BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

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

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)	**CASE NO. 2016-00371**

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

March 3, 2017

BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

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

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)	**CASE NO. 2016-00371**

TABLE OF CONTENTS

BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

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

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	**)**	**CASE NO. 2016-00371**

DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. Please state your occupation and employer.

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Business Administration in Accounting degree and a Master of Business Administration degree from the University of Toledo. I also earned a Master of Arts degree in theology from Luther Rice University. I am a Certified Public Accountant ("CPA"), with a practice license, a Certified Management Accountant ("CMA"), and a Chartered Global Management Accountant ("CGMA"). I am a member of numerous professional organizations, including the American Institute of Certified Public Accountants, the Institute of Management Accounting, and the Society of Depreciation Professionals.

I have been an active participant in the utility industry for more than thirty years, initially as an employee of The Toledo Edison Company from 1976 to 1983 and thereafter as a consultant in the industry since 1983. I have testified as an expert witness on planning, ratemaking, accounting, finance, and tax issues in proceedings before regulatory commissions and courts at the federal and state levels on nearly two hundred occasions, including numerous proceedings before the Kentucky Public Service Commission involving Kentucky Utilities Company ("KU"), Louisville Gas and Electric Company ("LG&E"), Kentucky Power Company, East Kentucky Power Company and Big Rivers Electric Corporation.[1]

[1] My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC"), a group of large customers taking electric service at retail from KU and LG&E (also referred to individually as "Company" or collectively as "Companies"). The members of KIUC participating in these proceedings are: AAK, USA K2, LLC, Air Liquide Industrial U.S. LP, Alliance Coal, LLC, Carbide Industries LLC, Cemex, Corning Incorporated, Clopay Plastic Products Co., Inc., Dow Corning Corporation, Ford Motor Company, Ingevity, Lexmark International, Inc., North American Stainless, The Chemours Company, and Toyota Motor Manufacturing, Kentucky, Inc.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to summarize the KIUC revenue requirement recommendations, address specific issues that affect each Company's revenue requirement, and quantify the effect on the revenue requirements of the return on equity recommendation of KIUC witness Mr. Richard Baudino.

Q. Please summarize your testimony.

A. I recommend that the Commission increase KU's base rates by no more than $10.461 million, a reduction of $92.637 million compared to its requested increase of $103.098 million. I recommend that the Commission increase LG&E's electric base rates by no more than $40.253 million, a reduction of $53.367 million compared to its requested increase of $93.621 million.

The following table lists each KIUC adjustment and the effect on the claimed revenue deficiency for each Company. The amounts for KU are shown on a Kentucky jurisdiction basis and the amounts for LG&E are electric only. The calculations are detailed in my workpapers for each Company, which are provided with my testimony in the form of an Excel workbook in live format. In the following sections of my testimony, I address each of the issues reflected in the table in greater detail, except for the return on common equity, which is addressed by Mr. Baudino.

Kentucky Utilities Company and Louisville Gas & Electric Company
Summary of Revenue Requirement Adjustments-Jurisdictional Electric Operations
Recommended by KIUC
Case Nos. 2016-00370 and 2016-00371
For the Test Year Ended June 30, 2018
($ Millions)

	KU Amount	LG&E Amount
Increase Requested by Company	103.098	93.621
KIUC Adjustments:		
Operating Income Issues		
Reduce O&M Expense by Rejecting Proposed AMS Rollout	(3.188)	(3.040)
Reduce Depreciation Expense by Rejecting Proposed AMS Rollout	(0.607)	(0.475)
Reduce Depreciation Expense to Reflect Reduction in Transmission Plant	(0.592)	
Reduce Property Tax Expense to Reflect Reduction in Net Transmission Plant	(0.381)	
Normalize Generation Outage Expense	(11.264)	(4.962)
Reject Projected Increase in Transmission Vegetation Mgmt. Expense	(5.054)	(1.066)
Reduce Property Tax Expense to Reflect Removal of 2% Escalation Factor in Rate	(0.440)	(0.520)
Reduce Amortization Expense for Expiring Regulatory Assets	(1.004)	(0.810)
Reduce Depreciation Expense to Remove Terminal Net Salvage	(9.717)	(5.832)
Reduce Depreciation Expense to Increase Life Spans to 45 Years	(12.176)	(5.709)
Reduce Depreciation Expense to Reflect CCS Software Remaining Life as 10 Years	(3.188)	(2.569)
Cost of Capital Issues		
Reduce Capitalization for CWIP Slippage	(1.848)	(0.979)
Reduce Capitalization by Rejecting Proposed AMS Rollout	(2.354)	(1.835)
Reduce Capitalization to Reflect Reduction in Net Transmission Plant Additions	(2.317)	
Reflect Return on Equity of 9.0%	(38.508)	(25.570)
Total KIUC Adjustments to Company Request	(92.637)	(53.367)
KIUC Recommended Change in Base Rates	10.461	40.253

In addition, the Commission should be aware of the need to act expeditiously to reduce the Companies' base rates coincident with the effective date of a federal income tax rate reduction, as has been proposed by the Trump administration. An income tax rate reduction also will affect certain of the Companies' other riders, including the Environmental Cost Recovery ("ECR") surcharge.

Finally, although I quantified the effect of the return on equity for purposes of these base rate proceedings, the return on equity also will affect the revenue requirements in the Companies' surcharges, primarily the ECR surcharges. The Commission should make clear that the return on equity authorized in this proceeding will supersede the return on equity presently applied in the Companies' ECR surcharges.

Q. Does the Companies' use of a forecast test year ending June 30, 2018 impact the Commission's review of their requests?

A. Yes. Unlike a historic test year based on actual results, a forecast test year is not anchored in actual results. All capitalization, operating expenses, and cost of capital components are projected based on tens of thousands of assumptions, including programs and approaches that may or not reflect the actual costs that are incurred from July 1, 2017 through June 30, 2018. In fact, utilities, in conjunction with a forecast test year, have every incentive to overstate their costs to maximize their revenues. The utilities are not obligated to incur those costs once the Commission sets their revenue requirements. In addition, the utilities have every incentive to propose new programs that increase capitalization, which is the basis for earnings and growth in earnings, an important consideration for their shareholders when sales are stagnant and don't contribute to increased revenues and earnings.

The Commission should review the Companies' requests with healthy skepticism, particularly when they seek approval for new programs, such as the AMS, and significant increases in costs, such as transmission capital expenditures, transmission maintenance expenses, generation outage expenses, and depreciation expense, among others.

II. THE AMS IS UNNECESSARY AND UNECONOMIC; THE COMMISSION SHOULD NOT APPROVE THE REQUESTED CPCN AND SHOULD NOT INCLUDE THE COSTS IN THE REVENUE REQUIREMENT

Q. Please describe the Companies' request for a Certificate of Need and Public Necessity ("CPCN") for Automated Metering Systems ("AMS").

A. The Companies each seek a CPCN to replace their existing electric customer meters and to install AMS meters by the end of 2019, with the first AMS meters deployed in the third quarter of 2017.[2] This will involve the premature retirement and replacement of 530,000 KU electric customer meters and 418,000 LG&E electric customer meters, expanding the existing radio frequency ("RF") communications infrastructure to enable AMS RF communications throughout the

[2] LG&E also plans to install AMS gas-meter-reading indices on the majority of existing gas meters.

Companies' service territories, updating the existing meter head-end to support full system volume of endpoints, installing and integrating a meter data management system, meter asset management system, and meter operations center.[3]

The Companies estimate that the deployment of the AMS and related assets will require $320.4 million in capital expenditures and operation and maintenance (O&M) expenses of $30.0 million. Of these total amounts, KU will incur Kentucky jurisdiction $138.8 million in capital expenditures and $13.7 million in O&M expenses; LG&E electric will incur $119.0 million in capital expenditures and $13.0 million in O&M expenses.[4]

Q. Have the Companies provided a cost/benefit study in support of their request for a CPCN?

A. Yes. The Companies included their cost/benefit study as Exhibit JPM-1 attached to Mr. John Malloy's Direct Testimony. The cost/benefit study concludes that there is a net benefit to the deployment of the AMS of some $470 million on a nominal dollar basis, which equates to approximately $30.2 million on a net present value basis.[5]

The Companies claim that the total life-cycle costs (from 2017 through 2039) to

---

[3] John Malloy Direct Testimony at 15-17.
[4] John Malloy Direct at 17.
[5] *Id.*

deploy the AMS total $551 million in nominal dollars, consisting of $346 million in capital expenditures $165 million in O&M expense, and $40 million for existing meter retirements.[6]

The Companies claim that the total life-cycle savings over that same period total $1,020 million in nominal dollars. Of this amount, $489 million is due to a reduction in "non-technical losses;" $166 million in energy efficiency "savings" due to the eportal; $203 million in reduced meter reading expenses; $92 million in related services; $37 million in avoided meter capital expenditures; $20 million in avoided IT capital expenditures; and $13 million in avoided distribution asset costs, avoided outage restoration costs, and avoided "okay on arrival" costs.

Q. Does the Companies' cost/benefit study justify CPCNs for the AMS?

A. No. The cost/benefit study is significantly flawed. When the study is corrected to remove the most serious flaws, the AMS deployment results in a net cost to customers of at least $531 million on a nominal dollar basis.

Q. Please describe the most serious flaws in the Companies' cost/benefit study.

A. I will address the three most serious flaws in the study by order of magnitude, starting with the largest dollar impact.

---

[6] John Malloy Direct at 22.

The first and largest of these flaws is the claim that the AMS will reduce non-technical losses by $489 million, or nearly $25 million each year, although the study itself claims the reduction in losses is $16 million over 20 years, which would be $320 million, not $489 million. The premise of this claim is that the Companies' revenues will increase if the non-technical losses are reduced, all else equal. However, this is fundamentally not correct. Non-technical losses are those losses due to current theft and meters that are not calibrated properly. Such non-technical losses are different than technical, or thermal, line losses, which will be unaffected by the AMS, except indirectly.

There are several reasons why the Company's claim is incorrect. First, there will be no increase in revenues if there are reductions in non-technical losses. The fuel costs due to the non-technical losses are already recovered from customers through the fuel adjustment clause and the base revenues are recovered through base rates, albeit both on a somewhat increased amount per kW or kWh. If the losses are reduced, then the measured and billed kW and kWh will increase, but the amounts per kW and kWh will be reduced, all else equal. There will be no increase in revenues as these changes are factored into the fuel adjustment clause and base rates. Second, the Companies have no empirical evidence for their estimate of non-technical losses. Instead, they rely exclusively on a 2008 Electric Power Research Institute ("EPRI") study titled "Advanced Metering Infrastructure Technology: Limiting Non-Technical Distribution Losses In The Future." The EPRI "study" states that "estimates of non-technical losses range from 0.5% to 4.0% of base revenues." However, the study itself states that "Non-technical losses, by definition, are losses that are not accounted for and are, therefore, not subject to analytical measurement. . . there is no firm data to define the level of losses on an industrywide basis." The EPRI study also acknowledges that the estimates that it relied for its range were developed on an order of magnitude basis and that it had no accurate actual measures of such losses.[7] The EPRI study made no attempt to measure actual non-technical line losses.

The second largest of the flaws is that the study fails to include the cost of replacement meters as the new meters are retired and replaced throughout the 20 year study period. The Companies estimate the *maximum* service life of the AMS meters is 20 years, less than half of the service life of the Companies' existing electro-mechanical meters. In fact, the Companies propose a 15 year service life for depreciation purposes, which means that Mr. Spanos, their depreciation expert, believes that, on average, all new AMS meters will be replaced once within a 15 year period.[8] Under either scenario, all AMS meters will be retired and replaced at least once during the 20 year study period. Yet, the Companies assumed that not a single AMS meter will be replaced during the 20 years. This assumption alone understates the cost of the AMS by $346 million or more in capital expenditures, assuming that the replacement AMS meters will cost the

---

[7] KU Response to KIUC 1-16(a) pages 20-21 under the heading "Measurement." I have attached a copy of this response and the selected pages as my Exhibit___(LK-2).

[8] KU response to KIUC 1-16(j), which I have attached as my Exhibit___(LK-2).

same as the first AMS Meters.

The third largest of the flaws is the Companies' claim that customers will achieve $166 million in energy efficiency savings due to the eportal and their ability to monitor and control their energy usage. Of course, this assumes that the AMS is necessary for customers to somehow associate reduced consumption with energy savings, which it is not, or that time of use rates are available to all residential and commercial customers, which they are not. In addition, for customers who are interested, they can readily purchase technologically advanced thermostats that allow them to monitor and control their energy usage through apps at home stores, such as Home Depot and Lowes. Further, the energy efficiency savings, if any, will be reflected in *reduced* revenues, offset in part by lower fuel costs. This is a *cost* ("lost revenues"), not a savings, according to the Companies, which they are allowed to recover in their DSM Cost Recovery Mechanisms.[9] In short, the claimed savings of $166 million are no savings at all. The Companies themselves consider such lost revenues as a cost. The lost revenues cannot be considered a cost for purposes of the DSM Cost Recovery Mechanisms, but then considered a savings when attempting to justify the AMS.

Q. What is your recommendation?

A. I recommend that the Commission deny each utility a CPCN for the AMS. The

[9] KU response to KIUC 1-15 and LG&E response to KIUC 1-16. I have attached a copy of these responses as my Exhibit___(LK-3).

AMS is extremely uneconomic, will harm customers, and is unnecessary.

Q. What is the effect of your recommendation?

A. The effect is a reduction in the KU revenue requirement of $6.149 million, consisting of $2.354 million for the return on capitalization, $0.607 million for depreciation, and $3.188 million for O&M expenses. The effect is a reduction in the LG&E revenue requirement of $5.350 million, consisting of $1.835 million for the return on capitalization, $0.475 million for depreciation, and $3.040 million for O&M expenses.[10]

Q. If the Commission, nevertheless, decides to grant each of the Companies a CPCN for the AMS, then should it authorize recovery of the costs through base rates?

A. No. The better approach is to provide recovery through an AMS surcharge. An AMS surcharge will ensure that only actual costs are recovered and that actual savings are offset against those costs. An AMS surcharge avoids the need to forecast the costs or the timing of the costs using a forecast test year.

The Companies' environmental surcharge provides a pattern for calculating the revenue requirement for this form of recovery, including a calculation of rate base, cost of capital, and operating expenses, including O&M expense,

[10] KU response to KIUC 1-17 and LG&E response to KIUC 1-18. I have attached a copy of these responses as my Exhibit___(LK-4).

depreciation expense, and income tax expense.

Q. If the Commission grants each of the Companies a CPCN for the AMS and authorizes recovery of the costs through an AMS surcharge, then do you have additional recommendations?

A. Yes. First, at a minimum, the Commission should ensure that the costs do not grow from those set forth in the requests for CPCNs in these proceedings through increased costs and/or a subsequent expansion of scope.

Second, the Commission should adopt an initial 5.0% depreciation rate, consistent with the Companies' assumptions that the meters will have a service life of 20 years and there will be no interim retirements.

Third, the Commission should direct the Companies to reflect all savings as a reduction to the costs included in the AMS surcharge. These include, but are not limited to, the savings identified in the cost benefit study consisting of \$203 million in reduced meter reading expenses; \$92 million in related services; \$37 million in avoided meter capital expenditures; \$20 million in avoided IT capital expenditures; and \$13 million in avoided distribution asset costs, avoided outage restoration costs, and avoided "okay on arrival" costs. If the Commission agrees with the Company that "lost revenues" due to energy efficiencies resulting from the AMS are "savings," then those savings also should be reflected as a reduction to the costs included in the AMS surcharge.

Q. How should the AMS surcharge allocate the costs to customers?

A. OEG witness Mr. Baron addresses the allocation of costs on a per customer (per meter) AMS surcharge.

III. CAPITAL EXPENDITURES AND PLANT ADDITIONS ARE EXCESSIVE AND SHOULD BE REDUCED TO REFLECT ACTUAL EXPERIENCE

A. Forecasts of Capital Expenditures and Plant Additions Are Excessive Compared to Actual Experience; The Commission Should Apply A Slippage Factor

Q. Do the Companies tend to underspend their capital expenditure budgets and forecasts?

A. Yes. In most years, the Companies spend less than their budgets and forecasts on capital costs recovered through base rates. For example, in 2014, KU actually spent $259 million compared to its budget of $286 million.[11] In 2011, LG&E actually spent $207 million compared to its budget of $305 million.[12] This is typical, in my experience, particularly when the utility's rates are set based on costs in a forecast test year rather than actual costs in a historic test year. The percentage of actual costs to budgeted or projected costs is referred to as a "slippage factor."

Q. Has the Commission explicitly recognized slippage factors in prior cases?

---

[11] KU response to Staff 1-13(b). I have attached a copy of this response as my Exhibit___(LK-5).
[12] LG&E response to Staff 1-13(b). I have attached a copy of this response as my Exhibit___(LK-6).

A. Yes. The Commission typically applies a slippage factor to reduce construction and related plant costs in the forecast test year if the utility's actual capital expenditures historically are less than its budgeted or forecasted expenditures. For example, in its order in Union Light, Heat and Power Company Case No. 2005-00042, the Commission described its application of a "slippage factor" adjustment for the utility's forecast test year as follows:

> 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 service. The Commission has routinely applied a slippage factor in the forward-looking test period rate cases for Kentucky-American Water Company. 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.[13] (footnote omitted).

Similarly, in its order in Case No. 2004-00103, the Commission applied a slippage factor adjustment to the capital expenditures in the forecast test year. It described the slippage factor "as an indicator of Kentucky-American's accuracy in predicting the cost of its utility plant additions."[14]

Q. What are the slippage factors for KU and LG&E and what are the effects on the revenue requirements for each utility?

---

[13] Union Light, Heat and Power Company Case No. 2005-00042 Order at 8.
[14] Kentucky American Water Case No. 2004-00103 Order at 2.

A. In this proceeding, KU quantified a 97.204% slippage factor based on its actual experience compared to budget/forecast for the ten years 20016-2015.[15] If this factor is applied to KU's projected capital expenditures, it results in a reduction of $1.848 million in the Kentucky jurisdiction base revenue requirement.

LG&E quantified a 98.111% slippage factor based on its actual experience for the same ten years.[16] If this factor is applied to LG&E's projected capital expenditures, it results in a reduction of $0.979 million in the electric base revenue requirement.

Q. What is your recommendation?

A. I recommend that the Commission apply the slippage factors calculated by the Companies to reduce their capitalization and revenue requirements. This is appropriate based on the Company's actual experience compared to budget/forecast and is consistent with the Commission's precedent.

B. KU Transmission Capital Expenditures and Plant Additions Are Excessive

Q Is there another concern with KU's capital expenditures in the forecast test year?

A. Yes. KU's transmission capital expenditures in the forecast test year are

---

[15] KU response to Staff 1-13(b). I have attached a copy of this response as my Exhibit___(LK-5).

[16] LG&E's response to Staff 1-13(b). I have attached a copy of this response as my Exhibit___(LK-6).

excessive compared to its historic expenditures. KU included $106.339 million in transmission capital expenditures in the forecast test year. This is more than two times its historic transmission capital expenditures. Its actual transmission capital expenditures have ranged from a low of $40 million to a high of $55 million, or an average of $48.1 million from 2007 through 2015 as shown in the following table.[17]

Kentucky Utilities Company Transmission Capital Expenditures
($000)

2007	2008	2009	2010	2011	2012	2013	2014	2015	Base Period	Test Year
48,034	42,596	53,203	46,567	46,174	54,581	48,704	40,154	52,827	78,350	106,339

Q. Are transmission capital expenditures a controllable cost?

A. Yes, except in the event of damage, such as an ice or other storm event, or age-related and/or environmental deterioration. Transmission capital expenditures include specific projects for new construction and upgrade/rebuild construction, such as building new lines and upgrading existing lines and equipment, as well as other projects for routine construction, such as replacing damaged or aging fixtures and connectors.

Q. Is the KU proposal to more than double its historic transmission capital expenditures in the test year reasonable?

[17] KU response to KIUC 1-48. I have attached a copy of this response and page 25 of Attachment 2 as my Exhibit___(LK-7).

A. No. This is an example of how assumptions can drive increases in the revenue requirement and why it is necessary to compare the forecast costs to actual experience to test the reasonableness of the assumptions. In addition, even if the Commission includes the costs in the test year, that does not ensure that KU actually will spend the projected amounts.

Q. What is your recommendation?

A. I recommend that the Commission reflect the average of KU's actual transmission capital expenditures for 2007 through 2015 in the forecast test year, or $48.093 million instead of the $106.339 million sought by KU.

Q. If the Commission adopts your recommendation, then is it likely that KU actually will double its historic transmission capital expenditures in the rate effective year?

A. No. It is more likely that KU actually will incur an amount closer to its historic average. In other words, the Commission's decision on this issue likely will influence the actual capital expenditures. KU likely will respond to the Commission's decision by re-prioritizing its capital expenditures and reducing or eliminating lower priority expenditures in the rate effective year. In many cases, such reductions or eliminations are simply deferred to future years in the ongoing capital budgeting process.

Q. What is the effect of your recommendation on KU's revenue requirement?

A. The effect is a reduction of $3.290 million in KU's Kentucky jurisdiction revenue requirement, consisting of a reduction of $2.317 million in the return on capitalization, including income taxes; $0.592 million in depreciation expense; and $0.381 million in property tax expense.

IV. TRANSMISSION MAINTENANCE EXPENSE IS EXCESSIVE DUE TO PROPOSED CHANGE IN APPROACH TO VEGETATION MANAGEMENT

Q. Please describe the Companies' request to increase transmission maintenance expense for a change in their approach to vegetation management.

A. The Companies plan to change their approach to transmission vegetation management from a targeted approach to a cycled approach over five years. The change in approach will increase transmission maintenance expense by $5.027 million for KU and by $1.062 million for LG&E. This proposal will nearly double KU's transmission vegetation management expense, which has been relatively unchanged for the last three years (2014-2016) at $5.3 million annually.[18] The proposal will nearly double LG&E's average transmission vegetation management over the last three years (2014-2016) at $1.1 million annually. However, the change in approach will not result in savings or reduce future transmission maintenance expense until 2022 or later.

[18] KU and LG&E responses to AG 1-237. I have attached a copy of these responses as my Exhibit___(LK-8).

The Companies assert that this change in approach will improve the transmission system reliability.[19] However, this is an aspirational claim, not an actual target or even a goal-oriented claim based on specific reliability indices. They have not assessed or quantified the expected improvement in reliability indices, if any, for the proposed increases in maintenance expense.[20]

Q. What is your recommendation?

A. I recommend that the Commission reject these proposed increases in maintenance expense in the test year. They are unjustified. The Companies are free to change their approach at any time if they believe it will achieve better results, but the proposed change in approach does not inherently require additional maintenance expense. The Companies have not set targets to achieve any specific improvements in reliability as measured by standard reliability indices. The Companies may or may not spend the forecast vegetation management expense, even if the increase is included in the revenue requirement.

Consequently, the Commission should be wary of increasing the revenue requirement based on forecast assumptions that the Companies actually will change their approach, incur the additional expense, achieve improvements in reliability indices, and achieve some unknown and unquantified savings in the future.

[19] Paul Thompson Direct Testimony at 31.
[20] KU and LG&E responses to AG 1-10. I have attached a copy of these responses as my Exhibit___(LK-9).

V. GENERATION OPERATION AND MAINTENANCE EXPENSE IS EXCESSIVE DUE TO UNUSUALLY HIGH OUTAGE EXPENSES IN TEST YEAR AND SHOULD BE NORMALIZED TO REFLECT ACTUAL EXPERIENCE

Q. Please describe the Companies' generation outage expense in the test year and compare it to their actual experience.

A. The Companies' generation outage expense in the test year is unusually high compared to their actual experience. More specifically, KU's forecast generation outage expense is $90.201 million (total Company) compared to a five year average (2012-2016) of $77.384 million (total Company). LG&E's forecast generation outage expense is $63.814 million compared to a five year average of $58.873 million.

Q. Why is the forecast outage expense greater in the test year than the average of the actual expense over the last five years?

