100%)	**1.00**
Amount by each Goal/Target	
Financial	-
Cost Control	1,447,255
Customer Reliability	1,447,255
Customer Satisfaction	1,447,255
Safety	1,447,255
Individual / Team Effectiveness	4,631,216
Total	**10,420,237**

	KU Test Period
Total Team Incentive Award	
Net Income	-
Cost Control	1,447,255
Customer Reliability	1,447,255
Customer Satisfaction	1,447,255
Safety	1,447,255
Individual / Team Effectiveness	4,631,216
Total	**10,420,237**

Incentive Year	Financial Weighting	Financial Result	Financial Goal	Other O&M Weighting	Other O&M Result	Other O&M Goal	Capital Spend Weighting	Capital Spend Result	Capital Spend Goal	Customer Satisfaction Weighting	Customer Satisfaction Result	Customer Goal	Corporate Safety Weighting	Corporate Safety Result	Corporate Safety Goal	Team / Individual Weighting	Team / Individual Results	Team / Individual Goal	Total All Goals	Financial	Other O&M	Capital Spend	Customer Sat	Corporate Safety	Team / Individual	Total
Test Year	0%	100.0%	-	15.0%	100.0%	0.1500	15%	100.0%	0.1500	15%	100.0%	0.1500	15%	100.0%	0.1500	40%	120.0%	0.4800	1.0800	0.00%	13.89%	13.89%	13.89%	13.89%	44.44%	100%

Attachment to Response to Kroger-2 Question No. 3(d)
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Meiman

TIA By Account

Construction-Other	
107	2,435,235
108	103,496
163	157,070
184	976,268
426	42,755
512	57,861
908	89,005
Total Construction-Other	**3,861,692**

Operating		Jurisdicitional %	Jurisdictionalized Amount
500	675,798	0.870121	588,026.21
501	229,157	0.879382	201,516.87
502	748,037	0.870121	650,883.09
505	466,584	0.870121	405,984.50
506	125,197	0.870121	108,936.89
510	594,275	0.879382	522,594.81
511	92,214	0.870121	80,237.60
512	552,109	0.879382	485,514.69
513	124,110	0.879382	109,140.35
514	24,243	0.870121	21,094.64
541	12,881	0.870121	11,208.42
542	3,650	0.870121	3,175.72
546	26,959	0.870121	23,457.49
551	9,705	0.870121	8,444.58
553	67,506	0.870121	58,738.44
554	2,767	0.870121	2,407.54
556	200,329	0.870121	174,310.76
560	234,471	0.901548	211,387.00
561	323,853	0.901548	291,968.85
562	37,146	0.901548	33,489.31
566	10,323	0.901548	9,306.58
570	88,899	0.901548	80,147.10
571	9,082	0.901548	8,188.06
580	110,542	0.944360	104,391.16
581	34,498	0.944360	32,578.69
582	60,397	0.944360	57,036.09
583	191,016	0.944360	180,387.58
584	-	-	-
586	454,173	0.944360	428,902.51
587	-	-	-
588	268,452	0.944360	253,515.50
590	-	-	-
592	43,127	0.944360	40,727.46
593	461,407	0.944360	435,734.52
594	30,798	0.944360	29,084.18
595	3,836	0.944360	3,622.56
598	-	-	-
901	318,088	0.948783	301,796.48
902	59,057	0.948783	56,032.06
903	1,125,367	0.948783	1,067,729.42
907	57,922	0.997250	57,762.47
908	25,509	0.997250	25,439.30
920	3,556,333	0.903711	3,213,895.59
935	45,857	0.903711	41,441.74
Total Operating	**11,505,675**		**10,420,237**

Total TIA	**15,367,367**

Incentive Compensation
Opex only

	Test Period
Total Team Incentive Award	
Allocated From LGE and KU Service Company	6,786,882
Allocated From LGE	713,617
Allocated From KU	4,005,176
Total	**11,505,675**
Percentage for each Goal/Target	
Financial	0%
Other Operating and Maintenance	14%
Capital Spend	14%
Customer Satisfaction	14%
Safety	14%
Individual / Team Effectiveness	44%
Total (100%)	**1.00**
Amount by each Goal/Target	
Financial	-
Cost Control	1,598,010
Customer Reliability	1,598,010
Customer Satisfaction	1,598,010
Safety	1,598,010
Individual / Team Effectiveness	5,113,633
Total	**11,505,675**

	Test Period
Total Team Incentive Award	
Net Income	-
Cost Control	1,598,010
Customer Reliability	1,598,010
Customer Satisfaction	1,598,010
Safety	1,598,010
Individual / Team Effectiveness	5,113,633
Total	**11,505,675**

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's First Request for Information
Dated November 10, 2016

Case No. 2016-00370

Question No. 55

Responding Witness: Gregory J. Meiman

Q-55. Regarding the utility's employee compensation policy:

a. Provide the utility's written compensation policy as approved by the Board of Directors.

b. Provide a narrative description of the compensation policy, including the reasons for establishing the policy and the utility's objectives for the policy.

c. Explain whether the compensation policy was developed with the assistance of an outside consultant. If the compensation policy was developed or reviewed by a consultant, provide any study or report provided by the consultant.

d. Explain when the utility's compensation policy was last reviewed or given consideration by the Board of Directors.

A-55 a. Attached is the Company's written compensation policy in effect since 1997 and reviewed on a regular basis by Human Resources. The last review was completed in March 2015. While not approved by the Board, compensation decisions made under this policy are supported by various levels of approval. Individual salary recommendations made under the Company's written compensation policy are reviewed and approved by the manager, next level manager and Human Resources.

The annual salary increase budget is included in the Company's Business Plan which is reviewed and approved by the LG&E and KU Boards.

b. The Company believes the compensation policies and practices are effective in achieving objectives that produce sustainable operating results by attracting and retaining talented and experienced individuals. The Company's compensation program reflects the long established commitment to a pay-for-performance philosophy, under which compensation is aligned with company performance.

Using external market compensation data at the 50th percentile of the national general or utility industry, job midpoints are established. Salary range minimums and maximums are based on 70% and 130% of the 50th percentile midpoint, respectively. Individual employee compensation is then managed within this competitive range. Compensation is considered competitive if it's within +/- 10% of the midpoint when considering factors that include performance, time in position, tenure, education and experience.

c. The Company's compensation program was recently reviewed by a compensation consultant, David J. Wathen of Willis Towers Watson. See Tab 60 of the Filing Requirements for the results of Mr. Wathen's study.

d. See the response to part a.

LG&E and KU Energy LLC Policy

Compensation

Policy

Compensation practices are designed and implemented to attract, motivate and retain employees that the Company needs to meet its strategic objectives. The Company's compensation programs provide competitive fixed and variable compensation.

Scope

This policy applies to all LG&E and KU Energy LLC and subsidiary (Company) regular, full-time and part-time employees.

Definitions

Salaried Employees - Employees in exempt jobs (as defined by the Fair Labor Standards Act) and employees in non-exempt jobs who are neither represented by a bargaining unit nor classified as an hourly employee (as defined below).

Bargaining Unit Employees - Employees who are represented by a union under a recognized bargaining unit relationship with the Company and/or its subsidiaries.

Hourly Employees – Employees in non-exempt (as defined by the Fair Labor Standards Act) non-bargaining unit jobs directly involved in operations and maintenance responsibilities at Company facilities and not covered by a collective bargaining agreement.

General Requirements

1. The Company, in its sole discretion, may set compensation (both fixed and variable) for any salaried or hourly employee/group of employees, in connection with the pursuit and attainment of strategic objectives, provided such actions do not conflict with legal and/or regulatory requirements.

2. Compensation changes are not guaranteed to any employee and are effective only upon the review and approval by the appropriate supervisor, next level manager and Human Resources.

Competitive Compensation Levels: The Company provides its employees with a total compensation package that, at expected levels of performance, is competitive with compensation available to individuals with comparable positions and responsibility in the energy services and general industries. The Company uses reference points concerning competitive compensation for an individual position or group of positions based on a variety of external market resources (market pricing). Actual compensation (base salaries and earned incentives) varies from targeted

LG&E and KU Energy LLC Policy

Compensation

competitive compensation levels to reflect individual performance, company performance and experience.

Pay For Performance: The Company encourages the use of pay for performance variable compensation plans to emphasize and support the Company's strategic objectives. Where used, the short-term incentive plans are designed and administered to ensure that incentive compensation earned is directly related to performance against one or multiple predetermined objectives established by the Company. The predetermined incentive compensation objectives may be quantitative, qualitative, objective, subjective, financial, and/or operational and they may be linked to corporate, divisional, team, and/or individual performance.

Overtime: Employees in exempt jobs are not paid overtime for additional hours worked beyond the regular work schedule. Employees in non-exempt jobs are paid for actual hours worked. Overtime for employees in non-exempt jobs is paid in excess of 40 hours per week and/or eight hours per day (in most circumstances). Employees in non-exempt jobs who are regularly scheduled to work a shift in excess of eight hours per day will receive overtime at the applicable rate for all hours worked in excess of the regularly scheduled workday. The pay rate for overtime hours worked by non-exempt employees is normally one and one-half times the regular rate of pay.

Compensation Actions – Salaried and Hourly: Employees may receive changes to their targeted total cash compensation (base pay plus targeted incentive opportunity) in connection with one or more of the following:

1. Salary Increases - The Company may reward individual employees or groups of employees with additional base compensation to maintain the competitiveness of base salaries with market conditions.

2. Promotions - Promotional increases represent an advancement to a position with increased responsibilities recognized by the external market, internally by job family, and/or for business reasons. Market pricing provides reference information management may use to determine the appropriate promotional increase based on the incremental responsibilities.

3. Incentive Opportunity/Compensation Mix - The Company may change the available incentive opportunity through an existing or new incentive compensation plan for an employee or group of employees where business conditions indicate a change is required to provide ongoing competitive compensation.

Compensation

The Company may also change the compensation mix between fixed and variable for an employee or group of employees where business conditions indicate a change is required to provide ongoing competitive compensation.

4. Reassignment - The Company may reassign an employee into a position with market pricing equal to or less than the current market pricing:

   a) to more effectively use the employee's specific abilities in a different assignment;
   b) for career development purposes, and/or;
   c) because of a work force reduction.

   Reassignment will not be considered a demotion if, in management's opinion, the employee has performed in the present position to the best of his or her ability. In addition, if the Company is making the reassignment for career development purposes, the employee's compensation will normally remain the same depending on the facts and circumstances at the time.

5. Reclassification - Position responsibilities which have increased or decreased substantially and are not expected to be temporary may result in the reclassification and re-pricing of the position. This process may affect the compensation range for the position based on the revised market pricing data.

6. Demotion - A demotion is a voluntary or involuntary reduction in responsibilities and may be accompanied with a reduction in compensation.

Compensation Actions – Bargaining Unit: Employees may receive changes to their pay structure as a result of labor negotiations.

Key Contact: Division HR and the Compensation Department.

Reference: At-Will Employment for All Salaried Employees, Regular and Part-Time Employees and Staffing Policies.

Administrative Responsibility: Director HR - Corporate.

Revised: 03/01/08, 06/01/11, 3/9/2015

EXHIBIT RCS-8

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Attorney General's Initial Data Requests for Information Dated January 11, 2017

Question No. 9

Responding Witness: Lonnie E. Bellar

Q-9. State whether the Company's proposed conversion from a just-in-time approach to a five-year cycled approach to transmission vegetation management will:

a. reduce O&M expense, and if so, by what amount;

b. reduce both recurring annual transmission and distribution plant investment and removal costs due to longer line and equipment life; and

c. increase revenues due to increased usage, which otherwise would have been foregone during outages; and

d. increase the useful life of assets, and therefore lengthen the assets depreciation rates.

A-9.

a. Conversion to a cycle based approach and implementation of a hazard tree identification and removal program is expected to provide efficiencies and improved crew productivity while reducing the incidence of tree related outages. Total expenses related to transmission vegetation management after the five-year cycle is implemented may not be expense neutral.

b. To the extent tree related outages and associated damage to transmission and distribution plant is avoided there is expected to be less investment and removal costs than would otherwise be incurred.

c. To the extent tree related outages are avoided, there may be some increased energy usage and associated revenues.

d. It is not certain if reduction in tree related outages will or will not increase the useful life of assets and therefore lengthen the assets depreciation rates.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

**Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017**

Question No. 10

Responding Witness: Lonnie E. Bellar / John K. Wolfe

Q-10. For each $1 million spent in the proposed distribution and transmission vegetation management, state the percentage improvement the Company expects to produce in the CAIDI, SAIFI, SAIDI indices.

A-10. Growth patterns of trees and other vegetation in easements, disease and demise of trees within and outside of easements, tree killing insects such as the emerald ash borer, and other issues result in the need to constantly maintain sufficient clearance of vegetation from lines and equipment to maintain service reliability at existing levels. The relationship between reliability indices and spend on vegetation management is complex. The Company does not have an expected percentage of improvement in reliability indices for each $1 million spent on vegetation management.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 30

Responding Witness: Lonnie E. Bellar

Q.1-30. Refer to page 16, lines 11-14, of Mr. Garrett's Direct Testimony wherein he describes an annual increase of $5.0 million in transmission maintenance of overhead lines resulting primarily from a move to a five-year cycled approach from a just-in time approach.

a. Please provide copies of all studies and/or analyses relied upon to justify the change in methodology and the amount of the annual increase.

b. Please quantify the expected annual benefits resulting in reduced outage maintenance expense as the result of moving to the cycle approach. If none, then please explain why.

c. Please confirm that the change to a five-year cycle approach from a just-in time approach should be expense neutral or result in a savings due to more efficient trimming aside from any savings in outage maintenance expense. If this cannot be confirmed, then please provide a detailed explanation why this is not correct.

A.1-30.

a. See attached.

b. Conversion to a cycle based approach and implementation of a hazard tree identification and removal program as part of transmission vegetation management is expected to primarily provide reliability benefits to customers. The full benefit of these programs will not be realized until after conversion to the five-year maintenance cycle and completion of the first cycle of the hazard tree program. The Company expects some reduction in outage maintenance expense, but has not quantified the reduction.

c. The referenced increases include the cost to convert to a five year maintenance cycle and implementation of a new hazard tree identification and removal program which are expected to reduce tree related customer outages but may not be expense neutral. The Company did not specifically perform detailed analysis to determine O&M costs beyond the conversion timeframe.

ECI
ENVIRONMENTAL CONSULTANTS, INC.

Louisville Gas & Electric and Kentucky Utilities Transmission Program Review

Prepared for
Louisville Gas & Electric
Kentucky Utilities
Lexington, KY

February 20, 2015

Prepared by
ECI
520 Business Park Circle
Stoughton, WI 53589

Table of Contents

Executive Summary

At the request of Louisville Gas & Electric (LG&E) and Kentucky Utilities (KU), ECI has completed the survey of transmission rights-of-way and a review of the vegetation management program. The primary goal of the evaluation was to assess the vegetation workload on the LG&E and KU overhead transmission and develop a budget to support the vegetation management program. A secondary goal was to conduct a high-level assessment of the vegetation management program and identify general opportunities to enhance program management, reliability and cost effectiveness.

The workload survey was performed while accompanying LG&E and KU during fourth quarter aerial inspection. ECI's program assessment consisted of a review of available program documentation provided by LG&E and KU and interviews with key personnel involved with the program. The survey and program review was a cooperative effort between LG&E, KU and ECI.

On the basis of ECI's review, program strengths and opportunities for improvement were identified. Recommendations, based on the results of the review, ECI's experience, and industry best practices, have been developed to provide LG&E and KU with a general plan for program improvement.

Key Metrics

Vegetation conditions were sampled on approximately 18 percent of the total transmission line miles while the ECI survey team accompanied LG&E and KU during regularly scheduled aerial inspections. ECI survey teams inventoried approximately 1,076 transmission miles. The field data collected was used to estimate the total transmission system vegetation workload, maintenance budget and resource requirements. Table 1 presents a system summary of these results.

Table 1. Tree and Brush Workload Summary on the LG&E and KU Transmission System.

Voltage (kV)	System Miles	Yard Trees	Edge Pruning – Mechanical (ft.)	Edge Pruning – Manual (ft.)	Re-Clear (ft.)	Manageable Brush Acres	[1]Total System Cost (Millions)
69	2,570	10,400	6,602,600	1,826,300	26,900	16,900	$23.16
138	1,264	4,000	4,154,200	254,500	5,000	8,700	$10.62
161	667	400	2,636,700	887,400	10,500	6,800	$9.35
345	1,090	1,400	2,945,400	395,700	---------	7,100	$8.30
500	237	---------	224,600	1,019,600	5,400	3,000	$4.91
System:	**5,827**	**16,200**	**16,563,500**	**4,383,500**	**47,800**	**42,500**	**$56.32**

[1] Reflects the cost to maintain the entire system. The exact cycle length to distribute the cost will need to be determined by LG&E and KU.

General Assessment

STRENGTHS

Key strengths of the current LG&E and KU vegetation maintenance program include the following:

- LG&E and KU management is supportive of program improvements.
- The program is focused on reliability and regulatory compliance.
- A centralized management structure is in place.
- Right-of-way (ROW) conditions are inspected on a quarterly basis.
- 'Action Threshold Clearance' has been established to ensure minimum acceptable clearances are not encroached upon, providing increased margin of safety regarding reliability.
- Tree-caused outages are formally investigated and document, with trained personnel.
- Aerial herbicide applications are effectively used to control brush in rural ROW areas.

Recommendation

ECI recommends the following program specific items based on the field data collection and observations of current vegetation practices on the LG&E and KU transmission system:

1. Transition maintenance program to cyclical maintenance.
2. Continue to remove incompatible trees within the ROW and particularly under the conductors (within the wire zone corridor).
3. Determine and document the ROW width for all LG&E and KU transmission circuits.
4. Develop a hazard tree[2] ground patrol to address potential risk from trees that may not be visible through normal routine aerial inspections.
5. Establish a list or database of hazard tree locations and develop a priority program to determine which trees should be removed first. This database may include ash trees that could be affected by the emerald ash borer (EAB).
6. Continue to enforce vegetation maintenance clearance specifications for transmission voltages and the policies and standards specific to LG&E and KU needs and conditions. Current specifications appear adequate to maintain vegetation on the transmission system.
7. Ensure that vegetation maintenance crews exhibit reasonable production levels by implementing a work reporting / measurement system and utilize the records to evaluate crews and compare contractor performance.
8. Implement Integrated Vegetation Management (IVM[3]) as the guiding maintenance principle on the LG&E and KU transmission system.

[2] Danger trees are trees tall enough to breach action threshold if they fell toward lines regardless of condition.

9. Re-establish the transmission corridor ROW edges wherever practical to bring the corridors back to specification by voltage.
10. Continue to maximize herbicide use where practical to minimize future vegetation management costs and better manage for compatible plant communities.
11. Once established maintain consistent transmission vegetation maintenance program funding to maximize overall program effectiveness and ensure compliance with NERC Standards FAC-003.
12. Consider increasing vegetation management oversight to address the addition of approximately 46 crews to meet workload requirement for a 5-year cycle (Appendix D).

[3] IVM = A system of managing plant communities in which compatible and incompatible vegetation is identified, action thresholds are considered, control methods are evaluated, and selected control(s) are implemented to achieve a specific objective. Choice of control methods is based on effectiveness, environmental impact, site characteristics, safety, security and economics. *ANSI A300 (part 7)-2012 IVM.*

Introduction

At the request of LG&E and KU, ECI has documented the quantity and characteristics of the existing tree and brush workload that currently exists on the transmission system. In preparation for the survey:

- LG&E and KU supplied GPS transmission structure locations, flight schedule and helicopter for the vegetation survey, which included the states of Indiana, Kentucky, and Virginia.
- ECI provided the methodology, field personnel, and expertise necessary to conduct the study.

The fieldwork consisted of a sample survey of vegetation conditions that resulted in 18 percent (1,076 miles) of the transmission line miles throughout the service areas of two Pennsylvania Power and Light Corporation operating companies (OPCOs). These OPCOs are LG&E and KU. LG&E and KU supply power to 98 counties with combined total of approximately 1.3 million customers. The aerial survey occurred between October 20 and November 21, 2014. All data was collected on a span-by-span basis. Aerial data collection included: brush maintenance recommendations (mow, hand cut, foliar spray), edge tree maintenance workload, accessibility, and notations on danger[4] and hazard[56] trees adjacent to the ROW corridor (dead, dying, severe lean toward line, etc.). This report includes the following areas of evaluation:

1. Evaluation of field conditions designed to quantify the extent of maintenance required and recommended maintenance practices.
2. Evaluation of vegetation management practices and effectiveness compared to industry best practice methods.

Through phone interview and via email questionnaires, the current operation procedures and vegetation management practices were discussed with LG&E and KU staff.

[4] Danger tree: any tree that could contact the conductor if it fell or fall within the action threshold.
[5] Hazard tree: a danger tree predisposed to failure due to disease, structure, dead or in decline, lean or soil conditions.
[6] The six hazard trees observed during the aerial workload survey were reported to the LG&E and KU ROW Coordinate present during the flight.

Current Operating Practices

This section presents general findings of ECI's interview with LG&E and KU staff and the program information (i.e., historical budget, reliability, staffing level, etc.). On the basis of ECI's review, program strengths and opportunities for improvement were identified. Recommendations, based on the results of the review, ECI's experience, and industry best practices, have been developed to provide LG&E and KU with a general plan for program improvement.

Program Management and Supervision

LG&E and KU has a centralized staff that manages vegetation on the system. Supervision over the vegetation management group has recently changed to the Transmission Line Construction department. The overall transmission vegetation management program goals are based on safety, reliability, cost effectiveness, fire safety and utilizing industry best management practices. LG&E and KU does have a comprehensive vegetation management plan and clearance specifications; however, does not manage a specific cycle. Currently, there are three ROW Coordinators who are each assigned to a specific region (East, Central and West) to manage.

Vegetation maintenance needs are determined by LG&E and KU ROW Coordinators based upon quarterly inspections performed. The patrol of transmission lines is predominately performed by helicopter. The ROW Coordinators and other experienced staff have received training on recognizing vegetation maintenance priorities or conditions that require immediate attention.

Contract Crews

ROW Coordinators oversee vegetation maintenance performed by three vendors under a T&M contract. Asplundh Tree Expert, Co. and Phillips Tree Experts, Inc. are tree contractors used for vegetation maintenance from the ground. LG&E and KU are contracted with Summit Helicopters, Inc. to perform herbicide aerial spray treatments. Haverfield Aviation, Inc. was contracted to provide a helicopter for quarterly aerial inspection of the transmission lines.

Asplundh Tree Expert, Co. and Phillips Tree Experts, Inc. have signed a 5-year contract with LG&E and KU. The maintenance from the ground is equally split between the two contractors. Phillips Tree Experts, Inc. works in the eastern half of the transmission system where the terrain is stepper because of the rolling foothills and mountain ridges common to the Appalachian Mountain Range.

Customer Interface

LG&E and KU provide notification to land owners regarding maintenance activities based upon the location of the transmission line within the state. Customers abutting rural sections of transmission line typically do not receive notification in the eastern half of Kentucky. Landowners of agricultural land and horse farms and those located in urban area generally receive notifications. Special notification and access permission to ROW is provided when working on USDA Forest Service lands, military bases (Fort Knox) and other government owned land.

During a recent peer review project, LG&E and KU explained that land owner issues, skips, special areas were not tracked in any database. However, LG&E and KU informed ECI during an interview on August 20, 2014 that a spreadsheet to capture this information was being developed. Tracking customer issues or special previsions can help with reliability improvements, work planning, cycle selection, and tracking resolution status of refusals.

Regulatory Agencies

LG&E and KU follow the Kentucky Public Service Commission regulation pertaining to tree energized electrical equipment limits of approach. If these limits are breached by tree(s), lines are de-energized to perform vegetation maintenance. LG&E and KU have guidelines to determine immediate maintenance requirements (emergency or high priority due to vegetation proximity) vs. scheduled maintenance. LG&E and KU are subject to North American Electric Reliability Corporation (NERC) reliability standards and must practice due diligence in complying with NERC FAC-003 standards. LG&E and KU transmission system are specifically regulated by SERC Reliability Corporation, a regional entity of NERC. LG&E and KU have 1,327 miles of NERC lines (345 and 500kV system) and 4,500 miles of non-NERC lines (69, 138 and 161 kV system). LIDAR is performed on 50 percent of the NERC lines each year. Even though NERC FAC 003-3[7] standards require only one inspection per calendar year of vegetation conditions, LG&E and KU performs two vegetation only patrols during May and July. In addition, while LG&E and KU perform aerial patrols each quarter for critical visual inspection, the ROW Coordinator will document any vegetation that may have been missed during the vegetation only patrols in May and July.

Tree-Related Interruptions

LG&E and KU reliability staff perform an in-depth post-outage investigation of vegetation-caused outages. Outages listed as "vegetation" are separated by a secondary cause code (i.e., grow-in, fall-in from off-ROW, and fall-in from inside-ROW). The specific reason for a tree-caused outage is limited to three codes, but could be expanded to include additional cause codes for further reliability improvement. The additional secondary cause codes (i.e., hazard tree, mode of tree failure, etc.) would assist in further diagnosis of tree-caused outages.

A major concern for LG&E and KU are: hazard and danger trees – risk of fall-in from on and off ROW trees (117 fall-ins on 69, 138 and 161kV lines between 2008 and 2014). The all tree-caused interruptions are on non-NERC

[7] Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice – circuit, pole line, line miles of kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW. FAC 003-3 R6. 2013

transmission lines due to on and off-ROW trees falling into the ROW. LG&E and KU have very few "grow-in" outages on the 69kV and higher voltage lines. No "grows-in" have been recorded on 345 and 500kV lines between 2008 and 2014. Before 2012 the secondary cause code was limited to fall-in within in the ROW. The interruption may have resulted from a tree outside of the ROW but cause was classified as fall-in from inside the ROW. The secondary cause codes were expanded in 2012 to allow for the distinction between fall-ins for inside or outside of the ROW and grow-ins. Figure 1 shows the number of tree-caused outages between 2012 and 2014 for each of the secondary cause codes. Tree fall-ins, outside of the ROW, account for 85 percent of the tree-caused outages between 2012 and 2014.