A. The difference is due primarily to the number and scope of the outages planned in the test year. For example, the test year includes the first major maintenance outage for Trimble County 2, which went into service in 2010. Its next major outage will be in 2018 and the next after that is planned for 2026. In other words, it is on an eight year major outage cycle. The EW Brown Units 1, 2, and 3 are on eight to nine year cycles.[21] Cane Run Unit 7 will have its first combustor inspection in the test year. These inspection outages are planned every two

[21] KU response to Staff 2-20. I have attached a copy of this response as my Exhibit___(LK-10).

years.[22]

Q. Will the Companies incur the same generation outage expense each year?

A. No. The outage expense included in the test year is greater than in any of the five years preceding the test year. In some years, the generation outage expense will be less and in some years more. Again, it depends on the number and scope of outages in any year.

Q. What is your recommendation?

A. I recommend that the Commission normalize the generation outage expense in the test year by using the most recent five year average in lieu of the forecast expense. In this manner, the Companies will recover less than their forecast cost in the test year, but more than their actual costs in the years with fewer and reduced scope of outages.

Q. What is the effect of your recommendation?

A. The effects are a reduction in the KU revenue requirement of $11.264 million and in the LG&E revenue requirement of $4.962 million.

---

[22] KU response to Staff 2-23. I have attached a copy of this response as my Exhibit___(LK-11).

VI. PROPERTY TAX EXPENSE IS EXCESSIVE DUE TO UNSUPPORTED ESCALATION ASSUMPTION

Q. Please describe the Companies' calculation of property tax expense.

A. The Companies' calculated property tax expense for 2017 and 2018 and averaged the two results to determine the property tax expense for the test year. They started with the net plant, including construction work in progress, at the beginning of each year (the valuation date), segregated into various property tax categories, each category with a separate tax rate. They calculated the total property tax expense by category using the separate tax rates, subtracted capitalized property taxes, and subtracted property taxes recovered through other mechanisms, primarily the environmental surcharge.[23]

Q. What rates did the Companies use?

A. The Companies used the 2016 tax rates in 2017 and 2018 for the manufacturing machinery original costs and inventory categories. The Companies escalated the 2016 tax rate by 2% in 2017 and another 2% in 2018 for the real estate original costs and other tangible property original costs categories.

Q. Is the 2% escalation rate supported through any evidence in the Companies' filing or in response to discovery?

A. No. This is an assumption. The Companies' calculations simply include the note

[23] KU response to KIUC 1-25 and LG&E response to KIUC 1-26. I have attached a copy of these responses as my Exhibit___(LK-12).

"the average rate for local taxing authorities were increased 2% each year."

Q. What is your recommendation?

A. I recommend that the Commission disallow the escalation unless the Companies present sufficient evidence that the rates were or will be increased. At this point, the escalation, if any, is not known. Even if the Companies present evidence that the actual rates were increased as of January 1, 2017, the escalation for 2018, if any, still will remain unknown.

Q. What are the effects of your recommendation?

A. The effects are a reduction in the KU revenue requirement of $0.440 million and in the LG&E revenue requirement of $0.520 million.

VII. AMORTIZATION EXPENSE IS EXCESSIVE FOR DEFERRED COSTS THAT WILL BE FULLY AMORTIZED DURING OR SHORTLY AFTER THE TEST YEAR

Q. Please describe the amortization expense for deferred costs included in the test year.

A. The Companies provided a list of each deferred cost and the annual amortization expense in response to KIUC discovery in these proceedings.[24] For certain of these deferred costs, the amortization will be completed during the test year or

[24] KU responses to KIUC 1-27 and KIUC 2-8; LG&E responses to KIUC 1-28 and KIUC 2-8. I have attached a copy of these responses as my Exhibit___(LK-13).

within one or two years after the end of the test year.

More specifically, KU's rate case expenses – electric will be fully amortized in June 2019, 12 months after the end of the test year. The beginning balance in the test year is $2.463 million. The test year amortization expense is $1.272 million and the ending balance in the test year is $1.269 million. If the Commission includes the $1.272 million amortization expense in the KU revenue requirement and KU's base rates are not reset until July 2019, then KU will recover an additional $1.272 million after the ending balance in the test year is fully recovered. If KU's base rates are not reset until July 2020, then KU will recover an additional $2.544 million after the ending balance in the test year is fully recovered. Perhaps rather obviously, this is inappropriate.

In addition, KU's deferred Green River retirement costs will be fully amortized in April 2019, only 10 months after the end of the test year. The beginning balance in the test year is $2.583 million. The test year amortization expense is $1.409 million and the ending balance in the test year is $1.174 million. If the Commission includes the $1.409 million amortization expense in the KU revenue requirement and KU's base rates are not reset until July 2019, then KU will recover an additional $1.644 million after the ending balance in the test year is fully recovered. If KU's base rates are not reset until July 2020, then KU will recover an additional $3.053 million after the ending balance in the test year is fully recovered. This is inappropriate.

Similarly, LG&E's rate case expenses – electric will be fully amortized in June 2019, 12 months after the end of the test year. The beginning balance in the test year is $1.428 million. The test year amortization expense is $0.746 million and the ending balance in the test year is $0.733 million. If the Commission includes the $0.746 million amortization expense in the LG&E revenue requirement and LG&E's base rates are not reset until July 2019, then LG&E will recover an additional $0.746 million after the ending balance in the test year is fully recovered. If LG&E's base rates are not reset until July 2020, then LG&E will recover an additional $1.492 million after the ending balance in the test year is fully recovered. This is inappropriate.

Finally, LG&E's 2011 Summer Storm – electric will be fully amortized in the test year. The test year amortization expense is $0.805 million and the ending balance in the test year is $0. If the Commission includes the $0.805 million amortization expense in the LG&E revenue requirement and LG&E's base rates are not reset until July 2019, then LG&E will recover an additional $0.805 million after the ending balance in the test year is fully recovered. If KU's base rates are not reset until July 2020, then KU will recover an additional $1.492 million after the ending balance in the test year is fully recovered. This too is inappropriate.

Q. What is your recommendation?

A. I recommend that the Commission reset the amortization period to three years for the deferred costs that I identified. This will reduce the likelihood that the Companies will over-recover, but still provides the Companies full recovery of the deferred costs.

Q. What are the effects of your recommendation?

A. KU's amortization expense will be reduced by $1.450 million for the Rate Case Expenses – Electric and Green River Retirement deferred costs. LG&E's amortization expense will be reduced by $0.807 million for the Rate Case Expenses – Electric and 2011 Summer Storm – Electric deferred costs.

VIII. DEPRECIATION EXPENSE IS EXCESSIVE DUE TO TERMINAL NET SALVAGE INCLUDED IN DEPRECIATION RATES FOR GENERATION ASSETS AND UNDULY SHORT LIFE SPANS FOR GENERATION ASSETS AND CUSTOMER CARE SYSTEM

A. Projected Terminal Net Salvage Should Be Removed from Generation Asset Depreciation Rates and Expense

Q. Please describe the concepts of terminal net salvage and interim net salvage and how these affect depreciation rates and expense.

A. The concept of terminal net salvage assumes that a plant asset is not retired in place after it is removed from service and instead that the facilities are dismantled and the site is remediated. If the facilities are dismantled and the site is remediated, the cost to do so is considered "negative" salvage, or cost of removal, which is offset and reduced by the income from the sale or other disposal of the facilities and/or site. There is no history of actual terminal net salvage unless and until the generation asset is retired and facilities are dismantled and the site is remediated.

If the terminal net salvage is included in the depreciation rate during the service life of the asset, then it necessarily requires a projection of the costs and income many decades into the future, including the technology, equipment, and labor that will be required, as well as the prices of commodities for salvaged copper and other materials, and the market value of equipment, parts, and other inventory.

The concept of interim net salvage is similar; however, it addresses the costs of removal and income from the sale or other disposal of components of a generation asset throughout its service life. For example, a component of the turbine generator of a generation asset may be replaced every ten years during major maintenance outages, although the generation asset itself has a life span of 50 years. Unlike terminal net salvage, for which there is no actual data until a unit is retired and dismantled, there is a history of actual data for interim retirements. Over an asset's service life, there is an ever-growing history of interim retirements, e.g., replacement of the component every ten years, cost of removal, and income from salvage. Like terminal net salvage, if the interim net salvage is included in the depreciation rate during the service life of the asset, then it necessarily requires a projection of the costs and income into the future, although the history of interim retirements provides a reasonably informed basis for such projections.

If terminal net salvage is included in the depreciation rates, then the net salvage percentage is applied to the gross plant in each generation plant account. The resulting projected cost (if the terminal net salvage is negative, meaning that the cost of removal is more than the salvage income) is added to the net book value, or the projected income (if the terminal net salvage is positive, meaning that the income from salvage is more than the cost of removal) is subtracted from the net book value, to derive a total cost to recover and then divided by the remaining life of the plant asset. For example, if the terminal salvage is negative 15.0% and the gross plant in account 312 is $500 million, then the resulting projected cost is $75 million. If the remaining service life is 25 years, then the depreciation expense is $20 million ($500 million divided by 25 years) and the depreciation rate is 4.0% if no terminal net salvage is included. The depreciation expense increases to $23 million (($500 million plus $75 million) divided by 25 years) and the depreciation rate increases to 4.6% ($23 million divided by $500 million) if terminal net salvage is included.

The process is similar for interim retirements; however, the interim net salvage generally is applied only to the portion of the gross plant subject to interim retirements.

In the Companies' depreciation study in these proceedings, Mr. Spanos weighted the terminal net salvage and the interim net salvage applicable to the generation asset plant accounts.

Q. Do the Companies' present depreciation rates include terminal net salvage for the generation plant accounts?

A. Yes. However, this circumstance is not due to Commission adjudications of the terminal net salvage issue or the percentages included in the derivation of the depreciation rates, but is due instead to settlements in several rate case proceedings that adopted the Companies' proposed depreciation rates with no or limited modifications. Thus, the fact that there is terminal net salvage included in the present depreciation rates is not dispositive of the issue in these proceedings.

Q. What is the history of including terminal net salvage in the Companies' depreciation rates?

A. Prior to 2008, the Companies' depreciation rates did not include terminal net salvage for the generation plant accounts. The Commission addressed generation asset retirement issues and cost of removal on a case by case basis, but did not allow recovery of projections of such costs preemptively by including terminal net salvage in the depreciation rates. However, when the Companies first engaged Mr. Spanos, he began an ongoing effort to include terminal net salvage in the generation plant accounts and increase depreciation rates. His first foray was to apply the interim net salvage to the entirety of the plant costs, essentially assuming that the terminal net salvage rate was equal to interim net salvage, while denying that he had included any terminal net salvage. Those proceedings were resolved via settlement.[25] His second foray was to propose separate terminal net salvage rates. Those proceedings were resolved via settlement, which limited the terminal net salvage to negative 2.0% for the generation plant accounts.[26] His third foray is reflected in the depreciation studies in these proceedings where he proposes significant increases in the terminal salvage from negative 2.0% to negative 10.0% to 15.0% for most of the generation plant accounts, thus significantly increasing the depreciation rates, depreciation expense, and the revenue requirements in this proceeding.

Q. Are the projections of terminal net salvage reflected in the depreciation studies supported by any specific evidence?

A. No. Mr. Spanos assumed that the terminal net salvage would be $40/kW for coal-fired generation plant accounts and $10/kW for the natural gas-fired combustion turbine generation plant accounts and $20/kW for the natural gas-fired combined cycle generation plant accounts. The full extent of his testimony on this issue is a single question and answer that states in part: "Based on studies for other utilities and the cost estimates of KU, it was determined that the dismantlement or decommissioning costs for steam production facilities is best calculated at $40/KW of the assets subject to final retirement. The percentage for dismantlement of hydro and other production facilities is $10/KW of the assets surviving at final retirement with the exception of the combined facility, which is

---

[25] Case Nos. 2007-00564, 2007-00565, 2008-00251, and 2008-00252.
[26] Case Nos. 2012-00221 and 2012-00222.

$20/KW."[27] When asked to provide all support for these assumptions, Mr. Spanos provided the following description, but no documentation:[28]

> The determination of the $/KW levels for dismantlement of generating facilities was based on numerous studies performed by engineering consulting firms that specialize in the dismantlement of generating facilities and an initial study performed and presented by the American Gas Association and Edison Electric Institute.

Despite a follow-up request to provide the supporting documentation, Mr. Spanos failed to provide any documentation, including the study that he referenced in his earlier responses.[29] This is relevant because the study that he claims to have relied on is nothing more than an average of projected dismantling costs compiled by Deloitte Touche, an accounting and consulting firm, which it prepared and presented in 1995 to a joint committee of the American Gas Association and the Edison Electric Institute. This is not a study in the sense that it actually assessed the cost to dismantle any generating assets and it is not a reliable basis to support the terminal net salvage estimates proposed by Mr. Spanos in this proceeding, particularly when he chose not to produce it in response to two requests from KIUC and another request from the Attorney General ("AG").[30]

Q. What is your recommendation?

---

[27] John Spanos Direct Testimony at 10-11.

[28] KU and LG&E responses to KIUC 1-2(a). I have attached a copy of these responses as my Exhibit___(LK-14).

[29] KU and LG&E responses to KIUC 2-1. I have attached a copy of these responses as my Exhibit___(LK-15).

[30] KU and LG&E responses to AG 1-180. I have attached a copy of these responses as my Exhibit___(LK-16).

A. I recommend that the Commission remove all terminal net negative salvage from the Companies' proposed depreciation rates for all generation plant accounts. I recommend that the Commission require the Companies to seek authorization to retire generating units and retire the units in place unless the Companies present compelling evidence that they are legally required to dismantle the facilities and remediate the site or that it is cost beneficial to do so. This is consistent with the Commission's historic practice, as I describe in the next section of my testimony. It also ensures that there is no inherent presumption that the facilities will be dismantled and the sites remediated decades into the future by including projections of the costs to do so in depreciation rates and recovering those costs from customers for decades.

If the Companies incur actual dismantling (demolition) costs in excess of salvage, then I recommend that the Commission authorize recovery of the actual prudent and reasonable costs through a retirement rider, as I describe in more detail in the next section of my testimony.

Alternatively, I recommend that the Commission limit the terminal net salvage to the negative 2.0% reflected in the present depreciation rates for all generation plant accounts.

Q. What are the effects of your recommendation?

A. The effects are a reduction in KU's revenue requirement of $9.717 million and a reduction in LG&E's revenue requirement of $5.832 million.

Q. Do changes in depreciation rates and expense affect utility earnings?

A. No. Depreciation is a timing issue, although it also implicates decisions on dismantling and site remediation. The utility is allowed to recover the prudent and reasonable costs of its regulated utility investments. The parameters (or assumptions) used to determine the depreciation rates change from depreciation study to depreciation study as more historic data is gathered for a particular asset or group of assets. For example, the present depreciation rates reflect life spans of 30 years for most of the Companies' natural gas-fired combustion turbines ("CTs") and combined cycle ("CC") generating units. However, the data indicate that life spans of 45 years are more appropriate. Thus, the depreciation rate will be changed going forward if the Commission agrees with my recommendation to change this parameter.

In a rate case, depreciation rates are set and depreciation expense is determined. The Commission sets the revenue requirement so that it matches the amount of depreciation expense. Thus, there is no effect on a utility's earnings from a reduction in depreciation rates compared to the utility's depreciation study because the ratemaking process matches the expense and related revenues.

<u>B. Terminal Net Salvage (Demolition) Costs Should Be Recovered Through An Asset Retirement Rider, But Only If There Is A Legal Obligation Or Demolition Is Cost Justified And Then Only After Costs Are Actually Incurred</u>

Q. Please describe how the Commission historically has provided recovery of terminal net salvage (demolition) costs.

A. Historically, the utilities subject to the Commission's jurisdiction have retired generating units in place after stabilizing the facilities and securing the sites. They have not dismantled the facilities or remediated the sites. In most cases, there is no legal obligation to dismantle the facilities or remediate the site as long as it is secured and monitored. To the extent that there are dismantlement or remediation costs, then the Commission has authorized deferrals of these costs and subsequent recoveries through amortization expense on a case by case basis. For example, the Commission recently authorized the Companies to defer the costs of ash pond remediation at retired plant sites and to recover the deferred costs through amortization expense in the ECR.[31]

Q. Has the Commission also recently authorized a form of surcharge recovery for retired generating facilities in a Kentucky Power Company proceeding?

A. Yes. The Commission adopted a retirement cost rider for Big Sandy 1 and the

[31] Case Nos. 2016-00026 and 2016-00027.

coal-fired components of Big Sandy 2 as the result of a settlement in Case No. 2012-00578. This retirement rider allows Kentucky Power Company to recover its remaining net book value of the coal-fired units, plus actual costs of removal, less actual salvage income. The Commission approved the retirement cost rider after it reviewed and determined that Kentucky Power Company's proposed shutdown and retirement of Big Sandy 1 and the conversion of Big Sandy 2 to natural gas were prudent and reasonable.

Q. How would this process and form of recovery apply to KU and LG&E for their future generating unit retirements, demolition, and site remediation?

A. First, it ensures that prudent and reasonable demolition and site remediation costs are recovered from customers, but only after they actually are incurred. Thus, it avoids all the nonsense of attempting to forecast the costs of dismantlement and remediation many decades before those events occur, if indeed they actually occur.

Second, it avoids the presumption that the facilities will be dismantled and the sites remediated decades before the decisions actually will be made. It involves the Commission in the review of the costs and benefits closer to the date of retirement and the decision to retire in place or dismantle and remediate before the facilities are retired and demolished and involves the Commission in oversight of the costs to dismantle and remediate if it approves this approach after its review.

Third, it ensures that only actual costs are recovered from customers, nothing more and nothing less.

C. Gas-Fired Generation Asset Life Spans Should Be Increased to Reflect Actual Experience And Planned Continued Operation of Assets As Shown in Companies' Integrated Resource Plan ("IRP") Filings

Q. Please describe the life spans assumed by Mr. Spanos in the depreciation studies for the natural gas-fired CT and CC generating units.

A. Mr. Spanos assumed that most of the Companies' CTs have life spans of 30 years and CCs (Cane Run 7) have life spans of 40 years, except for KU's Brown CT Units 9 and 10, which he assumed have life spans of 37 and 36 years, respectively; KU's Haefling CT Units 1, 2, and 3, which he assumed have life spans of 50 years; LG&E's Cane Run CT Unit 11 and Paddy's Run CT Units 11 and 12, which he assumed have a life spans of 48 years, LG&E's Zorn and River Road CT, which he assumed has a life span of 49 years.[32] Mr. Spanos also provided the probable retirement dates for each of these CTs and CCs in the depreciation studies, consistent with his proposed life spans.

Q. Are the life spans for these CTs and CCs reasonable?

A. No, the life spans for these units are unduly short and inconsistent with the

[32] Exhibit JJS-KU-1 and Exhibit JJS-LG&E-1 attached to Mr. Spanos Direct Testimony for each Company. The KU depreciation study includes a table showing proposed life spans and probable retirement dates at III-6 through III-7. The LG&E depreciation study includes a table showing proposed life spans and probable retirement dates at III-7 through III-8. I have attached a copy of these pages from the depreciation studies as my Exhibit___(LK-17) for ease of reference.

Companies' actual experience and plans for continued operation, except for the Haefling Units 1, 2, and 3, Cane Run Unit 11, Paddy's Run Units 11 and 12, and Zorn and River Road, which have longer life spans. With continued maintenance and investment, the Companies' actual experience is that they operate their gas-fired units for at least 45 years. They don't actually retire their units after only 30 years of service.

The Companies have no specific plans to retire the units with the shorter life spans. The probable retirement dates were developed and used by Mr. Spanos solely for the purposes of his depreciation studies.[33] In fact, the Companies plan to continue to maintain and invest in each generating unit "in such a way so as to ensure that, year over year, a minimum 20-year remaining useful life is expected."[34] This is further borne out by the Companies' Integrated Resource Plan ("IRP") filing in which they have a table wherein they specifically state that there are no scheduled retirement dates and another table that shows continued operation of all CT and CC units at least through 2028.[35] In 2028, some of the CT units will have been service for 60 years.

Q. What is your recommendation?

---

[33] KU response to KIUC 1-9 and LG&E response to KIUC 1-10, which state that "The Company does not assign retirement dates to its generating units, however, probable retirement dates are projected in order to calculate depreciation." I have attached a copy of these responses as my Exhibit___(LK-18).

[34] KU and LG&E responses to AG 1-193. I have attached a copy of these responses as my Exhibit___(LK-19).

[35] I have attached copies of selected pages from the Companies' 2014 IRP as my Exhibit___(LK-20).

A. I recommend that the Commission use a life span of at least 45 years for all CT and CC generating units. This is consistent with the Companies' actual experience for their oldest operating CT generating units and its consistent with the Companies' plans to continue operating their CT and CC generating units as long as it is economic for them to do so. Life spans of at least 45 years is still less than the 60 year life spans indicated for the older CT units in the Companies' IRP.

Q. What are the effects of your recommendation?

A. The effects are a reduction in KU's revenue requirement of $12.176 million and a reduction in LG&E's revenue requirement of $5.709 million. As discussed previously, even though my depreciation recommendation will reduce the rate increase on consumers, it will have no effect on the earnings of the Companies. This is because depreciation is a timing issue and the revenue requirement is set to match the depreciation expense in the test year. If the depreciation expense and revenue requirement are both reduced by the same amount, then there is no effect on earnings.

D. Customer Care System ("CCS") Life Span Should Be Increased to Reflect Upgrade That Is Underway And Planned Continued Use

Q. What is the probable retirement date used by Mr. Spanos in the depreciation studies for the CCS?

A. The Companies propose a probable retirement date of June 2019.

Q. Is that probable retirement date correct?

A. No. The correct probable retirement date is no earlier than June 2027. The Companies are presently in the process of upgrading the CCS. The upgrade will be installed in mid-2017. The Companies plan to continue to use the CCS at least through mid-2027. The Companies plan another upgrade in the 2021-2022 timeframe, which may extend the probable retirement date to mid-2032. There are no current plans to retire or replace the CCS.[36]

Q. What is your recommendation?

A. I recommend that the Commission modify the probable retirement date for the CCS to June 2027. This will reduce the depreciation rate for the CCS from 10.06% proposed by Mr. Spanos to 3.52%.

Q. What are the effects of your recommendation?

A. The effects are a reduction in KU's revenue requirement of $3.188 million and a reduction in LG&E's revenue requirement of $2.569 million. Again, because depreciation is a timing issue and the revenue requirement is set to match the depreciation expense in the test year, my recommendation will have no effect on the earnings of the Companies.

[36] KU response to KIUC 1-8 and LG&E response to KIUC 1-9. I have attached a copy of these responses as my Exhibit___(LK-21).

IX. QUANTIFICATION OF RETURN ON EQUITY

Q. Have you quantified the effect of Mr. Baudino's recommended return on common equity?

A. Yes. Mr. Baudino recommends a return on equity of 9.0% compared to the Companies' requested return on equity of 10.23%. Mr. Baudino's recommended return on equity for KU is 14.78% when grossed up for income taxes, bad debt expense, and Commission assessment, compared to KU's requested return on equity of 16.80% when grossed-up for income taxes, bad debt expense, and Commission assessment. Mr. Baudino's recommended return on equity for LG&E is 14.77% when grossed up for income taxes, bad debt expense, and Commission assessment compared to LG&E's return on equity of 16.79% when grossed-up for income taxes, bad debt expense, and Commission assessment. It is the grossed-up return on equity that is recovered in customer rates.

Q. What are the effects of Mr. Baudino's recommendations?

A. The effects are a reduction in KU's revenue requirement of $38.508 million and a reduction in LG&E's revenue requirement of $25.570 million, using the capitalization for each Company after KIUC's recommended adjustments.

Q. Have you quantified the effects of a 1.0% change in the return on common equity for each Company?

A. Yes. For KU, each 1.0% return on equity equals $31.207 million in revenue requirements. For LG&E, each 1.0% return on equity equals $20.788 million in revenue requirements. These quantifications reflect the capitalization for each Company after KIUC's recommended adjustments.

X. COMMISSION SHOULD BE AWARE OF POSSIBLE TAX CHANGES

Q. Do the Companies' revenue requirements reflect income tax expense and ADIT at the present federal income tax rate of 35%?