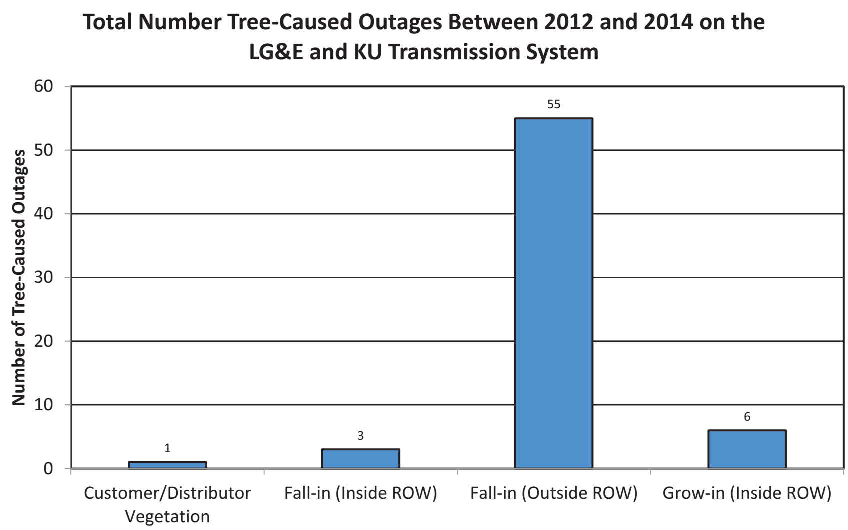


Figure 1. Total number tree-caused outages by secondary caused.

Hazard trees are removed as they are found. However, since LG&E and KU have had 117 fall-ins over the course of 7 years there appears to be hazard trees that are possibly being missed during aerial inspections. A ground patrol may be warranted to identify hazard trees that are hidden under the canopy of larger mature trees.

Recordkeeping and Crew Productivity

A comprehensive recordkeeping and reporting system is an essential component of an effective line clearance program. A record keeping system should be capable of providing management with the following information:

- Justification of management decisions.
- Projections of annual budget requirements.
- Determination of the most cost effective crew type for various locations and work types.
- Prioritizing work by analysis of tree-caused outages and the inclusion of other metrics important to the utility.
- Detailed monitoring of crew productivity.

- Establishment of guidelines for tree removal and replacement (if implemented).
- Establishing a tracking process for customer refusals and hazard trees.

A comprehensive line clearance record keeping system depends on recording four components of all field activities: work location (i.e. circuit number), description of work completed (number of trims, removals, etc.), time required to complete the activity and any required materials (man and equipment hours). Time report verification, evaluation of crew productivity and accumulation of cost and production data all depend on these elements of activity reporting.

Recording crew time by specific work units and work related activities will provide the means to (1) examine detailed costs, (2) evaluate productivity, and (3) initiate appropriate changes to maximize the efficiency of the program. All record keeping needs to be adjusted to conform to the type of contract in place and the desired system metrics LG&E and KU desires.

Time Utilization

Time utilization measures can be used to evaluate crew time and production figures: time utilization, performance, and effectiveness.

Time utilization calculations allow a utility to determine what each crew does with the time it controls on a daily basis. For example, if time utilization is low, it indicates that the crew has excessive nonproductive time.

Performance

Performance is a measure that compares the actual time required to prune or remove a tree to the expected or standard time. Standards are developed from actual local data and are periodically evaluated for accuracy. The performance rating provides a good means for evaluating the production rates of each crew relative to an established set of standards. If performance is too high, it may suggest that a crew is inaccurately reporting work, obtaining inadequate clearance, or trimming brush (rather than removing brush). If performance is too low, it may suggest that the need for increased supervision and/or training.

Effectiveness

Effectiveness is calculated as a product of time utilization and performance (time utilization X performance/100). It provides a relative measure of what the return on expenditures is for each contract crew. Effectiveness ratings can be used to compare individual crews.

LG&E and KU has an electronic record keeping system to track circuit history, crew number, man hours, start and stop pole locations, labor cost, material cost, equipment cost, aerial spray acres and aerial spray cost. Even though their record keeping system tracks this information, the detail is limited and prevents any crew production analysis. The start/stop pole information does not include a linear distance and type of work performed (i.e., number of trims, linear distance mechanically pruned, removal, brush acres mowed, etc.). While LG&E and KU record the crew number for all work performed, the number of men or type of equipped used by the crew is not included. Once the electronic record keeping system is expanded to include this additional information, LG&E and KU can establish production metrics to track the efficiency of the vegetation maintenance program (i.e., cost per acre, cost per mile, etc.).

LG&E and KU does not currently possess the metrics necessary to effectively and efficiently manage the program. Data is collected from contractor invoices regarding total cost and man-hours only and are not tracked by individual work unit even though this type of information is available. The data contractor invoice does include information regarding number of units maintained or miles covered. Work is categorized on the LG&E and KU-required timesheet by the following classifications:

- Man-hours for each employee and equipment
  - Daily Hours (RT, OT, and DT)
  - Holiday
  - Vacation
  - Other
- Type of Work
- Type of Billing (T&M, Cost Plus, Unit, and Contract)
- Type of Crew (Tree or Other)
- Project number or account number (i.e. distribution, new construction)
- Herbicide Concentrate
  - Amount by unit (lbs or gallons)
- Tree Units and Man-hours by Unit
- Brush Units and Man-hours by Unit

Unit data (i.e. number of trees by maintenance type) is recorded on the timesheet but not captured as part of the current process for the electronic record keeping system. Additional details about contractor production would allow movement toward a performance-based component within a T&M contract, or become a basis for a unit cost removal component of firm priced contracts (Appendix A). At a minimum, more detailed production data would provide an accurate assessment of production cost for various work-types for both internal and external comparisons.

Both record keeping software and record keeping services are available to provide streamlined invoice verification, cost tracking by asset and work type, metrics for process improvement and documentation of work accomplishment.

Vegetation Work Practices

LG&E and KU are doing an admirable job in managing transmission vegetation with a limited budget. The size of the annual budget has necessitated a "just-in-time" approach to vegetation maintenance. The current maintenance practice of "just in time" or "hot spot" mowing, herbicide treatment, edge pruning on non-NERC lines has resulted in a system that is a patch work of various vegetation conditions on the ROW's. Vegetation conditions on any given line range from clear (just maintained) to very tall brush or edge trees on low voltage lines requiring immediate attention. This can result in excessive "jumping" from location to location by the contractor, thus incurring additional travel time. The limited detail in the records regarding maintenance cost preclude developing a line maintenance history, determining the efficiency of the vendor and over-all lack of data to forecast future work effort and cost.

Through ECI's aerial patrols, the vegetation workload was quantified, and utilizing LG&E and KU historical maintenance cost and available supplemental industry cost data, a maintenance budget has been established. Because maintenance has been on a "hot spot" basis, conversion to a more efficient and cost effective cyclic maintenance schedule will require several years to implement. During this implementation phase, "hot spot" maintenance will be required to maintain system reliability until cycles can be established. In addition, the early years of the conversion to cyclic maintenance may require a higher budget. Converting to a cyclic maintenance schedule will reduce unit production cost (lower density and shorter height brush), provide for reduced planning effort each year through reducing the number aerial inspections and provide for a sound basis to consider other contracting strategies.

Vegetation Maintenance Expenditures

The vegetation maintenance budget is presented to LG&E and KU senior management on an annual basis for approval. Budgets have been based on historical levels, not specifically to address cyclic maintenance requirements. The annual budget has remained fairly flat over the past 6 years (Table 2).

Table 2. LG&E and KU Historical Transmission Vegetation Maintenance Expenditures.

Year	ROW Actuals	CPI[8] – 2014[9]
2009	$4,425,830.31	$4,883,788.64
2010	$4,616,948.52	$5,012,464.34
2011	$5,313,879.93	$5,592,568.11
2012	$4,912,862.53	$5,065,687.36
2013	$5,570,389.98	$5,660,752.17
2014	$6,151,060.19[10]	$6,151,060.19

Production and Cost

LG&E and KU provided ECI with the electronic record keeping system for records from 2010 through 2014. From these records, ECI calculated aerial spray cost per acre. In addition, LG&E and KU provided ECI with weekly rates by crew type for calculating the estimated number crews need to manage the transmission system. LG&E and KU may choose to re-calculate the budget by changing some of the brush acres classified as low and high-volume foliar treatments to aerial spray treatments.

Vegetation Assessment

Vegetation conditions were sampled on 18 percent of the total transmission line miles to estimate the existing vegetation workload for each of the five voltages. ECI survey teams inventoried approximately 1,076 transmission miles. Field data gathered by the survey teams focused on tree and brush quantities, conditions, and maintenance requirements. The results of the study are included in the following sections.

Specific Survey Criterion

ECI's survey teams utilized the *Louisville Gas & Electric and Kentucky Utilities Services Company Transmission Vegetation Management Program (Revision 2013)* as the basis for determining current and future vegetation work load. The survey teams collected data on the vegetation conditions on the LG&E and KU transmission system using the form found in Appendix B.

[8] CPI – Consumer Price Index.
[9] The actual vegetation expenses for each year were adjusted using the correct CPI and the base year of 2014. The adjustment was down to allow for a better comparison between years.
[10] Actual vegetation expense through the end of November.

Vegetation Workload Survey Data

This section presents general findings of ECI's workload assessment. Total workload projections are based on the total line miles as provided by LG&E and KU.

Total Workload

Table 3 represents the estimated total vegetation workload summary for the LG&E and KU transmission system by voltage class based on the sample survey.

Table 3. Tree and Brush Workload by Voltage Category (Transmission).

Voltage	*System Miles*	*System Acres*	*Yard Trees*	*Edge Pruning - Mechanical (ft.)*	*Edge Pruning - Manual (ft.)*	*Re-clear (ft.)*	*Manageable Brush Acres*
69	2,570	46,723	10,400	6,602,600	1,826,300	26,900	16,900
138	1,264	22,973	4,000	4,154,200	254,500	5,000	8,700
161	667	12,119	400	2,636,700	887,400	10,500	6,800
345	1,090	19,822	1,400	2,945,400	395,700		7,100
500	237	4,313		224,600	1,019,600	5,400	3,000
TOTAL	**5,827**	**105,949**	**16,200**	**16,563,500**	**4,383,500**	**47,800**	**42,500**

Total projected workload was projected for the LG&E and KU system based upon the conditions noted on the sampled miles. Table 2 indicates that approximately 16,563,500 linear feet (actual footage to be pruned not line footage) of ROW edge can be pruned using mechanical equipment (i.e. Jarraff or Skytrim crews), 4,383,500 feet consist of manual workload and 47,800 feet of ROW edge needs to be re-cleared to the establish ROW width. The estimated linear footage of ROW needing to be re-cleared was minimal because the ECI survey team counted work that had encroached from the established ROW width and not the actual easement width. LG&E and KU could not provide ECI the actual ROW easement or edge-to-edge width for each circuit. The small amount of estimated re-clear footage for 500kV lines resulted from the need to achieve additional clearance when a span of line extended from one ridge top to another.

More than 59 percent of the ROW edge workload was found on 138, 161, 345 and 500 kV lines which is expected considering these four voltages comprise approximately 55 percent of the total transmission line miles. Figure 2 shows the distribution of edge tree maintenance workload across the varying voltage classifications. Alternatively, Figure 3 presents the linear distance of edge tree maintenance on a per mile basis, which shows 161kV lines as having the highest concentration, followed by 500kV and 138kV lines.

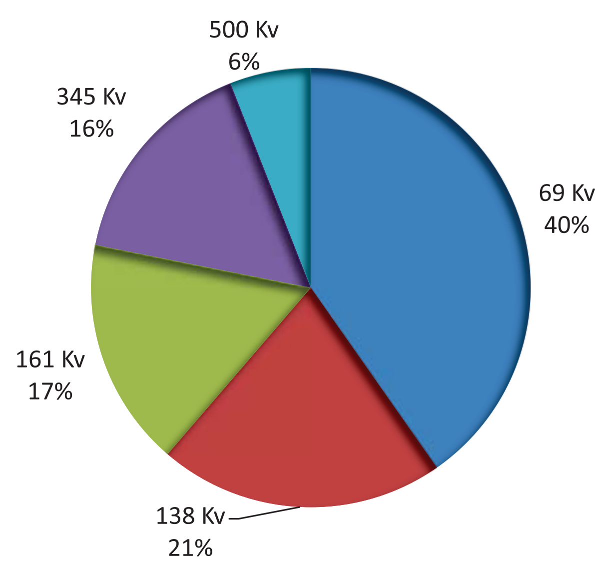


Figure 2. Percentage of Edge Tree Maintenance Workload by Voltage Classification.

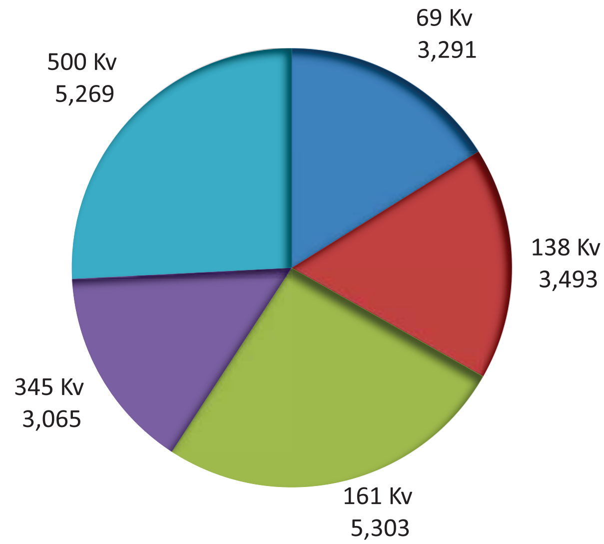


Figure 3. Linear Distance of Edge Tree Maintenance per Mile by Voltage Classification[11].

Yard trees account for approximately 16,200 total trees or 2.7 trees per mile at the system level. ECI estimates there are approximately 105,950 acres that comprise the entire LG&E and KU transmission system. Of those total acres, approximately 40 percent (or 42,500 acres) contain manageable brush acreage. Brush will be defined in greater detail later in the Brush Workload Characteristics section.

Average Density and Statistical Error

Tree and brush density was quantified in terms of trees per mile, linear distance per mile and acres per mile. Table 4 shows the average trees per mile (Yard Trees), linear distance per mile of ROW edge trimming (Mechanical, Manual and Re-clear), and brush acres per mile by voltage class on the LG&E and KU transmission system. These are trees and acres of brush requiring maintenance according to *Louisville Gas & Electric and Kentucky Utilities Services Company Transmission Vegetation Management Program (Revision 2013).* The tree counts and brush acres per mile values as expressed in Table 4 were used to estimate the total quantities at the system level (as shown in Table 3).

[11] Each side of the ROW was counted separately and then combined to provide actual footage to be pruned. Therefore, the liner footage per mile of workload can result in a number larger than a mile.

Table 4. Average per mile tree and brush densities per mile on the LG&E and KU transmission system.

Voltage	Total System Miles	Number of Yard Trees	Linear Distance for Mechanical Trimming (ft.)	Linear Distance for Manual Trimming (ft.)	Linear Distance for Re-clear of ROW (ft.)	Manageable Brush Acres
69	2,570	4.0	2569.4	710.7	10.5	6.6
138	1,264	3.2	3287.8	201.4	4.0	6.9
161	667	0.6	3955.6	1331.3	15.7	10.1
345	1,090	1.3	2701.7	363.0	0.0	6.5
500	237	0.0	946.9	4298.6	23.0	12.5
SYSTEM AVERAGE	**5,827**	**2.7**	**2918.8**	**692.8**	**7.8**	**7.3**

The statistical sampling error was calculated for the transmission survey samples by voltage class. Statistical sampling error calculation was based upon the mean linear distance of tree workload and brush acreage per span at the 90 percent level of confidence. Sampling error for linear distance of tree workload per span for each voltage category were: 69kV = ± 3 percent; 138kV = ± 4 percent; 161kV = ± 4 percent; 345kV = ± 5 percent; and 500kV = ± 11 percent. Sampling error for brush acres per span for each voltage category were: 69kV = ± 3 percent; 138kV = ± 4 percent; 161kV = ± 4 percent; 345kV = ± 4 percent; and 500kV = ± 7 percent.

Brush Workload Characteristics

Brush workload was collected and characterized by maintenance practice. Table 5 shows the total estimated brush acres on the LG&E and KU system by maintenance practice.

Table 5. Brush Workload by Voltage Category and Maintenance Practice.

Voltage	Total System Miles	Total System Acres	Mow Acres	Hand Cut and Treat Acres	Low-Volume Foliar Acres	High-Volume Foliar Acres	Manageable Brush Acres
69	2,570	46,723	1,100	1,500	13,500	800	16,900
138	1,264	22,973	1,100	800	6,300	500	8,700
161	667	12,119	500	500	5,500	300	6,800
345	1,090	19,822	500	500	5,300	800	7,100
500	237	4,314	100	100	900	1,900	3,000
TOTAL	**5,827**	**105,950**	**3,300**	**3,400**	**31,500**	**4,300**	**42,500**

Of the 105,950 total system acres identified on the LG&E and KU transmission system, approximately 40 percent (or 42,500 acres) currently contain brush species (Figure 4). When estimating brush acres, locations that had the potential to support brush were included in the in low-volume foliar management practice. The remaining 60 percent (or 63,450 acres) (Figure 5) are currently void of brush due to land use (e.g., agricultural land, maintained lawns, waterways, etc.).

Approximately 74 percent of the total manageable transmission brush acres were classified suitable for the maintenance practice of low-volume foliar treatment (i.e., backpack application of herbicide). For a location to be classified as low-volume foliar the stem heights were shorter than seven feet and stem density was approximately 1,500 or less per acre. Therefore, a large majority of the LG&E and KU transmission system is potentially manageable through low-volume herbicide maintenance work.

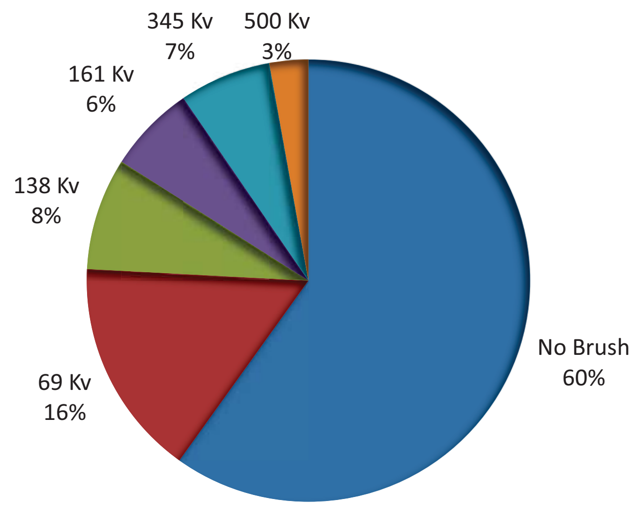


Figure 4. Percentage of Brush Acreage by Voltage Classification.

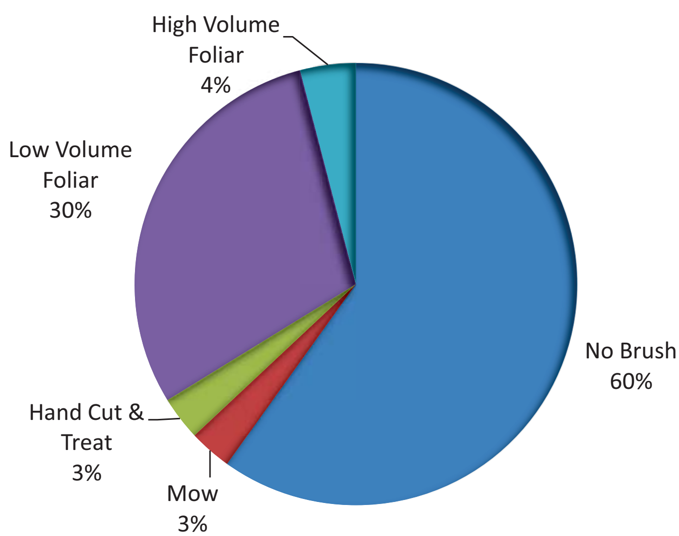


Figure 5. Percentage of Brush Acreage by Maintenance Practice.

Since the manageable brush acres on LG&E and KU transmission system was comprised of approximately 84 percent brush acres in the low and high-volume foliar treatment category, aerial treatments can be performed in an extremely cost effective manner using herbicides (where practical).

ROW Edge Clearing Characteristics

ECI documented specific transmission spans that fell short of the established ROW width. Table 2 presents the estimated linear feet of edge clearing required to reclaim existing overgrown rights-of-way to the established ROW edge. The tree and immature tree categories were deemed important in understanding the nature of the widening or re-clearing requirements, particularly since each may yield different clearing costs. Immature trees that could be cleared with a bush hog or hydro-axe were classified as mow acres. When clearing large trees required equipment such as a bull dozer or feller buncher then the work was classified as re-clear footage. Figure 6 shows examples of the specialized equipment commonly used for ROW clearing.

Figure 6. Specialized Equipment Commonly Used in Transmission ROW Clearing and Widening.

The 47,800 feet of ROW edge identified as requiring re-clearing back to the established ROW edge, comprised of less than one percent of the total linear distance requiring some form of tree maintenance.

Maintenance Characteristics

As part of the field data collection, the ECI surveyors classified the workload within each span into eight maintenance categories. Accessibility was also recorded for each span for the purpose to estimate potential workload that would be ideal for aerial saw trimming. ECI estimated that for 17 percent of the workload, aerial saw trimming may be a suitable means to maintain the edge of the ROW. The categories used for classifying the workload are:

- MST – Mechanical side Trim (sky trim, Jarraff, etc)
- MT – manual trim
- RC – re-clear
- YT – yard tree
- MBH – mow: brush hog or hydro Ax (kershaw or similar)
- HC – hand cutting
- LVF – low-volume foliar herbicide treatment
- HVF – high-volume foliar herbicide treatment

Dependent upon the location a span may have work that was separated into different categories. For example, due to terrain a span may have a mixture of mechanical and manual side trimming work. It should also be noted that the total brush acres to be maintained over a five-year cycle would be higher than total brush acres observed on the system because some brush acres mechanically cut or hand cut should have a subsequent follow-up herbicide application scheduled in a future year (currently two years).

Recommendations were assigned based on current field conditions with emphasis on minimizing maintenance costs. In most cases, herbicide was recommended in lieu of mowing unless specific site conditions warranted otherwise. However, specific herbicide restrictions may negate some herbicide recommendations. The data provided here has not been adjusted to balance the annual spend.

Note that these recommendations serve only as an estimate of the workload by maintenance practice. Prior to beginning any work or budgeting for specific vegetation needs, it is recommended that the specific transmission lines to be worked be individually prescribed. This data serves only to characterize the existing workload.

Budget and Man-Hour Estimates

Total vegetation management estimated costs and man-hours for the LG&E and KU transmission system are presented in Table 6. The detail in Table 7 presents the system total cost to maintain the tree and brush workload by management category and voltage on the LG&E and KU transmission system. Unit costs and weekly crew rates were used to calculate loaded labor and equipment rates (Table 8). The unit cost values were derived by ECI utilizing available industry data.

Table 6. Total Transmission Budget and Man-Hour Estimate By Voltage.

Voltage	Estimated Total Cost	Estimated Total Man Hours
69	$23,158,000	716,800
138	$10,616,000	316,000
161	$9,345,000	289,500
345	$8,295,000	269,700
500	$4,908,000	231,400
Grand Total	$56,322,000	1,823,200

Table 7. Total Budget by Management Category and Voltage for the LG&E and KU Transmission System.

Voltage	Yard Trees	Mechanical	Manual	Re-Clear	Mow	Hand Cut	Low-Volume Foliar	High-Volume Foliar
69	$780,000	$7,923,000	$5,844,000	$148,000	$556,000	$2,850,000	$4,725,000	$332,000
138	$300,000	$4,985,000	$814,000	$28,000	$556,000	$1,520,000	$2,205,000	$208,000
161	$30,000	$3,164,000	$2,840,000	$58,000	$253,000	$950,000	$1,925,000	$125,000
345	$105,000	$3,534,000	$1,266,000		$253,000	$950,000	$1,855,000	$332,000
500		$270,000	$3,263,000	$30,000	$51,000	$190,000	$315,000	$789,000
Total	**$1,215,000**	**$19,876,000**	**$14,027,000**	**$263,000**	**$1,667,000**	**$6,460,000**	**$11,025,000**	**$1,785,000**

Table 8. Unit Cost and LLER

Management Category	Unit Cost	Unit	LLER
Yard Tree	$75.00	per tree	$31.48
Mechanical	$1.20	per foot	$41.05
Manual	$3.20	per foot	$29.47
Re-Clear	$5.50	per foot	$82.58
Mow	$505.00	per acre	$57.22
Hand Cut and Treat	$1,900.00	per acre	$32.22
Low-Volume Foliar	$350.00	per acre	$29.49
High-Volume Foliar	$415.00	per acre	$50.61
Aerial Spray	$297.00	per acre	

Total budget to maintain the LG&E and KU transmission system for a targeted five-year cycle is estimated to be approximately $56.32 million (or approximately $11.26M annually) and requires approximately 1.82 million man-hours (or 364,640 man-hours annually). The average system cost per transmission mile based on the estimated budget is $9,665 per mile or roughly $532 per system acre. Approximately 20 percent of the total budget dollars are allocated to low-volume herbicide work (LVF). Yard trees account for another two percent and incompatible ROW trees less than one percent. The three maintenance types (mechanical side trim, manual trim, and re-clear) for which industry unit cost values were used, account for approximately 61 percent of the total budget.