A. Yes. The Companies' income tax expense and ADIT are calculated based on a federal income tax rate of 35% base rate and surcharge purposes.

Q. If the federal income tax rate is reduced, perhaps to 15% or 20%, as proposed by the Trump administration, then what is the effect on the Companies' income tax expense, ADIT, and base rate and surcharge revenue requirements?

A. There will be significant reductions in the Companies' income tax expense and revenue requirements both from a reduction in the income tax expense calculated using the federal income tax rate and from an amortization of "excess" ADIT. This will reduce income tax expense included in the base revenue requirement as well as the income tax expense included in the environmental surcharge revenue requirement and all other surcharge revenue requirements that include income tax expense.

Income tax expense will be reduced by 57% if the federal income tax rate is reduced to 15%. For KU, this will result in a reduction in income tax expense of $53.568 million compared to the KIUC recommendations in this proceeding. For LG&E, this will result in a reduction in income tax expense of $35.334 million compared to the KIUC recommendations in this proceeding. I haven't calculated the reductions in the ECR revenue requirement for purposes of these proceedings, but the effects are significant and in addition to the effects on the base revenue requirements.

In addition, 57% of the ADIT will become "excess" and no longer will represent a future tax liability to be paid to the federal government. Instead, the ADIT will be amortized as negative income tax expense and further reduce the Companies' revenue requirements.

Q. What is your recommendation?

A. I recommend that the Commission be aware of the need to act expeditiously to reduce the Companies' revenue requirements coincident with the effective date of the federal income tax rate reduction.

Q. Does this complete your testimony?

A. Yes.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

LANE KOLLEN, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Lane Kollen

Sworn to and subscribed before me on this 3rd day of March 2017.

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
JULY 31, 2018
CHEROKEE COUNTY, GEORGIA

BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

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

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	**)))))**	**CASE NO. 2016-00371**

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

March 3, 2017

EXHIBIT ____ (LK-1)

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

Luther Rice University, MA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

Mr. Kollen has more than thirty years of utility industry experience in the financial, rate, tax, and planning areas. He specializes in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition and diversification. Mr. Kollen has expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

RESUME OF LANE KOLLEN, VICE PRESIDENT

EXPERIENCE

1986 to Present:	**J. Kennedy and Associates, Inc.:** Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Maryland, Minnesota, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, West Virginia and Wisconsin state regulatory commissions and the Federal Energy Regulatory Commission.
1983 to 1986:	**Energy Management Associates:** Lead Consultant. Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.
1976 to 1983:	**The Toledo Edison Company:** Planning Supervisor. Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including: Rate phase-ins. Construction project cancellations and write-offs. Construction project delays. Capacity swaps. Financing alternatives. Competitive pricing for off-system sales. Sale/leasebacks.

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
CF&I Steel, L.P.
Climax Molybdenum Company
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
Gallatin Steel
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for
  Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Customers, Inc.
Kimberly-Clark Company
Lehigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial
  Energy Consumers
Occidental Chemical Corporation
Ohio Energy Group
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy
  Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Cities in Texas-New Mexico Power Company's Service Territory
Cities in AEP Texas Central Company's Service Territory
Cities in AEP Texas North Company's Service Territory
Georgia Public Service Commission Staff
Kentucky Attorney General's Office, Division of Consumer Protection
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York State Energy Office
Office of Public Utility Counsel (Texas)

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation
Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan.
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County, completion.
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric Corp.	Financial workout plan.
5/88	M-87017-1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.

Date	Case	Jurisdict.	Party	Utility	Subject
5/88	M-87017-2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.
7/88	M-87017-1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
7/88	M-87017-2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense.
10/88	88-170-EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171-EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	8800-355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71).
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.

Date	Case	Jurisdict.	Party	Utility	Subject
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Recovery of CAAA costs, least cost financing.
9/91	91-231-E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	PUC Docket 10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.

Date	Case	Jurisdict.	Party	Utility	Subject
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense.
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
11/92	8649	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base.
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
3/93	93-01-EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission	Gulf States Utilities /Entergy Corp.	Merger.
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.

Date	Case	Jurisdict.	Party	Utility	Subject
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.
4/94	U-20647 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.
11/94	U-19904 Initial Post-Merger Earnings Review (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.
6/95	3905-U Rebuttal	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.

Date	Case	Jurisdict.	Party	Utility	Subject
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co., The Cleveland Electric Illuminating Co.	Competition, asset write-offs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC Docket 14965	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co., and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.
9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co., Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.
8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness.
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.

Date	Case	Jurisdict.	Party	Utility	Subject
11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.
11/97	U-22491	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	U-22491 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.

Date	Case	Jurisdict.	Party	Utility	Subject
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
4/99	99-02-05	Ct	Connecticut Industrial Utility Customers	Connecticut Light and Power Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Co.	Alternative regulation.
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.
6/99	U-23358	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, American Electric Power Co.	Merger Settlement and Stipulation.
7/99	97-596 Surrebuttal	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.

Date	Case	Jurisdict.	Party	Utility	Subject
7/99	98-0452-E-GI	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 Surrebuttal	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
8/99	98-474 98-083 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
8/99	98-0452-E-GI Rebuttal	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
10/99	U-24182 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
11/99	PUC Docket 21527	TX	The Dallas-Fort Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.
01/00	U-24182 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
04/00	99-1212-EL-ETP 99-1213-EL-ATA 99-1214-EL-AAM	OH	Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
05/00	2000-107	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	ECR surcharge roll-in to base rates.
05/00	U-24182 Supplemental Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments.
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.
05/00	99-1658-EL-ETP	OH	AK Steel Corp.	Cincinnati Gas & Electric Co.	Regulatory transition costs, including regulatory assets and liabilities, SFAS 109, ADIT, EDIT, ITC.
07/00	PUC Docket 22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements in projected test year.
07/00	U-21453	LA	Louisiana Public Service Commission	SWEPCO	Stranded costs, regulatory assets and liabilities.

Date	Case	Jurisdict.	Party	Utility	Subject
08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated affiliates, ratemaking adjustments.
10/00	SOAH Docket 473-00-1015 PUC Docket 22350	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.
10/00	R-00974104 Affidavit	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009	PA	Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.
12/00	U-21453, U-20925, U-22092 (Subdocket C) Surrebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
01/01	U-21453, U-20925, U-22092 (Subdocket B) Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	GPU, Inc. FirstEnergy Corp.	Merger, savings, reliability.
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on overall plan structure.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.

Date	Case	Jurisdict.	Party	Utility	Subject
05/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
07/01	U-21453, U-20925, U-22092 (Subdocket B) Transmission and Distribution Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Company	Revenue requirements, Rate Plan, fuel clause recovery.
11/01	14311-U Direct Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
11/01	U-25687 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, capital structure, allocation of regulated and nonregulated costs, River Bend uprate.
02/02	PUC Docket 25230	TX	The Dallas-Fort Worth Hospital Council and the Coalition of Independent Colleges and Universities	TXU Electric	Stipulation. Regulatory assets, securitization financing.
02/02	U-25687 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
03/02	14311-U Rebuttal Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards.
03/02	14311-U Rebuttal Panel with Michelle L. Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Revenue requirements. Nuclear life extension, storm damage accruals and reserve, capital structure, O&M expense.
04/02	U-25687 (Suppl. Surrebuttal)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
04/02	U-21453, U-20925 U-22092 (Subdocket C)	LA	Louisiana Public Service Commission	SWEPCO	Business separation plan, T&D Term Sheet, separations methodologies, hold harmless conditions.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
08/02	U-25888	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. and Entergy Louisiana, Inc.	System Agreement, production cost disparities, prudence.

Date	Case	Jurisdict.	Party	Utility	Subject
09/02	2002-00224 2002-00225	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Line losses and fuel clause recovery associated with off-system sales.
11/02	2002-00146 2002-00147	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Environmental compliance costs and surcharge recovery.
01/03	2002-00169	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Power Co.	Environmental compliance costs and surcharge recovery.
04/03	2002-00429 2002-00430	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Extension of merger surcredit, flaws in Companies' studies.
04/03	U-26527	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
06/03	EL01-88-000 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
06/03	2003-00068	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Environmental cost recovery, correction of base rate error.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Unit power purchases and sale cost-based tariff pursuant to System Agreement.
11/03	ER03-583-000, ER03-583-001, ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, ER03-682-002 ER03-744-000, ER03-744-001 (Consolidated)	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Marketing, L.P, and Entergy Power, Inc.	Unit power purchases and sale agreements, contractual provisions, projected costs, levelized rates, and formula rates.
12/03	U-26527 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
12/03	2003-0334 2003-0335	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Earnings Sharing Mechanism.
12/03	U-27136	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Purchased power contracts between affiliates, terms and conditions.
03/04	U-26527 Supplemental Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
03/04	2003-00433	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.

Date	Case	Jurisdict.	Party	Utility	Subject
03/04	2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	SOAH Docket 473-04-2459 PUC Docket 29206	TX	Cities Served by Texas-New Mexico Power Co.	Texas-New Mexico Power Co.	Stranded costs true-up, including valuation issues, ITC, ADIT, excess earnings.
05/04	04-169-EL-UNC	OH	Ohio Energy Group, Inc.	Columbus Southern Power Co. & Ohio Power Co.	Rate stabilization plan, deferrals, T&D rate increases, earnings.
06/04	SOAH Docket 473-04-4555 PUC Docket 29526	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Stranded costs true-up, including valuation issues, ITC, EDIT, excess mitigation credits, capacity auction true-up revenues, interest.
08/04	SOAH Docket 473-04-4555 PUC Docket 29526 (Suppl Direct)	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Interest on stranded cost pursuant to Texas Supreme Court remand.
09/04	U-23327 Subdocket B	LA	Louisiana Public Service Commission Staff	SWEPCO	Fuel and purchased power expenses recoverable through fuel adjustment clause, trading activities, compliance with terms of various LPSC Orders.
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission Staff	SWEPCO	Revenue requirements.
12/04	Case Nos. 2004-00321, 2004-00372	KY	Gallatin Steel Co.	East Kentucky Power Cooperative, Inc., Big Sandy Recc, et al.	Environmental cost recovery, qualified costs, TIER requirements, cost allocation.
01/05	30485	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric, LLC	Stranded cost true-up including regulatory Central Co. assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
02/05	18638-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements.
02/05	18638-U Panel with Tony Wackerly	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Comprehensive rate plan, pipeline replacement program surcharge, performance based rate plan.
02/05	18638-U Panel with Michelle Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Energy conservation, economic development, and tariff issues.
03/05	Case Nos. 2004-00426, 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, excess common equity ratio, deferral and amortization of nonrecurring O&M expense.
06/05	2005-00068	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, margins on allowances used for AEP system sales.
06/05	050045-EI	FL	South Florida Hospital and Heallthcare Assoc.	Florida Power & Light Co.	Storm damage expense and reserve, RTO costs, O&M expense projections, return on equity performance incentive, capital structure, selective second phase post-test year rate increase.

Date	Case	Jurisdict.	Party	Utility	Subject
08/05	31056	TX	Alliance for Valley Healthcare	AEP Texas Central Co.	Stranded cost true-up including regulatory assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
09/05	20298-U	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Revenue requirements, roll-in of surcharges, cost recovery through surcharge, reporting requirements.
09/05	20298-U Panel with Victoria Taylor	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Affiliate transactions, cost allocations, capitalization, cost of debt.
10/05	04-42	DE	Delaware Public Service Commission Staff	Artesian Water Co.	Allocation of tax net operating losses between regulated and unregulated.
11/05	2005-00351 2005-00352	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Workforce Separation Program cost recovery and shared savings through VDT surcredit.
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	System Sales Clause Rider, Environmental Cost Recovery Rider. Net Congestion Rider, Storm damage, vegetation management program, depreciation, off-system sales, maintenance normalization, pension and OPEB.
03/06	PUC Docket 31994	TX	Cities	Texas-New Mexico Power Co.	Stranded cost recovery through competition transition or change.
05/06	31994 Supplemental	TX	Cities	Texas-New Mexico Power Co.	Retrospective ADFIT, prospective ADFIT.
03/06	U-21453, U-20925, U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
03/06	NOPR Reg 104385-OR	IRS	Alliance for Valley Health Care and Houston Council for Health Education	AEP Texas Central Company and CenterPoint Energy Houston Electric	Proposed Regulations affecting flow- through to ratepayers of excess deferred income taxes and investment tax credits on generation plant that is sold or deregulated.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	2002-2004 Audit of Fuel Adjustment Clause Filings. Affiliate transactions.
07/06	R-00061366, Et. al.	PA	Met-Ed Ind. Users Group Pennsylvania Ind. Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of NUG-related stranded costs, government mandated program costs, storm damage costs.
07/06	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
08/06	U-21453, U-20925, U-22092 (Subdocket J)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
11/06	05CVH03-3375 Franklin County Court Affidavit	OH	Various Taxing Authorities (Non-Utility Proceeding)	State of Ohio Department of Revenue	Accounting for nuclear fuel assemblies as manufactured equipment and capitalized plant.
12/06	U-23327 Subdocket A Reply Testimony	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.

Date	Case	Jurisdict.	Party	Utility	Subject
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
03/07	PUC Docket 33309	TX	Cities	AEP Texas Central Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	PUC Docket 33310	TX	Cities	AEP Texas North Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Interim rate increase, RUS loan covenants, credit facility requirements, financial condition.
03/07	U-29157	LA	Louisiana Public Service Commission Staff	Cleco Power, LLC	Permanent (Phase II) storm damage cost recovery.
04/07	U-29764 Supplemental and Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
04/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and state income tax effects on equalization remedy receipts.
04/07	ER07-684-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Fuel hedging costs and compliance with FERC USOA.
05/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and account 924 effects on MSS-3 equalization remedy payments and receipts.
06/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC, Entergy Gulf States, Inc.	Show cause for violating LPSC Order on fuel hedging costs.
07/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Revenue requirements, post-test year adjustments, TIER, surcharge revenues and costs, financial need.
07/07	ER07-956-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Storm damage costs related to Hurricanes Katrina and Rita and effects of MSS-3 equalization payments and receipts.
10/07	05-UR-103 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	05-UR-103 Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	25060-U Direct	GA	Georgia Public Service Commission Public Interest Adversary Staff	Georgia Power Company	Affiliate costs, incentive compensation, consolidated income taxes, §199 deduction.
11/07	06-0033-E-CN Direct	WV	West Virginia Energy Users Group	Appalachian Power Company	IGCC surcharge during construction period and post-in-service date.

Date	Case	Jurisdict.	Party	Utility	Subject
11/07	ER07-682-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	ER07-682-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	07-551-EL-AIR Direct	OH	Ohio Energy Group, Inc.	Ohio Edison Company, Cleveland Electric Illuminating Company, Toledo Edison Company	Revenue requirements.
02/08	ER07-956-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.
03/08	ER07-956-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.
04/08	2007-00562, 2007-00563	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas and Electric Co.	Merger surcredit.
04/08	26837 Direct Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Suppl Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
06/08	2008-00115	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Environmental surcharge recoveries, including costs recovered in existing rates, TIER.
07/08	27163 Direct	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Revenue requirements, including projected test year rate base and expenses.
07/08	27163 Taylor, Kollen Panel	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Affiliate transactions and division cost allocations, capital structure, cost of debt.
08/08	6680-CE-170 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Nelson Dewey 3 or Colombia 3 fixed financial parameters.
08/08	6680-UR-116 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	CWIP in rate base, labor expenses, pension expense, financing, capital structure, decoupling.

Date	Case	Jurisdict.	Party	Utility	Subject
08/08	6680-UR-116 Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Capital structure.
08/08	6690-UR-119 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, incentive compensation, Crane Creek Wind Farm incremental revenue requirement, capital structure.
09/08	6690-UR-119 Surrebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, Section 199 deduction.
09/08	08-935-EL-SSO, 08-918-EL-SSO	OH	Ohio Energy Group, Inc.	First Energy	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	08-917-EL-SSO	OH	Ohio Energy Group, Inc.	AEP	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	2007-00564, 2007-00565, 2008-00251 2008-00252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Company	Revenue forecast, affiliate costs, ELG v ASL depreciation procedures, depreciation expenses, federal and state income tax expense, capitalization, cost of debt.
11/08	EL08-51	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities, regulatory asset and bandwidth remedy.
11/08	35717	TX	Cities Served by Oncor Delivery Company	Oncor Delivery Company	Recovery of old meter costs, asset ADFIT, cash working capital, recovery of prior year restructuring costs, levelized recovery of storm damage costs, prospective storm damage accrual, consolidated tax savings adjustment.
12/08	27800	GA	Georgia Public Service Commission	Georgia Power Company	AFUDC versus CWIP in rate base, mirror CWIP, certification cost, use of short term debt and trust preferred financing, CWIP recovery, regulatory incentive.
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
01/09	ER08-1056 Supplemental Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Blytheville leased turbines; accumulated depreciation.
02/09	EL08-51 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities regulatory asset and bandwidth remedy.
02/09	2008-00409 Direct	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Revenue requirements.
03/09	ER08-1056 Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
03/09 04/09	U-21453, U-20925 U-22092 (Sub J) Direct Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
04/09	2009-00040 Direct-Interim (Oral)	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Emergency interim rate increase; cash requirements.

Date	Case	Jurisdict.	Party	Utility	Subject
04/09	PUC Docket 36530	TX	State Office of Administrative Hearings	Oncor Electric Delivery Company, LLC	Rate case expenses.
05/09	ER08-1056 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
06/09	2009-00040 Direct-Permanent	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements, TIER, cash flow.
07/09	080677-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Multiple test years, GBRA rider, forecast assumptions, revenue requirement, O&M expense, depreciation expense, Economic Stimulus Bill, capital structure.
08/09	U-21453, U-20925, U-22092 (Subdocket J) Supplemental Rebuttal	LA	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
08/09	8516 and 29950	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Modification of PRP surcharge to include infrastructure costs.
09/09	05-UR-104 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company	Revenue requirements, incentive compensation, depreciation, deferral mitigation, capital structure, cost of debt.
09/09	09AL-299E	CO	CF&I Steel, Rocky Mountain Steel Mills LP, Climax Molybdenum Company	Public Service Company of Colorado	Forecasted test year, historic test year, proforma adjustments for major plant additions, tax depreciation.
09/09	6680-UR-117 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Power and Light Company	Revenue requirements, CWIP in rate base, deferral mitigation, payroll, capacity shutdowns, regulatory assets, rate of return.
10/09	09A-415E Answer	CO	Cripple Creek & Victor Gold Mining Company, et al.	Black Hills/CO Electric Utility Company	Cost prudence, cost sharing mechanism.
10/09	EL09-50 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
10/09	2009-00329	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Trimble County 2 depreciation rates.
12/09	PUE-2009-00030	VA	Old Dominion Committee for Fair Utility Rates	Appalachian Power Company	Return on equity incentive.
12/09	ER09-1224 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	ER09-1224 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.

Date	Case	Jurisdict.	Party	Utility	Subject
01/10	EL09-50 Rebuttal Supplemental Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
02/10	ER09-1224 Final	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
02/10	30442 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Revenue requirement issues.
02/10	30442 McBride-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Affiliate/division transactions, cost allocation, capital structure.
02/10	2009-00353	KY	Kentucky Industrial Utility Customers, Inc., Attorney General	Louisville Gas and Electric Company, Kentucky Utilities Company	Ratemaking recovery of wind power purchased power agreements.
03/10	2009-00545	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Ratemaking recovery of wind power purchased power agreement.
03/10	E015/GR-09-1151	MN	Large Power Interveners	Minnesota Power	Revenue requirement issues, cost overruns on environmental retrofit project.
03/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation expense and effects on System Agreement tariffs.
04/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Revenue requirement issues.
04/10	2009-00458, 2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas and Electric Company	Revenue requirement issues.
08/10	31647	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Revenue requirement and synergy savings issues.
08/10	31647 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Affiliate transaction and Customer First program issues.
08/10	2010-00204	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	PPL acquisition of E.ON U.S. (LG&E and KU) conditions, acquisition savings, sharing deferral mechanism.
09/10	38339 Direct and Cross-Rebuttal	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Revenue requirement issues, including consolidated tax savings adjustment, incentive compensation FIN 48; AMS surcharge including roll-in to base rates; rate case expenses.
09/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation rates and expense input effects on System Agreement tariffs.
09/10	2010-00167	KY	Gallatin Steel	East Kentucky Power Cooperative, Inc.	Revenue requirements.

Date	Case	Jurisdict.	Party	Utility	Subject
09/10	U-23327 Subdocket E Direct	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
11/10	U-23327 Rebuttal	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
09/10	U-31351	LA	Louisiana Public Service Commission Staff	SWEPCO and Valley Electric Membership Cooperative	Sale of Valley assets to SWEPCO and dissolution of Valley.
10/10	10-1261-EL-UNC	OH	Ohio OCC, Ohio Manufacturers Association, Ohio Energy Group, Ohio Hospital Association, Appalachian Peace and Justice Network	Columbus Southern Power Company	Significantly excessive earnings test.
10/10	10-0713-E-PC	WV	West Virginia Energy Users Group	Monongahela Power Company, Potomac Edison Power Company	Merger of First Energy and Allegheny Energy.
10/10	U-23327 Subdocket F Direct	LA	Louisiana Public Service Commission Staff	SWEPCO	AFUDC adjustments in Formula Rate Plan.
11/10	EL10-55 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation rates and expense input effects on System Agreement tariffs.
12/10	ER10-1350 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
01/11	ER10-1350 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
03/11 04/11	ER10-2001 Direct Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Arkansas, Inc.	EAI depreciation rates.
04/11	U-23327 Subdocket E	LA	Louisiana Public Service Commission Staff	SWEPCO	Settlement, incl resolution of S02 allowance expense, var O&M expense, sharing of OSS margins.
04/11 05/11	38306 Direct Suppl Direct	TX	Cities Served by Texas-New Mexico Power Company	Texas-New Mexico Power Company	AMS deployment plan, AMS Surcharge, rate case expenses.
05/11	11-0274-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company, Wheeling Power Company	Deferral recovery phase-in, construction surcharge.
05/11	2011-00036	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements.
06/11	29849	GA	Georgia Public Service Commission Staff	Georgia Power Company	Accounting issues related to Vogtle risk-sharing mechanism.
07/11	ER11-2161 Direct and Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
07/11	PUE-2011-00027	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Return on equity performance incentive.

Date	Case	Jurisdict.	Party	Utility	Subject
07/11	11-346-EL-SSO 11-348-EL-SSO 11-349-EL-AAM 11-350-EL-AAM	OH	Ohio Energy Group	AEP-OH	Equity Stabilization Incentive Plan; actual earned returns; ADIT offsets in riders.
08/11	U-23327 Subdocket F Rebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Depreciation rates and service lives; AFUDC adjustments.
08/11	05-UR-105	WI	Wisconsin Industrial Energy Group	WE Energies, Inc.	Suspended amortization expenses; revenue requirements.
08/11	ER11-2161 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
09/11	PUC Docket 39504	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Investment tax credit, excess deferred income taxes; normalization.
09/11	2011-00161 2011-00162	KY	Kentucky Industrial Utility Consumers, Inc.	Louisville Gas & Electric Company, Kentucky Utilities Company	Environmental requirements and financing.
10/11	11-4571-EL-UNC 11-4572-EL-UNC	OH	Ohio Energy Group	Columbus Southern Power Company, Ohio Power Company	Significantly excessive earnings.
10/11	4220-UR-117 Direct	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.
11/11	4220-UR-117 Surrebuttal	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.
11/11	PUC Docket 39722	TX	Cities Served by AEP Texas Central Company	AEP Texas Central Company	Investment tax credit, excess deferred income taxes; normalization.
02/12	PUC Docket 40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Temporary rates.
03/12	11AL-947E Answer	CO	Climax Molybdenum Company and CF&I Steel, L.P. d/b/a Evraz Rocky Mountain Steel	Public Service Company of Colorado	Revenue requirements, including historic test year, future test year, CACJA CWIP, contra-AFUDC.
03/12	2011-00401	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Big Sandy 2 environmental retrofits and environmental surcharge recovery.
4/12	2011-00036 Direct Rehearing Supplemental Direct Rehearing	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Rate case expenses, depreciation rates and expense.
04/12	10-2929-EL-UNC	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, CRES capacity charges, Equity Stabilization Mechanism
05/12	11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, Equity Stabilization Mechanism, Retail Stability Rider.