Crew Resource Allocations

Based on the existing vegetation workload and the production values provided by LG&E and KU, crew resource needs were estimated. Table 9 presents a summary of the estimated annual crew resource requirements based on a five-year cycle.

It should be noted that crew estimates are approximate and are based on the average crew sizes as indicated. Available annual work hours were estimated to be 1,800 hours.

Table 9. Annual Crew Resource Allocation Estimate by Crew Type (# of crews).

Voltage	3-Man Yard Tree Crew	3-Man Mechanical Trimmer	3-Man Climbing Crew	3-Man Excavator Re-Clear Crew	3-Man Mowing Crew	3-Man Hand Cut Brush Crew	3-Man Low-Volume Foliar Crew	2-Man High-Volume Foliar Crew
69	0.92	7.15	7.35	0.07	0.36	3.28	5.93	2.25
138	0.35	4.50	1.02	0.01	0.36	1.75	2.77	1.41
161	0.04	2.85	3.57	0.03	0.16	1.09	2.33	2.25
345	0.12	3.19	1.59	0.00	0.16	1.09	2.33	2.25
500	0.00	0.24	4.10	0.01	0.03	0.22	0.40	5.34
Total	**1.43**	**17.93**	**17.63**	**0.12**	**1.08**	**7.43**	**13.85**	**12.09**

Crew estimates are based on the work type and recommended maintenance practice as determined by the ECI field surveyor. Changes to the maintenance practice will affect crew make-ups and allocations.

Herbicide crews account for approximately 25.9 crews annually or 36 percent of the total crews and will utilize approximately 34 percent of the annual budget. The two and three-man herbicide crews will provide the required support to complete the low and high-volume herbicide workload. Three-man mechanical and climbing crews are the largest resource requirement at approximately 35.7 crews annually or 50 percent of the total crews and will utilize approximately 60 percent of the annual spend. The three-man mechanical and climbing crews will be responsible for all side trimming, incompatible ROW tree removals, and priority trees.

Recommendations

Utilizing the information gathered in the ground survey, ECI developed the estimated total transmission workload, budget, and man-hour requirements for the LG&E and KU transmission system.

Budget and workload assumptions:

- Recommended maintenance practices for the identified work units assume the utilization of Integrated Vegetation Management (IVM) principals and the maximization of herbicide use wherever possible to minimize future vegetation management expenditures. The use of herbicides will decrease future work (fewer stems per acre) thus requiring far less effort when IVM is fully implemented on the LG&E and KU system. With the implementation of IVM and continued herbicide use there should be minimal mowing required in future cycles.
- Brush acres maintained through mechanical brush clearing methods (i.e. mowers) were not incorporated into acre counts for high or low-volume herbicide treatment.
- Per request from LG&E and KU, the ROW width used for calculating the amount of brush acres was 150 feet for all transmission voltages. Actual ROW width varies between and within each voltage category and it is recommend that prior to assigning work brush acres would be re-calculated to represent actual ROW width for those schedule circuits.

Best management practices and IVM are the focus of the ECI recommendations presented in this section. Refer to Appendix C for additional details on recommended industry best management practices.

Recommendations

ECI recommends the following program specific items based on the field data collection and observations of current vegetation practices on the LG&E and KU transmission system:

1. Transition maintenance program to cyclical maintenance.
2. Continue to remove incompatible trees within the ROW and particularly under the conductors (within the wire zone corridor).
3. Determine and document the ROW width for all LG&E and KU transmission circuits.
4. Develop a hazard tree[12] ground patrol to address potential risk from trees that may not be visible through normal routine aerial inspections.
5. Establish a list or database of hazard tree locations and develop a priority program to determine which trees should be removed first.

[12] Danger trees are trees tall enough to breach action threshold if they fell toward lines regardless of condition.

This database may include ash trees that could be affected by the emerald ash borer (EAB).

6. Continue to enforce vegetation maintenance clearance specifications for transmission voltages and the policies and standards specific to LG&E and KU needs and conditions. Current specifications appear adequate to maintain vegetation on the transmission system.
7. Ensure that vegetation maintenance crews exhibit reasonable production levels by implementing a work reporting / measurement system and utilize the records to evaluate crews and compare contractor performance.
8. Implement Integrated Vegetation Management (IVM[13]) as the guiding maintenance principle on the LG&E and KU transmission system.
9. Re-establish the transmission corridor ROW edges wherever practical to bring the corridors back to specification by voltage.
10. Continue to maximize herbicide use where practical to minimize future vegetation management costs and better manage for compatible plant communities.
11. Once established maintain consistent transmission vegetation maintenance program funding to maximize overall program effectiveness and ensure compliance with NERC Standards FAC-003.
12. Consider increasing vegetation management oversight to address the addition of approximately 46 crews to meet workload requirement for a 5-year cycle (Appendix D).

[13] IVM = A system of managing plant communities in which compatible and incompatible vegetation is identified, action thresholds are considered, control methods are evaluated, and selected control(s) are implemented to achieve a specific objective. Choice of control methods is based on effectiveness, environmental impact, site characteristics, safety, security and economics. *ANSI A300 (part 7)-2012 IVM.*

Appendix A: Contracting Strategies

Introduction to Contracting Strategies

Three different approaches are commonly used by electric utilities to contract line clearance work. These include "time and material/equipment" (T&M), "unit price" and "firm price" or "lump sum" pricing strategies. Each has advantages and disadvantages that are important to understand, and there are multiple variations possible within each pricing family. Each carries a different risk profile for the contractor and the utility. Unit price and firm price contacts are inherently performance-based contracts. However, T&M with incentive pricing can also be a performance-based contracting strategy.

Performance-based contract strategies generally offer the lowest production risk for the utility by placing the burden to monitor crew productivity on the tree contractor and “incentivizing” the contractor to control costs. This applies to firm price, lump sum, unit price, and T&M with incentive type contracts. However, it should be understood that in order for these contract strategies to be effective, the utility and contractor should have a thorough understanding of the work scope, historical man-hours and costs for the work units to be maintained within the contract period. While it is possible to utilize these specific contract types for all work (i.e. ticket type work as well as preventative maintenance work), they are the most effective in situations where the scope of work is better defined such as on preventative maintenance. Ticket work such as Customer Trim Requests and Restoration are often too variable and can lead to higher “unit” prices due to the “contingency” contractors may build into their bid to account for this uncertainty.

Where historical data is not available, some utilities are successful in developing performance-based contracts by clearly defining the project scope prior to bidding through the development of detailed work plans. Pre-planning to define clearances, clearance exceptions, and removals has proven to be a very effective strategy in receiving least cost competitive bids. Contractors provide pricing on the defined work scope that the utility has pre-designated, thus eliminating guess work on the part of the contractor and eliminating the “contingency” cost that contractors build into bids. However, this does require additional effort on the part of the utility to employ knowledgeable personnel to perform the pre-work planning as well as post work acceptance. This strategy generally works well when the utility is developing firm price contracts in the form of a guaranteed cost per mile or a guaranteed cost per circuit.

Utilizing a T&M with incentives, such as Target Pricing, is a viable alternative for preventative maintenance work, but does require an extensive knowledge of historical man-hours in order to develop “should take times” in order to set contractor valid targets or thresholds for each work unit. In this contract type, the utility agrees to pay the contractor for their total actual man-hours incurred to complete the work unit. The contractor in turn, agrees to meet the established target and “share” with the utility any cost savings achieved by completing the work unit with less man-hours than allotted. Some contracts also include a shared "penalty" where the contractor agrees to also share the cost of any work units exceeding the threshold man-hours thus, this provides the contractor with an incentive to find cost savings while minimizing their perceived risk in relation to their skepticism to utility provided targets.

Another variation to this contract type includes a T&M not to exceed. In this contract type, the contractor and utility agree that any cost savings will be shared; however, the contractor bears the entire burden for any cost over-runs above the man-hour threshold set by the utility. The advantage to this contract strategy is that the utility can have 100 percent confidence in their maximum expenditure which they can then use to better plan and budget. The disadvantage is that the contractor may include higher pricing due to the "contingency" variable and therefore, it may not offer the same cost savings as could be expected through the shared incentive/penalty contract.

Utilizing multiple contract strategies for vegetation management is generally the most cost effective. Performance based contracts are preferred for preventative maintenance type work but should be utilized in combination with other contract strategies to ensure overall program cost effectiveness. Firm price or unit price contracts are most effective for brush maintenance or herbicide treatment programs where the contractor can easily inspect and quantify the work volume. Competitive bidding of these work types ensures the contractor will provide the lowest unit price based on their estimated cost to complete the defined work scope and their known material costs (i.e. herbicide costs). T&M contracts (without incentives) offer the greatest level of flexibility to the utility in terms of being able to easily add or remove work scope and therefore are recommended for ticket type work. For the contractor, T&M minimizes their risk where work scope is variable or undefined as in Customer Trim Requests and Restoration type work. This allows the contractor to provide better pricing but shifts the burden to the utility to ensure that crews remain productive. Even so, T&M is generally considered the preferred method for these work types. A combination of all the contract strategies tailored toward specific work types, will offer the greatest potential for cost savings to the utility while minimizing the resources required to monitor contractor performance.

Well-documented inspection of completed work and establishment of clear standards are critical to achieving value from firm price or unit price contracts. Where clearance requirements may be variable due to customer concerns or in situations where work scope is not clearly defined (as with ticket work), T&M normally can provide a better value.

In recent years, the impacts of fuel price fluctuations have become a major concern for contractors as well for the utilities they work for. Concerns arise when contract rates are set at a time when fuel prices are at the extremes and then change dramatically over the life of the contract. This either leaves the contractor with a windfall profit if fuel prices decrease (and the utility with higher costs) or can result in significant loss of profits for the contractor if fuel prices increase. Shorter contract periods (i.e. one-year) can minimize potential risk, but can be costly in terms of the cost to develop new contracts every year, and in terms of higher rates from contractors due to increased risk from shorter contract periods. Many utilities have elected to incorporate fuel escalators into their contracts to offset this concern.

The following are brief descriptions of the common contracting strategies:

Time and Materials (T&M)

T&M is normally the least risky for the contractor since most of the production-related risk is born by the utility. T&M contracts with performance measures and incentives tend to move some of the production risk back to the contractor. T&M often results in the highest work quality. Poor performance may subject a contractor to contract termination or result in assignment of "penalty points" as part of future bid evaluations. For work that is highly variable in nature, difficult to quantify in advance and where quality and customer relations are significant concerns, T&M may be the most desirable method.

Unit Price

Unit price work shifts production risk to the contractor but requires preplanning by the utility to designate which units the contractor should complete. Units are normally a tree trimmed, a square area of brush removed, footage cleared, or a tree removed by diameter classes. There is a natural incentive for the contractor to provide only the level of quality enforced by the utility. Consequently, quality control inspection by the utility is an important administrative requirement for this pricing strategy as well as work completion inspection. Administration of unit price contracts can become burdensome for utilities with high tree densities.

Firm Price

Firm price work also shifts production to the contractor but also shifts work unit selection to the contractor. The natural incentive in this pricing strategy is for the contractor to select the minimum acceptable units and provide the minimum acceptable quality. Post-work inspection by the utility is critical to assuring that all work was completed in compliance with the established specification. Tree removal is often an issue in a firm price contract since costs for tree removal can be highly variable. Consequently, trees to be removed are sometimes identified in advance as part of the bid package preparation. Alternatively, unit prices by size class for tree removal can be established or tree removal can be completed on a T&M basis for trees specifically authorized by the utility. Firm price is best suited to situations where the work can be clearly defined and understood by the bidders. It should also be limited to locations where there will be good competition by a number of bidders. Awarding of concurrent firm price contracts to multiple contractors is desirable. Small firm price contracts bid to companies that do not have a local presence frequently results in higher pricing to cover the cost of per diems or personnel relocations necessary to establish a labor force.

Turnkey and Incentive Based Contracts

Turnkey pricing shifts the maximum risk from the utility to the turnkey service provider. This pricing strategy normally is accomplished by establishing incentives tied to accomplishment of specific objectives such as cost control, tree-related reliability targets, and customer relations. Because most of the program management responsibility is that of the contractor, it is critical that the utility closely monitor the performance objects through periodic review of key performance indicators. A variation of turnkey pricing is a management services contract with a third party management firm that administers contracts on behalf of the utility. The contracts for craft labor and equipment may continue to be with the utility or through the management company. The management services company may utilize any or all of the other pricing methods. This pricing strategy should be utilized if the utility has limited management resources or desires to totally overhaul existing systems, methods and practices.

Target Pricing Strategy

Target Pricing involves an efficient and effective use of combined customer notification and tree selection work planning that becomes a basis for establishment of Target Price for individual circuits or circuit segments. Documented workload in terms of tree pruning, tree removal and brush control units, multiplied by realistic costs per unit worked (based on work history by district) allows creation of the target price that contractors can be incented to meet or beat.

Using this system the line clearance contractor is paid on the basis of T&M rates as work progresses. Reconciliation of actual production cost compared to the Target Pricing occurs quarterly.

This strategy requires designation of specific work units and agreement from the line clearance contractors to work the units designated by the Work Planner. Work Plan packets are prepared and distributed to crews from a Work Planning database and populated through Work Planning data acquisition software. Line clearance crew time and production must be monitored and recorded in a production database.

A simplified example of a Target Pricing work sheet is illustrated in Table 10. Table 11 is an example of a simplified quarterly reconciliation table.

Table 10. Target Pricing Circuit Summary.

Unit Description	Plan Quantity Circuit xyz	Standard $/Unit	Quantity x Unit Price
Bucket Trim 4"- 8"	300	$20	$6,000
Trim 8" - 12"	47	$30	$1,410
Removal 12.1" to 24"	3	$170	$510
Manual Trim 4"- 8"	655	$25	$16,375
Trim 12" - 24"	9	$140	$1,260
Brush removal	57	$240	$13,680
Total Standard Cost for Circuit xyz			$39,235

Table 11. Target Pricing Quarterly Reconciliation.

Unit Description	Quantity x Unit Price
Standard Cost	$96,268
Actual Cost	$83,040
Amount Actual Lower than Standard	$13,228
Percent Actual Below Standard Cost	13.7%
5 to 25% Qualified Bonus Tier Percentage	25%
Incentive Amount	$3,307

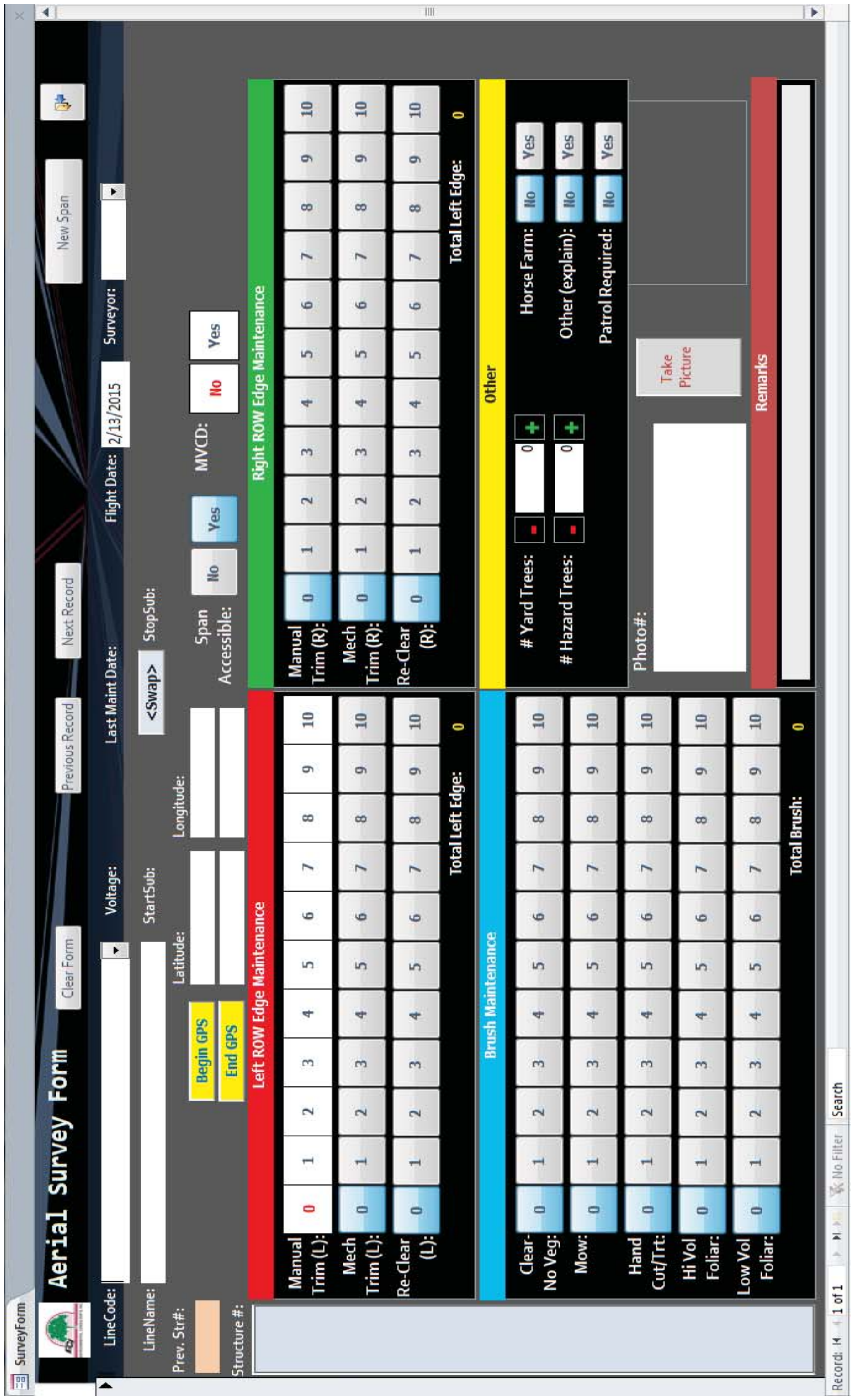
There are several requirements that must be in place for a Target Pricing strategy to be effective. They include:

1. Effective processes for work planning
2. A field data collection and work documentation system
3. Realistic production data by district or by characteristics such as maintained/unmaintained, accessible/inaccessible, overhang, etc.
4. Contracts with line clearance contractors that complement the Target Pricing strategy

Benefits of this strategy have included lower costs than firm priced or T&M bidding strategies. Because tree selection is closely aligned with utility goals, adequate reliability can be efficiently achieved.

Appendix B: Transmission System Vegetation Survey Form

TRANSMISSION RIGHT-OF-WAY VEGETATION SURVEY
LG&E and KU



Appendix C: Recommended Industry Best Management Practice Strategies

Recommended Industry Best Practices Strategies

Transmission owners need to develop practices that fulfill the requirements of the vegetation standard in a cost effective manner. These practices or strategies must be documented and consistently implemented. Over time, certain practices have been shown to be successful in preventing outages due to vegetation. Many of these practices were incorporated into the NERC Standard FAC-003 since the group that developed and approved the standard included experienced transmission vegetation managers. The American National Standards Institute (ANSI) has established standards for vegetation maintenance on transmission ROW[14]. In addition, the International Society of Arboriculture (ISA) has issued a companion publication to ANSI A300 Part 7, Best Management Practices, Integrated Vegetation Management.[15]

Work Management

ECI proposes the following best practice work management recommendations as part of any successful transmission vegetation management program. The utilization of some or all of these work management tools and methods may already be in use at LG&E and KU and therefore, these recommendations in no way imply the current lack of appropriate procedures. The original scope of this workload study did not include a review of the transmission program procedures or strategies. The recommendations presented here should be considered for implementation by LG&E and KU if not already integrated into the existing management program.

- **Develop and keep current a vegetation management plan.** Even though the current NERC standard FAC-003 does not explicitly require a vegetation management plan (TVMP), a TVMP is an extremely valuable tool to plan and implement both short-term and long-term vegetation management goals. A TVMP is the “road map” for vegetation management and provided direction and overview of system goals. It details how the work will be determined, planned and executed and provides a framework on how vegetation management will be implemented to ensure the reliability of the system. Annual plans are a subset of multi-year long-range plans. A plan will aid in developing budgets and tracking the work performed on individual lines.
- **Develop and keep a current work schedule.** The TVMP will detail system and procedures for documenting and tracking the planned work. Plans are in need of constant update as work progresses. Updating will track work in progress and allow notice for any necessary adjustments.
- **Implement a system of inspecting planned work.** Documenting the inspection of completed work is also necessary to properly approve payment and ensure work reported as complete by the contractor meets

[14] ANSI. 2006. The American National Standard for Tree Care Operations - *Tree, Shrub, and Other Woody Plant Maintenance- Standard practices (Integrated Vegetation Management a. Electric Utility Rights-of-way).* A 300 Part 7. American National Standards Institute, NY.
[15] Miller, R.H. 2007. Best Management Practices- Integrated Vegetation Management. International Society of Arboriculture, Champaign, Il.

LG&E's and KU's expectations. Spot checks of completed work are commonly used with inspections of additional completed work when deficiencies are found. It is important to identify work that does not meet the standard early so that corrections can be made before more deficient work is completed. This will save time for both the utility and the contractor performing the work. Formal documentation of the work inspection is recommended.

- **Provide for consistent budgeting.** A consistent plan needs consistent funding. Budget reductions mid-year can cause workforce disruptions that increase future costs. Any changes to the established annual plan require documentation.
- **Establish and enforce work specifications.** The personnel performing the work must know exactly what is expected of them. The work inspector must know the specifications to properly enforce them. If future contract strategies are being considered, a clear, concise specification is required to communicate LG&E and KU vegetation maintenance goals to perspective contractors. The clearer the contract specification, the better the pricing from a perspective new contractor.
- **Develop action thresholds.** Develop a "clearance at time of maintenance" (clearance 1) distance and establish a minimum clearance threshold (clearance 2) that vegetation should never exceed. This threshold clearance will provide an additional margin of error to allow for vegetation growth, line sag and variations in maintenance cycles. Best practice utilities have developed an action threshold clearance value between Clearance 1 and Clearance 2 in order have a intermediate point to take appropriate action to avoid violating the vegetation standard. Another type of action threshold relates to the maximum height that brush[16] is allowed to attain to provide efficient and cost effective foliar application of herbicides. Since herbicide application is frequently less costly than mechanical clearing, it is important that brush is not allowed to grow taller than the maximum height 8-12 feet for effective herbicide use.
- **Develop a mitigation plan for exceptions/non-standard maintenance.** Keeping a record of locations where exceptions to standard practices exist is important to prevent outages or violations of LG&E's and KU's minimum acceptable clearance (between vegetation and conductors). An example would be where pruning is the only vegetation maintenance option allowed by the easement. The record should be specific as to the nature of the situation and regular inspection should be scheduled. Use of an automatic reminder system is recommended. Renegotiating or acquiring easements to eliminate clearance restrictions, payment for tree removal or replacing tall

[16] Brush is normally defined as immature (less than 10.2 cm or 4 inches in diameter), tall-growing tree species that would grow tall enough to interfere with conductors

growing trees with compatible vegetation should be considered to eliminate the situation.

- **Develop standardized processes.** A uniform vegetation management plan for the entire LG&E and KU system that coincides with LG&E's and KU's current specification is key.
- **Implement an Integrated Vegetation Management program (IVM).** IVM is the art of controlling plant populations based on scientific principles from such fields as ecology, zoology and biology. Vegetation is managed to produce desired conditions (plant community density, structure and composition) and associated values consistent with stakeholder objectives on a sustainable basis. Stakeholders include both easement or fee holders, and all stakeholders and interested parties who may be influenced by IVM activities.
- **Manage the ROW by zones.** Managing the ROW in the zone immediately beneath the conductors differently from the rest of the ROW, known as the wire zone-border zone concept, is a successful approach to prevent outages in a cost effective manner (Figure 7), where sufficient ROW width is present. Different management techniques can be applied to these two zones and result in the many economic, operational and environmental benefits associated with the use of IVM techniques.

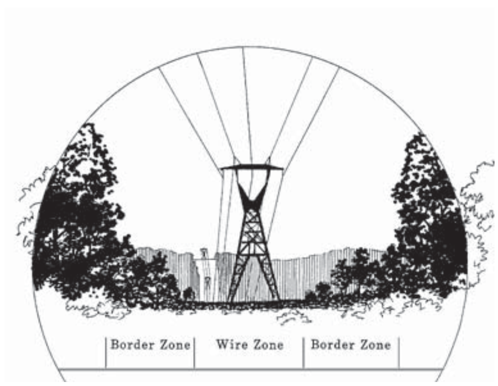


Figure 7. Wire Zone / Border Zone Vegetation Management.

- **Maintain the ROW edge**. Side pruning consists of pruning trees on the edge of the ROW. This work can be accomplished through the use of truck-mounted aerial lift equipment (bucket trucks), by manual climbing, or through the use of mechanical pruning equipment, such as a Jarraff, Aerial Saw, or similar tools.
- **Coordinate transmission work with related distribution work**. Occasionally distribution lines are found on the same ROW and even the same structures as a transmission line. Managing the vegetation simultaneously on both facilities can be cost effective. Problems can arise when different departments within the same company manage facilities with varying cycles, maintenance methods and budgets. The

transmission maintenance organization should take the lead in coordinating and ensuring that the work is completed because a transmission outage has greater consequences than a distribution outage.

Integrated Vegetation Management

In Integrated Vegetation Management (IVM), the selection of control options is based on effectiveness, site characteristics, environmental impacts, safety, and economics. Good vegetation management is based on an understanding of plants and their environment. A holistic approach considers the inter-relationship of plants, site, and species composition and growth rates.

IVM is recognized as an industry best practice, and it is therefore recommended that LG&E and KU adopt this strategy for the maintenance of undesirable brush on its transmission system. In general, this would be a combination of brushing, mechanical clearing (hydro-axe), and the use of herbicides to manage trees and bush on the LG&E and KU system.

Cutting deciduous brush without applying a follow-up herbicide application to the stump surface will permit the vegetation to re-sprout, thus requiring future maintenance. Trimming brush and/or allowing it to mature results in its becoming a more expensive and often permanent part of the workload. Trimming brush and the failure to use herbicides on cut stumps are not cost effective long term brush management techniques.

ECI recommends that LG&E and KU continue to remove trees with the ROW and ROW edge and treat the deciduous cut-stumps of trees and brush with appropriate herbicides whenever possible. LG&E and KU should continue to enforce the existing specifications for removal and stump treatment. This will prevent future expansion of the system vegetation workload and future line clearance cost increases.

On most of the LG&E and KU transmission system, there appears to be an opportunity to treat standing brush less than 8 - 12 feet tall with either foliar or basal herbicide applications, avoiding hand cutting. Taller standing dead brush can become a source of complaints, and taller brush can be difficult to control with foliar applications without risking exposure to off-target plants. This use of a basal bark-applied herbicide would be a particularly valuable tool in the removal of tall-growing tree species growing in sensitive areas or where there is concern for off-target damage.

Use of herbicides is essential if LG&E and KU is to maximize the benefits of mechanical clearing and brushing. Herbicide use is an important component of an IVM strategy. LG&E and KU should continue to enforce the specifications that require use of herbicides to treat stumps. The effectiveness of selective herbicide applications has been well documented through long-term studies on utility rights-of-way in the central and northeastern United States. Results from treatment simulation models developed through these studies project that sites dominated by deciduous species would nearly double in stem density by the end of two cycles if simply cut without a follow-up herbicide application (Figure 8). These same sites would be expected to exhibit about a 50 percent reduction in stem density over the same time period if treated with a selective herbicide application.

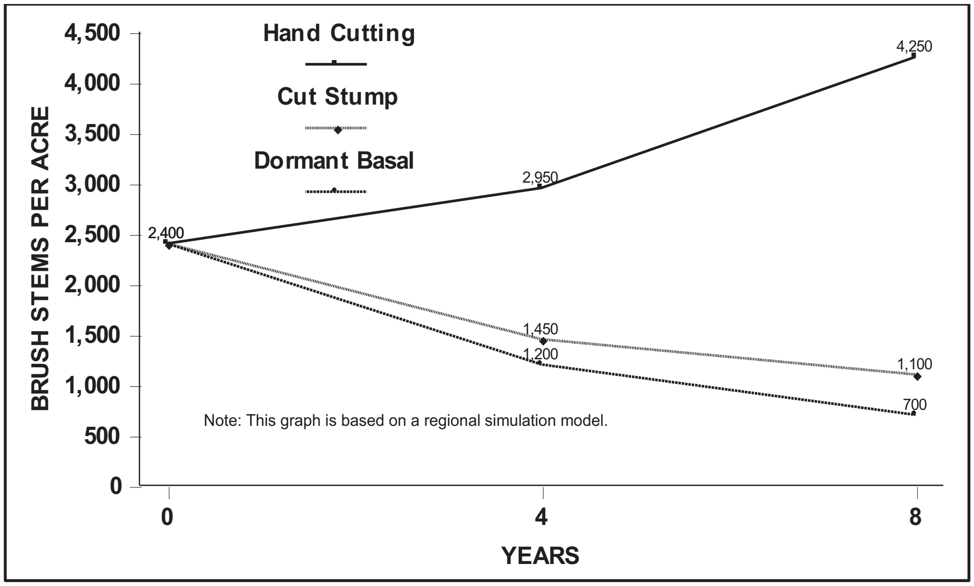


Figure 8. Effectiveness of Herbicides for Control of Brush Over Time. Results of long term study of brush management on utility rights-of-way in the northeast United States.

Currently, herbicides are effectively used in the control of ROW vegetation. This is an integral part of any IVM program. An important consideration is that a herbicide program must be environmentally safe and professionally supervised to maintain public acceptance. Line clearance crews performing herbicide applications should receive proper training in species identification and herbicide application methods that are approved and deemed acceptable by the public and land owners.

It is recommended that LG&E and KU continue to pursue the selective use of herbicides (e.g., foliar and basal) for the management of communities of deciduous brush species as a part of IVM program. Utilizing contractors trained and experienced in the use of herbicides will ensure the continued success of the LG&E and KU vegetation management program.

Herbicide Safety and Risk Assessments

Today's herbicides control tree/brush re-sprouting by blocking chemicals needed by plants to convert water, sunlight and nutrients into food for growth. Since these same chemicals are not present in animals and humans, the herbicides are very low in toxicity to people or animals. Without any food, the treated weed trees on the right-of-way wither and decompose. Treated stumps dry out and don't re-sprout.

Safety for humans and the environment includes not causing adverse effects that are unacceptable. In this context, risk assessment is the process by which the likelihood of unacceptable adverse effects from the use of various methods of vegetation management can be determined.

An extensive report prepared by ECI provided the technical basis for and a summary of the risk to human health, wildlife and the environment from the use of 10 herbicides by a utility owner in the US. These herbicide uses included broadcast foliar, selective foliar, basal bark and cut stump applications. This assessment concluded that the margins of safety for herbicide use by the utility that commissioned the assessment were "adequate to assure protection of human health of workers and the general public."

ECI also completed an environmental impact statement resulting in the authorization of herbicides to control right-of-way vegetation in the LG&E and KU National Forest in Pennsylvania (US). Subsequent evaluation of herbicide use in the National Forest confirmed safe and effective use of foliar herbicides to control brush on utility right-of-way.

The human health risk assessment methodology used in these reports was the one generally recognized by the scientific community as necessary to characterize the potential adverse human health effects of chemicals in the environment. It is the same process used in judging the human health risk from cosmetics, food additives, pharmaceuticals, various household chemicals, and many other materials.

Herbicide Acceptance by Wildlife Groups in the United States

In the US, stump control herbicides are used not only by electric utilities, but also by numerous private and governmental wildlife habitat improvement organizations. Examples include:

- The Nature Conservancy on projects designed to limit the spread of invasive and non-native trees and shrubs. This would be similar to the efforts in the UK to eradicate the invasive plants Japanese Knotweed and Himalayan Balsam.
- Under the banner of a former organization called Project Habitat®, groups such as the National Wild Turkey Federation, Buckmasters, Butterfly Lovers International and Quail Unlimited have joined together to encourage utilities to implement an "Integrated Vegetation Management" (IVM) approach to maintaining utility easements that appropriately utilizes herbicides as a component in the control of right-of-way vegetation. They have recognized that environmental benefits of herbicides, when properly used, outweigh any adverse risk and are far more desirable than the alternatives to herbicide use, such as frequent mowing or hand cutting of undesirable trees.

Significant research has been undertaken over the past 30 years in the United States to document the impact of right-of-way herbicide use on the environment, wildlife and management costs. Much of this research has been conducted by ECI and its university research associates. Stems per acre decrease over time through the use of herbicides, as does associated maintenance costs.

Brush control through the use of herbicides is an extremely cost effective maintenance tool. Figure 9 illustrates the successful use of herbicides and provides cost effective, environmentally acceptable and long-term brush control.

Figure 9. Example of good brush control through the use of herbicides.

Appendix D: Recommended Staffing to Contract Tree Crew Ratio

Need for Additional LG&E and KU Vegetation Maintenance Staffing

The vegetation maintenance program at LG&E and KU is sufficiently staffed to effect the administration of the current line clearance contracts and contractor staffing at the time of this review. The three ROW Coordinators manage 25 contract tree crews. As LG&E and KU adopts ECI's budget and staffing recommendations additional contract crews will be added to the system manage the increase workload. Additional staff (in house or contracted) will be required to effectively manage the increased work force.

Figure 10 shows data from two benchmarking studies that evaluated the average number of line clearance crews supervised by utility arborists. In the Pennsylvania Electric Association (PEA) and Edison Electric Institute (EEI) studies, the average ratio of line clearance crews to each utility arborist was respectively 8 and 11 (Figure 10). However, in both studies 75 percent of the reporting utilities average 10 crews or less per supervising arborist. Figure 10 also shows that in a recent benchmarking study of over 20 utilities, the two overall best-in-class utilities have a ratio of approximately one utility arborist (including the system arborist) for every 6 line clearance crews. Figure 10 also compares the current crews supervised by the system forester to the anticipated ratio should seven-year cycle be adopted.

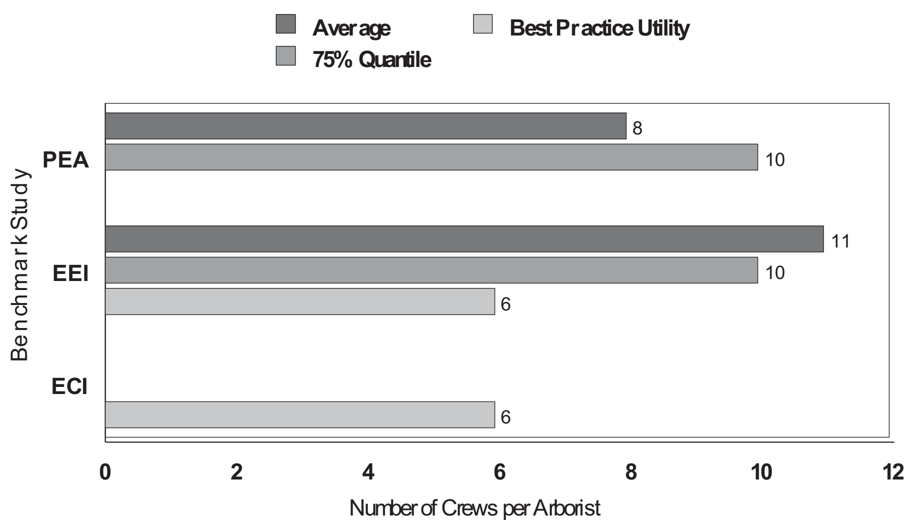


Figure 10. Comparative Data on the Average Number of Line Clearance Crews Overseen by Utility Foresters[17].

Based on the anticipated increase in contractor tree crew staffing on the transmission system it is recommended that LG&E and KU establish an additional three Utility Forester positions (in-house or contract) to assist the ROW Coordinators in the day to day management of the program. If fully implemented, the LG&E and KU Transmission VM contractor tree crew work

[17] PEA = Data from a 7 utility survey conducted by the Pennsylvania Electric Association.
EEI = Data from the Edison Electric Institute benchmark study of 29 utilities.
ECI = Data from a 1998 benchmarking study of 22 North American utilities.

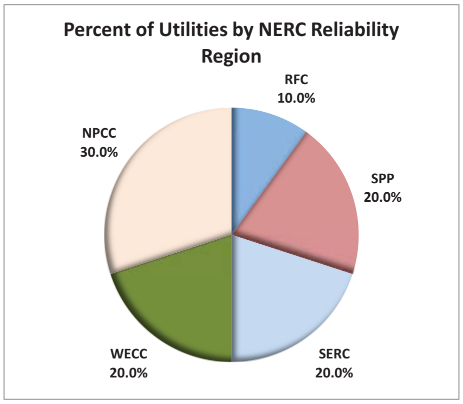
force will be approximately 72 crews for the first cycle. This will provide a ratio of approximately 12 crews per LG&E and KU vegetation management staffing. In order for the program recommendations to be implemented properly it has to be implemented correctly in the field. These three additional individuals will be primarily responsible for planning work and auditing the tree crews. They should also be capable of assisting the ROW Coordinators with any work that is appropriate for them to do. For example inspecting customer requests, work associated with new construction, supervising tree crews, and handling of customer complaints or refusals. After the completion of the first cycle, the number of tree crews is may decline, then staffing can be reduced to meet the need. The use of contract foresters would be an option for staffing these positions as they are more easily flexed.

The individuals should primarily be responsible for field implementation of the line clearance program and the evaluation of the line clearance crews and contractors within their area of responsibility. The Utility Foresters should report directly to the ROW Coordinators. This will provide a measure of control over individual interpretation of company guidelines and will ensure consistent implementation of appropriate work practices and operating procedures across the system. These positions will assist in ensuring contractor compliance to ANSI A-300 standards and that crews are properly instructed on the correct and safe use of herbicides. The position will audit contractor work to ensure that clearance requirements are met.

The Utility Foresters will assist in managing programs that provide ongoing information on field conditions, including tree crew production records (trees pruned removals, herbicide use, and brush treatment), electric service interruption data and conduct post-outage investigations.

The Utility Foresters should be trained in all aspects of utility vegetation management, including proper pruning techniques and herbicide use. The Utility Foresters should have a minimum of 2 years of experience in utility vegetation management, ISA certification and, preferably, a Bachelor's Degree in Forestry or a related field. This will help to ensure consistent implementation of program policies and will enable the ROW Coordinators to effectively evaluate the work being completed by the line clearance crews.

Appendix E: LG&E and KU Transmission System Benchmark Comparison



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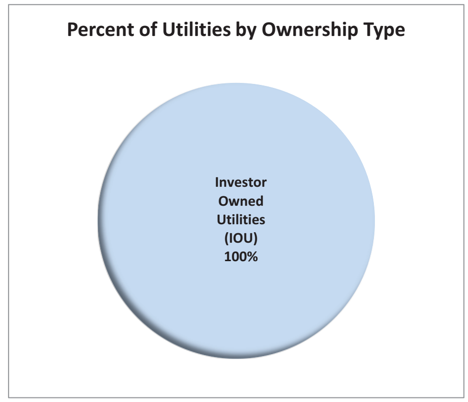

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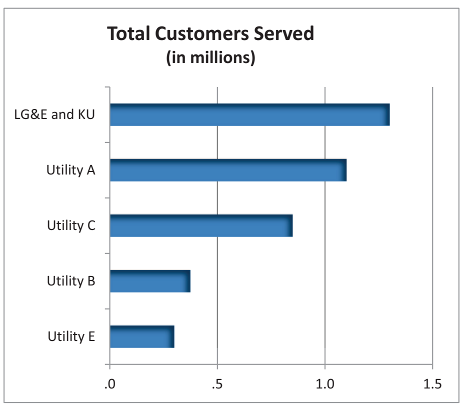
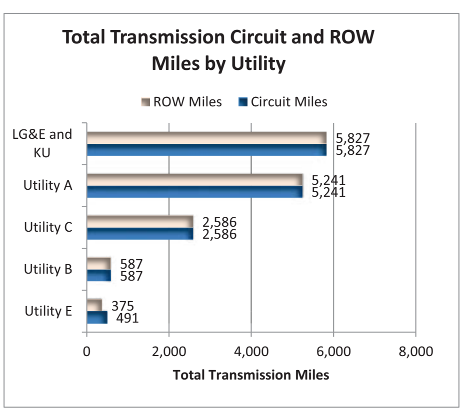


Figure 12

Transmission Program Attributes

Utilities Regulated by a Public Utility or Service Commission(s) or other Agency(s):	............................100%
Centralized VM Program:	............................100%
VM Managed by Professional Forester or Arborist:	.... 80%

Figure 15



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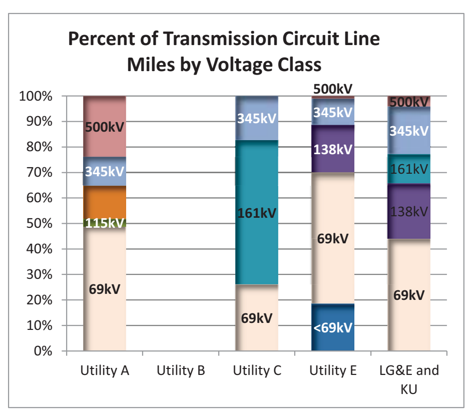

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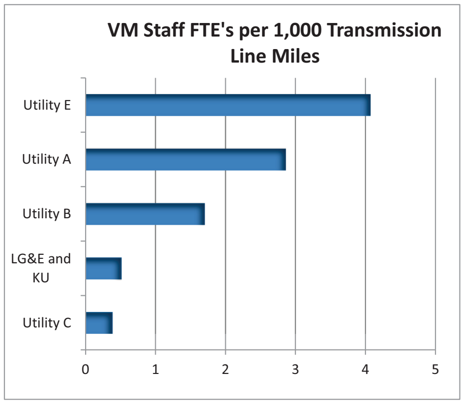

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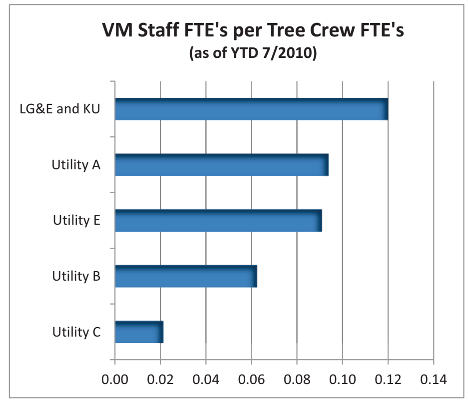

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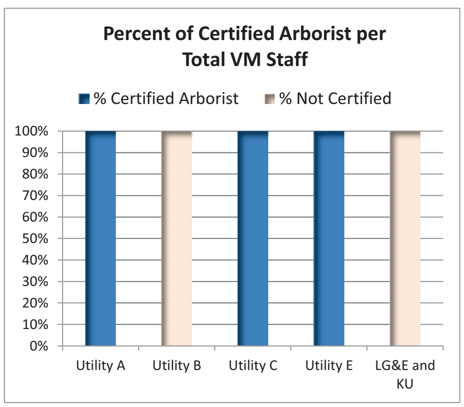

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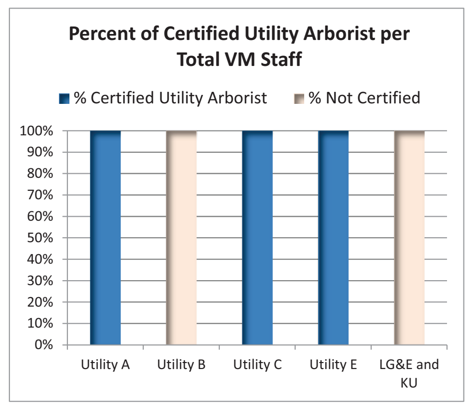

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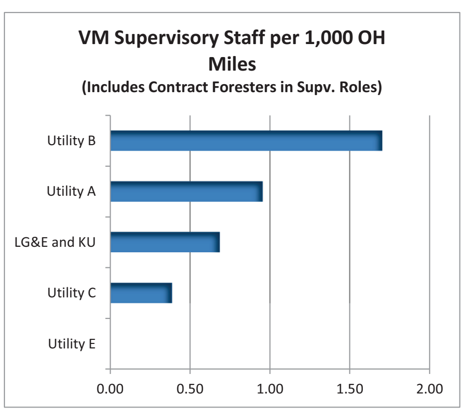

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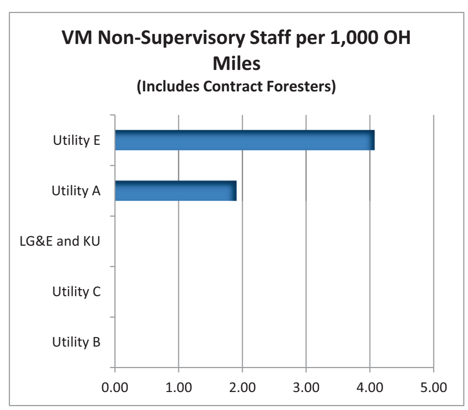

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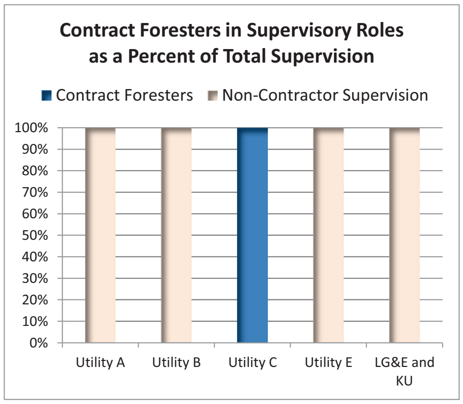

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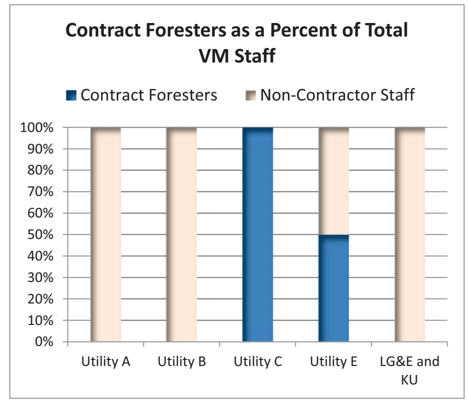

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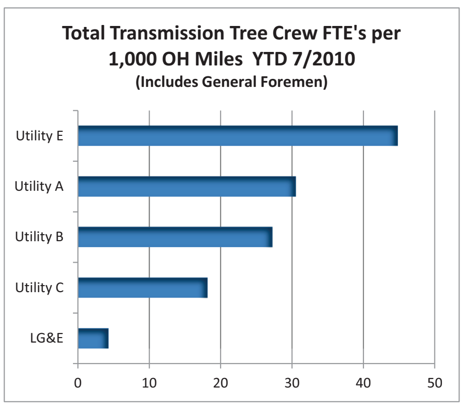

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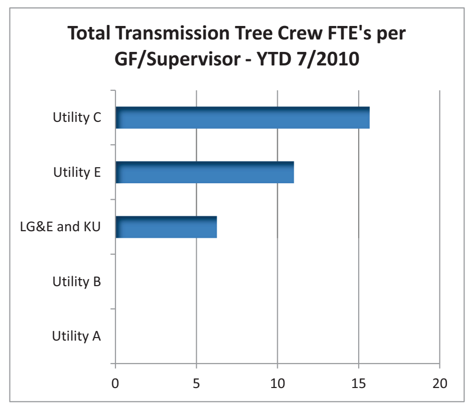

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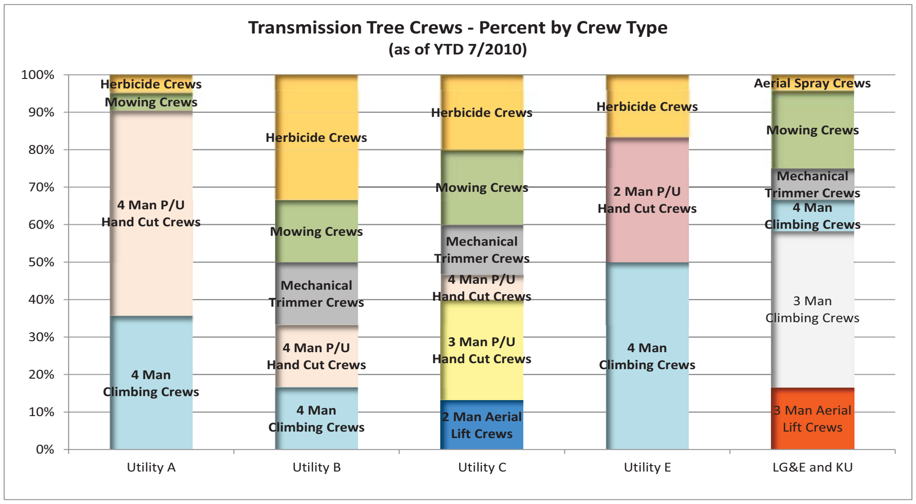

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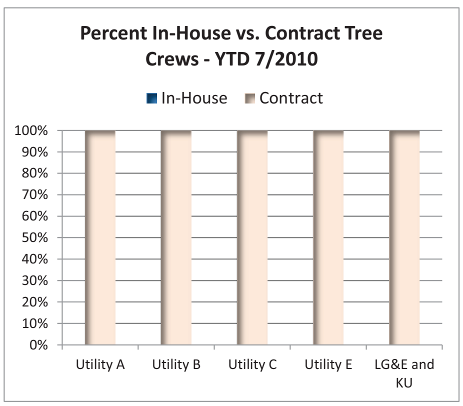

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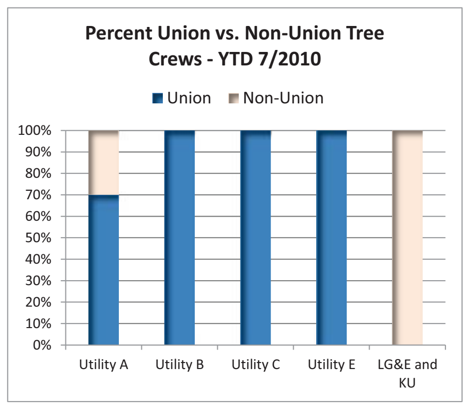

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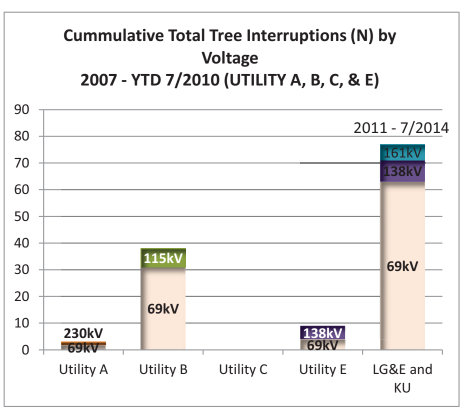