Date	Case	Jurisdict.	Party	Utility	Subject
05/12	11-4393-EL-RDR	OH	Ohio Energy Group	Duke Energy Ohio, Inc.	Incentives for over-compliance on EE/PDR mandates.
06/12	40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Revenue requirements, including ADIT, bonus depreciation and NOL, working capital, self insurance, depreciation rates, federal income tax expense.
07/12	120015-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Revenue requirements, including vegetation management, nuclear outage expense, cash working capital, CWIP in rate base.
07/12	2012-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental retrofits, including environmental surcharge recovery.
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Company	Section 1603 grants, new solar facility, payroll expenses, cost of debt.
10/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Revenue requirements, including off-system sales, outage maintenance, storm damage, injuries and damages, depreciation rates and expense.
10/12	120015-EI Direct	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Settlement issues.
11/12	120015-EI Rebuttal	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Settlement issues.
10/12	40604	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Policy and procedural issues, revenue requirements, including AFUDC, ADIT – bonus depreciation & NOL, incentive compensation, staffing, self-insurance, net salvage, depreciation rates and expense, income tax expense.
11/12	40627 Direct	TX	City of Austin d/b/a Austin Energy	City of Austin d/b/a Austin Energy	Rate case expenses.
12/12	40443	TX	Cities Served by SWEPCO	Southwestern Electric Power Company	Revenue requirements, including depreciation rates and service lives, O&M expenses, consolidated tax savings, CWIP in rate base, Turk plant costs.
12/12	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Termination of purchased power contracts between EGSL and ETI, Spindletop regulatory asset.
01/13	ER12-1384 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Little Gypsy 3 cancellation costs.
02/13	40627 Rebuttal	TX	City of Austin d/b/a Austin Energy	City of Austin d/b/a Austin Energy	Rate case expenses.
03/13	12-426-EL-SSO	OH	The Ohio Energy Group	The Dayton Power and Light Company	Capacity charges under state compensation mechanism, Service Stability Rider, Switching Tracker.
04/13	12-2400-EL-UNC	OH	The Ohio Energy Group	Duke Energy Ohio, Inc.	Capacity charges under state compensation mechanism, deferrals, rider to recover deferrals.
04/13	2012-00578	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Resource plan, including acquisition of interest in Mitchell plant.

Date	Case	Jurisdict.	Party	Utility	Subject
05/13	2012-00535	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.
06/13	12-3254-EL-UNC	OH	The Ohio Energy Group, Inc., Office of the Ohio Consumers' Counsel	Ohio Power Company	Energy auctions under CBP, including reserve prices.
07/13	2013-00144	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Biomass renewable energy purchase agreement.
07/13	2013-00221	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Hawesville Smelter market access.
10/13	2013-00199	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.
12/13	2013-00413	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Sebree Smelter market access.
01/14	ER10-1350	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 lease accounting and treatment in annual bandwidth filings.
04/14	ER13-432 Direct	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	UP Settlement benefits and damages.
05/14	PUE-2013-00132	VA	HP Hood LLC	Shenandoah Valley Electric Cooperative	Market based rate; load control tariffs.
07/14	PUE-2014-00033	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Fuel and purchased power hedge accounting, change in FAC Definitional Framework.
08/14	ER13-432 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	UP Settlement benefits and damages.
08/14	2014-00134	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Requirements power sales agreements with Nebraska entities.
09/14	E-015/CN-12-1163 Direct	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class cost allocation.
10/14	2014-00225	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Allocation of fuel costs to off-system sales.
10/14	ER13-1508	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy service agreements and tariffs for affiliate power purchases and sales; return on equity.
10/14	14-0702-E-42T 14-0701-E-D	WV	West Virginia Energy Users Group	First Energy-Monongahela Power, Potomac Edison	Consolidated tax savings; payroll; pension, OPEB, amortization; depreciation; environmental surcharge.
11/14	E-015/CN-12-1163 Surrebuttal	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class allocation.
11/14	05-376-EL-UNC	OH	Ohio Energy Group	Ohio Power Company	Refund of IGCC CWIP financing cost recoveries.

Date	Case	Jurisdict.	Party	Utility	Subject
11/14	14AL-0660E	CO	Climax, CF&I Steel	Public Service Company of Colorado	Historic test year v. future test year; AFUDC v. current return; CACJA rider, transmission rider; equivalent availability rider; ADIT; depreciation; royalty income; amortization.
12/14	EL14-026	SD	Black Hills Industrial Intervenors	Black Hills Power Company	Revenue requirement issues, including depreciation expense and affiliate charges.
12/14	14-1152-E-42T	WV	West Virginia Energy Users Group	AEP-Appalachian Power Company	Income taxes, payroll, pension, OPEB, deferred costs and write offs, depreciation rates, environmental projects surcharge.
01/15	9400-YO-100 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Energy Corporation	WEC acquisition of Integrys Energy Group, Inc.
01/15	14F-0336EG 14F-0404EG	CO	Development Recovery Company LLC	Public Service Company of Colorado	Line extension policies and refunds.
02/15	9400-YO-100 Rebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Energy Corporation	WEC acquisition of Integrys Energy Group, Inc.
03/15	2014-00396	KY	Kentucky Industrial Utility Customers, Inc.	AEP-Kentucky Power Company	Base, Big Sandy 2 retirement rider, environmental surcharge, and Big Sandy 1 operation rider revenue requirements, depreciation rates, financing, deferrals.
03/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company and Louisville Gas and Electric Company	Revenue requirements, staffing and payroll, depreciation rates.
04/15	2014-00450	KY	Kentucky Industrial Utility Customers, Inc. and the Attorney General of the Commonwealth of Kentucky	AEP-Kentucky Power Company	Allocation of fuel costs between native load and off-system sales.
04/15	2014-00455	KY	Kentucky Industrial Utility Customers, Inc. and the Attorney General of the Commonwealth of Kentucky	Big Rivers Electric Corporation	Allocation of fuel costs between native load and off-system sales.
04/15	ER2014-0370	MO	Midwest Energy Consumers' Group	Kansas City Power & Light Company	Affiliate transactions, operation and maintenance expense, management audit.
05/15	PUE-2015-00022	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Fuel and purchased power hedge accounting; change in FAC Definitional Framework.
05/15 09/15	EL10-65 Direct, Rebuttal Complaint	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Accounting for AFUDC Debt, related ADIT.
07/15	EL10-65 Direct and Answering Consolidated Bandwidth Dockets	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback ADIT, Bandwidth Formula.
09/15	14-1693-EL-RDR	OH	Public Utilities Commission of Ohio	Ohio Energy Group	PPA rider for charges or credits for physical hedges against market.

Date	Case	Jurisdict.	Party	Utility	Subject
12/15	45188	TX	Cities Served by Oncor Electric Delivery Company	Oncor Electric Delivery Company	Hunt family acquisition of Oncor; transaction structure; income tax savings from real estate investment trust (REIT) structure; conditions.
12/15 01/16	6680-CE-176 Direct, Surrebuttal, Supplemental Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Need for capacity and economics of proposed Riverside Energy Center Expansion project; ratemaking conditions.
03/16 0/16 04/16 05/16 06/16	EL01-88 Remand Direct Answering Cross-Answering Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Bandwidth Formula: Capital structure, fuel inventory, Waterford 3 sale/leaseback, Vidalia purchased power, ADIT, Blythesville, Spindletop, River Bend AFUDC, property insurance reserve, nuclear depreciation expense.
03/16	15-1673-E-T	WV	West Virginia Energy Users Group	Appalachian Power Company	Terms and conditions of utility service for commercial and industrial customers, including security deposits.
04/16	39971 Panel Direct	GA	Georgia Public Service Commission Staff	Southern Company, AGL Resources, Georgia Power Company, Atlanta Gas Light Company	Southern Company acquisition of AGL Resources, risks, opportunities, quantification of savings, ratemaking implications, conditions, settlement.
04/16	2015-00343	KY	Office of the Attorney General	Atmos Energy Corporation	Revenue requirements, including NOL ADIT, affiliate transactions.
04/16	2016-00070	KY	Office of the Attorney General	Atmos Energy Corporation	R & D Rider.
05/16	2016-00026 2016-00027	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Need for environmental projects, calculation of environmental surcharge rider.
05/16	16-G-0058 16-G-0059	NY	New York City	Keyspan Gas East Corp., Brooklyn Union Gas Company	Depreciation, including excess reserves, leak prone pipe.
06/16	160088-EI	FL	South Florida Hospital and Healthcare Association	Florida Power and Light Company	Fuel Adjustment Clause Incentive Mechanism re: economy sales and purchases, asset optimization.
07/16	160021-EI	FL	South Florida Hospital and Healthcare Association	Florida Power and Light Company	Revenue requirements, including capital recovery, depreciation, ADIT.
08/16	15-1022-EL-UNC 16-1105-EL-UNC	OH	Ohio Energy Group	AEP Ohio Power Company	SEET earnings, effects of other pending proceedings.
9/16	2016-00162	KY	Office of the Attorney General	Columbia Gas Kentucky	Revenue requirements, O&M expense, depreciation, affiliate transactions.
09/16	E-22 Sub 519, 532, 533	NC	Nucor Steel	Dominion North Carolina Power Company	Revenue requirements, deferrals and amortizations.

Date	Case	Jurisdict.	Party	Utility	Subject
09/16	15-1256-G-390P (Reopened) 16-0922-G-390P	WV	West Virginia Energy Users Group	Mountaineer Gas Company	Infrastructure rider, including NOL ADIT and other income tax normalization and calculation issues.
10/16	10-2929-EL-UNC 11-346-EL-SSO 11-348-EL-SSO 11-349-EL-SSO 11-350-EL-SSO 14-1186-EL-RDR	OH	Ohio Energy Group	AEP Ohio Power Company	State compensation mechanism, capacity cost, Retail Stability Rider deferrals, refunds, SEET
11/16	16-0395-EL-SSO Direct	OH	Ohio Energy Group	Dayton Power & Light Company	Credit support and other riders; financial stability of Utility, holding company
01/17	46238	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Company	Acquisition of Oncor by Hunt family-owned entities; restructuring as REIT; income taxes
02/17	16-0395-EL-SSO Direct (Stipulation)	OH	Ohio Energy Group	Dayton Power & Light Company	Non-unanimous stipulation re: credit support and other riders; financial stability of utility, holding company
02/17	45414	TX	Cities of Midland, McAllen, and Colorado City	Sharyland Utilities, LP, Sharyland Distribution & Transmission Services, LLC	Income taxes, depreciation, deferred costs, affiliate expenses

EXHIBIT ____ (LK-2)

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. 16

Responding Witness: Robert M. Conroy / John P. Malloy

Q.1-16. Refer to Exhibit JPM-l at Section 7.

a. Refer to page 35 and the references to the 2008 EPRI study. Please provide a copy of this study and all other documents reviewed by the Companies to determine the avoidable non-technical line losses.

b. Please provide the annual actual distribution line losses for the most recent ten years.

c. Please provide a copy of all empirical studies and/or analyses performed by or on behalf of the Companies or other PPL affiliates that attempts to quantify actual non-technical line losses, if any. If none, then please explain why the Companies or other PPL affiliates have not performed such studies and/or analyses.

d. Please provide all studies performed by PPL affiliates that address their actual experience in reduction of non-technical line losses or actual line losses after implementation of AMS.

e. Please confirm that the Companies assume that the AMS meters will have service lives of 20 years and that, once installed, none of the meters will be retired or replaced.

f. Please confirm that the Companies' cost/benefit study is limited to 20 years and does not address replacement of the entirety of the AMS meters within the next 5 years.

g. Please indicate whether the Companies considered a longer cost/benefit study period but decided to truncate the study period in order to avoid including the cost to replace most or all of the AMS meters within the 25 year period.

h. Please provide the average service life for the AMS meters. Provide a copy of all support relied on for this determination.

i. Please confirm that the meters in account 370.20 Meters — AMS at December 31, 2015 were placed in service in 2015.

j. Please confirm that Mr. Malloy agrees with the claims by Mr. Spanos in his depreciation study filed in this proceeding that "These meters are expected to have a shorter average life and maximum life than the standard meters they are replacing. The most consistent average life within the industry for new technology electric meters is 15 years, with a maximum life potential of 25 years." On this basis, Mr. Spanos used 15 years for the service life in his depreciation study. If Mr. Malloy does not agree with Mr. Spanos with respect to the 15 year service life of these meters, then please describe the specific disagreement(s) and the reasons why Mr. Malloy disagrees with Mr. Spanos.

k. Please indicate if Mr. Maloy and Mr. Spanos discussed the assumptions and inconsistencies regarding AMS meter service lives reflected in the depreciation study and/or the AMS business case economic analyses.

A.1-16.

a. See attached. EPRI has recently moved the study referenced by the Company to the public domain. In addition to the EPRI study, the Company referenced Duke Energy Kentucky Inc.'s KPSC Case No. 2016-00152 which cited the same EPRI study.

b. See response to AG 1-13.

c. See attached.

d. The Company is not aware of any studies performed by PPL affiliates that address their actual experience in reduction of non-technical line losses or actual line losses after implementation of AMS.

e. The Company confirms that the AMS meters are expected to have service lives of 20 years, but the Company does not confirm that once installed none of the meters will be retired or replaced.

f. The Companies' cost-benefit study is limited to 24 years to include the projected deployment years through the full expected service life of the meters. The cost-benefit study does not address replacement of the entirety of the AMS meters within the next 5 years, which is appropriate because the cost-benefit study also does not attempt to account for the benefits associated with such replacement meters over their useful lifetimes.

g. The Companies considered various cost-benefit study periods but decided to use a 20 year horizon to best align with the expected service life of the meters. See also the response to f. above.

h. The average service life for the AMS meters is assumed to be 20 years. See attached.

i. Confirmed.

j. The Company agrees with the claims by Mr. Spanos.

k. Messrs. Malloy and Spanos did not have such a discussion. But the Company disagrees with the premise of the question. Mr. Spanos noted that lives for AMS-type meters can extend to 25 years. The Companies have their own experience in this regard, particularly with the Landis + Gyr system deployed in Wilmore, Kentucky, which indicates such meters can have service lives beyond 15 years. Therefore, assuming a 20-year useful life for the Companies' cost-benefit analysis was reasonable.

ELECTRIC POWER
RESEARCH INSTITUTE

Advanced Metering Infrastructure Technology

Limiting Non-Technical Distribution Losses In The Future

1016049

Measurement

Non-technical losses, by definition, are losses that are not accounted for and are, therefore, not subject to analytical measurement. Non-technical losses are simply the difference between the energy delivered to the distribution system and billed to end-users, less technical losses. Although there is agreement on the importance of non-technical losses, there is no firm data to define the level of losses on an industrywide basis. However, the importance of non-technical losses, especially in terms of their impact on revenue, is such that distribution utilities try to quantify them.

Such quantification is very difficult. Quantifying what statisticians call "unaccountable for" attempts the impossible. There is an inherent difficulty is obtaining data on unmetered supplies and theft. Estimating the revenue impact of non-technical losses presents yet further difficulties. This is brought into relief when trying to measure the benefits of AMI in reducing non-technical losses. Although there are expectations that AMI will help to reduce non-technical losses, the measurement of benefits (or costs) from AMI deployment are considered non-quantifiable. For example, the framework for the business case adopted by the California Public Utilities Commission lists the reduction of non-technical losses as a benefit, but states that they are "not quantifiable, qualitative."[5]

Utilities rely on studies that are designed to calculate the magnitude, composition, and distribution of system losses based on annual aggregate metering information for energy purchases, energy sales, and system modeling methods. These studies are compared to industry and academic studies and models to establish the magnitude, composition, and distribution of losses.

Utilities have developed methods to measure non-technical losses primarily based on detection by manual meter readings and statistical analysis. These are often inaccurate. This is because the data rely heavily on the records of detected cases, rather than by actual measurement of the electrical power system. The reason that measurement or monitoring the power system is not the preferred method of measuring non-technical losses is because the infrastructure of the system, specifically the metering system, makes accurate and detailed loss determination impossible.[6] Measuring distribution line loses directly is not economic.[7]

The metering system is focused on the end-user, not on intermediary stages in the power distribution where technical and non-technical losses could be more accurately measured.

[5] *AMI Potential Benefits Categories Recommended Framework for the Business Case Analysis of Advanced Metering Infrastructure* (Draft Report), Moises Chavez, CPUC and Mike Messenger, CEC April 14, 2004. Easier identification of energy theft is categorized as "not quantifiable, qualitative"; meter accuracy, detection of meter failures, reduction in "idle usage," and billing accuracy are categorized as "short term."

[6] *Non-Technical Losses in Electrical Power Systems*, Thesis, Fritz J. and Dolores H. Russ College of Engineering and Technology Ohio University, Dan Suriyamongkol. November 2002.

[7] For the accurate measurement of technical losses on transmission and distribution systems, it would be necessary to install metering equipment at each voltage level of transmission and transformation.

The only real solution for identifying the non-technical loss component from transmission and distribution losses is through studies at the distribution utility level. Technical losses can be isolated at substations, and the differences with end-use consumption calculated from that point. Unfortunately, such studies are not conducted on a consistent or industrywide basis.

To get a magnitude measure of the impact of non-technical losses on revenue for purposes of this study, the approach is to examine aggregate measurements of revenue and "distribution" losses from reliable government statistical sources and apply ratios from various industry surveys and reports. The available data sources and their limitations must be taken into close account when considering the accuracy of the results. Economic loss levels tend to be system-specific. In the end, the resulting measure of revenue impact from non-technical losses is an order of magnitude estimation. Nonetheless, this approach is sufficient to demonstrate the value of each distribution utility taking its own measure of non-technical losses.

Data Sources

Data on revenue losses from non-technical losses are extremely difficult to come by. Data on non-technical losses are not collected by the Energy Information Administration (EIA) or industry associations. Data on the revenue attributable to those losses are not collected or estimated on an industrywide basis. Electric utilities consider these data confidential because they have implications for operating and financial performance.

Statistics on net generation and "transmission and distribution losses and unaccounted for," measured in kilowatt hours, are available in the Annual Energy Review.[8] Statistics on revenue from retail sales to ultimate customers and the supply and disposition of electricity are available from the Electric Power Annual.[9]

The most exhaustive study on revenue *metering* losses per se was made by EPRI in 2000.[10] The focus of this study was metering, anomalies, metering integrity, and theft rather than revenue and the full economic impact of non-technical losses.[11] This study was conducted before the benefits of automatic meter reading (AMR)/AMI had become noticeable. The study looks forward to that day though in its conclusion.

> "[Utilities have] a strong interest in quantifying these losses to assess their full effect on utility revenues and to provide a basis for mitigating technologies, such as Automatic

[8] Table 8.1 Electricity Overview, 1949-2006, Report No. DOE/EIA-0384(2006), Annual Energy Review 2006.

[9] Table 7.3 Revenue from Retail Sales of Electricity to Ultimate Customers by Sector, by Provider, 1995 through 2006 and Table ES2 Supply and Disposition of Electricity, 1995 through 2006, Electric Power Annual. October 22, 2007.

[10] *Revenue Metering Loss Assessment*, EPRI, Palo Alto, CA, Arizona Public Service Co., Phoenix, AZ, National Grid USA, Worcester, MA, South Carolina Electric & Gas Co., Columbia, SC and Baltimore Gas & Electric Co., Baltimore, MD: 2001. 1000365.

[11] Ibid. For example, the definition of meter/billing errors states, "Included in this class are all scenarios involving personnel actions, where 'people errors' compromise metering integrity because of inexperience, inattention, lack of review, and lack of training. ... Meter mis-installation falls into this category."

EXHIBIT ____ (LK-3)

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. 15

Responding Witness: Robert M. Conroy / John P. Malloy / Counsel

Q.1-15. Refer to page 23, lines 8-14 of Mr. Malloy's Direct Testimony wherein he states:

The other large driver of savings results from customers using less energy and using it more efficiently as they learn more about their own usage from the web portal that will be available to them as part of the AMS deployment. The Companies and other utilities have observed that customers who actively access such information tend to decrease their usage slightly. Aggregating those savings through 2039 produces net savings of over $166 million (nominal) and over $66 million NPV, which are savings customers will receive directly by reducing their bills through reduced usage.

a. Please confirm that a reduction in customer revenues is not a reduction in the Companies' costs and that the $166 million is not a savings to the Companies. If the Company cannot confirm this, then please explain why not.

b. Please confirm that the reduction in customer revenues does not result in a reduction in the Companies' revenue requirements; it simply means that the Companies' costs must be recovered over fewer billing units, all else equal. If the Company cannot confirm this, then please explain why not.

c. Please provide a copy of all internal correspondence that addresses whether a reduction in revenues is a valid benefit that should be included in the Companies' cost/benefit analyses.

d. Please identify each person, their position, and their role in the decision to include a reduction in revenues as a savings in the Companies' cost/benefit analyses.

e. Please confirm that the Companies recover the revenues lost due to energy efficiency and demand response initiatives through increased charges per billing unit, all else equal. If the Company cannot confirm this, then please explain why not.

A.1-15.

a. The $166 million (nominal) is a savings residential customers are projected to receive directly by reducing their bills through reduced energy usage. The Companies will presumably spend less on fuel and other consumables resulting from these energy savings, though those reduced variable costs will be less than $166 million (nominal). The net reduction in revenues would result in less revenue (at least relatively less revenue) from those customers to meet the Companies' revenue requirements.

b. See the response to a. above.

c. See the Company's objection filed on January 20, 2017. The Company has not identified any non-privileged documents.

d. Decisions such as these are made collectively through a process of information gathering, conversation, and discussion amongst leadership teams across the organization, including senior levels for strategic direction. Final decisions are reviewed in a formal Investment Committee process.

e. Within the terms of the Company's Demand-Side Management ("DSM") Cost Recovery Mechanism (Sheet Nos. 86 *et seq.*), the premise of the question is correct: the mechanism includes a lost sales component (for no more than the three most recent years' lost sales) related to sales lost due to the Company's own DSM and energy efficiency programs (but not to customer-implemented savings measures or practices). Also, the mechanism is billed on a per-kWh basis to customers to whom DSM programs are available.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

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

Question No. 16

Responding Witness: Robert M. Conroy / John P. Malloy / Counsel

Q.1-16. Refer to page 23, lines 8-14 of Mr. Malloy's Direct Testimony wherein he states:

> The other large driver of savings results from customers using less energy and using it more efficiently as they learn more about their own usage from the web portal that will be available to them as part of the AMS deployment. The Companies and other utilities have observed that customers who actively access such information tend to decrease their usage slightly. Aggregating those savings through 2039 produces net savings of over $166 million (nominal) and over $66 million NPV, which are savings customers will receive directly by reducing their bills through reduced usage.

a. Please confirm that a reduction in customer revenues is not a reduction in the Companies' costs and that the $166 million is not a savings to the Companies. If the Company cannot confirm this, then please explain why not.

b. Please confirm that the reduction in customer revenues does not result in a reduction in the Companies' revenue requirements; it simply means that the Companies' costs must be recovered over fewer billing units, all else equal. If the Company cannot confirm this, then please explain why not.

c. Please provide a copy of all internal correspondence that addresses whether a reduction in revenues is a valid benefit that should be included in the Companies' cost/benefit analyses.

d. Please identify each person, their position, and their role in the decision to include a reduction in revenues as a savings in the Companies' cost/benefit analyses.

e. Please confirm that the Companies recover the revenues lost due to energy efficiency and demand response initiatives through increased charges per billing unit, all else equal. If the Company cannot confirm this, then please explain why not.