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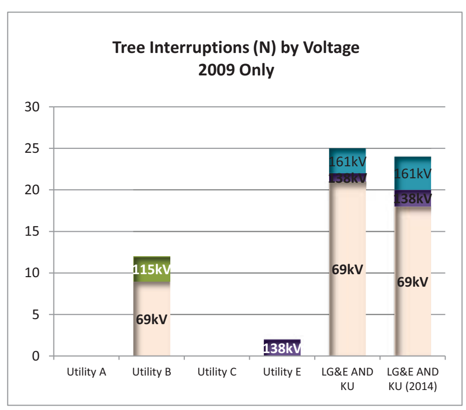

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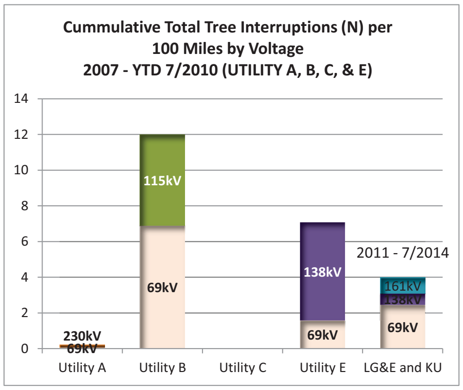

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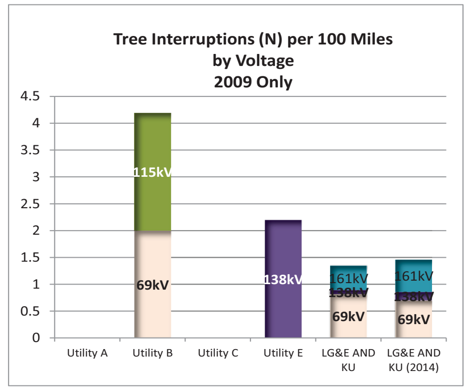

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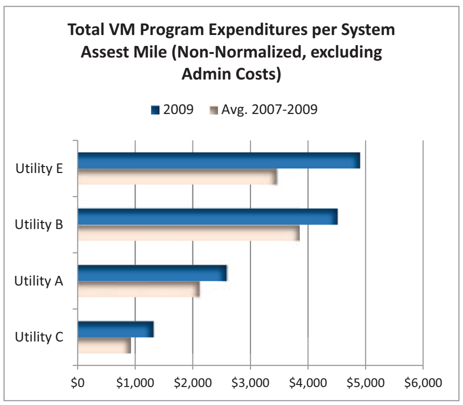

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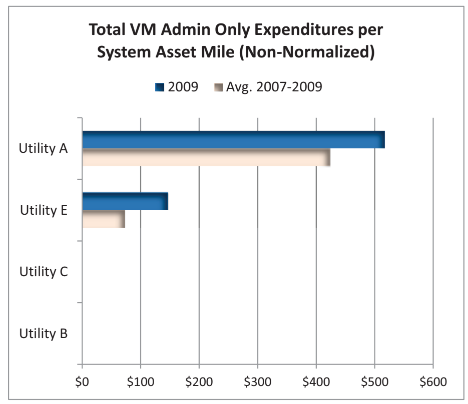

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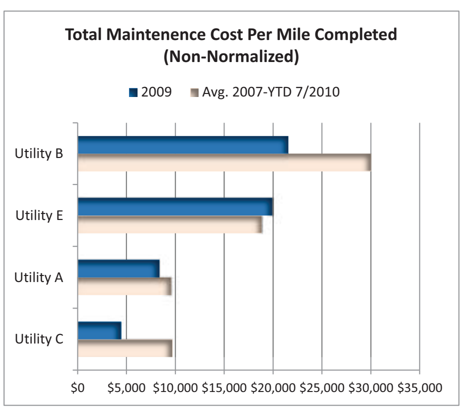

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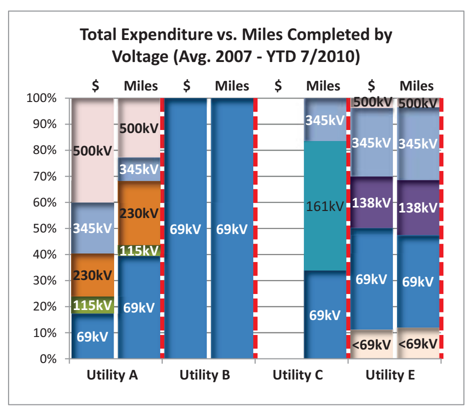

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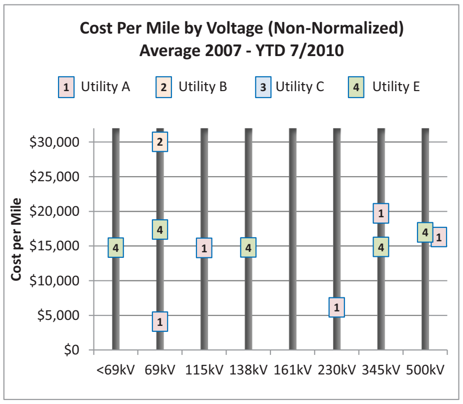

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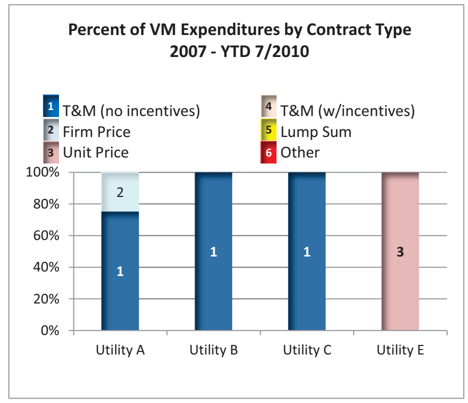

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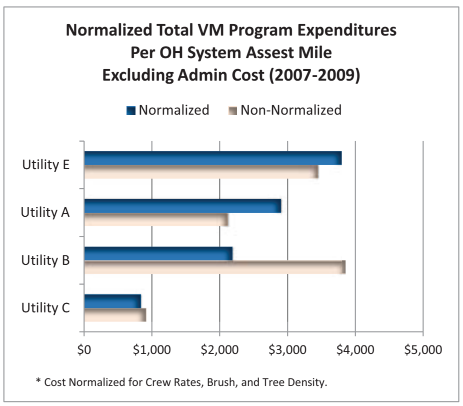

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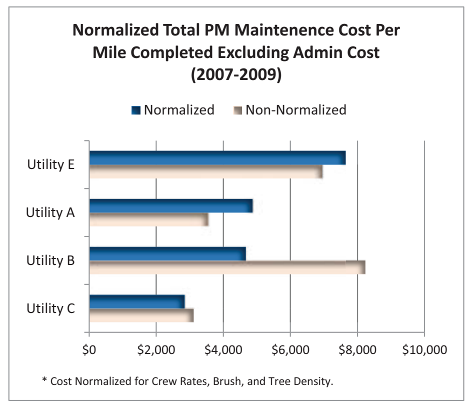

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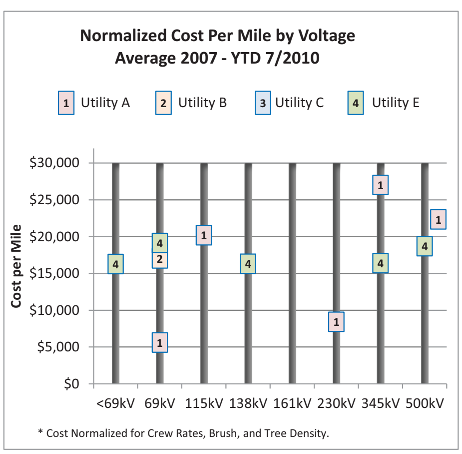

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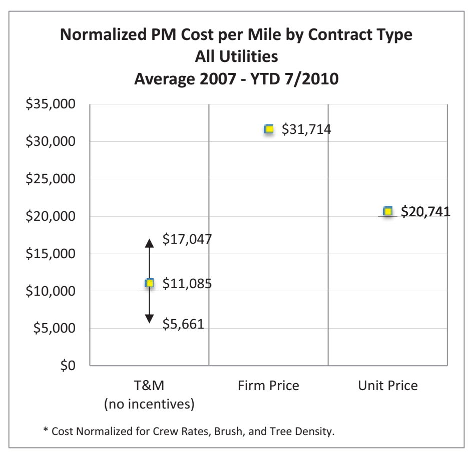

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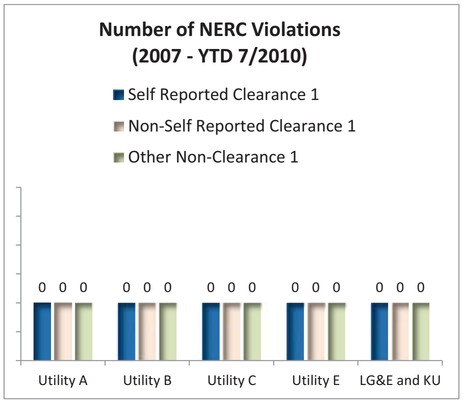

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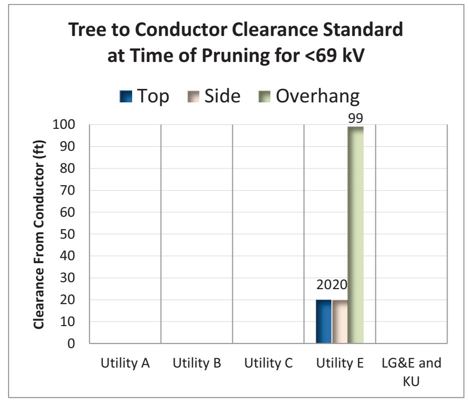

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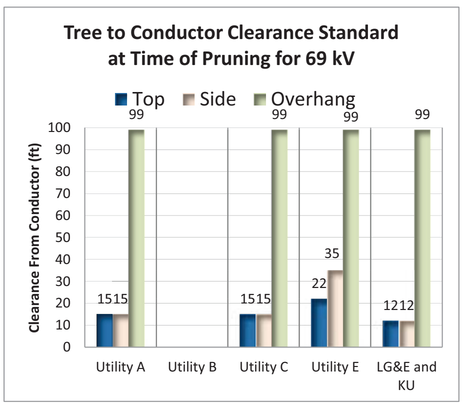

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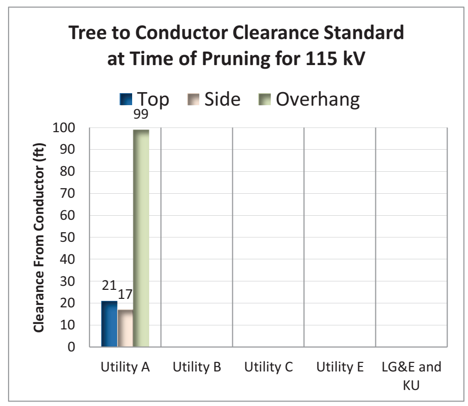

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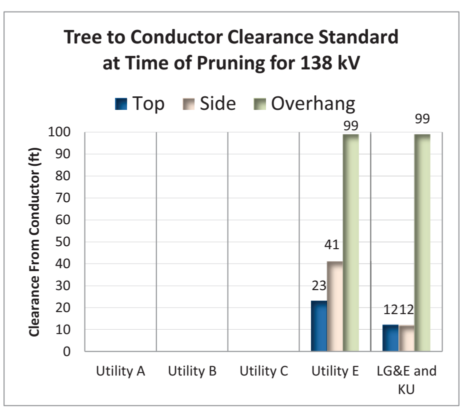

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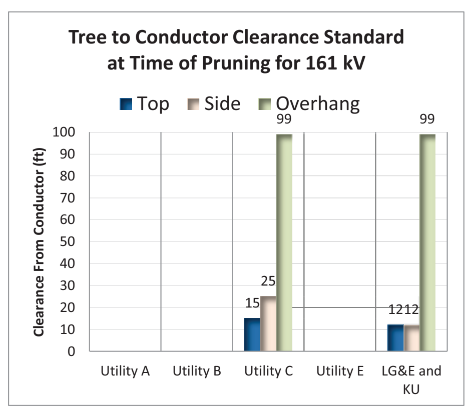

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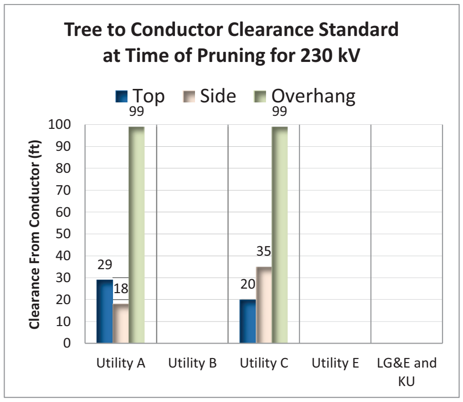

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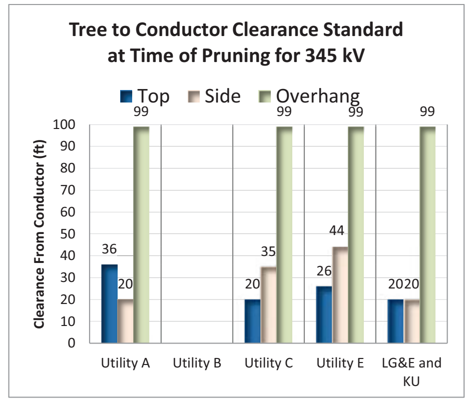

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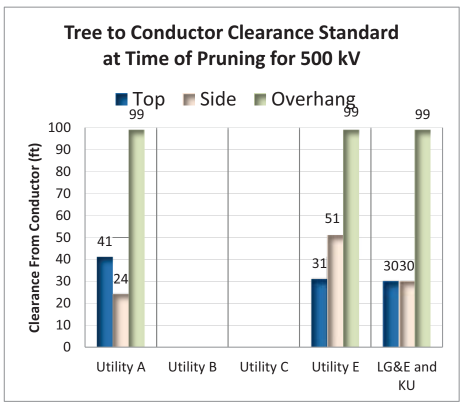

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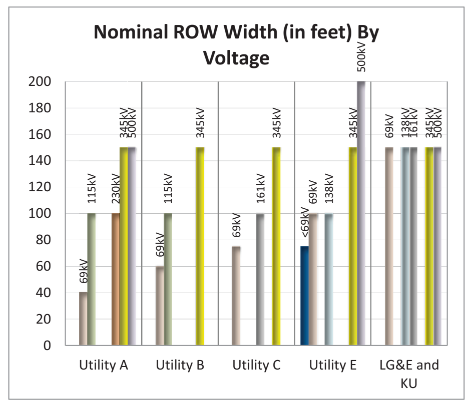

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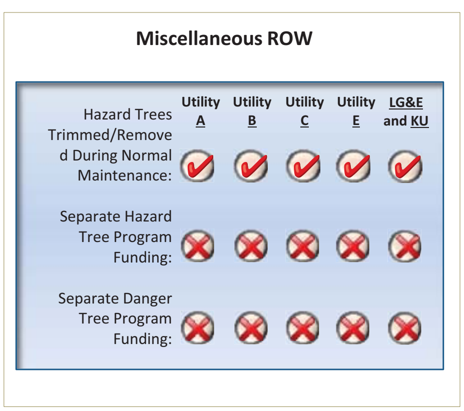

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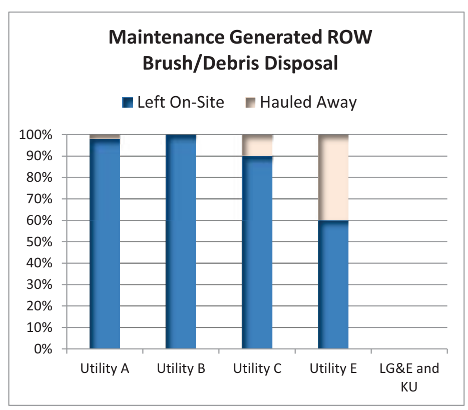

Figure 55

Tree Inventory System Capabilities	Utility A	Utility B	Utility C	Utility E
Work Prescription and Estimating (Work Planning)	X			
Map, Manifest and Work Package Generation	X			
GIS Tree Location Information	X			
Electronic Facility Asset Maps with Tree Inventory Overlay	X			
Cost Generation and Budgeting				
QA/QC Audit and Inspection Tracking	X			
Payment Processing				
Electronic Billing and Payment Processing				
Productivity Tracking and Analysis				
Work Status and Completion Tracking (Work Management)	X			
Reliability Tracking and Follow-Up Investigations	X			
Emergency Work and Restoration Management Coordination				

Figure 56

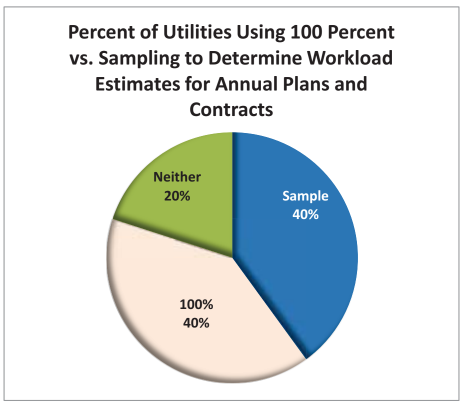

Figure 57

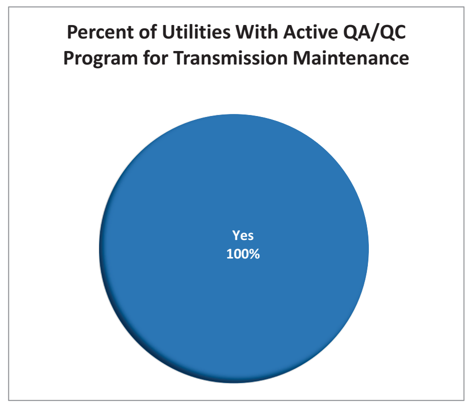

Figure 59

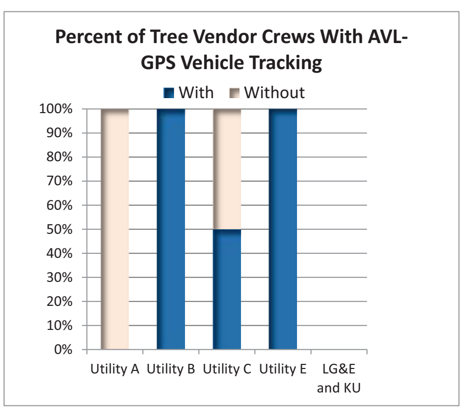

Figure 58

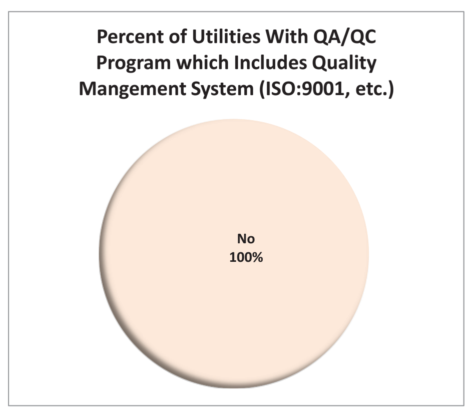

Figure 60

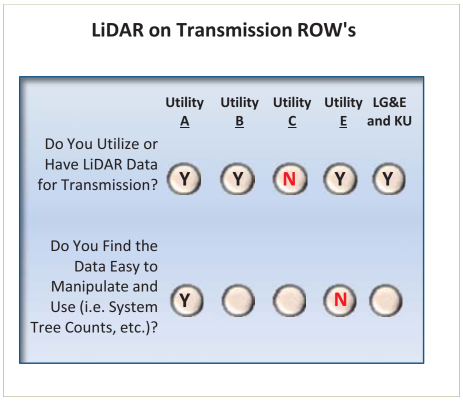

Figure 61

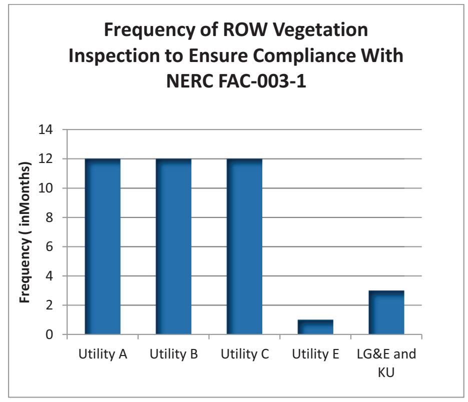

Figure 63

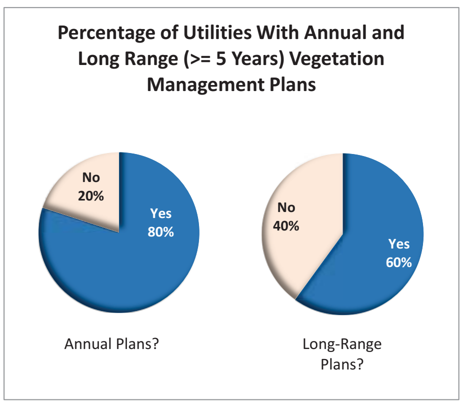

Figure 62

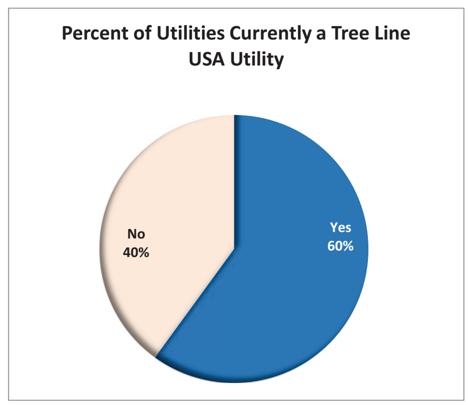

Figure 64

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 7, 2017

Question No. 12

Responding Witness: Lonnie E. Bellar

Q.2-12. Refer to the response to KIUC 1-30. Provide a schedule showing transmission vegetation management costs by FERC account for each year 2007 through 2016, the base year, and the test year. On that same schedule, provide the transmission line miles by voltage.

A.2-12. Transmission vegetation management costs are recorded in FERC 571.

2007	$2,851,413
2008	$2,899,128
2009	$3,887,218
2010	$4,066,864
2011	$4,108,149
2012	$4,148,767
2013	$4,511,675
2014	$5,310,433
2015	$5,329,253
2016	$5,286,815
Base Yr.	$5,629,253
Test Yr.	$9,992,809

See Mr. Thompson's testimony, Exhibit PWT-2 (page 6, Table 1) for a breakdown of transmission line miles by voltage. The Company did not track line miles worked by voltage for the years requested.

EXHIBIT RCS-9

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 25

Responding Witness: Christopher M. Garrett

Q-25. Gross Revenue Conversion Factor (GRCF). Refer to Schedule H-1. Show in detail how each of the following items was derived. Include all supporting calculations electronically in Excel and include all supporting workpapers and documentation.

a. UNCOLLECTIBLE ACCOUNTS EXPENSE

b. PSC FEES

c. PRODUCTION ACTIVITIES DEDUCTION-STATE

d. PRODUCTION ACTIVITIES DEDUCTION-FEDERAL

A-25. a. See attached.

b. See attached.

c. See the response to PSC 1-54 Att_KU_PSC_1-54_Sch H.xlsx for Schedule H-1 and workpaper in Excel format.

d. See the response to PSC 1-54 Att_KU_PSC_1-54_Sch H.xlsx for Schedule H-1 and workpaper in Excel format. The federal production activities deduction is zero due to KU's net operating loss carryforward as a result of the extension of bonus depreciation.

KU			
Year	Sales to Ultimate Consumers	Net Write Offs	Net Write Offs as % of Sales to Ultimate Consumers (C/B)
2011	$ 1,380,638,258	$ 5,923,147	0.43%
2012	$ 1,379,454,638	$ 3,942,528	0.29%
2013	$ 1,489,643,183	$ 3,477,109	0.23%
2014	$ 1,591,706,493	$ 7,676,254	0.48%
2015	$ 1,557,585,371	$ 5,110,346	0.33%
Uncollectible Accounts Expense Factor (5-Year Average)			0.352%

LGE			
Year	Sales to Ultimate Consumers	Net Write Offs	Net Write Offs as % of Sales to Ultimate Consumers (C/B)
2011	$ 1,188,620,830	$ 4,355,141	0.37%
2012	$ 1,195,803,393	$ 1,749,753	0.15%
2013	$ 1,312,698,196	$ 1,766,183	0.13%
2014	$ 1,387,772,813	$ 4,255,057	0.31%
2015	$ 1,381,030,448	$ 2,329,232	0.17%
Uncollectible Accounts Expense Factor (5-Year Average)			0.226%

Commonwealth of Kentucky
Finance and Administration Cabinet
OFFICE OF THE SECRETARY
Room 383, Capitol Annex
702 Capital Avenue
Frankfort, KY 40601-3462
(502) 564-4240
Fax (502) 564-6785

Matthew G. Bevin
Governor

William M. Landrum III
Secretary

MEMORANDUM

TO: Daniel Bork, Commissioner
Department of Revenue

FROM: William M. Landrum, III
Secretary

Date: June 08, 2016

Subject: Millage Rate for Fiscal Year 2017

The Department of Revenue, as directed by KRS 278.150(2), collects the annual assessments from the Commonwealth's utility companies and places these receipts to the credit of the General Fund.

Based upon the certification of gross receipts received in this office on June 1, 2016 from the Public Service Commission per KRS 278.150(1), the Finance and Administration Cabinet is establishing a millage rate for fiscal year 2016-2017 of 1.941 mills in accordance with KRS 278.150(2).

Attachment

Cc: John E. Chilton
Janice Tomes
Glenna Goins
Greg Harkenrider
Aaron Greenwell
Jeff Cline

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 85

Responding Witness: Valerie. L. Scott

Q-85. Uncollectibles. Provide the net charge-off percentage for uncollectibles for 2015 and 2016. Explain any material variations in the percentage between years.

A-85. The net charge-off percentage for uncollectibles is 0.34% for 2015 and 0.26% for 2016.

EXHIBIT RCS-10

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 38

Responding Witness: Gregory J. Meiman / Valerie L. Scott

Q-38. Provide the following monthly Company labor data, in total, for December 31, 2014 through December 31, 2016, showing annual totals:

a. Number of actual employees broken down between type (e.g. salaried, hourly, union, non-union, temporary, etc.).

b. Number of authorized employees broken down between type (e.g. salaried, hourly, union, non-union, temporary, etc.).

c. Regular payroll broken down between expensed, capitalized, and other.

d. Overtime payroll broken down between expensed, capitalized, and other.

e. Temporary payroll broken down between expensed, capitalized, and other; and

f. Other payroll (specify).

A-38.

a – b. See attached.

c – f. See attached.

Kentucky Utilities Company
Case No. 2016-00370

Question 38(a)

KU - Actual Employee Headcount

2014	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Union-Hourly	600	600	598	600	599	603	606	598	596	596	595	599
Exempt	148	150	149	149	149	148	149	149	149	148	148	143
Non-exempt	202	203	205	205	206	204	203	209	207	209	210	209
Temporary	3	3	3	3	5	9	10	8	7	6	6	6
Total	**953**	**956**	**955**	**957**	**959**	**964**	**968**	**964**	**959**	**959**	**959**	**957**

2015	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Union-Hourly	598	597	593	595	589	583	579	585	587	584	572	580
Exempt	141	139	141	141	141	141	140	141	143	142	142	145
Non-exempt	211	211	211	208	211	210	211	211	211	212	203	205
Temporary	6	6	6	6	11	14	14	10	10	10	10	10
Total	**956**	**953**	**951**	**950**	**952**	**948**	**944**	**947**	**951**	**948**	**927**	**940**

2016	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Union-Hourly	579	577	574	567	570	572	573	570	570	575	575	575
Exempt	144	146	149	146	148	143	144	145	147	146	131	129
Non-exempt	206	202	201	207	200	201	203	201	201	200	219	219
Temporary	10	10	9	10	17	22	21	20	18	17	17	14
Total	**939**	**935**	**933**	**930**	**935**	**938**	**941**	**936**	**936**	**938**	**942**	**937**

Total employees from affliates - headcount has not been allocated

LGE - Actual Employee Headcount

2014	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Union-Hourly	709	706	717	718	720	717	718	714	711	708	711	714
Exempt	262	263	268	270	273	276	277	277	279	280	280	271
Non-exempt	37	35	38	40	40	42	41	43	43	44	44	45
Temporary	12	11	11	10	18	18	18	8	9	9	8	6
Total	**1,020**	**1,015**	**1,034**	**1,038**	**1,051**	**1,053**	**1,054**	**1,042**	**1,042**	**1,041**	**1,043**	**1,036**

2015	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Union-Hourly	718	709	719	720	718	720	693	682	680	677	682	679
Exempt	271	270	271	274	277	277	275	274	270	273	272	273
Non-exempt	45	44	45	49	50	51	51	51	51	49	49	49
Temporary	14	14	14	13	14	15	14	17	22	24	24	16
Total	**1,048**	**1,037**	**1,049**	**1,056**	**1,059**	**1,063**	**1,033**	**1,024**	**1,023**	**1,023**	**1,027**	**1,017**

2016	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Union-Hourly	677	668	677	673	683	686	687	685	683	685	692	696
Exempt	271	270	271	270	273	278	279	277	277	278	282	280
Non-exempt	51	49	50	50	48	50	50	49	48	48	47	47
Temporary	26	25	25	24	26	26	27	26	26	27	25	15
Total	**1,025**	**1,012**	**1,023**	**1,017**	**1,030**	**1,040**	**1,043**	**1,037**	**1,034**	**1,038**	**1,046**	**1,038**

Kentucky Utilities Company
Case No. 2016-00370

LG&E AND KU SERVICE CO - Actual Employee Headcount

2014	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Union-Hourly	-	-	-	-	-	-	-	-	-	-	-	-
Exempt	1,013	1,017	1,020	1,029	1,035	1,041	1,040	1,037	1,041	1,038	1,044	1,068
Non-exempt	460	462	463	454	451	452	451	448	448	458	457	454
Temporary	51	51	51	50	55	59	60	53	49	49	49	49
Total	**1,524**	**1,530**	**1,534**	**1,533**	**1,541**	**1,552**	**1,551**	**1,538**	**1,538**	**1,545**	**1,550**	**1,571**

2015	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Union-Hourly	-	-	-	-	-	-	-	-	-	-	-	-
Exempt	1,066	1,068	1,070	1,072	1,076	1,077	1,074	1,070	1,076	1,079	1,081	1,088
Non-exempt	451	463	457	462	460	455	462	460	470	469	466	465
Temporary	46	43	43	44	53	60	61	52	51	51	55	47
Total	**1,563**	**1,574**	**1,570**	**1,578**	**1,589**	**1,592**	**1,597**	**1,582**	**1,597**	**1,599**	**1,602**	**1,600**

2016	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Union-Hourly	-	-	-	-	-	-	-	-	-	-	-	-
Exempt	1,086	1,088	1,088	1,094	1,107	1,109	1,102	1,096	1,095	1,096	1,094	1,099
Non-exempt	472	478	479	463	462	472	462	490	486	494	488	485
Temporary	48	48	48	49	57	56	52	45	47	50	51	47
Total	**1,606**	**1,614**	**1,615**	**1,606**	**1,626**	**1,637**	**1,616**	**1,631**	**1,628**	**1,640**	**1,633**	**1,631**

Question 38(b)

KU - Budgeted Employee Headcount

2014	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Union-Hourly	613	613	612	618	618	618	618	618	618	609	609	608
Exempt	151	151	151	151	151	151	151	153	150	154	154	154
Non-exempt	212	212	212	215	215	215	218	218	218	209	209	209
Temporary	3	3	3	3	4	4	4	4	3	3	3	4
Total	**979**	**979**	**978**	**987**	**988**	**988**	**991**	**993**	**989**	**975**	**975**	**975**

2015	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Union-Hourly	608	608	607	606	606	606	606	606	606	606	606	606
Exempt	153	153	155	155	155	155	155	155	155	155	155	155
Non-exempt	211	211	211	212	212	212	212	212	212	212	212	212
Temporary	10	10	10	10	11	11	11	11	10	10	10	11
Total	**982**	**982**	**983**	**983**	**984**	**984**	**984**	**984**	**983**	**983**	**983**	**984**

2016	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Union-Hourly	593	593	593	593	594	594	598	598	597	597	597	597
Exempt	149	149	149	148	147	147	149	149	149	149	149	149
Non-exempt	201	201	201	202	202	202	202	202	202	202	202	202
Temporary	15	15	15	15	15	15	15	15	15	15	15	15
Total	**958**	**958**	**958**	**958**	**958**	**958**	**964**	**964**	**963**	**963**	**963**	**963**

Attachment to Response to AG-1 Question No. 38(a-b)
Page 3 of 3
Meiman

Kentucky Utilities Company
Case No. 2016-00370

Total employees from affliates - headcount has not been allocated
LGE - Budgeted Employee Headcount

2014	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Union-Hourly	741	741	746	751	754	754	752	752	751	752	752	752
Exempt	270	270	270	271	271	274	274	275	276	276	276	276
Non-exempt	54	54	54	57	57	57	57	57	57	57	57	57
Temporary	10	10	11	11	11	11	10	11	11	11	11	11
Total	**1,075**	**1,075**	**1,081**	**1,090**	**1,093**	**1,096**	**1,093**	**1,095**	**1,095**	**1,096**	**1,096**	**1,096**

2015	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Union-Hourly	736	736	743	742	727	727	726	726	726	725	724	724
Exempt	283	284	286	287	277	277	276	275	275	275	275	275
Non-exempt	45	45	49	49	48	48	48	48	48	48	48	48
Temporary	11	11	11	11	9	9	9	9	9	9	9	9
Total	**1,075**	**1,076**	**1,089**	**1,089**	**1,061**	**1,061**	**1,059**	**1,058**	**1,058**	**1,057**	**1,056**	**1,056**

2016	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Union-Hourly	697	697	704	709	709	708	707	706	706	705	711	710
Exempt	272	273	273	272	273	273	275	275	274	271	271	271
Non-exempt	54	54	54	54	54	54	54	54	54	54	54	54
Temporary	11	11	11	11	14	14	14	14	12	11	11	11
Total	**1,034**	**1,035**	**1,042**	**1,046**	**1,050**	**1,049**	**1,050**	**1,049**	**1,046**	**1,041**	**1,047**	**1,046**

LG&E AND KU SERVICE CO - Budgeted Employee Headcount

2014	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Union-Hourly	1	1	1	1	1	1	1	1	1	1	1	1
Exempt	1,044	1,044	1,043	1,042	1,042	1,042	1,047	1,047	1,051	1,052	1,052	1,052
Non-exempt	438	438	438	438	438	439	440	440	440	440	440	440
Temporary	63	63	63	63	64	64	66	66	65	65	65	65
Total	**1,546**	**1,546**	**1,545**	**1,544**	**1,545**	**1,546**	**1,554**	**1,554**	**1,557**	**1,558**	**1,558**	**1,558**

2015	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Union-Hourly	1	1	1	1	1	1	1	1	1	1	1	1
Exempt	1,082	1,082	1,085	1,085	1,087	1,087	1,092	1,092	1,091	1,091	1,091	1,091
Non-exempt	454	454	454	454	454	454	454	454	454	454	454	454
Temporary	71	71	71	71	74	74	74	74	72	71	71	71
Total	**1,608**	**1,608**	**1,611**	**1,611**	**1,616**	**1,616**	**1,621**	**1,621**	**1,618**	**1,617**	**1,617**	**1,617**

2016	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Union-Hourly	-	-	-	-	-	-	-	-	-	-	-	-
Exempt	1,110	1,111	1,116	1,121	1,122	1,123	1,123	1,123	1,123	1,127	1,127	1,126
Non-exempt	476	478	481	482	482	482	482	482	491	491	491	491
Temporary	67	67	67	65	66	66	66	66	65	64	64	64
Total	**1,653**	**1,656**	**1,664**	**1,668**	**1,670**	**1,671**	**1,671**	**1,671**	**1,679**	**1,682**	**1,682**	**1,681**

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 43

Responding Witness: Gregory J. Meiman

Q-43. Provide a detailed explanation of all variations between actual and budgeted employee counts for 2015 and 2016.

A-43. See attached.

Kentucky Utilities Company
Case No. 2016-00370

Actual vs. Budget Variance

Kentucky Utilities Company	DECEMBER 2015	DECEMBER 2016	Explanation of Variation
CHIEF EXECUTIVE OFFICER	**-**	**-**	
GENERAL COUNSEL	**-**	**-**	
HUMAN RESOURCES	**-**	**-**	
TOTAL CHIEF OPERATING OFFICER	**44**	**27**	
CHIEF OPERATING OFFICER	-	-	
ELECTRIC DISTRIBUTION	-	8	Transfers to LGE-KU Services (2) and normal attrition (6)
SAFETY AND TECHNICAL TRAINING	-	-	
GAS DISTRIBUTION	-	-	
TOTAL GENERATION	45	7	2015 - Green River Plant closure budgeted to occur in 2016; Move of 7 employees in Commercial Ops to Servco; 2016 - captured attrition at plants
GENERATION SERVICES	-	-	
PROJECT ENGINEERING	-	-	
ENERGY SUPPLY AND ANALYSIS	-	-	
TRANSMISSION	-	-	
TOTAL CUSTOMER SERVICES	(1)	12	Normal attrition primarily in business offices and fewer transfers from Green River Plant closing and were filled with contractors.
FINANCE IT AND SUPPLY CHAIN	-	**(1)**	
TOTAL INFORMATION TECHNOLOGY	(1)	-	Normal Attrition
STATE REG. AND RATES	-	-	
CONTROLLER	-	-	
AUDIT SERVICES	-	-	
TREASURER	-	(2)	
SUPPLY CHAIN	1	1	Normal Attrition
Total	**44**	**26**	

Kentucky Utilities Company
Case No. 2016-00370

Actual vs. Budget Variance

Louisville Gas and Electric Company

	DECEMBER 2015	DECEMBER 2016	Explanation of Variation
CHIEF EXECUTIVE OFFICER	-	**-**	
GENERAL COUNSEL	-	**-**	
HUMAN RESOURCES	-	**-**	
TOTAL CHIEF OPERATING OFFICER	**40**	**8**	
CHIEF OPERATING OFFICER	-	-	
ELECTRIC DISTRIBUTION	2	2	Transfers to LGE-KU Services Company
SAFETY AND TECHNICAL TRAINING	-	-	
GAS DISTRIBUTION	3	1	Normal Attrition
TOTAL GENERATION	28	(3)	Increase in retirements/separation due to Cane Run Plant closure (20); Move of 9 Commercial Ops employees to Servco
GENERATION SERVICES	1	-	Normal Attrition
PROJECT ENGINEERING	-	-	
ENERGY SUPPLY AND ANALYSIS	-	-	
TRANSMISSION	-	-	
TOTAL CUSTOMER SERVICES	6	8	Normal attrition primarily in the business offices which are offset with contractors
FINANCE IT AND SUPPLY CHAIN	**(1)**	**-**	
TOTAL INFORMATION TECHNOLOGY	(1)	-	Normal Attrition
STATE REG. AND RATES	-	-	
CONTROLLER	-	-	
AUDIT SERVICES	-	-	
TREASURER	-	-	
SUPPLY CHAIN	-	-	
Total	**39**	**8**	

Kentucky Utilities Company
Case No. 2016-00370

Actual vs. Budget Variance

LG&E and KU Services Company

	DECEMBER 2015	DECEMBER 2016	Explanation of Variation
CHIEF EXECUTIVE OFFICER	2	**-**	Elimination of Chief Admininstrative Officer and Adm. Assistant
GENERAL COUNSEL	1	**5**	Normal attrition in Compliance (1), Legal(2), Federal Reg (1) and Environmental (1). Two of these are interns
HUMAN RESOURCES	2	**8**	Increased level of attrition in the fourth quarter of 2016
TOTAL CHIEF OPERATING OFFICER	**(8)**	**5**	
CHIEF OPERATING OFFICER	-	1	Normal Attrition
ELECTRIC DISTRIBUTION	(1)	(6)	Transfers from LGE and KU
SAFETY AND TECHNICAL TRAINING	-	-	
GAS DISTRIBUTION	-	-	
TOTAL GENERATION	(18)	(3)	Move of 16 Commercial Ops employees from utilities to Servco
GENERATION SERVICES	4	10	Timing on hiring of interns (5); delay in hiring (3); re-evaluation of positions (2)
PROJECT ENGINEERING	(1)	1	Normal Attrition
ENERGY SUPPLY AND ANALYSIS	-	2	Normal Attrition
TRANSMISSION	4	-	Normal Attrition
TOTAL CUSTOMER SERVICES	4	-	Normal Attrition
FINANCE IT AND SUPPLY CHAIN	**20**	**32**	
TOTAL INFORMATION TECHNOLOGY	18	28	Employee transferred to other departments, consolidation of IT Infrastructure organization and the use of contractors instead of employees.
STATE REG. AND RATES	1	-	
CONTROLLER	2	5	Normal attrition in Financial Reporting(1), Property Accounting (1), Regulatory Accounting (2), Revenue Accounting (2), and Corporate Accounting (-1)
AUDIT SERVICES	1	-	Normal Attrition
TREASURER	1	3	Normal Attrition
SUPPLY CHAIN	(3)	(4)	For 2015, there were retirements on Jan 1, 2016 and backfills were already hired. For 2016, reorganization and move contract administrators from IT.
Total	**17**	**50**	

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 67

Responding Witness: Gregory J. Meiman

Q-67. Provide the following for each employee position during 2015 and 2016 that experienced a change of incumbent:

a. Position title;

b. Employee replaced;

c. Annual salary of replaced employee;

d. Replacement employee;

e. Annual salary of replacement employee; and

f. Date of replacement

A-67. a – f. See attached. Certain information requested is confidential and is being provided under seal pursuant to a petition for confidential protection.

CONFIDENTIAL INFORMATION REDACTED

Position Title/Employee Replaced	Annual Salary of Replaced Employee	Replacement Employee/Title	Annual Salary of Replacement Employee	Date of Replacement
Customer Representative I	[redacted]	Customer Representative I	[redacted]	8/29/2016
Line Technician A		Trainee B		4/27/2015
Trainee B		Line Technician A		11/30/2015
Line Technician A		Line Technician B		7/18/2016
Customer Representative I		Customer Representative I		7/20/2015
Mgr Maint - Pwr Gen		Mgr Maint - Pwr Gen		11/1/2015
Manager - Production		Manager - Production		11/1/2015
Mgr Operations Center		Mgr Operations Center		12/27/2015
Supervisor - Maintenance		Supervisor - Maintenance		8/31/2015
Team Ldr -Line Const & Maint		Team Ldr -Line Const & Maint		3/20/2016
Area Retail Operations Mgr		Area Retail Operations Mgr		8/1/2016
Grp Ldr - SC&M		Grp Ldr - SC&M		8/21/2016
Team Ldr Subst Constr & Main		Team Ldr Substation Maint		10/30/2016
P.P. Shift Supervisor		P.P. Shift Supervisor		1/25/2016
P.P. Shift Supervisor		P.P. Shift Supervisor		5/17/2015
P.P. Shift Supervisor		P.P. Shift Supervisor		7/24/2016
P.P. Shift Supervisor		P.P. Shift Supervisor		5/4/2015
Line Or Service Supervisor A		Line Or Service Supervisor A		10/17/2016
Substation Technician B		Substation Tech Trainee		10/31/2016
Maintenance Planner		Maintenance Planner		2/21/2016
Line Or Service Supervisor A		Line Or Service Supervisor A		8/21/2016
Line Or Service Supervisor A		Line Or Service Supervisor A		5/17/2015
Substation Supervisor A		Substation Supervisor A		1/24/2016
Line Or Service Supervisor B		Line Technician B		11/15/2015
Grp Ldr - Engineering		Grp Ldr - Engineering		12/28/2015
Sr Electrical Engineer		Electrical Engineer I		5/18/2015
Sr Chemist		Laboratory Supervisor		10/18/2015
Team Ldr -Line Const & Maint		Team Ldr -Line Const & Maint		5/15/2016
Sr Budget Analyst		Sr Budget Analyst		10/4/2015
Team Ldr -Line Const & Maint		Team Ldr -Line Const & Maint		3/20/2016
Maintenance Planner		Maintenance Planner		2/21/2016
Electrical Engineer I		Electrical Engineer I		12/25/2016
Sr Electrical Engineer		Engineering Assistant		3/21/2016
Telecom Technician Senior		Telecom Technician Intermediat		3/29/2015
Chief Mechanic		Chief Mechanic		1/10/2016
Chief Mechanic		Chief Mechanic		4/17/2016
Chief Mechanic		Chief Mechanic		3/6/2016
Eng Design Tech Sr - Dist Ops		Eng Design Tech Begin-Dist Ops		7/24/2016
Lead Mechanic		Maintenance Technician C (M)		6/20/2016
Unit Operator		Trainee A (Operations)		8/10/2015
Unit Operator		Trainee A (Operations)		10/31/2016
Unit Operator		Trainee A		11/28/2016
Unit Operator		Trainee A (Operations)		4/27/2015
Unit Operator		Trainee A (Operations)		10/31/2016
Unit Operator		Auxiliary Operator		5/31/2015

CONFIDENTIAL INFORMATION REDACTED

Position Title/Employee Replaced	Annual Salary of Replaced Employee	Replacement Employee/Title	Annual Salary of Replacement Employee	Date of Replacement
Customer Representative I	[redacted]	Customer Representative I	[redacted]	12/21/2015
Customer Representative I	[redacted]	Customer Representative I	[redacted]	8/8/2016
Trainee A (Operations)	[redacted]	Trainee A (Operations)	[redacted]	9/1/2015
Service Technician A	[redacted]	Service Technician A	[redacted]	10/2/2015
Service Technician A	[redacted]	Service Technician A	[redacted]	9/18/2016
Service Technician A	[redacted]	Line Technician A	[redacted]	8/23/2015
Substation Supervisor B	[redacted]	Substation Technician A	[redacted]	11/1/2015
Line Technician A	[redacted]	Line Technician B	[redacted]	5/4/2015
Line Technician A	[redacted]	Line Technician B	[redacted]	5/4/2015
Line Technician A	[redacted]	Line Technician B	[redacted]	7/5/2016
Line Technician A	[redacted]	Line Technician A	[redacted]	10/30/2016
Maintenance Technician A (M)	[redacted]	Maintenance Technician C (M)	[redacted]	9/28/2015
Maintenance Technician B (M)	[redacted]	Maintenance Technician C (M)	[redacted]	12/21/2015
Service Technician A	[redacted]	Service Technician A	[redacted]	7/4/2016
Maintenance Technician A (I)	[redacted]	Maintenance Technician C (I)	[redacted]	3/21/2016
Line Technician A	[redacted]	Line Technician B	[redacted]	11/27/2016
Maintenance Technician C (M)	[redacted]	Maintenance Technician C (M)	[redacted]	3/31/2016
Substation Technician B	[redacted]	Substation Tech Trainee	[redacted]	7/11/2016
Line Technician A	[redacted]	Line Technician B	[redacted]	12/28/2015
Line Technician B	[redacted]	Line Technician B	[redacted]	6/6/2016
Line Technician A	[redacted]	Line Technician A	[redacted]	2/16/2015
Line Technician B	[redacted]	Line Technician A	[redacted]	4/3/2016
Line Or Service Supervisor B	[redacted]	Line Or Service Supervisor B	[redacted]	8/9/2015
Line Technician A	[redacted]	Line Technician B	[redacted]	8/8/2016
Line Technician B	[redacted]	Line Technician A	[redacted]	6/28/2015
Line Technician A	[redacted]	Line Technician B	[redacted]	10/17/2016
Substation Technician A	[redacted]	Substation Tech Trainee A	[redacted]	10/24/2016
Substation Technician A	[redacted]	Substation Technician B	[redacted]	8/9/2015
Line Technician A	[redacted]	Line Technician B	[redacted]	10/30/2016
Service Technician A	[redacted]	Service Technician A	[redacted]	5/29/2016
Service Technician A	[redacted]	Service Technician A	[redacted]	5/31/2015
Service Technician A	[redacted]	Service Technician A	[redacted]	7/12/2015
Service Technician A	[redacted]	Service Technician A	[redacted]	2/7/2016
Line Technician B	[redacted]	Line Technician B	[redacted]	2/22/2016
Line Technician B	[redacted]	Line Technician B	[redacted]	8/22/2016
Line Technician A	[redacted]	Line Technician A	[redacted]	3/1/2015
Line Technician A	[redacted]	Line Technician A	[redacted]	4/3/2016
Line Technician A	[redacted]	Line Technician A	[redacted]	6/29/2015
Substation Technician B	[redacted]	Substation Tech Trainee A	[redacted]	12/28/2015
Coal Yard Supervisor	[redacted]	Coal Yard Supervisor	[redacted]	2/22/2015
Coal Yard Supervisor	[redacted]	Coal Yard Supervisor	[redacted]	4/4/2016
Sr Mechanical Engineer	[redacted]	Sr Mechanical Engineer	[redacted]	9/21/2015
Customer Representative I	[redacted]	Customer Representative I	[redacted]	6/27/2016
Eng Design Tech Sr - Dist Ops	[redacted]	Eng Design Tech Begin-Dist Ops	[redacted]	11/27/2016
Lead Electrician (I)	[redacted]	Lead Electrician (I)	[redacted]	11/1/2015
Auxiliary Operator	[redacted]	Trainee A	[redacted]	4/27/2015
Customer Representative I	[redacted]	Customer Representative I	[redacted]	8/29/2016
Auxiliary Operator	[redacted]	Trainee A (Operations)	[redacted]	4/20/2016

CONFIDENTIAL INFORMATION REDACTED

Position Title/Employee Replaced	Annual Salary of Replaced Employee	Replacement Employee/Title	Annual Salary of Replacement Employee	Date of Replacement
Auxiliary Operator	[redacted]	Trainee A (Operations)	[redacted]	5/9/2016
Unit Operator		Trainee A (Operations)		5/9/2016
Eng Design Tech Begin-Dist Ops		Eng Design Tech Begin-Dist Ops		5/23/2016
Line Technician A		Line Technician A		4/3/2016
Line Technician A		Line Technician A		4/3/2016
Line Technician A		Line Technician B		9/6/2016
Line Technician A		Line Technician A		4/3/2016
Line Technician A		Line Technician B		11/16/2015
Line Technician B		Line Technician B		7/10/2016
Order Specialist		Order Specialist		8/31/2015
Customer Order Technician		Customer Order Technician		6/1/2016
Order Specialist		Order Specialist		8/24/2015
Line Technician A		Line Technician C		6/28/2015
Line Or Service Supervisor B		Line Or Service Supervisor B		2/21/2016
Line Technician A		Line Technician B		2/22/2016
Line Technician B		Line Technician A		7/24/2016
Customer Order Technician		Customer Order Technician		5/1/2016
Substation Technician A		Substation Technician A		12/27/2016
Customer Order Technician		Customer Order Technician		6/1/2015
Line Technician A		Line Technician B		4/22/2016
Line Technician A		Line Technician A		7/26/2015
Customer Order Technician		Customer Order Technician		6/26/2016
Line Technician A		Line Technician A		5/1/2016
Storeroom Specialist		Storeroom Specialist		10/26/2015
Storeroom Specialist		Storeroom Specialist		10/17/2016
Sr Customer Representative		Customer Representative I		9/12/2016
Line Technician B		Line Technician C		4/27/2015
Line Technician C		Line Technician B		7/18/2016
Sr Distribution Ops Assistant		Distribution Ops Assistant		7/24/2016
Sr Customer Representative		Sr Customer Representative		2/1/2016
Sr Customer Representative		Customer Representative I		10/31/2016
Telecom Technician Intermediat		Telecom Technician Associate		5/18/2015
Sr Clerk		Electric Meter Associate		10/10/2016
Line Technician A		Line Technician A		2/9/2015
Sr Customer Representative		Sr Customer Representative		4/18/2016
Customer Representative I		Customer Representative I		12/7/2015
Sr Customer Representative		Customer Representative I		2/15/2016
Sr Customer Representative		Sr Customer Representative		8/1/2015
Facility Records Tech II		Facility Records Tech I		7/25/2016
Sr Customer Representative		Customer Representative I		11/14/2016
Sr Customer Representative		Sr Customer Representative		4/18/2016
Sr Customer Representative		Sr Customer Representative		10/17/2016
Sr Customer Representative		Customer Representative I		8/10/2015
Customer Representative I		Sr Customer Representative		10/17/2016
Customer Representative II		Customer Representative I		10/17/2016
Customer Representative I		Customer Representative I		11/14/2016
Sr Customer Representative		Customer Representative I		4/11/2016
Sr Distribution Ops Assistant		Sr Distribution Ops Assistant		1/1/2016