A.1-16.

a. The $166 million (nominal) is a savings residential customers are projected to receive directly by reducing their bills through reduced energy usage. The Companies will presumably spend less on fuel and other consumables resulting from these energy savings, though those reduced variable costs will be less than $166 million (nominal). The net reduction in revenues would result in less revenue (at least relatively less revenue) from those customers to meet the Companies' revenue requirements.

b. See the response to a. above.

c. See the Company's objection filed on January 20, 2017. The Company has not identified any non-privileged documents.

d. Decisions such as these are made collectively through a process of information gathering, conversation, and discussion amongst leadership teams across the organization, including senior levels for strategic direction. Final decisions are reviewed in a formal Investment Committee process.

e. Within the terms of the Company's Demand-Side Management ("DSM") Cost Recovery Mechanism (Sheet Nos. 86 *et seq.*), the premise of the question is correct: the mechanism includes a lost sales component (for no more than the three most recent years' lost sales) related to sales lost due to the Company's own DSM and energy efficiency programs (but not to customer-implemented savings measures or practices). Also, the mechanism is billed on a per-kWh basis to customers to whom DSM programs are available.

EXHIBIT ____ (LK-4)

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

Project	Capital Including 108					Test Year Ended June 30, 2018			
	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

	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					Test Year Ended June 30, 2018			
	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 KU Rev. Reqts.
Advanced Metering Systems (AMS)	$ 159,805	$ 159,805	$ 60,110	$ 26,241	$ 1,834	$ 2,567	$ 676	$ 3,352	$ 6,595
							KU KY Juris. Cap & Depr.	KU KY Juris. O&M	KU KY Juris.
									$ 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

	Test Year Ended June 30, 2018				
		Total			
Project	O&M	Rev. Reqts.		Electric	Gas
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

Plant 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
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

Plant 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
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

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

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

Question No. 18

Responding Witness: Christopher M. Garrett

Q.1-18. Please provide a quantification of the electric revenue requirement included for the AMS initiative in the test year, including all rate base/capitalization components and all operating expenses. 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.1-18. 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	$\boxed{\$ \ 13,255}$

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

Project	Capital Including 108					Test Year Ended June 30, 2018			
	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

	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 KU Rev. Reqts.
Advanced Metering Systems (AMS)	$ 159,805	$ 159,805	$ 60,110	$ 26,241	$ 1,834	$ 2,567	$ 676	$ 3,352	$ 6,595
							KU KY Juris. Cap & Depr.	KU KY Juris. O&M	KU KY Juris. $ 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

	Test Year Ended June 30, 2018				
		Total			
Project	O&M	Rev. Reqts.		Electric	Gas
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 ____ (LK-5)

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.

Schedule 13b(1)

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

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

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 ____ (LK-6)

LOUISVILLE GAS AND ELECTRIC COMPANY

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

Case No. 2016-00371

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 electric and gas operations separately. 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 Factors" separately for electric and gas construction projects. The Slippage Factors 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 Slippage Factors.

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. LG&E 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 (98.111% for LG&E and 97.204% for KU) on capital projects that are recovered in base rates demonstrate the reasonableness of LG&E and KU'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 (87.631% for LG&E and 90.383% for KU) 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., the Companies' Environmental Cost Recovery mechanism) is recovered based on actual amounts spent. Therefore, any consideration, if any, of a slippage factor 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.

Schedule 13b(1)

Louisville Gas and Electric Company
Case No. 2016-00371
Calculation of Capital Construction Project Slippage Factor -Non-Mechanism Construction Projects

Source: Schedule 13a - Construction Projects

Year	Base Rate Capital Actual Cost	Base Rate Capital Budget Cost	Variance in Dollars	Variance as a percent	Slippage Factor
2015	213,433,085	213,558,521	(125,436)	-0.06%	99.941%
2014	233,542,915	246,109,548	(12,566,633)	-5.11%	94.894%
2013	301,411,194	297,836,538	3,574,656	1.20%	101.200%
2012 [1]	198,826,795	214,793,287	(15,966,492)	-7.43%	92.567%
2011	197,524,642	226,223,175	(28,698,533)	-12.69%	87.314%
2010	203,125,349	170,001,291	33,124,058	19.48%	119.485%
2009	167,411,673	179,893,509	(12,481,836)	-6.94%	93.062%
2008	212,232,535	216,569,290	(4,336,754)	-2.00%	97.998%
2007	202,326,523	221,184,943	(18,858,420)	-8.53%	91.474%
2006	145,065,671	128,674,790	16,390,881	12.74%	112.738%
Totals	**2,074,900,383**	**2,114,844,892**	**(39,944,509)**	**-1.889%**	**98.111%**

10 Year Average Slippage Factor (Mathematic Average of the Yearly Slippage Factors / 10 Years)	**99.067%**

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.

Louisville Gas and Electric Company
Case No. 2016-00371
Calculation of Capital Construction Project Slippage Factor -Mechanism Construction Projects Only

Source: Schedule 13a - Construction Projects

	A	B	C	D = A+B+C	E	F	G	H=E+F+G	I=D-H	J=I/H	K=D/H
Year	Actual ECR	Actual DSM	Actual GLT	Mechanism Capital Actual Total	ECR	DSM	GLT	Mechanism Capital Budget Total	Variance in Dollars	Variance as a percent	Slippage Factor
2015	332,975,913	2,956,595	54,787,547	390,720,056	328,957,067	1,546,665	52,747,681	383,251,413	7,468,643	1.95%	101.949%
2014	404,522,580	1,407,752	51,358,901	457,289,233	286,241,263	2,102,330	54,601,467	342,945,060	114,344,172	33.34%	133.342%
2013	247,148,691	1,530,891	44,368,114	293,047,695	323,761,867	1,307,381	48,259,066	373,328,314	(80,280,619)	-21.50%	78.496%
2012	80,423,350	248,316	15,858,155	96,529,821	231,552,739	1,603,839	14,753,636	247,910,214	(151,380,392)	-61.06%	38.937%
2011	9,605,232	-	-	9,605,232	77,034,797	1,900,012	-	78,934,809	(69,329,578)	-87.83%	12.169%
2010	7,859,154	-	-	7,859,154	17,203,191	-	-	17,203,191	(9,344,037)	-54.32%	45.684%
2009	17,420,492	-	-	17,420,492	11,793,861	-	-	11,793,861	5,626,631	47.71%	147.708%
2008	25,900,841	-	-	25,900,841	26,519,109	-	-	26,519,109	(618,268)	-2.33%	97.669%
2007	16,228,937	-	-	16,228,937	20,224,498	-	-	20,224,498	(3,995,561)	-19.76%	80.244%
2006	9,269,214	-	-	9,269,214	8,629,002	-	-	8,629,002	640,212	7.42%	107.419%
Totals	1,151,354,404	6,143,554	166,372,716	1,323,870,674	1,331,917,394	8,460,226	170,361,851	1,510,739,471	(186,868,796)	-12.369%	87.631%

10 Year Average Slippage Factor (Mathematic Average of the Yearly Slippage Factors / 10 Years)	84.362%

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 – The Mill Creek Environmental Air project was above budget due to change orders and higher actual costs against the target pricing contract in place with the primary contractor Zachry, partially offset by lower costs on the Trimble landfill due to delays in the permitting process.

2014 – The Mill Creek Environmental Air project was well above budget due to change orders and higher actual costs against the target pricing contract in place with the primary contractor Zachry.

2013 – Continued permitting delays on the Trimble County landfill and less work completed on the Mill Creek Environmental Air Project than had been expected in the budget.
With regards to DSM, there were 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 Mill Creek 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 – Later start to the Mill Creek 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 – Delay in the Trimble County barge Loading (Holcim) project, and the Mill Creek SAM mitigation cancelled.

2009 – More costs incurred on the Trimble County Bottom Ash Pond that had been expected in the budget.

Schedule 13b(3)

Louisville Gas and Electric Company
Case No. 2016-00371
Calculation of Capital Construction Project Slippage Factor - Includes Mechanism Construction Projects

Source: Schedule 13a - Construction Projects

Year	Annual Actual Cost	Annual Original Budget	Variance in Dollars	Variance as a percent	Slippage Factor
2015	604,153,141	596,809,934	7,343,207	1.23%	101.230%
2014	690,832,148	589,054,609	101,777,539	17.28%	117.278%
2013	594,458,889	671,164,852	(76,705,963)	-11.43%	88.571%
2012 [1]	295,356,617	462,703,501	(167,346,884)	-36.17%	63.833%
2011	207,129,874	305,157,985	(98,028,110)	-32.12%	67.876%
2010	210,984,503	187,204,482	23,780,021	12.70%	112.703%
2009	184,832,164	191,687,370	(6,855,205)	-3.58%	96.424%
2008	238,133,377	243,088,399	(4,955,022)	-2.04%	97.962%
2007	218,555,460	241,409,441	(22,853,980)	-9.47%	90.533%
2006	154,334,886	137,303,792	17,031,094	12.40%	112.404%
Totals	**3,398,771,058**	**3,625,584,363**	**(226,813,305)**	**-6.256%**	**93.744%**

10 Year Average Slippage Factor (Mathematic Average of the Yearly Slippage Factors / 10 Years)	94.881%

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 ____ (LK-7)

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. 48

Responding Witness: Lonnie E. Bellar

Q.1-48. Please provide a history of transmission capital expenditures and closings to plant in service for each calendar year 2006 through 2015, the base year, and the test year separated into routine projects and specific projects (by project) on a total Company and jurisdictional basis.

A.1-48. See attached.

Closings to plant in service for each calendar year 2006 through 2015 are not readily available in a manner that can be reproduced.

Kentucky Utilities
Total Company Capital Expenditures
$'000s

Type	Project #	Project Name	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Base Period	Test Period
	152225	Brown N 345kV 934 Brkr Rpl	-	-	-	-	-	-	-	-	-	-	200	52
	152230	PBU-Wickliffe T01 Bush Rpl	-	-	-	-	-	-	-	-	-	-	48	-
	152231	POR-Shelbyville 69kV PT Rpl	-	-	-	-	-	-	-	-	-	-	65	-
	152237	PAR-W. Frankfort Arrester Rpl	-	-	-	-	-	-	-	-	-	-	14	-
	152266	SCADA PRIVATE NTWK_KU_2016	-	-	-	-	-	-	-	-	-	-	36	-
	152329	N.A.S. Secondary Containment	-	-	-	-	-	-	-	-	-	-	130	-
	152358	TEP-Hardin Co Xfmr Add-P&C	-	-	-	-	-	-	-	-	-	-	165	172
	152401	Green River C&P/Switch Rpl	-	-	-	-	-	-	-	-	-	-	279	304
	152608	TEP-Matanzas-Wilson Riser Rpl	-	-	-	-	-	-	-	-	-	-	32	-
	152623	West Lexington #3 Bushing Rpl	-	-	-	-	-	-	-	-	-	-	19	-
	152971	Earlington N 634 Brkr Overhaul	-	-	-	-	-	-	-	-	-	-	31	-
	152972	PGDP Reconfig GV	-	-	-	-	-	-	-	-	-	-	-	60
	152983	Bonds Mill Relay Rpl	-	-	-	-	-	-	-	-	-	-	80	-
	153026	Green River SPCC	-	-	-	-	-	-	-	-	-	-	250	-
	153030	REL Line Mod-In Line Breakers	-	-	-	-	-	-	-	-	-	-	-	168
	153036	Brown Campus Sonet Loop	-	-	-	-	-	-	-	-	-	-	120	-
	153068	REL Lebanon S Motor Add	-	-	-	-	-	-	-	-	-	-	-	100
	153073	REL Cynthiana S MOS 569-605	-	-	-	-	-	-	-	-	-	-	-	75
	153076	REL Girdler MOS Add	-	-	-	-	-	-	-	-	-	-	-	100
	153116	POR-Pisgah PT Rpl	-	-	-	-	-	-	-	-	-	-	17	-
	153205	American Ave 614 Brkr CT Rpl	-	-	-	-	-	-	-	-	-	-	32	-
	153212	PIN-Grahamville 834 Switch Rpl	-	-	-	-	-	-	-	-	-	-	112	-
	153230	POR-Lansdowne Brkr CT Rpl	-	-	-	-	-	-	-	-	-	-	32	-
	153232	POR-Loudon 644 Brkr CT Rpl	-	-	-	-	-	-	-	-	-	-	32	-
	153256	PBU-Haefling 718-4 Bushing Rpl	-	-	-	-	-	-	-	-	-	-	19	-
	153284	ROR-London Bird Deterrent	-	-	-	-	-	-	-	-	-	-	8	-
	24014	WINCHESTER RD HWY RELOC	-	7	-	-	-	-	-	-	-	-	-	-
	25180	HIG-LEX 69KV LINE RELOC	-	9	-	-	-	-	-	-	-	-	-	-
	25195	LEX-PARIS 69 KV HWY 25	-	-	37	-	-	-	-	-	-	-	-	-
Specific Total			10,408	40,302	34,127	28,885	32,510	28,118	31,227	27,544	21,990	30,600	59,578	41,918
KU Total			17,978	48,034	42,596	53,203	46,567	46,174	54,581	48,704	40,154	52,827	78,350	106,339

EXHIBIT ____ (LK-8)

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

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

Question No. 237

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

Q-237. Vegetation Management. For each year 2011 through 2016, provide, by account, the amount expensed and the amount capitalized for scheduled tree trimming, for other right of way clearing and for tree trimming other than scheduled tree trimming.

A-237. See attached. The amounts for Distribution capitalized tree trimming are not available.

KU - Total Company
Question 237
$000's

DISTRIBUTION Expensed Scheduled Tree Trimming	2011	2012	2013	2014	2015	2016
408	$ 43	$ -	$ -	$ -	$ -	$ -
426	$ -	$ 1	$ -	$ -	$ -	$ -
588	$ 2	$ 1	$ 1	$ 0	$ 0	$ 0
593	$ 14,642	$ 15,762	$ 16,500	$ 15,206	$ 14,340	$ 14,922
925	$ 5	$ -	$ -	$ -	$ -	$ -
926	$ 307	$ -	$ -	$ -	$ -	$ -
Total	$ 14,998	$ 15,765	$ 16,500	$ 15,206	$ 14,340	$ 14,922

TRANSMISSION Expensed Scheduled Tree Trimming	2011	2012	2013	2014	2015	2016
571	$ 4,108	$ 4,149	$ 4,487	$ 5,310	$ 5,330	$ 5,287
Total	$ 4,108	$ 4,149	$ 4,487	$ 5,310	$ 5,330	$ 5,287

DISTRIBUTION Expensed Storms Tree Trimming	2011	2012	2013	2014	2015	2016
408	$ 2	$ -	$ -	$ -	$ -	$ -
593	$ 264	$ 347	$ 80	$ 495	$ 259	$ 224
925	$ 0	$ -	$ -	$ -	$ -	$ -
926	$ 3	$ -	$ -	$ -	$ -	$ -
Total	$ 268	$ 347	$ 80	$ 495	$ 259	$ 224

TRANSMISSION Expensed Storms Tree Trimming	2011	2012	2013	2014	2015	2016
571	$ 3	$ 1	$ 3	$ 1	$ -	$ 4
Total	$ 3	$ 1	$ 3	$ 1	$ -	$ 4

TRANSMISSION Capitalized Scheduled Tree Trimming	2011	2012	2013	2014	2015	2016
107	$ 90	$ 71	$ 54	$ 168	$ 200	$ 522
108	$ 10	$ 9	$ 12	$ 2	$ 14	$ 2
Total	$ 100	$ 80	$ 66	$ 170	$ 214	$ 524

TRANSMISSION Capitalized Storms Tree Trimming	2011	2012	2013	2014	2015	2016
107	$ 4	$ -	$ 1	$ 8	$ 2	$ 10
108	$ -	$ -	$ -	$ -	$ -	$ 2
Total	$ 4	$ -	$ 1	$ 8	$ 2	$ 12

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

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

Question No. 237

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

Q-237. Vegetation Management. For each year 2011 through 2016, provide, by account, the amount expensed and the amount capitalized for scheduled tree trimming, for other right of way clearing and for tree trimming other than scheduled tree trimming.

A-237. See attached. The amounts for Distribution capitalized tree trimming are not available.

LG&E
Question 237
$000's

DISTRIBUTION Expensed Scheduled Tree Trimming	2011	2012	2013	2014	2015	2016
408	$ 18	$ -	$ -	$ -	$ -	$ -
421	$ -	$ -	$ (13)	$ (19)	$ (3)	$ -
593	$ 6,111	$ 6,703	$ 6,732	$ 8,377	$ 9,532	$ 8,653
925	$ 2	$ 1	$ 1	$ -	$ -	$ -
926	$ 126	$ -	$ -	$ 0	$ -	$ -
Total	$ 6,258	$ 6,704	$ 6,720	$ 8,359	$ 9,529	$ 8,653

TRANSMISSION Expensed Scheduled Tree Trimming	2011	2012	2013	2014	2015	2016
571	$ 1,206	$ 764	$ 1,059	$ 685	$ 794	$ 1,774
Total	$ 1,206	$ 764	$ 1,059	$ 685	$ 794	$ 1,774

DISTRIBUTION Expensed Storms Tree Trimming	2011	2012	2013	2014	2015	2016
408	$ 2	$ -	$ -	$ -	$ -	$ -
593	$ 1,063	$ 145	$ 240	$ 515	$ 237	$ 144
925	$ 0	$ -	$ -	$ -	$ -	$ -
926	$ 8	$ -	$ -	$ -	$ -	$ -
Total	$ 1,074	$ 145	$ 240	$ 515	$ 237	$ 144

TRANSMISSION Expensed Storms Tree Trimming	2011	2012	2013	2014	2015	2016
571	$ 3	$ -	$ -	$ -	$ 5	$ -
Total	$ 3	$ -	$ -	$ -	$ 5	$ -

TRANSMISSION Capitalized Scheduled Tree Trimming	2011	2012	2013	2014	2015	2016
107	$ -	$ 6	$ 32	$ 58	$ 921	$ 30
108	$ -	$ -	$ -	$ -	$ -	$ 1
Total	$ -	$ 6	$ 32	$ 58	$ 921	$ 31

TRANSMISSION Capitalized Storms Tree Trimming	2011	2012	2013	2014	2015	2016
107	$ 1	$ -	$ -	$ 1	$ -	$ -
108	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 1	$ -	$ -	$ 1	$ -	$ -

EXHIBIT ____ (LK-9)

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.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

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.

EXHIBIT ____ (LK-10)

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

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

Question No. 20

Responding Witness: Lonnie E. Bellar

Q-20. Refer to FR 16.8.d, Schedule D-1, page 2 of 8, line 32, Maintenance of Boiler Plant. The description of the $5.542 million adjustment from the base period to the forecasted test period reads, "Major planned generator overhauls in forecasted test period for Trimble County unit 2 and EW Brown Units."

a. Provide the year(s) in which the most recent generator overhauls were performed on Trimble County unit 2 and the E.W. Brown units.

b. Provide the existing cycles for generator overhauls of Trimble County unit 2 and the E.W. Brown units.

c. State in what year(s) generator overhauls will be planned for Trimble County unit 2 and the E.W. Brown units after the test period.

d. Provide the projected cost of the overhaul at each unit.

e. Explain whether there will be similar overhauls on other units during the base period. If there are such overhauls, identify the unit(s) and provide the actual or projected cost thereof.

A-20.

a. Trimble County unit 2 went in service in 2010; therefore, this is its first major overhaul.

Unit	Year
EW Brown Unit 1	2015
EW Brown Unit 2	2009
EW Brown Unit 3	2012
Trimble County Unit 2	NA

b.

Unit	Year
EW Brown Unit 1	2022
EW Brown Unit 2	2018
EW Brown Unit 2	2025
EW Brown Unit 3	2020
Trimble County Unit 2	2018
Trimble County Unit 2	2026

c. See response to Item b above.

d. The costs reflected in the table below represent maintenance costs for planned and scheduled routine and major overhauls requiring a unit outage. These costs are not jurisdictionalized and do not include costs related to daily maintenance activities included in this account.

	Base $	Test $
EW Brown Unit 1	455,632	608,000
EW Brown Unit 2	595,497	1,794,000
EW Brown Unit 3	855,328	1,208,000
Trimble County Unit 2	1,181,241	4,700,000

e. There will be similar overhauls on other units during the base and test periods. These costs are not jurisdictionalized and do not include costs related to daily maintenance activities included in this account. Costs related to Ghent Unit 4 are outside of the test period.

	Base $	Test $	Type of overhaul
Ghent Unit 1	1,503,553	2,433,000	Routine maintenance/inspections
Ghent Unit 2	2,249,992	2,482,000	Routine maintenance/inspections
Ghent Unit 3	2,298,142	1,358,000	Routine maintenance/inspections
Ghent Unit 4	2,251,261	-	Routine maintenance/inspections

EXHIBIT ____ (LK-11)

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

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

Question No. 23

Responding Witness: Lonnie E. Bellar

Q-23. Refer to FR 16.8.d, Schedule D-1, page 3 of 8, line 56, Maintenance of Structures. The description of the $1,001,478 adjustment from the base period to the forecasted test period reads, "Major planned overhaul in forecasted test period for Cane Run 7."

a. Explain the need for the major overhaul of Cane Run 7 in the forecasted test period.

b. Provide the year(s) in which the most recent such overhauls were performed on Cane Run 7.

c. Provide the existing cycle for such overhauls for Cane Run 7.

d. State in what years such overhauls will be planned after the test period.

e. Explain whether there will be similar overhauls on other units during the base period. Identify the unit(s) and provide the actual or projected cost thereof.

A-23.

a. During the test period, Cane Run 7 (CR7) will complete the first Combustor Inspection. Since CR7 is a base load unit, this overhaul is needed every two years and includes a visual inspection of all gas path parts. The test year includes costs to completely disassemble the combustor sections in order to ensure the individual component parts are either capable of being re-installed and operational until the next similar outage, or if they will need to be repaired/replaced. Inspections of this nature are standard for this type of unit across all original equipment manufacturers.

b. Cane Run 7 was placed in service in June 2015; therefore, the first iteration of this type of inspection will take place in 2017.

c. Below is a table of the current cycles of overhauls for CR7. Unlike coal units, this schedule is based on forecasted generation and is flexible depending on demand and fuel prices.

Type	**Year**
Combustor Inspection (CI)	2017
Hot Gas Path Inspection (includes CI)	2019
Combustor Inspection (CI)	2021
Major Inspection (includes CI)	2023
Combustor Inspection (CI)	2025

d. See response to item c above.

e. There are no similar overhauls on other units during the base period.

EXHIBIT ____ (LK-12)

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. 25

Responding Witness: Christopher M. Garrett

Q.1-25. Please provide a schedule showing how property taxes were computed for the base year and include copies of all workpapers used to determine the amount in electronic format with all formulas intact.

A.1-25. See the attachment being provided in Excel format.

Kentucky Utilities Company
2017 BP
Property & Other Taxes
Income Statement impact:
(round to $1,000's)

Budgeted Property Taxes	2016	2017	2018	Base Year Ending 02/28/17	Test Year Ending 06/30/18
Property Taxes (P&L)					
KU	27,307	29,085	31,882	27,604	30,483
Less Capitalization:					
KU - Non-Mech	(315)	(463)	(331)	(340)	(397)
KU - Mech	(196)	(84)	(268)	(177)	(176)
	26,797	28,538	31,282	27,087	29,910
P&L Property Taxes					
KU	26,797	28,538	31,282	27,087	29,910
	26,797	**28,538**	**31,282**	**27,087**	**29,910**
KU Electric	25,082	26,565	29,316	25,329	27,941
KU ECR	1,714	1,973	1,966	1,758	1,969
KU Totals	26,797	28,538	31,282	27,087	29,910
	-	-	-	-	-

Assumptions in MTP years (2017-2021):

The 2017 business plan years (2017 - 2021) were calculated based on UI Planner exports from the KY Plant Account, Balance Sheet, and CWIP-RWIP reports. An average rate was used to calculated the tax liability for each property tax classification. The average rate for local taxing authorities were increased 2% each year.