Position Title/Employee Replaced	Annual Salary of Replaced Employee	Replacement Employee/Title	Annual Salary of Replacement Employee	Date of Replacement
Sr Customer Representative	[redacted]	Customer Representative I	[redacted]	4/25/2016
Customer Representative I		Customer Representative I		10/30/2016
Customer Representative I		Customer Representative I		8/17/2015
Customer Representative II		Customer Representative I		9/19/2016
Substation Tech Trainee A		Substation Tech Trainee A		12/21/2015
Line Technician A		Line Technician B		7/10/2016
Line Technician A		Line Technician B		3/1/2015
Sr Budget Analyst		Budget Analyst II		11/7/2016
Line Technician C		Line Technician A		11/9/2015
Line Technician A		Line Technician A		5/1/2016
Maintenance Technician A (E)		Maintenance Technician A (I)		2/1/2016
Lead Mechanic		Maintenance Technician C (M)		6/20/2016
Line Technician A		Line Technician A		10/30/2016
Line Technician A		Line Technician B		3/6/2016
Line Technician A		Line Technician C		9/6/2015
Line Technician C		Line Technician C		10/10/2016
Buyer II		Buyer I		9/19/2016
Customer Representative II		Customer Representative I		9/12/2016
Civil Engineer III		Engineer II		4/11/2016
Inspector - Substation		Inspector - Substation		12/27/2015
Inspector - Substation		Inspector - Substation		9/18/2016
Maintenance Planner		Maintenance Planner		11/29/2015
Maintenance Technician A (M)		Maintenance Technician C (M)		9/28/2015
Trainee A (M)		Trainee A (M)		6/20/2016
Substation Technician B		Substation Tech Trainee A		11/2/2015
Unit Operator		Trainee A (Operations)		1/25/2016
Trainee A (Operations)		Trainee A (Operations)		3/14/2016
Maintenance Technician A (M)		Trainee A		5/31/2016
Customer Representative I		Customer Representative I		7/6/2015
Chemical Engineer III		Chemical Engineer I		3/28/2016
Grp Ldr - Engineering		Mgr Engineering&Technical Srvc		11/1/2015
Line Technician A		Line Technician A		5/8/2016
Substation Technician A		Substation Technician A		2/22/2015
Customer Order Technician		Customer Order Technician		8/10/2015
Customer Representative I		Customer Representative I		7/13/2015
Line Or Service Supervisor B		Line Or Service Supervisor B		2/7/2016
Facility Records Tech I		Facility Records Tech I		7/25/2016
Supervisor - Maintenance		Supervisor - Maintenance		3/6/2016
Customer Representative I		Customer Representative I		2/29/2016
Line Technician C		Trainee B		6/28/2015
Meter Reader		Meter Reader		8/15/2016
Maintenance Technician A (I)		Maintenance Technician B (E)		3/21/2016
Team Ldr -Line Const & Maint		Team Ldr -Line Const & Maint		2/8/2015
Substation Technician A		Substation Technician A		8/21/2016
Substation Technician A		Substation Technician A		11/14/2016
Unit Operator		Trainee A (Operations)		5/9/2016
Supervisor - Production		Supervisor - Production		12/14/2015
P.P. Shift Supervisor		P.P. Shift Supervisor		5/4/2015

Position Title/Employee Replaced	Annual Salary of Replaced Employee	Replacement Employee/Title	Annual Salary of Replacement Employee	Date of Replacement
Unit Operator Assistant	[redacted]	Trainee A (Operations)	[redacted]	5/9/2016
Customer Representative I	[redacted]	Customer Representative I	[redacted]	6/6/2016
Maintenance Technician C (E)	[redacted]	Trainee A (M)	[redacted]	12/21/2015
Auxiliary Operator	[redacted]	Unit Operator Assistant	[redacted]	5/31/2015
Auxiliary Operator	[redacted]	Unit Operator Assistant	[redacted]	5/31/2015
Control Specialist	[redacted]	Trainee A	[redacted]	5/16/2016
Auxiliary Operator	[redacted]	Trainee A (Operations)	[redacted]	8/10/2015
Maintenance Technician C (M)	[redacted]	Maintenance Technician C (M)	[redacted]	9/28/2015
Maintenance Technician C (M)	[redacted]	Maintenance Technician C (M)	[redacted]	6/20/2016

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to the Attorney General's Supplemental Data Requests
Dated February 7, 2017

Question No. 8

Responding Witness: Kent W. Blake

Q-8. Refer to the response to AG-1-49.

a. Does the Company's claimed revenue requirement include Labor Cost for authorized but unfilled positions?

b. Is the $.224 million amount for KU's four vacant positions for payroll costs only? If not, show a detailed breakout between payroll and benefit costs, showing the amount for each type of benefit.

c. Is the $5.7 million amount for LG&E and KU Services Company's 34 vacant positions for payroll costs only? If not, show a detailed breakout between payroll and benefit costs, showing the amount for each type of benefit.

d. Show in detail how much LG&E and KU Services Company Labor Cost was included in the claimed revenue requirement for the KU electric utility.

e. If possible, show the amounts identified in the response to part (d) by account.

A-8.

a. Yes, the Company's filed forecast test period includes authorized positions for the twelve month period ended June 30, 2018. This differs from the positions filled as of December 31, 2016. The number of positions provided in response to AG 1-49 represent the difference between the number of employees for the respective companies as of December 31, 2016, and those projected as of June 30, 2018.

b. No. See attached. In preparing this response, the Company noted an average salary across all departments was used rather than using the average salary for departments where the positions filled as of December 31, 2016 were lower than those projected as of June 30, 2018. This raised the amount shown in question 8(a) above, from $0.224 million to $0.409 million.

c. No. See attached. In preparing this response, the Company noted an average salary across all departments was used rather than using the average salary for departments where the positions filled as of December 31, 2016 were lower than those projected as of June 30, 2018. This lowered the amount shown in question 8(c) above, from \$5.7 million to \$4.7 million.

d. As noted above, in responding to AG 1-49, the Companies provided the difference in actual headcount as of December 31, 2016, and that projected as of June 30, 2018, the end of the forecast test period. The estimated dollar amounts in Question No. 8(b) and 8(c) above were developed based on average pay rates by department multiplied by this difference in headcount with applicable benefit burden adders applied, as noted above. This represented total dollar costs as noted in the Company's response to AG 1-49. Using the average expense percentage for departments with such headcount differences, the dollar figures charged to expense above would be \$0.260 million for Question No. 8(b) and \$3.7 million for Question No. 8(c). Using the average company allocation for each department in Question No. 8(c), an estimated \$2.0 million would be applied to KU.

e. It is not possible to show the amounts identified in the response to part (d) by account, due to the manner in which the budget is prepared.

Kentucky Utilities Company
Case No. 2016-00370

Comparing Actual Headcount at December 31, 2016 to Budgeted Headcount at June 30, 2018

	Kentucky Utilities
Number of Vacant Positions	**4**
Salary	**280,561**
Team Incentive Award	**25,250**
401(k) Match	11,784
Retirement Income	8,417
Group Life Insurance	1,367
LTD	1,473
Post Retirement Benefits	7,738
Post Employment Benefits	-
Workers Compensation	2,426
Dental	2,213
Medical	44,388
Other Misc	1,200
Payroll Taxes	22,175
Total Benefits and Taxes	**103,181**
Total	**408,992**

Kentucky Utilities Company
Case No. 2016-00370

Comparing Actual Headcount at December 31, 2016 to Budgeted Headcount at June 30, 2018

	LG&E and KU Services Company
Number of Vacant Positions	**34**
Salary	**3,348,176**
Team Incentive Award	**301,336**
401(k) Match	140,623
Retirement Income	100,445
Group Life Insurance	16,312
LTD	17,578
Post Retirement Benefits	59,806
Post Employment Benefits	19,075
Workers Compensation	2,579
Dental	18,809
Medical	377,298
Other Misc	10,200
Payroll Taxes	262,187
Total Benefits and Taxes	**1,024,912**
Total	**4,674,424**

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's First Request for Information
Dated November 10, 2016

Case No. 2016-00370

Question No. 33

Responding Witness: Gregory J. Meiman

Q-33. List separately the budgeted and actual numbers of full- and part-time employees by employee group, by month and by year, for the three most recent calendar years, the base period, and the forecasted test period.

A-33. See attached. LKS employees serve LG&E, KU and other subsidiaries of LKE. The number of LKS employees is not allocated; however, labor dollars are allocated in accordance with the Cost Allocation Manual, filed with the Filing Requirements in Tab 51.

Kentucky Utilities Company
Case No. 2016-00370
Question No. 33
Kentucky Utilities Headcount by Employee Type by Month - Budget

2013	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Union-Hourly	599	600	600	600	600	600	611	610	610	610	611	611
Exempt	143	144	144	144	144	144	144	144	144	144	144	144
Non-exempt	214	214	214	214	214	214	216	216	216	216	216	216
Part-time other	4	4	4	4	5	5	5	5	4	4	4	4
Total	960	962	962	962	963	963	976	975	974	974	975	975

2014	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Union-Hourly	613	613	612	618	618	618	618	618	618	609	609	608
Exempt	151	151	151	151	151	151	151	153	150	154	154	154
Non-exempt	212	212	212	215	215	215	218	218	218	209	209	209
Part-time other	3	3	3	3	4	4	4	4	3	3	3	4
Total	979	979	978	987	988	988	991	993	989	975	975	975

2015	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Union-Hourly	608	608	607	606	606	606	606	606	606	606	606	606
Exempt	153	153	155	155	155	155	155	155	155	155	155	155
Non-exempt	211	211	211	212	212	212	212	212	212	212	212	212
Part-time other	10	10	10	10	11	11	11	11	10	10	10	11
Total	982	982	983	983	984	984	984	984	983	983	983	984

Base Year: Mar 2016-Feb 2017	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**
Union-Hourly	593	593	594	594	598	598	597	597	597	597	584	584
Exempt	149	148	147	147	149	149	149	149	149	149	153	153
Non-exempt	201	202	202	202	202	202	202	202	202	202	205	205
Part-time other	15	15	15	15	15	15	15	15	15	15	11	11
Total	958	958	958	958	964	964	963	963	963	963	953	953

Forecast Test Year: Jul 2017-Jun 2018	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**
Union-Hourly	583	583	583	583	583	582	578	578	578	577	577	577
Exempt	150	149	149	149	149	149	147	147	147	147	147	147
Non-exempt	205	205	205	205	205	205	203	203	203	203	203	203
Part-time other	12	11	11	11	11	11	9	9	9	9	10	10
Total	950	948	948	948	948	947	937	937	937	936	937	937

LG&E and KU Services Employees serve LGE, KU and other subsidiaries of LKE. Number of LG&E and KU Services Employees is not allocated; however, labor dollars are allocated in accordance with the Cost Allocation Manual.

Kentucky Utilities Company
Case No. 2016-00370
Question No. 33
Kentucky Utilities Headcount by Employee Type by Month - Actuals

2013	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Union-Hourly	594	588	589	594	595	599	601	606	604	602	600	599
Exempt	141	142	142	142	143	142	143	142	141	143	145	147
Non-exempt	204	208	210	209	208	206	207	207	198	198	197	198
Part-time other	3	2	2	2	5	6	6	3	3	3	3	3
Total	942	940	943	947	951	953	957	958	946	946	945	947

2014	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Union-Hourly	600	600	598	600	599	603	606	598	596	596	595	599
Exempt	148	150	149	149	149	148	149	149	149	148	148	143
Non-exempt	201	202	203	203	204	202	201	207	205	208	208	207
Part-time other	4	4	5	5	7	11	12	10	9	7	8	8
Total	953	956	955	957	959	964	968	964	959	959	959	957

2015	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Union-Hourly	598	597	593	595	589	583	579	585	587	584	572	580
Exempt	141	139	141	141	141	141	140	141	143	142	142	145
Non-exempt	209	209	208	205	208	206	207	208	208	209	200	201
Part-time other	8	8	9	9	14	18	18	13	13	13	13	14
Total	956	953	951	950	952	948	944	947	951	948	927	940

Base Year: Mar 2016-Feb 2017	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb
Union-Hourly	574	567	570	572	573	570	570	575				
Exempt	148	145	147	142	143	144	146	145				
Non-exempt	197	203	197	198	200	197	197	196				
Part-time other	14	15	21	26	25	25	23	22				
Total	933	930	935	938	941	936	936	938	-	-	-	-

Forecast Test Year: Jul 2017-Jun 2018	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
Union-Hourly												
Exempt												
Non-exempt												
Part-time other												
Total	-	-	-	-	-	-	-	-	-	-	-	-

Kentucky Utilities Company
Case No. 2016-00370
Question No. 33
LGE - KU Services Company Headcount by Employee Type by Month - Budget

2013	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Union-Hourly	-	-	-	-	-	-	-	-	-	-	-	-
Exempt	996	998	1,000	1,001	1,001	1,003	1,007	1,007	1,009	1,009	1,009	1,010
Non-exempt	421	421	422	422	422	422	425	425	425	425	425	425
Part-time other	64	64	64	64	65	65	65	65	63	63	63	63
Total	1,481	1,483	1,486	1,487	1,488	1,490	1,497	1,497	1,497	1,497	1,497	1,498

2014	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Union-Hourly	1	1	1	1	1	1	1	1	1	1	1	1
Exempt	1,044	1,044	1,043	1,042	1,042	1,042	1,047	1,047	1,051	1,052	1,052	1,052
Non-exempt	438	438	438	438	438	439	440	440	440	440	440	440
Part-time other	63	63	63	63	64	64	66	66	65	65	65	65
Total	1,546	1,546	1,545	1,544	1,545	1,546	1,554	1,554	1,557	1,558	1,558	1,558

2015	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Union-Hourly	1	1	1	1	1	1	1	1	1	1	1	1
Exempt	1,082	1,082	1,085	1,085	1,087	1,087	1,092	1,092	1,091	1,091	1,091	1,091
Non-exempt	454	454	454	454	454	454	454	454	454	454	454	454
Part-time other	71	71	71	71	74	74	74	74	72	71	71	71
Total	1,608	1,608	1,611	1,611	1,616	1,616	1,621	1,621	1,618	1,617	1,617	1,617

Base Year: Mar 2016-Feb 2017	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb
Union-Hourly	-	-	-	-	-	-	-	-	-	-	-	-
Exempt	1,116	1,121	1,122	1,123	1,123	1,123	1,123	1,127	1,127	1,126	1,150	1,150
Non-exempt	481	482	482	482	482	482	491	491	491	491	476	476
Part-time other	67	65	66	66	66	66	65	64	64	64	65	65
Total	1,664	1,668	1,670	1,671	1,671	1,671	1,679	1,682	1,682	1,681	1,691	1,691

Forecast Test Year: Jul 2017-Jun 2018	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
Union-Hourly	-	-	-	-	-	-	-	-	-	-	-	-
Exempt	1,160	1,160	1,155	1,152	1,149	1,143	1,144	1,144	1,144	1,144	1,144	1,144
Non-exempt	480	480	480	480	479	479	481	480	479	478	477	476
Part-time other	67	66	66	65	65	65	64	64	64	64	66	66
Total	1,707	1,706	1,701	1,697	1,693	1,687	1,689	1,688	1,687	1,686	1,687	1,686

Kentucky Utilities Company
Case No. 2016-00370
Question No. 33
LGE - KU Services Company Headcount by Employee Type by Month - Actuals

2013	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Union-Hourly	-	-	-	-	-	-	-	-	-	-	-	-
Exempt	954	952	960	962	977	976	979	981	987	992	993	1,000
Non-exempt	384	397	393	389	384	386	385	394	422	439	436	434
Part-time other	68	71	67	68	81	79	78	76	77	76	78	78
Total	1,406	1,420	1,420	1,419	1,442	1,441	1,442	1,451	1,486	1,507	1,507	1,512

2014	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Union-Hourly	-	-	-	-	-	-	-	-	-	-	-	-
Exempt	1,003	1,006	1,009	1,019	1,026	1,033	1,032	1,029	1,033	1,030	1,036	1,060
Non-exempt	448	450	451	442	439	438	439	436	436	446	445	444
Part-time other	73	74	74	72	76	81	80	73	69	69	69	67
Total	1,524	1,530	1,534	1,533	1,541	1,552	1,551	1,538	1,538	1,545	1,550	1,571

2015	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Union-Hourly	-	-	-	-	-	-	-	-	-	-	-	-
Exempt	1,056	1,058	1,060	1,062	1,066	1,068	1,065	1,061	1,068	1,071	1,073	1,080
Non-exempt	441	453	447	452	450	445	454	451	462	461	459	458
Part-time other	66	63	63	64	73	79	78	70	67	67	70	62
Total	1,563	1,574	1,570	1,578	1,589	1,592	1,597	1,582	1,597	1,599	1,602	1,600

Base Year: Mar 2016-Feb 2017	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb
Union-Hourly	-	-	-	-	-	-	-	-				
Exempt	1,080	1,086	1,099	1,101	1,094	1,089	1,088	1,089				
Non-exempt	470	454	451	460	451	479	475	482				
Part-time other	65	66	76	76	71	63	65	69				
Total	1,615	1,606	1,626	1,637	1,616	1,631	1,628	1,640	-	-	-	-

Forecast Test Year: Jul 2017-Jun 2018	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
Union-Hourly												
Exempt												
Non-exempt												
Part-time other												
Total	-	-	-	-	-	-	-	-	-	-	-	-

EXHIBIT RCS-11

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

**Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017**

Question No. 51

Responding Witness: Kent W. Blake

Q-51. How many service companies exist in the overall PPL organization, which functions are performed by each affiliated service company, and why are there different service companies serving the utility operations in Kentucky and Pennsylvania?

a. Are there any plans to consolidate the affiliated service companies? If not, explain fully why not. If so, explain.

b. Provide copies of any and all studies that may have been performed regarding the feasibility and/or cost effectiveness of merging the affiliated service companies.

A-51. There are three service companies within the PPL Corporation system. LG&E and KU Services Company is a subsidiary of LKE that provides services to LG&E and KU Energy LLC, and its subsidiaries, including LG&E and KU. PPL EU Services Corporation is a subsidiary of PPL Corporation that provides support services and corporate functions such as financial, supply chain, human resources and facilities management services primarily to PPL Electric and its affiliates. PPL Services Corporation is a subsidiary of PPL that provides administrative, management and support services to PPL and its subsidiaries.

The Kentucky Commission approved PPL Corporation's acquisition of the ownership and control of KU and LG&E in the final order of May 28, 2010. LKS and PPL Services were in place prior to that acquisition. In its approval of the acquisition, the Commission specifically did not require a study of savings to be achieved through the consolidation of the respective service companies of PPL Corporation and LG&E and KU Energy LLC. Instead the Commission continued to require commitments, as it had required in prior change of control cases involving LG&E and KU that balanced customer interests and service with potential savings through the exchange of best practices between the Kentucky and Pennsylvania utility operations. A key commitment to the approval by the Commission and the acceptance of the commitments by the parties was to maintain the headquarters of LG&E and KU Energy LLC in downtown Louisville, Kentucky. That headquarters contains the employees who perform the typical functions of a corporate headquarters and are employed by LG&E and KU Service Company, which is used for compliance with federal affiliate transaction regulations. These and the other commitments are designed to ensure the continued operation of LG&E and KU on the same stand-alone basis and were essential to the Commission's approval of the PPL Corporation acquisition as being in the public interest.

a. No. PPL Corporation operates largely on a decentralized business model with services provided locally near the operations of each of its utility businesses. However, where it has been deemed cost effective, like in the areas of cybersecurity and infrastructure and operations within information technology, efforts have been made to jointly provide specific functions across the domestic operations of PPL.

b. No such studies regarding the feasibility and/or cost effectiveness of merging the affiliated service companies have been performed by LG&E or KU.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to the Attorney General's Supplemental Data Requests
Dated February 7, 2017

Question No. 11

Responding Witness: Daniel K. Arbough

Q-11. Refer to the response to AG-1-50(d). Provide an itemization showing what is included in the forecasted PPL Services Corporation charges to KU for each account:

a. account 920

b. account 921

c. account 926

A-11. See table below for a-c.

Account 920	
IT Joint Initiatives	**139,317**
Account 921	
Audit - PCAOB Fees	37,118
Office of Compliance	58,208
Credit Services	7,891
Financial Statement Reporting Software	3,514
Hyperion Financial Management Software	9,676
Insurance Services	77,465
Internal Reporting	172,549
Investor Relations	210,283
IT Joint Initiatives	78,947
Office of General Counsel	470,722
Pension/Investments	251,821
UI Planner Software	10,486
Wall Street Software	37,440
	1,426,120
Account 926	
IT Joint Initiatives	**100,896**

EXHIBIT RCS-13

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 7, 2017

Question No. 8

Responding Witness: Valerie L. Scott / Daniel K. Arbough

Q.2-8. Refer to the response to KIUC 1-27.

a. Provide the attachment to KIUC 2-17 in an Excel spreadsheet in live format and with formulas intact.

b. Provide revised schedules for the base year and test year in the same format used for calendar years 2012 through 2016, separately showing the annual activity (deferrals) and the amortization expense.

c. Provide the calculation of the activity and amortization expense for all regulatory assets by month in 2016, 2017, and 2018. Provide all electronic spreadsheets in live format with all formulas intact and a copy of all source documents relied on for the data or assumptions reflected in the calculations.

d. Provide the calculation of the annual activity and amortization expense for all regulatory assets in the base year and test year that are reflected in the Company's filing. Provide all electronic spreadsheets in live format with all formulas intact and a copy of all source documents relied on for the data or assumptions reflected in the calculations.

e. Provide a description of the forward starting swap losses regulatory asset and the basis for the amortization period.

f. Provide a citation to the Orders in the proceedings cited for Commission approval of recovery and the amortization period for the forward starting swap losses.

A.2-8.

a. See attachment being provided in Excel format.

b. See the response to part d.

c. See attachment being provided in Excel format.

d. See attachment being provided in Excel format

e. By Order in Case No. 2014-00082 on June 16, 2014, KU was authorized by the KPSC to issue First Mortgage Bonds in aggregate principal amount of up to $500 million and enter into hedging agreements (forward starting swaps) to lock in interest rates for debt to be issued in 2015. KU entered into hedging agreements totaling $250 million for the 10 year bond and $250 million for the 30 year bond. Debt was issued in September 2015, totaling $250 million in 10 year First Mortgage Bonds and $250 million in 30 year First Mortgage Bonds. The forward starting swaps were settled at a loss of $14,076,899 related to the $250 million, 10 year First Mortgage Bonds and $29,611,403 related to the $250 million, 30 year First Mortgage Bonds. The Report of Action, dated 10/16/2015 filed with the KPSC, indicated that the losses on the forward starting swaps settlement would be amortized over the life of the associated bonds (10 and 30 years). These regulatory assets were also described in the 2014 rate case (Case No. 2014-00371).

   The losses on the settlement of the forward starting swaps are treated consistent with the regulatory liability which represents the gains on the settlement of forward starting swaps settled in 2013. By Order in Case No. 2012-00232, KU was authorized by the KPSC to enter into hedging agreements to lock in interest rates for debt that was issued in November 2013. In October 2012, KU entered into $150 million of forward-starting swaps and in April 2013, KU added an additional $100 million of forward-starting swaps. The initial swaps expired in September and KU received a payment of $49,325,370.50, and KU entered into additional $250 million of forward-starting swaps, effectively extending the start date of the prior hedges from September 2013 to December 2013. New debt totaling $250 million was issued in November 2013 and the hedges issued in September were terminated at the same time at a cost of $6,297,402.74. The Report of Action, dated 12/13/2013 filed with the KPSC, indicated that the net gain on the forward starting swaps settlements totaling $43,027,967.76 would be amortized over the 30 year life of the associated bonds. As such, the gains on the settlement of these forward starting swaps were recognized as regulatory liabilities in FERC account 254 and are being amortized over the life of the associated bonds. These regulatory liabilities were also described in the 2012 rate case (Case No. 2012-00221) and 2014 rate case (Case No. 2014-00371). Amortization of the gains is booked as a reduction to interest expense and was included in the test period in Case No. 2014-00371 and is included in the test period in this case.

f. See the response to part e.