KY Aug 2016 Forecast (2017 BP-Prelim View)- No RC	Year 2015	Year 2016	Year 2017
AW:[Net Plant (excl CWIP and RWIP)]			
KU_DSM	6,072	7,955	8,935
KU_ECR	1,148,956	1,320,304	1,313,147
H:[Ending CWIP]			
KU_DSM	-	-	-
KU_ECR	137,228	50,972	174,304
S:[Ending RWIP]			
KU_DSM	-	-	-
KU_ECR	-	0	2,163

	Year 2016	Year 2017	Year 2018
KU_ECR Net Plant Beg Bal	1,286,183	1,371,276	1,489,614
Property Tax Rate	0.0015	0.0015	0.0015
Property Tax Expense	1,929	2,057	2,234

Provided by Budgeting Department

	Tax-2017	Tax-2018
0110	546,564	599,961
Mechanism	83,871	268,477
Non-Mechanism	462,693	331,484
Grand Total	909,379	1,383,444

Kentucky Utilities Company
Property Tax Analysis
2017 BP

	1/1/2016	1/1/2017	1/1/2018
Summary			
Net Plant	5,939,465.674	6,221,025	6,264,398
CWIP and RWIP	293,663	113,211	275,544
Total Plant	**6,233,128**	**6,334,236**	**6,539,941**
Exclude:			
Virginia and Tennessee Property	(82,942)	(88,352)	(94,911)
Virginia and Tennessee CWIP	(2,649)	(2,340)	(2,340)
Intangibles (ARO's, Org, Franch & Cons)	(276,492)	(233,005)	(187,729)
Vehicles	(3,965)	(3,653)	(3,896)
Add:			
Assessed Franchise Value			
AS:[Fuel Inventory-151.0]	98,514	104,113	83,241
AU:[M&S Inventory-154.0]	39,139	42,310	42,005
AX:[Stores Expense-163.0]	9,372	10,515	10,515
Net Book Reportable for KY Property Tax	**6,014,105**	**6,163,824**	**6,386,826**
	51.805		
KY Reportable Original Costs			
Real Estate Original Costs	248,543	255,828	265,106
Manufacturing Machinery Original Costs	4,309,084	4,494,862	4,455,401
Other Tangible Property Original Costs	1,020,185	1,145,325	1,257,354
	5,577,812	**5,896,015**	**5,977,861**
Plant account 311	165,337	159,627	156,869
Real Estate allocation	109,312	105,536	103,713
Manufacturing Machinery allocation	56,026	54,091	53,156
Plant account 341	64,585	63,368	61,102
Real Estate allocation	4,695	4,607	4,442
Manufacturing Machinery allocation	59,890	58,762	56,660
Allocated CWIP and RWIP			
Real Estate Original Costs	8,713	3,340	8,229
Manufacturing Machinery Original Costs	221,210	84,786	208,925
Other Tangible Property Original Costs	59,345	22,746	56,049
	289,269	**110,871**	**273,204**
Net Book Value Reported on Schedule J			
Real Estate Original Costs	257,256	259,168	273,335
Manufacturing Machinery Original Costs	4,530,295	4,579,648	4,664,326
Other Tangible Property Original Costs	1,128,040	1,220,895	1,365,923
Inventory	98,514	104,113	83,241
	6,014,105	**6,163,824**	**6,386,826**
	(0)	-	-
Average Tax Rates per Category (per $100)			
Real Estate Original Costs	1.1019	1.1215	1.1415
Manufacturing Machinery Original Costs	0.1500	0.1500	0.1500
Other Tangible Property Original Costs	1.4824	1.5031	1.5241
Inventory	0.0500	0.0500	0.0500
KY Property Tax Expense	**Year 2016**	**Year 2017**	**Year 2018**
Real Estate Original Costs	2,835	2,907	3,120
Manufacturing Machinery Original Costs	6,795	6,869	6,996
Other Tangible Property Original Costs	16,722	18,351	20,818
Inventory	49	52	42
Kentucky Property Tax	**26,402**	**28,179**	**30,977**
Virginia Property Tax	663	663	663
Paid and Assessed Locally	243	243	243
Total Property Tax Expense	**27,307**	**29,085**	**31,882**

KY Aug 2016 Forecast (2017 BP-Prelim View)- No RC

	Year 2015	Year 2016	Year 2017
H:[Ending CWIP]			
Kentucky Utilities	$267,027	$110,641	$267,321
LG&E	$389,846	$104,695	$290,028
S:[Ending RWIP]			
Kentucky Utilities	$26,636	$2,570	$8,222
LG&E	$43,746	$29,572	$15,418

KY Aug 2016 Forecast (2017 BP-Prelim View)- No RC

	Year 2015	Year 2016	Year 2017
Kentucky Utilities			
AS:[Fuel Inventory-151.0]	$97,051	$102,650	$81,778
AU:[M&S Inventory-154.0]	41,183	44,354	44,049
AX:[Stores Expense-163.0]	9,372	10,515	10,515
LG&E			
AS:[Fuel Inventory-151.0]	$71,040	$62,039	$34,880
AU:[M&S Inventory-154.0]	32,048	34,541	34,001
AW:[Gas Inventory-164.0]	42,069	42,329	43,206
AX:[Stores Expense-163.0]	5,547	6,422	6,422

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

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

Question No. 26

Responding Witness: Christopher M. Garrett

Q.1-26. Please provide a schedule showing how property taxes were computed for the base year and include copies of all workpapers used to determine the amount in electronic format with all formulas intact.

A.1-26. See the attachment being provided in Excel format.

Louisville Gas and Electric Company
2017 BP
Property & Other Taxes
Income Statement impact:
(round to $1,000's)

Budgeted Property Taxes	2016	2017	2018	Base Year Ending 02/28/17	Test Year Ending 06/30/18
Property Taxes (P&L)					
LG&E	29,727	32,190	35,209	30,138	33,700
LG&E - Non-Mech	(274)	(267)	(511)	(273)	(389)
LG&E - Mech	(362)	(96)	(272)	(317)	(184)
	29,092	31,827	34,426	29,548	33,127
P&L Property Taxes					
LG&E	29,092	31,827	34,426	29,548	33,127
	29,092	**31,827**	**34,426**	**29,548**	**33,127**
LG&E Electric	20,592	22,148	24,123	20,851	23,135
LG&E Gas	5,231	5,078	5,079	5,205	5,078
LG&E GLT	2,042	2,879	3,527	2,182	3,203
LG&E ECR	1,227	1,723	1,697	1,309	1,710
LG&E Totals	29,092	31,827	34,426	29,548	33,127

Assumptions in MTP years (2017-2021):

The 2017 business plan years (2017 - 2021) were calculated based on UI Planner exports from the KY Plant Account, Balance Sheet, and CWIP-RWIP reports. An average rate was used to calculated the tax liability for each property tax classification. The average rate for local taxing authorities were increased 2% each year.

KY Aug 2016 Forecast (2017 BP-Prelim View)- No RC	Year 2015	Year 2016	Year 2017
AW:[Net Plant (excl CWIP and RWIP)]			
LGEE_DSM	5,137	6,729	7,576
LGEG_DSM	-	-	-
LGE_ECR	821,816	1,153,165	1,143,867
LGE_GLT	158,394	213,100	254,390
H:[Ending CWIP]			
LGEE_DSM	-	-	-
LGE_ECR	244,170	59,263	168,750
LGE_GLT	-	0	2,000
S:[Ending RWIP]			
LGEE_DSM	-	-	-
LGE_ECR	-	(0)	(0)
LGE_GLT	-	-	0

	Year 2016	Year 2017	Year 2018
LGE_ECR Net Plant Beg Bal	1,065,987	1,212,428	1,312,617
Property Tax Rate	0.0015	0.0015	0.0015
Property Tax Expense	1,599	1,819	1,969
LGE_GLT Net Plant Beg Bal	158,394	213,100	256,390
Property Tax Rate	0.01327	0.01351	0.01376
Property Tax Expense	2,102	2,879	3,527

Provided by Budgeting Department

	Tax-2017	Tax-2018
0100	362,815	783,483
Mechanism	95,842	272,303
Non-Mechanism	266,973	511,180

Louisville Gas and Electric Company
Property Tax Analysis
2017 BP

	1/1/2016	1/1/2017	1/1/2018
Summary			
Net Plant	4,074,464	4,645,396	4,802,842
CWIP and RWIP	433,593	134,266	305,446
Total Plant	**4,508,057**	**4,779,662**	**5,108,288**
Exclude:			
Indiana Property	(45,140)	(55,868)	(54,375)
Indiana CWIP	(11,680)	(11,680)	(11,680)
Fort Knox Estimate	(51,555)	(54,133)	(56,839)
Intangibles (ARO's, Org, Franch & Cons)	(132,192)	(112,422)	(98,525)
Nonrecoverable Natural Gas	(1,547)	(1,467)	(1,388)
Vehicles	(2,918)	(5,018)	(5,429)
Vehicles in CWIP	(1,916)	(1,916)	(1,916)
Railcars estimate (includes trailers)	(603)	(603)	(603)
Add:			
Assessed Franchise Value			
Assessed Land Value	3,549	3,549	3,549
AW:[Gas Inventory-164.0]	42,069	42,329	43,206
AW:[Gas Inventory-164.0] Less Indiana	(4,703)	(4,703)	(4,703)
AS:[Fuel Inventory-151.0]	71,874	62,039	34,880
AU:[M&S Inventory-154.0]	31,215	34,541	34,001
AX:[Stores Expense-163.0]	5,547	6,422	6,422
Net Book Reportable for KY Property Tax	**4,410,055**	**4,680,732**	**4,994,888**
KY Reportable Original Costs (less Fort Knox and railcars)			
Real Estate Original Costs	776,243	846,621	908,164
Manufacturing Machinery Original Costs	2,264,426	2,663,141	2,714,556
Other Tangible Property Original Costs	812,712	919,462	976,791
	3,853,381	**4,429,223**	**4,599,511**
Plant account 311 Split	113,235	118,634	115,647
Real Estate 58%	65,676	68,808	67,076
Manufacturing Machinery 42%	47,559	49,826	48,572
Plant account 316 Split	12,098	11,969	27,151
Other Tangible 62%	7,501	7,421	16,834
Manufacturing Machinery 38%	4,597	4,548	10,317
Allocated CWIP and RWIP			
Real Estate Original Costs	17,723	5,092	12,315
Manufacturing Machinery Original Costs	338,186	97,165	235,001
Other Tangible Property Original Costs	64,088	18,413	44,534
	419,997	**120,670**	**291,850**
Net Book Value Reported on Schedule J			
Real Estate Original Costs	793,966	851,713	920,479
Manufacturing Machinery Original Costs	2,602,612	2,760,306	2,949,557
Other Tangible Property Original Costs	913,562	978,837	1,061,748
Inventory - Gas Stored Underground (exclude Fort Knox)	28,042	27,837	28,224
Inventory - Fuel	71,874	62,039	34,880
	4,410,055	**4,680,731**	**4,994,888**
	(0)	(0)	(0)
Average Tax Rates per Category (per $100)			
Real Estate Original Costs	1.2204	1.2424	1.2648
Manufacturing Machinery Original Costs	0.1500	0.1500	0.1500
Other Tangible Property Original Costs	1.6781	1.7026	1.7277
Inventory - Gas Stored Underground (exclude Fort Knox)	1.0952	1.1161	1.1374
Inventory - Fuel	0.0500	0.0500	0.0500
KY Property Tax Expense	**Year 2016**	**Year 2017**	**Year 2018**
Real Estate Original Costs	9,689	10,581	11,642
Manufacturing Machinery Original Costs	3,904	4,140	4,424
Other Tangible Property Original Costs	15,330	16,666	18,344
Inventory - Gas Stored Underground (exclude Fort Knox)	307	311	321
Inventory - Fuel	36	31	17
Kentucky Property Tax	**29,266**	**31,729**	**34,748**
Indiana Property Tax	245	245	245
Paid and Assessed Locally	216	216	216
Total Property Tax Expense	**29,727**	**32,190**	**35,209**

KY Aug 2016 Forecast (2017 BP-Prelim View)- No RC

	Year 2015	Year 2016	Year 2017
H:[Ending CWIP]			
Kentucky Utilities	$267,027	$110,641	$267,321
LG&E	$389,846	$104,695	$290,028
S:[Ending RWIP]			
Kentucky Utilities	$26,636	$2,570	$8,222
LG&E	$43,746	$29,572	$15,418

KY Aug 2016 Forecast (2017 BP-Prelim View)- No RC

	Year 2015	Year 2016	Year 2017
Kentucky Utilities			
AS:[Fuel Inventory-151.0]	$97,051	$102,650	$81,778
AU:[M&S Inventory-154.0]	41,183	44,354	44,049
AX:[Stores Expense-163.0]	9,372	10,515	10,515
LG&E			
AS:[Fuel Inventory-151.0]	$71,040	$62,039	$34,880
AU:[M&S Inventory-154.0]	32,048	34,541	34,001
AW:[Gas Inventory-164.0]	42,069	42,329	43,206
AX:[Stores Expense-163.0]	5,547	6,422	6,422

EXHIBIT ____ (LK-13)

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. 27

Responding Witness: Valerie L. Scott

Q.1-27. Please provide a schedule of the amortization expense associated with each regulatory asset for (a) each year 2012 through 2016, (b) the base year and (c) the test year. Provide the balance of each regulatory asset at the beginning and end of each of those years, the amortization period that was used in each of those years, and the FERC accounts utilized to record the amortization expense. In addition, please source the amortization period to the Case No. in which the Commission approved the recovery and the amortization period, if any.

A.1-27. See attached. Also see the response to PSC 1-8.

KENTUCKY UTILITIES COMPANY
Case No. 2016-00370
Amortization of Regulatory Assets

Account	Description	Account Used for Amortization	Amortization Period	Order No. / Docket No.
182320/182345	WINTER STORM 2009 - ELECTRIC	571/593	Aug-10 to Jul-20	KPSC 2009-00174 KPSC 2009-00548 KPSC 2012-00221 KPSC 2014-00371
182321	MISO EXIT FEE	440-445	Mar-09 to Dec-14	KPSC 2003-00266 KPSC 2008-00251 FERC ER13-2428-000 FERC EL14-5-000 FERC EC06-4-000 FERC EC06-4-001 FERC ER06-20-000 FERC ER06-20-001
182322/182335	RATE CASE EXPENSES - ELECTRIC	928	Jan-13 to Jun-18	KPSC 2009-00548 KPSC 2012-00222 KPSC 2014-00371 307 U.S. at 120-121 294 U.S. at 73
182324/182337	EKPC FERC TRANSMISSION COST - KY PORTION		Mar-09 to Feb-14	FERC ER06-1458
182332/182348	CARBON MANAGEMENT RESEARCH GROUP	930	Aug-10 to Jul-20	KPSC 2008-00308 KPSC 2009-00548 KPSC 2012-00221 KPSC 2014-00371
182333/182349	KY CONSORTIUM FOR CARBON STORAGE	930	Aug-10 to Jul-14	KPSC 2009-00548
182334/182347	WIND STORM 2008	593	Aug-10 to Jul-20	KPSC 2008-00457 KPSC 2009-00548 KPSC 2012-00221 KPSC 2014-00371
182339	MOUNTAIN STORM - ELECTRIC	593	Nov-11 to Dec-17	VSCC PUE 2011-00013 VSCC PUE 2013-00013 VSCC PUE-2015-00063
182364/182371	FORWARD STARTING SWAP LOSSES	427	Ranging maturities from Sep-15 to Oct-45	KPSC 2014 - 00082 KPSC 2014-00371
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	928	Jan-13 to Dec-15	KPSC 2012-00222
182367	REG ASSET - MUNI MISO EXIT FEE	440-445	Jul-15 to May-17	FERC ER13-2428-000 FERC EL14-5-000 FERC EC06-4-000 FERC EC06-4-001 FERC ER06-20-000 FERC ER06-20-001
182313	PENSION GAIN/LOSS AMORTIZATION-15 YEAR	926	Rolling 15 years	KPSC 2014-00371
182369	GREEN RIVER RETIREMENT	408, 500-514, 925-92(	Jul-15 to Jun-18	KPSC 2014-00371

KENTUCKY UTILITIES COMPANY
Case No. 2016-00370
Amortization of Regulatory Assets

Account	Description	2012 Beginning Balance	Annual Activity	Amortization	Ending Balance
182320/182345	WINTER STORM 2009 - ELECTRIC	49,128,218	-	(5,723,676)	43,404,542
182321	MISO EXIT FEE	3,643,950	-	(1,345,267)	2,298,683
182322/182335	RATE CASE EXPENSES - ELECTRIC	1,140,004	1,654,125	(748,283)	2,045,847
182324/182337	EKPC FERC TRANSMISSION COST - KY PORTION	725,177	-	(334,697)	390,480
182332/182348	CARBON MANAGEMENT RESEARCH GROUP	162,197	102,440	(102,440)	162,197
182333/182349	KY CONSORTIUM FOR CARBON STORAGE	595,433	-	(230,490)	364,943
182334/182347	WIND STORM 2008	1,884,485	-	(219,552)	1,664,933
182339	MOUNTAIN STORM - ELECTRIC	5,840,281	-	(1,208,334)	4,631,947
182364/182371	FORWARD STARTING SWAP LOSSES				
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	140,906	1,615	-	142,521
182367	REG ASSET - MUNI MISO EXIT FEE	-	-	-	-
182313	PENSION GAIN/LOSS AMORTIZATION-15 YEAR	-	-	-	-
182369	GREEN RIVER RETIREMENT	-	-	-	-

Account	Description	2013 Beginning Balance	Annual Activity	Amortization	Ending Balance
182320/182345	WINTER STORM 2009 - ELECTRIC	43,404,542	-	(5,723,676)	37,680,866
182321	MISO EXIT FEE	2,298,683	(382,728)	(127,069)	1,788,886
182322/182335	RATE CASE EXPENSES - ELECTRIC	2,045,847	116	(943,097)	1,102,866
182324/182337	EKPC FERC TRANSMISSION COST - KY PORTION	390,480	-	(334,697)	55,783
182332/182348	CARBON MANAGEMENT RESEARCH GROUP	162,197	122,000	(102,440)	181,757
182333/182349	KY CONSORTIUM FOR CARBON STORAGE	364,943	-	(230,490)	134,453
182334/182347	WIND STORM 2008	1,664,933	-	(219,552)	1,445,382
182339	MOUNTAIN STORM - ELECTRIC	4,631,947	-	(1,208,334)	3,423,613
182364/182371	FORWARD STARTING SWAP LOSSES	-			-
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	142,521	-	(47,507)	95,014
182367	REG ASSET - MUNI MISO EXIT FEE	-	-	-	-
182313	PENSION GAIN/LOSS AMORTIZATION-15 YEAR	-	-	-	-
182369	GREEN RIVER RETIREMENT	-	-	-	-

Account	Description	Beginning Balance	2014 Annual Activity	Amortization	Ending Balance
182320/182345	WINTER STORM 2009 - ELECTRIC	37,680,866	-	(5,723,676)	31,957,190
182321	MISO EXIT FEE	1,788,886	(1,679,029)	(109,857)	-
182322/182335	RATE CASE EXPENSES - ELECTRIC	1,102,866	1,357,905	(551,375)	1,909,396
182324/182337	EKPC FERC TRANSMISSION COST - KY PORTION	55,783	-	(55,783)	-
182332/182348	CARBON MANAGEMENT RESEARCH GROUP	181,757	122,000	(141,560)	162,197
182333/182349	KY CONSORTIUM FOR CARBON STORAGE	134,453	-	(134,453)	-
182334/182347	WIND STORM 2008	1,445,382	-	(219,552)	1,225,830
182339	MOUNTAIN STORM - ELECTRIC	3,423,613	-	(1,208,334)	2,215,279
182364/182371	FORWARD STARTING SWAP LOSSES	-	33,287,299	-	33,287,299
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	95,014	-	(47,507)	47,507
182367	REG ASSET - MUNI MISO EXIT FEE	-	1,208,048	-	1,208,048
182313	PENSION GAIN/LOSS AMORTIZATION-15 YEAR	-	-	-	-
182369	GREEN RIVER RETIREMENT	-	-	-	-

Account	Description	2015 Beginning Balance	Annual Activity	Amortization	Ending Balance
182320/182345	WINTER STORM 2009 - ELECTRIC	31,957,190	-	(5,723,676)	26,233,515
182321	MISO EXIT FEE	-			-
182322/182335	RATE CASE EXPENSES - ELECTRIC	1,909,396	554,664	(870,322)	1,593,738
182324/182337	EKPC FERC TRANSMISSION COST - KY PORTION	-			-
182332/182348	CARBON MANAGEMENT RESEARCH GROUP	162,197	224,440	(224,440)	162,197
182333/182349	KY CONSORTIUM FOR CARBON STORAGE	-			-
182334/182347	WIND STORM 2008	1,225,830	-	(219,552)	1,006,278
182339	MOUNTAIN STORM - ELECTRIC	2,215,279	-	(1,208,334)	1,006,945
182364/182371	FORWARD STARTING SWAP LOSSES	33,287,299	43,065,873	(33,287,299)	43,065,873
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	47,507	-	(47,507)	-
182367	REG ASSET - MUNI MISO EXIT FEE	1,208,048	77,758	(563,539)	722,267
182313	PENSION GAIN/LOSS AMORTIZATION-15 YEAR	-	4,544,466	-	4,544,466
182369	GREEN RIVER RETIREMENT	-	6,457,622	-	6,457,622

Account	Description	Beginning Balance	2016 Annual Activity	Amortization	Ending Balance
182320/182345	WINTER STORM 2009 - ELECTRIC	26,233,515	-	(5,723,676)	20,509,839
182321	MISO EXIT FEE	-			-
182322/182335	RATE CASE EXPENSES - ELECTRIC	1,593,738	4,486,484	(2,812,290)	3,267,932
182324/182337	EKPC FERC TRANSMISSION COST - KY PORTION	-			-
182332/182348	CARBON MANAGEMENT RESEARCH GROUP	162,197	224,440	(224,440)	162,197
182333/182349	KY CONSORTIUM FOR CARBON STORAGE	-			-
182334/182347	WIND STORM 2008	1,006,278	-	(219,552)	786,727
182339	MOUNTAIN STORM - ELECTRIC	1,006,945	-	(534,119)	472,826
182364/182371	FORWARD STARTING SWAP LOSSES	43,065,873		(2,397,988)	40,667,885
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	-			-
182367	REG ASSET - MUNI MISO EXIT FEE	722,267	240,683	(814,536)	148,414
182313	PENSION GAIN/LOSS AMORTIZATION-15 YEAR	4,544,466	4,624,843	(361,502)	8,807,807
182369	GREEN RIVER RETIREMENT	6,457,622	(2,583,049)		3,874,573

Account	Description	Forecast Base Period (3/16 - 2/17) Beginning Balance	Annual Activity	Ending Balance
182320/182345	WINTER STORM 2009 - ELECTRIC	25,280,000	(5,724,000)	19,556,000
182321	MISO EXIT FEE	-	-	-
182322/182335	RATE CASE EXPENSES - ELECTRIC	1,487,000	877,000	2,364,000
182324/182337	EKPC FERC TRANSMISSION COST - KY PORTION	-	-	-
182332/182348	CARBON MANAGEMENT RESEARCH GROUP	248,000	-	248,000
182333/182349	KY CONSORTIUM FOR CARBON STORAGE	-	-	-
182334/182347	WIND STORM 2008	970,000	(220,000)	750,000
182339	MOUNTAIN STORM - ELECTRIC	866,000	(472,000)	394,000
182364/182371	FORWARD STARTING SWAP LOSSES	42,673,000	(2,392,000)	40,281,000
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	-	-	-
182367	REG ASSET - MUNI MISO EXIT FEE	642,000	(574,000)	68,000
182313	PENSION GAIN/LOSS AMORTIZATION-15 YEAR	4,544,000	4,006,000	8,550,000
182369	GREEN RIVER RETIREMENT	6,027,000	(2,583,000)	3,444,000

Account	Description	Forecast Test Period (7/17 - 6/18) Beginning Balance	Annual Activity	Ending Balance
182320/182345	WINTER STORM 2009 - ELECTRIC	17,171,000	(5,247,000)	11,924,000
182321	MISO EXIT FEE	-	-	-
182322/182335	RATE CASE EXPENSES - ELECTRIC	2,463,000	(1,194,000)	1,269,000
182324/182337	EKPC FERC TRANSMISSION COST - KY PORTION	-	-	-
182332/182348	CARBON MANAGEMENT RESEARCH GROUP	213,000	-	213,000
182333/182349	KY CONSORTIUM FOR CARBON STORAGE	-	-	-
182334/182347	WIND STORM 2008	677,000	(220,000)	457,000
182339	MOUNTAIN STORM - ELECTRIC	236,000	(236,000)	-
182364/182371	FORWARD STARTING SWAP LOSSES	39,482,000	(2,391,000)	37,091,000
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	-	-	-
182367	REG ASSET - MUNI MISO EXIT FEE	-	-	-
182313	PENSION GAIN/LOSS AMORTIZATION-15 YEAR	12,929,000	7,532,000	20,461,000
182369	GREEN RIVER RETIREMENT	2,583,000	(1,409,000)	1,174,000

Account	Description	Account Used for Amortization	Amortization Period	Order No. / Docket No.
	AMS REGULATORY ASSET (a)			
182305/182315	ASC 715 - PENSION AND POSTRETIREMENT	926	Ongoing	KPSC 2003-00434 KPSC 2008-00251 KPSC 2009-00548 KPSC 2012-00221 KPSC 2014-00371 FERC AI04-2-000 FERC AI07-1-000
182328-182331	ASC 740 - INCOME TAXES	282/283	Ongoing	KPSC 2005-00181 KPSC 2006-00456 KPSC 2009-00548 KPSC 2012-00221 KPSC 2014-00371
182317-18/182325	ASSET RETIREMENT OBLIGATION	407	Ongoing	KPSC 2003-00427 KPSC 2003-00434 KPSC 2008-00251 KPSC 2009-00548 KPSC 2012-00221 KPSC 2014-00371 FERC FA 12-12-000 FERC ER08-1588-000 VSCC PUE 2011-00013 VSCC PUE 2013-00013 VSCC PUE 2015-00063
182372 - 182380	ARO - GENERATION - COAL COMBUSTION RESIDUALS (b)	407	Jul-16 to Jun-26 Jul-16 to Jun-41	KPSC 2003-00427 KPSC 2003-00434 KPSC 2008-00251 KPSC 2009-00548 KPSC 2012-00221 KPSC 2014-00371 FERC FA 12-12-000 FERC ER08-1588-000 VSCC PUE 2011-00013 VSCC PUE 2013-00013 VSCC PUE 2015-00063 KPSC 2016-00026 FERC ER17-234-000
182311	FERC JURISDICTIONAL PENSION EXPENSES	926	Ongoing	FERC AI04-2-000 FERC AI07-1-000
182356	VA FUEL COMPONENT	440-445	Ongoing	Title 56 of the Code of Virginia, Chapter 10; Section 56-249.6
182363	DSM COST RECOVERY	440-445, 480-482, 48§	Ongoing	KRS 278.285
182307	ENVIRONMENTAL COST RECOVERY	440-445	Ongoing	KRS 278.183
182306	FUEL ADJUSTMENT CLAUSE	803	Ongoing	807 KAR 5:056
182366	MUNICIPAL FORMULA RATE TRUE-UP	447	Ongoing	FERC ER-13-2428
182370	OFF-SYSTEM TRACKER	440-445	Ongoing	KPSC 2014-00371
KU Regulatory Assets Total				

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
b) ARO CCR detail is not available from the Business Plan in UI Planner - detail is combined in the ARO line item
* These balances are a result of netting the regulatory asset and the regulatory liability in the forecast - the net balance was a regulatory liability

Account	Description	Beginning Balance	2012 Annual Activity	Amortization	Ending Balance
	AMS REGULATORY ASSET (a)				
182305/182315	ASC 715 - PENSION AND POSTRETIREMENT	113,264,146	30,318,408	(7,539,817)	136,042,737
182328-182331	ASC 740 - INCOME TAXES	75,212,355	33,090	(2,415,064)	72,830,381
182317-18/182325	ASSET RETIREMENT OBLIGATION	7,421,292	15,399,231	(11,591,122)	11,229,401
182372 - 182380	ARO - GENERATION - COAL COMBUSTION RESIDUALS (b)	-	-	-	-
182311	FERC JURISDICTIONAL PENSION EXPENSES	5,875,853	793,470	(2,562)	6,666,761
182356	VA FUEL COMPONENT	3,794,000	1,702,000	(1,853,000)	3,643,000
182363	DSM COST RECOVERY	-	1,008,008	(606,096)	401,912
182307	ENVIRONMENTAL COST RECOVERY	-	-	-	-
182306	FUEL ADJUSTMENT CLAUSE	-	-	-	-
182366	MUNICIPAL FORMULA RATE TRUE-UP	-	-	-	-
182370	OFF-SYSTEM TRACKER	-	-	-	-
KU Regulatory Assets Total		268,828,296	51,012,386	(33,920,399)	285,920,284

a) Business Plan assumed a regulatory asset would be recorded as retirements of meters occurred. meter replacement
b) ARO CCR detail is not available from the Business Plan in UI Planner - detail is combined in t
* These balances are a result of netting the regulatory asset and the regulatory liability in the forec

Account	Description	Beginning Balance	2013 Annual Activity	Amortization	Ending Balance
	AMS REGULATORY ASSET (a)	-			
182305/182315	ASC 715 - PENSION AND POSTRETIREMENT	136,042,737	12,304,469	(60,493,548)	87,853,658
182328-182331	ASC 740 - INCOME TAXES	72,830,381	249,447	(1,803,509)	71,276,319
182317-18/182325	ASSET RETIREMENT OBLIGATION	11,229,401	12,208,433	(879,757)	22,558,077
182372 - 182380	ARO - GENERATION - COAL COMBUSTION RESIDUALS (b)	-	-	-	-
182311	FERC JURISDICTIONAL PENSION EXPENSES	6,666,761	-	(6,666,761)	-
182356	VA FUEL COMPONENT	3,643,000	64,000	(3,707,000)	-
182363	DSM COST RECOVERY	401,912	6,578,440	(1,633,843)	5,346,509
182307	ENVIRONMENTAL COST RECOVERY	-	6,763,123	(2,127,797)	4,635,326
182306	FUEL ADJUSTMENT CLAUSE	-	-	-	-
182366	MUNICIPAL FORMULA RATE TRUE-UP	-	-	-	-
182370	OFF-SYSTEM TRACKER	-	-	-	-
KU Regulatory Assets Total		285,920,284	37,907,300	(86,249,076)	237,578,508

a) Business Plan assumed a regulatory asset would be recorded as retirements of meters occurred.
b) ARO CCR detail is not available from the Business Plan in UI Planner - detail is combined in t
* These balances are a result of netting the regulatory asset and the regulatory liability in the forec

Account	Description	2014 Beginning Balance	Annual Activity	Amortization	Ending Balance
	AMS REGULATORY ASSET (a)	-			
182305/182315	ASC 715 - PENSION AND POSTRETIREMENT	87,853,658	49,839,661	(4,725,090)	132,968,229
182328-182331	ASC 740 - INCOME TAXES	71,276,319	1,106,327	(1,917,617)	70,465,029
182317-18/182325	ASSET RETIREMENT OBLIGATION	22,558,077	28,905,698	(708,077)	50,755,698
182372 - 182380	ARO - GENERATION - COAL COMBUSTION RESIDUALS (b)	-	-	-	-
182311	FERC JURISDICTIONAL PENSION EXPENSES	-	-	-	-
182356	VA FUEL COMPONENT	-	-	-	-
182363	DSM COST RECOVERY	5,346,509	2,316,317	(7,662,826)	-
182307	ENVIRONMENTAL COST RECOVERY	4,635,326	2,007,000	(5,839,326)	803,000
182306	FUEL ADJUSTMENT CLAUSE	-	12,320,000	(9,856,000)	2,464,000
182366	MUNICIPAL FORMULA RATE TRUE-UP	-	-	-	-
182370	OFF-SYSTEM TRACKER	-	-	-	-
KU Regulatory Assets Total		237,578,508	130,791,225	(38,901,032)	329,468,702

a) Business Plan assumed a regulatory asset would be recorded as retirements of meters occurred.
b) ARO CCR detail is not available from the Business Plan in UI Planner - detail is combined in t
* These balances are a result of netting the regulatory asset and the regulatory liability in the forec

Account	Description	2015 Beginning Balance	Annual Activity	Amortization	Ending Balance
	AMS REGULATORY ASSET (a)	-			
182305/182315	ASC 715 - PENSION AND POSTRETIREMENT	132,968,229	12,508,031	(24,770,247)	120,706,013
182328-182331	ASC 740 - INCOME TAXES	70,465,029	1,420,946	(1,924,923)	69,961,052
182317-18/182325	ASSET RETIREMENT OBLIGATION	50,755,698	54,140,172	(19,201,691)	85,694,179
182372 - 182380	ARO - GENERATION - COAL COMBUSTION RESIDUALS (b)	-		-	-
182311	FERC JURISDICTIONAL PENSION EXPENSES	-	-	-	-
182356	VA FUEL COMPONENT	-	-	-	-
182363	DSM COST RECOVERY	-	-	-	-
182307	ENVIRONMENTAL COST RECOVERY	803,000	11,590,000	(1,337,000)	11,056,000
182306	FUEL ADJUSTMENT CLAUSE	2,464,000	-	(2,464,000)	-
182366	MUNICIPAL FORMULA RATE TRUE-UP	-	15,563,209	(8,622,209)	6,941,000
182370	OFF-SYSTEM TRACKER	-	-	-	-
KU Regulatory Assets Total		329,468,702	150,147,181	(100,464,738)	379,151,144

a) Business Plan assumed a regulatory asset would be recorded as retirements of meters occurred.
b) ARO CCR detail is not available from the Business Plan in UI Planner - detail is combined in t
* These balances are a result of netting the regulatory asset and the regulatory liability in the forec

Account	Description	Beginning Balance	2016 Annual Activity	Amortization	Ending Balance
	AMS REGULATORY ASSET (a)	-			
182305/182315	ASC 715 - PENSION AND POSTRETIREMENT	120,706,013	7,190,261	(8,243,980)	119,652,294
182328-182331	ASC 740 - INCOME TAXES	69,961,052	2,446,697	(2,491,238)	69,916,511
182317-18/182325	ASSET RETIREMENT OBLIGATION	85,694,179	42,762,892	(118,135,322)	10,321,749
182372 - 182380	ARO - GENERATION - COAL COMBUSTION RESIDUALS (b)	-	131,600,004	(573,002)	131,027,002
182311	FERC JURISDICTIONAL PENSION EXPENSES	-	-	-	-
182356	VA FUEL COMPONENT	-	-	-	-
182363	DSM COST RECOVERY	-	-	-	-
182307	ENVIRONMENTAL COST RECOVERY	11,056,000	2,098,000	(13,154,000)	-
182306	FUEL ADJUSTMENT CLAUSE	-			-
182366	MUNICIPAL FORMULA RATE TRUE-UP	6,941,000	16,548,565	(13,217,897)	10,271,668
182370	OFF-SYSTEM TRACKER	-	-	-	-
KU Regulatory Assets Total		379,151,144	209,639,821	(168,903,541)	419,887,424

a) Business Plan assumed a regulatory asset would be recorded as retirements of meters occurred.
b) ARO CCR detail is not available from the Business Plan in UI Planner - detail is combined in (
* These balances are a result of netting the regulatory asset and the regulatory liability in the forec

Account	Description	Forecast Base Period (3/16 - 2/17) Beginning Balance	Annual Activity	Ending Balance
	AMS REGULATORY ASSET (a)			
182305/182315	ASC 715 - PENSION AND POSTRETIREMENT	120,706,013	43,867,987	164,574,000
182328-182331	ASC 740 - INCOME TAXES	404,000	(404,000)	-
182317-18/182325	ASSET RETIREMENT OBLIGATION	95,950,000	61,579,000	157,529,000
182372 - 182380	ARO - GENERATION - COAL COMBUSTION RESIDUALS (b)			
182311	FERC JURISDICTIONAL PENSION EXPENSES	-	-	-
182356	VA FUEL COMPONENT	-	-	-
182363	DSM COST RECOVERY	-	-	-
182307	ENVIRONMENTAL COST RECOVERY	697,000	(4,494,459)	(3,797,459)
182306	FUEL ADJUSTMENT CLAUSE	-	-	-
182366	MUNICIPAL FORMULA RATE TRUE-UP	8,335,000	345,000	8,680,000
182370	OFF-SYSTEM TRACKER	4,300	(23,793)	(19,493)
KU Regulatory Assets Total		308,833,313	93,787,735	402,621,048

a) Business Plan assumed a regulatory asset would be recorded as retirements of meters occurred.
b) ARO CCR detail is not available from the Business Plan in UI Planner - detail is combined in t
* These balances are a result of netting the regulatory asset and the regulatory liability in the forec

Account	Description	Forecast Test Period (7/17 - 6/18) Beginning Balance	Annual Activity	Ending Balance	
	AMS REGULATORY ASSET (a)	-	2,300,000	2,300,000	
182305/182315	ASC 715 - PENSION AND POSTRETIREMENT	157,742,000	(13,393,000)	144,349,000	
182328-182331	ASC 740 - INCOME TAXES	-	1,959,000	1,959,000	
182317-18/182325	ASSET RETIREMENT OBLIGATION	183,423,000	53,312,000	236,735,000	
182372 - 182380	ARO - GENERATION - COAL COMBUSTION RESIDUALS (b)				
182311	FERC JURISDICTIONAL PENSION EXPENSES	-	-	-	
182356	VA FUEL COMPONENT	-	-	-	
182363	DSM COST RECOVERY	-	-	-	
182307	ENVIRONMENTAL COST RECOVERY	(1,368,874)	4,918,265	3,549,391	*
182306	FUEL ADJUSTMENT CLAUSE	-	-	-	
182366	MUNICIPAL FORMULA RATE TRUE-UP	6,137,000	(6,831,000)	(694,000)	*
182370	OFF-SYSTEM TRACKER	(71,000)	6,000	(65,000)	*
KU Regulatory Assets Total		421,616,126	39,106,265	460,722,391	

a) Business Plan assumed a regulatory asset would be recorded as retirements of meters occurred.

b) ARO CCR detail is not available from the Business Plan in UI Planner - detail is combined in t

* These balances are a result of netting the regulatory asset and the regulatory liability in the forec

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 COMPANY
Case No. 2016-00370
Schedule of Regulatory Assets

	Base Period				Test Period			
Description	**Beginning Balance**	**Activity**	**Amortization**	**Ending Balance**	**Beginning Balance**	**Activity**	**Amortization**	**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(c)

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 balance.
[4] = The response to KIUC 1-27 inadvertently reflected the net of the mechanisms balances and activity, this schedule reflects the regulatory asset balance only.
[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.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

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

Question No. 28

Responding Witness: Valerie L. Scott

Q.1-28. Please provide a schedule of the amortization expense associated with each regulatory asset for (a) each year 2012 through 2016, (b) the base year and (c) the test year. Provide the balance of each regulatory asset at the beginning and end of each of those years, the amortization period that was used in each of those years, and the FERC accounts utilized to record the amortization expense. In addition, please source the amortization period to the Case No. in which the Commission approved the recovery and the amortization period, if any.

A.1-28. See attached. Also see the response to PSC 1-8.

Account	Description	Account Used for Amortization	Amortization Period	Order No. / Docket No.
182320/182345	WINTER STORM 2009 - ELECTRIC	571/593	Aug-10 to Jul-20	KPSC 2009-00175 KPSC 2009-00549 KPSC 2012-00222 KPSC 2014-00372
182342/182346	WINTER STORM 2009 - GAS	880	Aug-10 to Jul-20	KPSC 2009-00175 KPSC 2009-00549 KPSC 2012-00222 KPSC 2014-00372
182321	MISO EXIT FEE	575.7	Mar-09 to Dec-14	KPSC 2003-00266 KPSC 2008-00252 KPSC 2012-00222 KPSC 2014-00372 FERC EC06-4-000 FERC EC06-4-001 FERC ER06-20-000 FERC ER06-20-001
182322/182335	RATE CASE EXPENSES - ELECTRIC	928	Jan-13 to Dec-15	KPSC 2009-00549 KPSC 2012-00222 KPSC 2014-00372 307 U.S. at 120-121 294 U.S. at 73
182323/182336	RATE CASE EXPENSES - GAS	928	Jan-13 to Dec-15	KPSC 2009-00549 KPSC 2012-00222 KPSC 2014-00372 307 U.S. at 120-121 294 U.S. at 73
182324/182337	EKPC FERC TRANSMISSION COST - KY PORTION	456/566	Mar-09 to Feb-14	FERC ER06-1458
182332/182348	CARBON MANAGEMENT RESEARCH GROUP	930	Aug-10 to Jul-20	KPSC 2008-00308 KPSC 2009-00549 KPSC 2012-00222 KPSC 2014-00372
182333/182349	KY CONSORTIUM FOR CARBON STORAGE	930.2	Aug-10 to Jul-14	KPSC 2008-00308 KPSC 2009-00549 KPSC 2012-00222 KPSC 2014-00372
182334/182347	WIND STORM REGULATORY ASSET	593	Aug-10 to Jul-20	KPSC 2008-00456 KPSC 2009-00549 KPSC 2012-00222 KPSC 2014-00372
182352	INTEREST RATE SWAPS (Mark to Market)	244	Varying from 2020 - 2033	KPSC 2000-00275 KPSC 2003-00299 KPSC 2003-00433 KPSC 2008-00252 KPSC 2009-00549 KPSC 2012-00222 KPSC 2014-00372
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	928	Jan-13 to Dec-15	KPSC 2012-00222
182360	GENERAL MANAGEMENT AUDIT - GAS	928	Jan-13 to Dec-15	KPSC 2012-00222
182361	2011 SUMMER STORM - ELECTRIC	593	Jan-13 to Dec-17	KPSC 2011-00380 KPSC 2012-00222 KPSC 2014-00372
182364	FORWARD STARTING SWAP LOSSES	427	Sep-15 to Oct-25 Sep-15 to Oct-45	KPSC 2014-00089 KPSC 2014-00372
182344	SWAP TERMINATION (Wachovia)	930	Aug-10 to Apr-35	KPSC 2009-00549 KPSC 2012-00222 KPSC 2014-00372
182381	SWAP TERMINATION (Bank of America)	427	Dec-16 to Oct 33	KPSC 2016-00393
182313	REG ASSET - PENSION GAIN-LOSS AMORTIZATION AMS REGULATORY ASSET (a)	926	Rolling 15 Years	KPSC 2014-00372

		2012			
Account	Description	Beginning Balance	Annual Activity	Amortization	Ending Balance
182320/182345	WINTER STORM 2009 - ELECTRIC	37,484,019	-	(4,367,070)	33,116,949
182342/182346	WINTER STORM 2009 - GAS	143,933	-	(16,769)	127,165
182321	MISO EXIT FEE	759,633	-	(749,834)	9,798
182322/182335	RATE CASE EXPENSES - ELECTRIC	484,359	894,414	(321,124)	1,057,649
182323/182336	RATE CASE EXPENSES - GAS	267,390	284,806	(173,974)	378,222
182324/182337	EKPC FERC TRANSMISSION COST - KY PORTION	367,407	-	(169,572)	197,834
182332/182348	CARBON MANAGEMENT RESEARCH GROUP	154,470	97,560	(97,560)	154,470
182333/182349	KY CONSORTIUM FOR CARBON STORAGE	567,068	-	(219,510)	347,558
182334/182347	WIND STORM REGULATORY ASSET	20,205,452	-	(2,354,033)	17,851,419
182352	INTEREST RATE SWAPS (Mark to Market)	59,566,464	(960,980)	-	58,605,484
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	90,545	1,038	-	91,583
182360	GENERAL MANAGEMENT AUDIT - GAS	29,486	338	-	29,824
182361	2011 SUMMER STORM - ELECTRIC	8,052,125	-	-	8,052,125
182364	FORWARD STARTING SWAP LOSSES				-
182344	SWAP TERMINATION (Wachovia)	8,937,222	-	(258,476)	8,678,746
182381	SWAP TERMINATION (Bank of America)				
182313	REG ASSET - PENSION GAIN-LOSS AMORTIZATION	-	-	-	-
	AMS REGULATORY ASSET (a)				

LOUISVILLE GAS AND ELECTRIC COMPANY
Case No. 2016-00371
Amortization of Regulatory Assets

Account	Description	2013 Beginning Balance	Annual Activity	Amortization	Ending Balance
182320/182345	WINTER STORM 2009 - ELECTRIC	33,116,949	-	(4,367,070)	28,749,879
182342/182346	WINTER STORM 2009 - GAS	127,165	-	(16,769)	110,396
182321	MISO EXIT FEE	9,798	(9,798)	-	-
182322/182335	RATE CASE EXPENSES - ELECTRIC	1,057,649	74	(461,373)	596,351
182323/182336	RATE CASE EXPENSES - GAS	378,222	24	(188,351)	189,895
182324/182337	EKPC FERC TRANSMISSION COST - KY PORTION	197,834		(169,572)	28,262
182332/182348	CARBON MANAGEMENT RESEARCH GROUP	154,470	78,000	(97,560)	134,910
182333/182349	KY CONSORTIUM FOR CARBON STORAGE	347,558	-	(219,510)	128,048
182334/182347	WIND STORM REGULATORY ASSET	17,851,419	-	(2,354,033)	15,497,386
182352	INTEREST RATE SWAPS (Mark to Market)	58,605,484	(22,692,563)	-	35,912,921
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	91,583	-	(30,528)	61,055
182360	GENERAL MANAGEMENT AUDIT - GAS	29,824	-	(9,941)	19,883
182361	2011 SUMMER STORM - ELECTRIC	8,052,125	-	(1,610,425)	6,441,700
182364	FORWARD STARTING SWAP LOSSES	-			-
182344	SWAP TERMINATION (Wachovia)	8,678,746	-	(388,659)	8,290,087
182381	SWAP TERMINATION (Bank of America)	-			
		-			
182313	REG ASSET - PENSION GAIN-LOSS AMORTIZATION	-	-	-	-
	AMS REGULATORY ASSET (a)	-			

Account	Description	2014 Beginning Balance	Annual Activity	Amortization	Ending Balance
182320/182345	WINTER STORM 2009 - ELECTRIC	28,749,879	-	(4,367,070)	24,382,809
182342/182346	WINTER STORM 2009 - GAS	110,396	-	(16,769)	93,627
182321	MISO EXIT FEE	-			-
182322/182335	RATE CASE EXPENSES - ELECTRIC	596,351	753,344	(298,138)	1,051,556
182323/182336	RATE CASE EXPENSES - GAS	189,895	188,336	(94,935)	283,296
182324/182337	EKPC FERC TRANSMISSION COST - KY PORTION	28,262		(28,262)	-
182332/182348	CARBON MANAGEMENT RESEARCH GROUP	134,910	78,000	(58,440)	154,470
182333/182349	KY CONSORTIUM FOR CARBON STORAGE	128,048		(128,048)	-
182334/182347	WIND STORM REGULATORY ASSET	15,497,386		(2,354,033)	13,143,352
182352	INTEREST RATE SWAPS (Mark to Market)	35,912,921	12,075,907	-	47,988,828
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	61,055	-	(30,528)	30,527
182360	GENERAL MANAGEMENT AUDIT - GAS	19,883	-	(9,941)	9,941
182361	2011 SUMMER STORM - ELECTRIC	6,441,700	-	(1,610,425)	4,831,275
182364	FORWARD STARTING SWAP LOSSES	-	33,263,681	-	33,263,681
182344	SWAP TERMINATION (Wachovia)	8,290,087	-	(388,659)	7,901,428
182381	SWAP TERMINATION (Bank of America)	-			
		-			
182313	REG ASSET - PENSION GAIN-LOSS AMORTIZATION	-	-	-	-
	AMS REGULATORY ASSET (a)	-			