KENTUCKY UTILITIES COMPANYCase No. 2016-00370Schedule of Regulatory Assets

Description	Base Period Beginning Balance	Base Period Activity	Base Period Amortization	Base Period Ending Balance	Test Period Beginning Balance	Test Period Activity	Test Period Amortization	Test Period Ending Balance
AMS REGULATORY ASSET (a)	$ -	$ -	$ -	$ -	$ -	$ 2,299,946	$ -	$ 2,299,946
ASC 740 - INCOME TAXES [1]	69,961,051	1,430,583	(866,075)	70,525,558	70,525,558	-	-	70,525,558
POSTRETIREMENT BENEFITS [2]	-	-	(264,948)	(264,948)	(311,337)	-	(139,169)	(450,506)
ASC 715 - PENSION [3]	120,706,013	50,038,994	(6,170,955)	164,574,053	158,512,914	(4,930,652)	(9,233,424)	144,348,838
PENSION GAIN/LOSS AMORTIZATION-15 YEAR	4,544,466	4,186,417	(180,760)	8,550,123	12,929,467	7,531,526	-	20,460,993
WINTER STORM 2009 - ELECTRIC [3]	25,279,569	-	(5,723,676)	19,555,893	17,648,001	-	(5,723,676)	11,924,325
WIND STORM 2008	969,686	-	(219,552)	750,135	676,951	-	(219,552)	457,399
MOUNTAIN STORM - ELECTRIC	866,848	-	(472,826)	394,022	236,413	-	(236,413)	-
RATE CASE EXPENSES - ELECTRIC	1,487,461	1,514,042	(637,661)	2,363,841	2,463,414	78,032	(1,272,256)	1,269,190
CARBON MANAGEMENT RESEARCH GROUP	247,563	102,440	(102,440)	247,563	213,417	102,440	(102,440)	213,416
FORWARD STARTING SWAP LOSSES	42,672,761	-	(2,391,436)	40,281,325	39,481,996	-	(2,391,436)	37,090,560
ASSET RETIREMENT OBLIGATION (ARO) [6] (b)	95,950,133	61,857,873	(279,365)	157,528,641	177,772,785	60,743,607	(1,781,349)	236,735,043
GREEN RIVER RETIREMENT	6,027,114	-	(2,583,054)	3,444,059	2,583,039	-	(1,408,926)	1,174,113
MUNI MISO EXIT FEE	642,040	(52,372)	(521,481)	68,187	-	-	-	-
MUNICIPAL FORMULA RATE TRUE-UP	8,335,000	345,437	-	8,680,437	6,136,662	(6,831,127)	-	(694,465)
ENVIRONMENTAL COST RECOVERY [4]	697,000	17,408,034	(18,172,493)	(67,459)	2,361,126	73,379,452	(68,461,188)	7,279,391
OFF-SYSTEM TRACKER (OST) [4]	4,300	(42,532)	144,766	106,534	54,541	(243,855)	250,654	61,340
VA FUEL COMPONENT [5]	-	-	1,071,500	1,071,500	1,785,833	-	357,167	2,143,000
FUEL ADJUSTMENT CLAUSE (FAC) [5]	-	(26,705,889)	33,423,499	6,717,610	4,089,942	(55,017,193)	54,071,703	3,144,452
Total Regulatory Assets*	**$ 378,391,005**	**$ 110,083,027**	**$ (3,946,958)**	**$ 484,527,074**	**$ 497,160,723**	**$ 77,112,174**	**$ (36,290,304)**	**$ 537,982,593**

*Balances agree to monthly Total Company Balance Sheet provided in Attachment to KU PSC1-54 Sch B
The derivation of the calculations are from UIPlanner. For assumptions used and the Orders authorizing the assumptions as it relates to the activity and amortization see response to KIUC 2-8(

a) Business Plan assumed a regulatory asset would be recorded as retirements of meters occurred. Since then the Company determined it should establish a regulatory asset at the end of the meter replacement program. No amortization has been forecasted. There is no impact on ratemaking.

b) ARO CCR detail is not available from the Business Plan in UI Planner - detail is combined in the ARO line item.

Notes:

[1] = The response to KIUC 1-27 inadvertently reflected the incorrect balances and included the net of the tax assets and liability balances and activity, this schedule reflects the regulatory asset balance and activity only.

[2] = The response to KIUC 1-27 did not include the activity related to the postretirement liability. However, for the forecasted periods, the activity related to the amortization of the service cost and actuarial gains and losses are recorded to the regulatory asset balance.

[3] = The response to KIUC 1-27, for the beginning balance of the forecasted period, inadvertently reflected the July 30, 2017 ending balance instead of the July 1, 2017 beginning balanc

[4] = The response to KIUC 1-27 inadvertently reflected the net of the mechanisms balances and activity, this schedule reflects the regulatory asset balance onl

[5] = The response to KIUC 1-27 did not include the activity for the FAC and the VA Fuel Component because these are regulatory liabilities. However, for the forecasted periods, the activity is recorded to the regulatory asset balance.

[6] = For the Forecasted Test Period, in the response to KIUC 1-27, we inadvertently used the incorrect month for the beginning balance and it did not include the CCR amortization which resulted in the incorrect beginning balance and activity total but the correct ending balance.

EXHIBIT RCS-14

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

**Response to the Attorney General's Supplemental Data Requests
Dated February 7, 2017**

Question No. 79

Responding Witness: John P. Malloy

Q-79. Reference the AMS Business Case, Exhibit JPM-1, page 38. The AMS Cost-Benefit Summary 2016-2039 indicates that the net present value of meter retirement is only \$3.8 million, while the nominal value of meter retirement is \$39.7 million.

a. Explain why the net present value of meter retirement is so much less than the nominal value.

b. Provide all assumptions and calculations used to determine a net present value of \$3.8 million from a nominal value of \$39.7 million. Include calculations by year over the 20-year benefit period utilized in the AMS business case in an executable MS Excel file with all cells and equations intact.

A-79.

a. The net present value calculation, as seen in the attachment to part b, includes a reduction in capital equal to the net book value of the retired meters. The Company is seeking Regulatory Asset treatment of this remaining value to be amortized over five years. Because the remaining book life of the retired meters is substantially longer than the 5-year amortization, the present value of the meter retirement is proportionally reduced from the nominal value.

b. See attachment being provided in Excel format. Note that since the Regulatory Asset amortization will be concluded in 2025, the attached calculation only extends 10 years.

EXHIBIT RCS-15

KENTUCKY UTILITIES COMPANY

**Response to Commission Staff's First Request for Information
Dated November 10, 2016**

Case No. 2016-00370

Question No. 54

Responding Witness: Paul W. Thompson / Daniel K. Arbough / Adrien M. McKenzie / David S. Sinclair / John P. Malloy / Robert M. Conroy / William Steven Seelye / Christopher M. Garrett

Q-54. Provide a copy of all exhibits and schedules that were prepared in the utility's rate application in Excel spreadsheet format with all formulas intact and unprotected and with all columns and rows accessible.

A-54. Attached to this response is a listing of all Excel spreadsheets submitted in response to this question. The label by which each file is to be identified on the Commission website, under the "Description of Document" heading, is listed in the first column of the attached list. The second column of the attached list specifies the actual name of the spreadsheet being submitted. The third column identifies the specific exhibit or schedule being submitted.

KY Aug 2016 Forecast (2017 BP-Prelim View)- No RC	a-Mar 2016	a-Apr 2016	a-May 2016	a-Jun 2016	a-Jul 2016	a-Aug 2016	Sep 2016	Oct 2016	Nov 2016	Dec 2016	Jan 2017	Feb 2017	
(000s)													
Kentucky Utilities													
Off System Sales:													
External OSS Sales:													
Wholesale Market Sales (GWhs)	1.25	5.37	6.48	8.30	14.26	17.16	3.36	0.61	1.71	3.24	2.09	0.30	
Wholesale Market Sales ($/MWh)	$34.10	$39.63	$36.23	$39.77	$43.37	$40.59	$179.97	$161.41	$59.11	$148.94	$41.00	$46.17	
Wholesale Market Sales	43	213	235	330	618	696	116	21	65	128	86	14	
447 External OSS Sales	**$43**	**$213**	**$235**	**$330**	**$618**	**$696**	**$116**	**$21**	**$65**	**$128**	**$86**	**$14**	
Intercompany OSS Sales (GWhs)	0.13	3.35	0.55	3.95	9.02	2.14	5.86	1.47	3.78	21.24	12.38	14.19	
Intercompany OSS Sales ($/MWh)							$27.57	$27.98	$28.13	$27.09	$27.29	$27.38	
Intercompany OSS Sales							162	41	106	575	338	389	
447 Internal OSS Sales	**$3**	**$96**	**$16**	**$117**	**$268**	**$62**	**$162**	**$41**	**$106**	**$575**	**$338**	**$389**	
Off Sytem Sales, Total	**$46**	**$309**	**$251**	**$448**	**$886**	**$758**	**$278**	**$62**	**$171**	**$703**	**$424**	**$402**	**$4,738.652**
Off System Fuel Costs:													
External OSS Fuel Costs:													
501 Fuel Costs for External OSS	9	82	93	215	329	330	(64)	(7)	24	43	49	8	
547 Fuel Costs for External OSS				1	22	27							
555 Purchased Power - OSS	1	2	2	12	23	12							
External OSS Costs	**$10**	**$85**	**$95**	**$228**	**$373**	**$368**	**($64)**	**($7)**	**$24**	**$43**	**$49**	**$8**	
501 Fuel Costs for Utility OSS	3	94	16	103	239	60	161	41	105	570	317	365	
547 Fuel Costs for Utility OSS				11	22	1							
555 Purchased Power Costs - External C	18	58	76	20	52	111	151	21	17	43	3		
Internal OSS Costs, Total	**$21**	**$152**	**$91**	**$134**	**$312**	**$172**	**$312**	**$62**	**$122**	**$613**	**$319**	**$365**	
Off System Sales Costs, Total	**$31**	**$236**	**$186**	**$362**	**$686**	**$540**	**$248**	**$55**	**$146**	**$656**	**$369**	**$373**	
Off System Sales Net Revenue	**$15**	**$73**	**$64**	**$86**	**$201**	**$219**	**$30**	**$8**	**$26**	**$47**	**$55**	**$29**	
Off System Expenses:													
565 Transmission - OSS External	0	0	1	6	(5)	0							
565 Transmission - OSS Utility	2	16	23	34	63	65	13	3	10	6	9	1	
557 RTO Costs - OSS External	(0)	1	(1)	2	4	5	7	1	3	4	2	1	
502 ECR Consumables - OSS External							3	1	4	5	2	0	
506 ECR Consumables - OSS External	1	3	3	7	12	12							
502 Other Consumables - OSS External	0	1	1	6	7	6	3	1	2	2	2	0	
506 Other Consumables - OSS External	0	1	1	2	3	3							
502 Other Consumables - OSS Utility	0	1	0	3	5	1	(2)	0	1	4	21	23	
506 Other Consumables - OSS Utility	0	1	0	1	2	1							
Off System Sales Expenses, Total	**$3**	**$24**	**$30**	**$62**	**$90**	**$93**	**$24**	**$6**	**$20**	**$22**	**$35**	**$26**	
Off System Sales Gross Margin	**$12**	**$49**	**$35**	**$24**	**$110**	**$126**	**$6**	**$1**	**$6**	**$25**	**$19**	**$3**	
OSS Margin Tracker calculation:													
Inter-System Losses	0	1	1	1	2	2	1	0	0	0	0	0	
Off System Sales Margin	**$12**	**$48**	**$34**	**$23**	**$108**	**$123**	**$5**	**$1**	**$5**	**$25**	**$19**	**$3**	**$406.640**
OSS Tracker - Customer Share	$9	$36	$25	$17	$81	$92	$4	$1	$4	$19	$14	$2	
OSS Tracker - Utility Share	3	12	8	6	27	31	1	0	1	6	5	1	

KY Aug 2016 Forecast (2017 BP-Prelim View)- No RC	Jun 2017	Jul 2017	Aug 2017	Sep 2017	Oct 2017	Nov 2017	Dec 2017	Jan 2018	Feb 2018	Mar 2018	Apr 2018	May 2018	Jun 2018	
(000s)														
Kentucky Utilities														
Off System Sales:														
External OSS Sales:														
Wholesale Market Sales (GWhs)	7.93	8.42	8.76	8.26	1.99	4.15	2.93	1.66	1.23	1.45	0.74	12.06	5.93	
Wholesale Market Sales ($/MWh)	$34.66	$39.52	$36.18	$35.80	$38.08	$36.68	$38.54	$41.13	$43.00	$38.42	$37.74	$36.18	$39.22	
Wholesale Market Sales	275	333	317	296	76	152	113	68	53	56	28	436	233	
447 External OSS Sales	**$275**	**$333**	**$317**	**$296**	**$76**	**$152**	**$113**	**$68**	**$53**	**$56**	**$28**	**$436**	**$233**	
Intercompany OSS Sales (GWhs)	5.38	6.94	5.05	7.49	2.64	1.93	19.67	20.00	23.54	6.82	6.00	10.15	6.26	
Intercompany OSS Sales ($/MWh)	$26.88	$27.65	$26.44	$25.72	$27.36	$27.00	$26.33	$26.78	$25.94	$26.67	$24.89	$24.76	$26.36	
Intercompany OSS Sales	145	192	133	193	72	52	518	536	610	182	149	251	165	
447 Internal OSS Sales	**$145**	**$192**	**$133**	**$193**	**$72**	**$52**	**$518**	**$536**	**$610**	**$182**	**$149**	**$251**	**$165**	
Off Sytem Sales, Total	**$420**	**$525**	**$450**	**$488**	**$148**	**$204**	**$631**	**$604**	**$663**	**$238**	**$177**	**$688**	**$398**	**$5,633.364**
Off System Fuel Costs:														
External OSS Fuel Costs:														
501 Fuel Costs for External OSS	159	195	191	175	43	85	64	43	29	35	18	240	143	
547 Fuel Costs for External OSS														
555 Purchased Power - OSS						0								
External OSS Costs	**$159**	**$195**	**$191**	**$175**	**$43**	**$85**	**$64**	**$43**	**$29**	**$35**	**$18**	**$240**	**$143**	
501 Fuel Costs for Utility OSS	136	181	125	181	68	49	486	501	572	171	140	235	155	
547 Fuel Costs for Utility OSS														
555 Purchased Power Costs - External C	35	18	24	24	6	16	9	0	3		1	43	8	
Internal OSS Costs, Total	**$171**	**$199**	**$150**	**$205**	**$74**	**$65**	**$495**	**$501**	**$575**	**$171**	**$141**	**$278**	**$163**	
Off System Sales Costs, Total	**$330**	**$394**	**$341**	**$380**	**$117**	**$150**	**$559**	**$544**	**$604**	**$206**	**$158**	**$518**	**$306**	
Off System Sales Net Revenue	**$90**	**$131**	**$110**	**$108**	**$31**	**$54**	**$72**	**$60**	**$60**	**$31**	**$19**	**$170**	**$92**	**$1,027.851**
Off System Expenses:														
565 Transmission - OSS External														
565 Transmission - OSS Utility	27	35	31	37	10	20	13	6	5	6	4	53	24	
557 RTO Costs - OSS External	3	6	4	5	1	2	1	1	3	1	0	8	3	
502 ECR Consumables - OSS External	7	6	7	7	2	4	2	1	1	1	1	11	5	
506 ECR Consumables - OSS External														
502 Other Consumables - OSS External	6	7	6	6	2	3	2	1	1	1	0	8	5	
506 Other Consumables - OSS External														
502 Other Consumables - OSS Utility	9	11	8	12	4	3	32	35	39	11	9	16	10	
506 Other Consumables - OSS Utility														
Off System Sales Expenses, Total	**$51**	**$65**	**$56**	**$68**	**$18**	**$31**	**$51**	**$45**	**$49**	**$20**	**$14**	**$96**	**$47**	
Off System Sales Gross Margin	**$39**	**$66**	**$53**	**$41**	**$13**	**$23**	**$21**	**$15**	**$11**	**$11**	**$5**	**$74**	**$46**	
OSS Margin Tracker calculation:														
Inter-System Losses	1	1	1	1	0	1	0	0	0	0	0	2	1	
Off System Sales Margin	**$38**	**$65**	**$52**	**$40**	**$13**	**$22**	**$20**	**$15**	**$11**	**$11**	**$4**	**$72**	**$45**	**$407.898**
OSS Tracker - Customer Share	$28	$49	$39	$30	$10	$17	$15	$11	$8	$8	$3	$54	$34	
OSS Tracker - Utility Share	9	16	13	10	3	6	5	4	3	3	1	18	11	

EXHIBIT RCS-16

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 50

Responding Witness: Valerie L. Scott

Q-50. The 2015 FERC Form 60 for PPL Services Corporation at page 307 shows $16,010,878 of charges to LG&E and KU Services Company.

a. How much of that was charged to KU?

b. Show the amounts charged to KU by account.

c. Why is PPL Services Corporation allocating cost to LG&E and KU Services Company?

d. How much cost by account has KU reflected for charges from PPL Services Corporation for the base period and projection period?

e. How much cost by account has KU reflected for charges from LG&E and KU Services Company for the base period and projection period?

A-50.

a. Of the $16,010,878, only $937,382 was charged to KU. See the response to PSC 1-61(b).

b. See the response to PSC 1-61(b).

c. PPL Services Corporation is a subsidiary of PPL that provides direct administrative, management and support services to PPL and its subsidiaries including acting as a billing agent and providing administrative, technical, management, and other services to its affiliates. Coordination of procurement and provision of certain limited goods and services within the PPL family of companies, including with LG&E and KU Services Company, may mitigate cost increases in the future. In addition, PPL Services Corporation allocates a portion of its indirect general and administrative costs to LG&E and KU Services Company. These costs are not charged to KU.

d. See attached.

e. See attached.

Kentucky Utilities Company
Charges from PPL Services Corporation

Period	Account Number	Account Description		Charged
Base Period[1]:				
	107	Construction work in progress—Electric	$	71,103
	580	Operation supervision and engineering		3,403
	920	Administrative and general salaries		371,012
	921	Office supplies and expenses		1,022,958
	923	Outside services employed		139,495
	925	Injuries and damages		(81,523)
	926	Employee benefits		292,510
	930.2	Miscellaneous general expenses		242,023
	Total		$	2,060,980
Forecasted Test Period[1]:				
	920	Administrative and general salaries	$	139,317
	921	Office supplies and expenses		1,426,120
	926	Employee benefits		100,896
	Total		$	1,666,333

[1] Convenience payments such as insurance are excluded from the base period and the forecasted test period. A convenience payment occurs when one affiliate, as a matter of convenience for the vendor, makes a payment on behalf of other affiliates and is subsequently reimbursed by those affiliates.

Kentucky Utilities
Charges from LG&E and KU Services Company

Period	Account Number	Account Description	Amount Charged
Base Period[1]:			
	107	Construction work in progress—Electric	$ 56,160,836
	108	Accumulated provision for depreciation of electric utility plant	2,971,730
	163	Stores expense undistributed	1,192,833
	165	Prepayments	14,024,864
	182.3	Other regulatory assets	1,519,626
	183	Preliminary survey and investigation charges	70,979
	184	Clearing accounts	10,625,821
	186	Miscellaneous deferred debits	184,173
	188	Research, development, and demonstration expenditures	291,985
	232	Accounts payable	90
	236	Taxes accrued	(326,151)
	408.1	Taxes other than income taxes, utility operating income	5,397,155
	416	Costs and expenses of merchandising, jobbing, and contract work	32
	421.1	Gain on disposition of property	(7,527)
	426.1	Donations	607,602
	426.3	Penalties	33,203
	426.4	Expenditures for certain civic, political and related activities	807,452
	426.5	Other deductions	838,732
	500	Operation supervision and engineering	6,204,434
	501	Fuel	1,425,656
	502	Steam expenses	135,430
	505	Electric expenses	13,989
	506	Miscellaneous steam power expenses	2,183,799
	510	Maintenance supervision and engineering	1,213,395
	511	Maintenance of structures	18,105
	512	Maintenance of boiler plant	5,064
	513	Maintenance of electric plant	104,884
	514	Maintenance of miscellaneous steam plant	27,966
	546	Operation supervision and engineering	1,568
	549	Miscellaneous other power generation expenses	2,950
	554	Maintenance of miscellaneous other power generation plant	18,228
	556	System control and load dispatching	1,921,186
	560	Operation supervision and engineering	1,656,019
	561	Operation supervision and engineering	1,802,726
	561.1	Load dispatch—Reliability	228,619
	561.2	Load dispatch—Monitor and operate transmission system	943,147
	561.3	Load dispatch—Transmission service and scheduling	360,927

Kentucky Utilities
Charges from LG&E and KU Services Company

Period	Account Number	Account Description	Amount Charged
	561.5	Reliability planning and standards development	404,684
	561.6	Transmission service studies	43,944
	562	Station expenses	224,599
	563	Overhead line expense	450,962
	566	Miscellaneous transmission expenses	2,636,411
	567	Rents	72,420
	570	Maintenance of station equipment	962,087
	571	Maintenance of overhead lines	2,960,626
	573	Maintenance of miscellaneous transmission plant	306,926
	580	Operation supervision and engineering	1,429,653
	581	Load dispatching	294,315
	581.1	Line and station expenses	62,215
	582	Station expenses	17,953
	583	Overhead line expenses	1,083,276
	586	Meter expenses	587,971
	587	Customer installations expenses	(11,200)
	588	Miscellaneous distribution expenses	1,732,768
	590	Maintenance supervision and engineering	1,109
	592.1	Maintenance of structures and equipment	9,168
	593	Maintenance of overhead lines	158,925
	598	Maintenance of miscellaneous distribution plant	37,997
	901	Supervision	2,743,995
	902	Meter reading expenses	166,234
	903	Customer records and collection expenses	12,986,821
	904	Uncollectible accounts	148,644
	905	Miscellaneous customer accounts expenses	620
	907	Supervision	387,219
	908	Customer assistance expenses	18,343,302
	909	Informational and instructional advertising expenses	468,657
	910	Miscellaneous customer service and informational expenses	871,300
	913	Advertising expenses	754,554
	920	Administrative and general salaries	33,678,374
	921	Office supplies and expenses	6,312,416
	923	Outside services employed	13,996,588
	924	Property insurance	1,430,675
	925	Injuries and damages	841,598
	926	Employee benefits	19,564,077
	928	Regulatory commission expenses	339,634
	930	Duplicate charges—Credit	4,706,108

Kentucky Utilities
Charges from LG&E and KU Services Company

Period	Account Number	Account Description	Amount Charged
	931	Rents	1,414,958
	935	Maintenance of general plant	1,438,366
	Total		$ 246,722,477
Forecasted Test Period[1]:			
	107	Construction work in progress—Electric	$ 108,409,339
	108	Accumulated provision for depreciation of electric utility plant	338,117
	163	Stores expense undistributed	1,975,310
	182.3	Other regulatory assets	660,032
	184	Clearing accounts	12,271,250
	408.1	Taxes other than income taxes, utility operating income	5,266,704
	426.1	Donations	926,051
	426.4	Expenditures for certain civic, political and related activities	679,808
	426.5	Other deductions	943,154
	500	Operation supervision and engineering	6,323,479
	501	Fuel	1,393,257
	502	Steam expenses	76,583
	505	Electric expenses	24,147
	506	Miscellaneous steam power expenses	2,825,109
	510	Maintenance supervision and engineering	3,012,539
	511	Maintenance of structures	105,214
	514	Maintenance of miscellaneous steam plant	21,348
	554.1	Maintenance of other power production plant	65,935
	556	System control and load dispatching	2,129,212
	560	Operation supervision and engineering	2,001,338
	561.1	Load dispatch—Reliability	491,027
	561.2	Load dispatch—Monitor and operate transmission system	1,938,653
	561.3	Load dispatch—Transmission service and scheduling	848,604
	561.5	Reliability planning and standards development	763,705
	562	Station expenses	741,990
	563	Overhead line expense	1,174,640
	566	Miscellaneous transmission expenses	2,594,999
	567.1	Operation supplies and expenses	124,236
	570	Maintenance of station equipment	1,651,824
	571	Maintenance of overhead lines	11,532,263
	573	Maintenance of miscellaneous transmission plant	345,925
	580	Operation supervision and engineering	1,484,318
	581	Load dispatching	225,571
	581.1	Line and station expenses	137,117

Kentucky Utilities
Charges from LG&E and KU Services Company

Period	Account Number	Account Description	Amount Charged
	583	Overhead line expenses	1,296,656
	586	Meter expenses	1,863,519
	587	Customer installations expenses	(100,800)
	588	Miscellaneous distribution expenses	2,458,684
	593	Maintenance of overhead lines	113,712
	597	Maintenance of meters	1,443,098
	598	Maintenance of miscellaneous distribution plant	56,945
	901	Supervision	3,140,212
	902	Meter reading expenses	224,438
	903	Customer records and collection expenses	13,944,707
	907	Supervision	640,059
	908	Customer assistance expenses	21,099,696
	909	Informational and instructional advertising expenses	411,160
	910	Miscellaneous customer service and informational expenses	1,833,990
	913	Advertising expenses	837,645
	920	Administrative and general salaries	36,899,860
	921	Office supplies and expenses	6,771,078
	923	Outside services employed	13,796,754
	924	Property insurance	6,236,560
	925	Injuries and damages	3,678,306
	926	Employee benefits	22,422,563
	928	Regulatory commission expenses	618,436
	930.1	General advertising expenses	46,180
	930.2	Miscellaneous general expenses	5,040,577
	931	Rents	1,219,491
	935	Maintenance of general plant	254,604
	Total		$ 319,750,927

[1] Convenience payments (including, but not limited to, fuel purchases, reagent purchases, medical claims and pension funding) are excluded from the base period and the forecasted test period. A convenience payment occurs when one affiliate, as a matter of convenience for the vendor, makes a payment on behalf of other affiliates and is subsequently reimbursed by those affiliates.