2015

Account	Description	Beginning Balance	Annual Activity	Amortization	Ending Balance
182320/182345	WINTER STORM 2009 - ELECTRIC	24,382,809	-	(4,367,070)	20,015,738
182342/182346	WINTER STORM 2009 - GAS	93,627		(16,769)	76,858
182321	MISO EXIT FEE	-			-
182322/182335	RATE CASE EXPENSES - ELECTRIC	1,051,556	383,892	(487,738)	947,710
182323/182336	RATE CASE EXPENSES - GAS	283,296	95,967	(142,335)	236,928
182324/182337	EKPC FERC TRANSMISSION COST - KY PORTION	-			-
182332/182348	CARBON MANAGEMENT RESEARCH GROUP	154,470	97,560	(97,560)	154,470
182333/182349	KY CONSORTIUM FOR CARBON STORAGE	-			-
182334/182347	WIND STORM REGULATORY ASSET	13,143,352		(2,354,033)	10,789,319
182352	INTEREST RATE SWAPS (Mark to Market)	47,988,828	(843,464)	-	47,145,364
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	30,527	-	(30,527)	-
182360	GENERAL MANAGEMENT AUDIT - GAS	9,941	-	(9,941)	-
182361	2011 SUMMER STORM - ELECTRIC	4,831,275	-	(1,610,425)	3,220,850
182364	FORWARD STARTING SWAP LOSSES	33,263,681	43,065,873	(33,263,681)	43,065,873
182344	SWAP TERMINATION (Wachovia)	7,901,428	-	(388,659)	7,512,769
182381	SWAP TERMINATION (Bank of America)	-			
		-			
182313	REG ASSET - PENSION GAIN-LOSS AMORTIZATION	-	5,747,780	-	5,747,780
	AMS REGULATORY ASSET (a)	-			

Account	Description	2016 Beginning Balance	Annual Activity	Amortization	Ending Balance
182320/182345	WINTER STORM 2009 - ELECTRIC	20,015,738	-	(4,367,070)	15,648,668
182342/182346	WINTER STORM 2009 - GAS	76,858		(16,769)	60,089
182321	MISO EXIT FEE	-			-
182322/182335	RATE CASE EXPENSES - ELECTRIC	947,710	1,370,908	(661,161)	1,657,457
182323/182336	RATE CASE EXPENSES - GAS	236,928	393,876	(184,152)	446,652
182324/182337	EKPC FERC TRANSMISSION COST - KY PORTION	-			-
182332/182348	CARBON MANAGEMENT RESEARCH GROUP	154,470	97,560	(97,560)	154,470
182333/182349	KY CONSORTIUM FOR CARBON STORAGE	-			-
182334/182347	WIND STORM REGULATORY ASSET	10,789,319		(2,354,033)	8,435,286
182352	INTEREST RATE SWAPS (Mark to Market)	47,145,364	(16,180,347)	-	30,965,017
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	-			-
182360	GENERAL MANAGEMENT AUDIT - GAS	-			-
182361	2011 SUMMER STORM - ELECTRIC	3,220,850	-	(1,610,425)	1,610,425
182364	FORWARD STARTING SWAP LOSSES	43,065,873		(2,397,988)	40,667,885
182344	SWAP TERMINATION (Wachovia)	7,512,769	-	(388,659)	7,124,110
182381	SWAP TERMINATION (Bank of America)	-	9,409,000		9,409,000
		-			
182313	REG ASSET - PENSION GAIN-LOSS AMORTIZATION	5,747,780	7,285,790	(2,148,328)	10,885,242
	AMS REGULATORY ASSET (a)	-			

		Forecast Base Period (3/16 - 2/17)		
Account	Description	Beginning Balance	Annual Activity	Ending Balance
182320/182345	WINTER STORM 2009 - ELECTRIC	19,288,000	(4,367,070)	14,920,930
182342/182346	WINTER STORM 2009 - GAS	74,000	(16,769)	57,231
182321	MISO EXIT FEE	-	-	-
182322/182335	RATE CASE EXPENSES - ELECTRIC	806,000	437,000	1,243,000
182323/182336	RATE CASE EXPENSES - GAS	300,000	158,000	458,000
182324/182337	EKPC FERC TRANSMISSION COST - KY PORTION	-	-	-
182332/182348	CARBON MANAGEMENT RESEARCH GROUP	236,000	-	236,000
182333/182349	KY CONSORTIUM FOR CARBON STORAGE	-	-	-
182334/182347	WIND STORM REGULATORY ASSET	10,397,000	(2,354,000)	8,043,000
182352	INTEREST RATE SWAPS (Mark to Market)	41,687,752	(2,972,726)	38,715,026
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	-	-	-
182360	GENERAL MANAGEMENT AUDIT - GAS	-	-	-
182361	2011 SUMMER STORM - ELECTRIC	2,952,000	(1,610,000)	1,342,000
182364	FORWARD STARTING SWAP LOSSES	42,673,000	(2,392,000)	40,281,000
182344	SWAP TERMINATION (Wachovia)	7,448,000	(389,000)	7,059,000
182381	SWAP TERMINATION (Bank of America)	13,068,248	(191,274)	12,876,974
182313	REG ASSET - PENSION GAIN-LOSS AMORTIZATION	5,748,000	5,430,000	11,178,000
	AMS REGULATORY ASSET (a)			

Account	Description	Forecast Test Period (7/17 - 6/18) Beginning Balance	Annual Activity	Ending Balance
182320/182345	WINTER STORM 2009 - ELECTRIC	13,463,000	(4,367,070)	9,095,930
182342/182346	WINTER STORM 2009 - GAS	54,000	(16,769)	37,231
182321	MISO EXIT FEE	-	-	-
182322/182335	RATE CASE EXPENSES - ELECTRIC	1,314,000	(636,000)	678,000
182323/182336	RATE CASE EXPENSES - GAS	488,000	(238,000)	250,000
182324/182337	EKPC FERC TRANSMISSION COST - KY PORTION	-	-	-
182332/182348	CARBON MANAGEMENT RESEARCH GROUP	203,000	-	203,000
182333/182349	KY CONSORTIUM FOR CARBON STORAGE	-	-	-
182334/182347	WIND STORM REGULATORY ASSET	7,258,000	(2,354,000)	4,904,000
182352	INTEREST RATE SWAPS (Mark to Market)	36,597,308	(6,271,279)	30,326,029
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	-	-	-
182360	GENERAL MANAGEMENT AUDIT - GAS	-	-	-
182361	2011 SUMMER STORM - ELECTRIC	805,000	(805,000)	-
182364	FORWARD STARTING SWAP LOSSES	39,482,000	(2,391,000)	37,091,000
182344	SWAP TERMINATION (Wachovia)	6,930,000	(389,000)	6,541,000
182381	SWAP TERMINATION (Bank of America)	12,617,692	(775,721)	11,841,971
182313	REG ASSET - PENSION GAIN-LOSS AMORTIZATION	17,787,000	11,220,000	29,007,000
	AMS REGULATORY ASSET (a)	-	5,249,000	5,249,000

Account	Description	Account Used for Amortization	Amortization Period	Order No. / Docket No.
182305/182315	ASC 715 - PENSION AND POSTRETIREMENT	926	Ongoing	KPSC 2003-00433 KPSC 2008-00252 KPSC 2009-00549 KPSC 2012-00222 KPSC 2014-00372 FERC AI04-2-000 FERC AI07-1-000
182328-182331	ASC 740 - INCOME TAXES	282/283	Ongoing	KPSC 2005-00180 KPSC 2006-00457 KPSC 2009-00549 KPSC 2012-00222 KPSC 2014-00372
182317-18/1823	ASSET RETIREMENT OBLIGATION - ELECTRIC	407	Ongoing	KPSC 2003-00426 KPSC 2003-00433 KPSC 2008-00252 KPSC 2009-00549 KPSC 2012-00222 KPSC 2014-00372 FERC FA 12-12-000 FERC ER08-1588-000
182326	ASSET RETIREMENT OBLIGATION - GAS	407	Ongoing	KPSC 2003-00426 KPSC 2003-00433 KPSC 2008-00252 KPSC 2009-00549 KPSC 2012-00222 KPSC 2014-00372 FERC FA 12-12-000 FERC ER08-1588-000
182327	ASSET RETIREMENT OBLIGATION - COMMON	407	Ongoing	KPSC 2003-00426 KPSC 2003-00433 KPSC 2008-00252 KPSC 2009-00549 KPSC 2012-00222 KPSC 2014-00372 FERC FA 12-12-000 FERC ER08-1588-000
182372-182373	ARO - GENERATION - COAL COMBUSTION RESIDUALS (b)	407	Jul-16 to Jun-26 Jul-16 to Jun-41	KPSC 2003-00426 KPSC 2003-00433 KPSC 2008-00252 KPSC 2009-00549 KPSC 2012-00222 KPSC 2014-00372 FERC FA 12-12-000 FERC ER08-1588-000 KPSC 2016-00027 FERC ER17-234-000
182307	ENVIRONMENTAL COST RECOVERY	440-445	Ongoing	KRS 278.183
182306	FUEL ADJUSTMENT CLAUSE	803	Ongoing	807 KAR 5:056
182340	PERFORMANCE-BASED RATES	803	Ongoing	KPSC 1997-00171 KPSC 2005-00031 KPSC 2009-00550 KPSC 2012-00222 KPSC 2014-00372
182308	GAS SUPPLY CLAUSE	803	Ongoing	KPSC 9133 KPSC 2003-00433 KPSC 2008-00252 KPSC 2009-00549 KPSC 2012-00222 KPSC 2014-00372
182363	DSM COST RECOVERY - UNDER-RECOVERY	440-445, 480-482, ‹	Ongoing	KRS 278.285
182365	GAS LINE TRACKER	480-482	Ongoing	KPSC 2012-00222 KPSC 2014-00372
182370	OFF-SYSTEM TRACKER	440-445	Ongoing	KPSC 2014-00371
LG&E Regulatory Assets Total				

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

b) ARO CCR detail is not available from the Business Plan in UI Planner - detail is combined in the ARO line item

* These balances are a result of netting the regulatory asset and the regulatory liability in the forecast - the net balance was a regulatory liability

Account	Description	2012 Beginning Balance	Annual Activity	Amortization	Ending Balance
182305/182315	ASC 715 - PENSION AND POSTRETIREMENT	225,305,162	31,200,453	(24,799,966)	231,705,649
182328-182331	ASC 740 - INCOME TAXES	14,730,134	118,389	(525,940)	14,322,583
182317-18/1823	ASSET RETIREMENT OBLIGATION - ELECTRIC	9,423,533	3,699,843	(113,009)	13,010,367
182326	ASSET RETIREMENT OBLIGATION - GAS	1,233,920	2,410,208	(1,646,097)	1,998,031
182327	ASSET RETIREMENT OBLIGATION - COMMON	9,107	8,585	(465)	17,227
182372-182373	ARO - GENERATION - COAL COMBUSTION RESIDUALS (b)	-	-	-	-
182307	ENVIRONMENTAL COST RECOVERY	-	1,055,680	(424,145)	631,535
182306	FUEL ADJUSTMENT CLAUSE	3,598,000	7,641,000	(5,171,000)	6,068,000
182340	PERFORMANCE-BASED RATES	4,018,092	4,262,010	(2,640,217)	5,639,885
182308	GAS SUPPLY CLAUSE	1,683,380	7,546,298	(3,790,439)	5,439,239
182363	DSM COST RECOVERY - UNDER-RECOVERY	-	1,538,143	(607,258)	930,885
182365	GAS LINE TRACKER	-	-	-	-
182370	OFF-SYSTEM TRACKER	-	-	-	-
LG&E Regulatory Assets Total		397,110,901	59,797,784	(48,446,460)	408,462,226

a) Business Plan assumed a regulatory asset would be recorded as retirements of meters occasset at the end of the meter replacement program. There is
b) ARO CCR detail is not available from the Business Plan in UI Planner - detail is combin
* These balances are a result of netting the regulatory asset and the regulatory liability in t

LOUISVILLE GAS AND ELECTRIC COMPANY
Case No. 2016-00371
Amortization of Regulatory Assets

Account	Description	Beginning Balance (2013)	Annual Activity (2013)	Amortization (2013)	Ending Balance (2013)
182305/182315	ASC 715 - PENSION AND POSTRETIREMENT	231,705,649	23,775,059	(91,392,827)	164,087,881
182328-182331	ASC 740 - INCOME TAXES	14,322,583	166,627	(431,860)	14,057,350
182317-18/1823	ASSET RETIREMENT OBLIGATION - ELECTRIC	13,010,367	6,705,785	(1,685,805)	18,030,347
182326	ASSET RETIREMENT OBLIGATION - GAS	1,998,031	1,903,745	(996,849)	2,904,927
182327	ASSET RETIREMENT OBLIGATION - COMMON	17,227	8,277	(506)	24,998
182372-182373	ARO - GENERATION - COAL COMBUSTION RESIDUALS (b)	-	-	-	-
182307	ENVIRONMENTAL COST RECOVERY	631,535	2,318,727	(789,551)	2,160,711
182306	FUEL ADJUSTMENT CLAUSE	6,068,000	9,635,000	(14,011,000)	1,692,000
182340	PERFORMANCE-BASED RATES	5,639,885	1,556,141	(4,621,995)	2,574,031
182308	GAS SUPPLY CLAUSE	5,439,239	11,936,838	(10,016,432)	7,359,645
182363	DSM COST RECOVERY - UNDER-RECOVERY	930,885	7,491,371	(4,818,123)	3,604,133
182365	GAS LINE TRACKER	-	-	-	-
182370	OFF-SYSTEM TRACKER	-	-	-	-
LG&E Regulatory Assets Total		408,462,226	42,873,308	(138,678,740)	312,656,794

a) Business Plan assumed a regulatory asset would be recorded as retirements of meters occ
b) ARO CCR detail is not available from the Business Plan in UI Planner - detail is combin
* These balances are a result of netting the regulatory asset and the regulatory liability in t

		2014			
Account	Description	Beginning Balance	Annual Activity	Amortization	Ending Balance
182305/182315	ASC 715 - PENSION AND POSTRETIREMENT	164,087,881	64,338,355	(13,887,774)	214,538,462
182328-182331	ASC 740 - INCOME TAXES	14,057,350	14,319	(279,552)	13,792,117
182317-18/1823	ASSET RETIREMENT OBLIGATION - ELECTRIC	18,030,347	6,941,551	(114,037)	24,857,861
182326	ASSET RETIREMENT OBLIGATION - GAS	2,904,927	2,020,595	(1,536,648)	3,388,874
182327	ASSET RETIREMENT OBLIGATION - COMMON	24,998	104,517	(129,515)	-
182372-182373	ARO - GENERATION - COAL COMBUSTION RESIDUALS (b)	-	-	-	-
182307	ENVIRONMENTAL COST RECOVERY	2,160,711	4,839,904	(3,160,615)	3,840,000
182306	FUEL ADJUSTMENT CLAUSE	1,692,000	4,681,000	(4,811,000)	1,562,000
182340	PERFORMANCE-BASED RATES	2,574,031	2,516,477	(3,379,290)	1,711,218
182308	GAS SUPPLY CLAUSE	7,359,645	25,465,387	(19,030,055)	13,794,977
182363	DSM COST RECOVERY - UNDER-RECOVERY	3,604,133	4,067,619	(7,671,752)	-
182365	GAS LINE TRACKER	-	-	-	-
182370	OFF-SYSTEM TRACKER	-	-	-	-
LG&E Regulatory Assets Total		312,656,794	161,348,991	(63,385,486)	410,620,299

a) Business Plan assumed a regulatory asset would be recorded as retirements of meters occ
b) ARO CCR detail is not available from the Business Plan in UI Planner - detail is combin
* These balances are a result of netting the regulatory asset and the regulatory liability in t

Account	Description	2015 Beginning Balance	Annual Activity	Amortization	Ending Balance
182305/182315	ASC 715 - PENSION AND POSTRETIREMENT	214,538,462	31,966,740	(37,548,834)	208,956,368
182328-182331	ASC 740 - INCOME TAXES	13,792,117	14,319	(279,552)	13,526,884
182317-18/1823	ASSET RETIREMENT OBLIGATION - ELECTRIC	24,857,861	29,252,876	(740,182)	53,370,555
182326	ASSET RETIREMENT OBLIGATION - GAS	3,388,874	1,947,945	(1,713,247)	3,623,572
182327	ASSET RETIREMENT OBLIGATION - COMMON	-	-	-	-
182372-182373	ARO - GENERATION - COAL COMBUSTION RESIDUALS (b)	-	-	-	-
182307	ENVIRONMENTAL COST RECOVERY	3,840,000	10,486,000	(1,020,000)	13,306,000
182306	FUEL ADJUSTMENT CLAUSE	1,562,000	2,088,000	(3,650,000)	-
182340	PERFORMANCE-BASED RATES	1,711,218	1,218,784	(1,500,798)	1,429,204
182308	GAS SUPPLY CLAUSE	13,794,977	2,074,932	(15,869,909)	-
182363	DSM COST RECOVERY - UNDER-RECOVERY	-			-
182365	GAS LINE TRACKER	-	1,286,856	-	1,286,856
182370	OFF-SYSTEM TRACKER	-	-	-	-
LG&E Regulatory Assets Total		410,620,299	128,884,060	(105,091,261)	434,413,098

a) Business Plan assumed a regulatory asset would be recorded as retirements of meters occ
b) ARO CCR detail is not available from the Business Plan in UI Planner - detail is combin
* These balances are a result of netting the regulatory asset and the regulatory liability in t

LOUISVILLE GAS AND ELECTRIC COMPANY
Case No. 2016-00371
Amortization of Regulatory Assets

Account	Description	2016 Beginning Balance	Annual Activity	Amortization	Ending Balance
182305/182315	ASC 715 - PENSION AND POSTRETIREMENT	208,956,368	(1,545,009)	3,550,620	210,961,979
182328-182331	ASC 740 - INCOME TAXES	13,526,884	1,023,098	(374,698)	14,175,284
182317-18/1823	ASSET RETIREMENT OBLIGATION - ELECTRIC	53,370,555	21,076,596	(38,578,975)	35,868,177
182326	ASSET RETIREMENT OBLIGATION - GAS	3,623,572	1,804,569	(2,054,147)	3,373,993
182327	ASSET RETIREMENT OBLIGATION - COMMON	-	-	-	-
182372-182373	ARO - GENERATION - COAL COMBUSTION RESIDUALS (b)	-	31,064,241	(95,997)	30,968,244
182307	ENVIRONMENTAL COST RECOVERY	13,306,000	6,865,000	(13,737,000)	6,434,000
182306	FUEL ADJUSTMENT CLAUSE	-			-
182340	PERFORMANCE-BASED RATES	1,429,204	107,000	(1,536,204)	-
182308	GAS SUPPLY CLAUSE	-	9,920,809	(7,104,687)	2,816,121
182363	DSM COST RECOVERY - UNDER-RECOVERY	-	-	-	-
182365	GAS LINE TRACKER	1,286,856	396,585	(1,683,441)	-
182370	OFF-SYSTEM TRACKER	-	-	-	-
LG&E Regulatory Assets Total		434,413,098	73,089,675	(75,840,674)	431,662,099

a) Business Plan assumed a regulatory asset would be recorded as retirements of meters occ
b) ARO CCR detail is not available from the Business Plan in UI Planner - detail is combin
* These balances are a result of netting the regulatory asset and the regulatory liability in t

LOUISVILLE GAS AND ELECTRIC COMPANY
Case No. 2016-00371
Amortization of Regulatory Assets

		Forecast Base Period (3/16 - 2/17)		
Account	Description	Beginning Balance	Annual Activity	Ending Balance
182305/182315	ASC 715 - PENSION AND POSTRETIREMENT	208,707,000	56,174,000	264,881,000
182328-182331	ASC 740 - INCOME TAXES	22,393,000	(22,393,000)	-
182317-18/1823	ASSET RETIREMENT OBLIGATION - ELECTRIC	55,672,000	23,524,000	79,196,000
182326	ASSET RETIREMENT OBLIGATION - GAS	5,800,000	2,374,000	8,174,000
182327	ASSET RETIREMENT OBLIGATION - COMMON	-	-	-
182372-182373	ARO - GENERATION - COAL COMBUSTION RESIDUALS (b)			
182307	ENVIRONMENTAL COST RECOVERY	7,525,000	(2,096,836)	5,428,164
182306	FUEL ADJUSTMENT CLAUSE	-	-	-
182340	PERFORMANCE-BASED RATES	981,000	(981,000)	-
182308	GAS SUPPLY CLAUSE	(2,495,738)	3,574,212	1,078,474
182363	DSM COST RECOVERY - UNDER-RECOVERY	-	-	-
182365	GAS LINE TRACKER	1,464,570	(1,524,660)	(60,090)
182370	OFF-SYSTEM TRACKER	(114,000)	(120,000)	(234,000)
LG&E Regulatory Assets Total		444,610,832	50,262,877	494,873,709

a) Business Plan assumed a regulatory asset would be recorded as retirements of meters occ
b) ARO CCR detail is not available from the Business Plan in UI Planner - detail is combin
* These balances are a result of netting the regulatory asset and the regulatory liability in t

		Forecast Test Period (7/17 - 6/18)		
Account	Description	Beginning Balance	Annual Activity	Ending Balance
182305/182315	ASC 715 - PENSION AND POSTRETIREMENT	240,642,000	(15,349,000)	225,293,000
182328-182331	ASC 740 - INCOME TAXES	21,613,000	(21,613,000)	-
182317-18/1823	ASSET RETIREMENT OBLIGATION - ELECTRIC	84,205,000	18,964,000	103,169,000
182326	ASSET RETIREMENT OBLIGATION - GAS	8,700,000	2,018,000	10,718,000
182327	ASSET RETIREMENT OBLIGATION - COMMON	-	-	-
182372-182373	ARO - GENERATION - COAL COMBUSTION RESIDUALS (b)			
182307	ENVIRONMENTAL COST RECOVERY	5,336,518	4,406,402	9,742,920
182306	FUEL ADJUSTMENT CLAUSE	-	-	-
182340	PERFORMANCE-BASED RATES	-	-	-
182308	GAS SUPPLY CLAUSE	718,983	(718,983)	-
182363	DSM COST RECOVERY - UNDER-RECOVERY	-	-	-
182365	GAS LINE TRACKER	-	-	- *
182370	OFF-SYSTEM TRACKER	(70,000)	(39,000)	(109,000) *
LG&E Regulatory Assets Total		498,144,501	(14,106,420)	484,038,081

a) Business Plan assumed a regulatory asset would be recorded as retirements of meters occ
b) ARO CCR detail is not available from the Business Plan in UI Planner - detail is combin
* These balances are a result of netting the regulatory asset and the regulatory liability in t

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

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. 2014-00089 on June 16, 2014, LG&E was authorized by the KPSC to issue First Mortgage Bonds in aggregate principal amount of up to $550 million and enter into hedging agreements (forward starting swaps) to lock in interest rates for debt to be issued in 2015. LG&E 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 $300 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 $300 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. 2014-00372).

   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. 2012-00233, LG&E 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, LG&E entered into $150 million of forward-starting swaps and in April 2013, LG&E added an additional $100 million of forward-starting swaps. The initial swaps expired in September and LG&E received a payment of $49,325,370.50, and LG&E entered into new forward-starting swaps with a total notional amount $250 million, 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. 2012-00222) and 2014 rate case (Case No. 2014-00372). Amortization of the gains is booked as a reduction to interest expense and was included in the test period in Case No. 2014-00372 and is included in the test period in this case.

f. See the response to part e.

LOUISVILLE GAS AND ELECTRIC COMPANY
Case No. 2016-00371
Schedule of Regulatory Assets

	Base Period				Forecasted Test Period			
Description	**Beginning Balance**	**Activity**	**Amortization**	**Ending Balance**	**Beginning Balance**	**Activity**	**Amortization**	**Ending Balance**
AMS REGULATORY ASSET (a)	$ -	$ -	$ -	$ -	$ -	$ 5,248,999	$ -	$ 5,248,999
ASC 740 - INCOME TAXES [1]	13,526,884	954,992	(134,208)	14,347,667	14,347,667	-	-	14,347,667
PENSION GAIN-LOSS AMORTIZATION - 15 years	5,747,780	5,467,431	(36,927)	11,178,284	17,786,752	11,220,572	-	29,007,324
ASC 715 - PENSION AND POSTRETIREMENT [2]	208,956,368	71,086,295	(15,162,370)	264,880,293	253,362,820	(9,040,922)	(19,028,778)	225,293,120
WINTER STORM 2009 - ELECTRIC [3]	19,287,893	-	(4,367,070)	14,920,823	13,465,133	-	(4,367,070)	9,098,063
WINTER STORM 2009 - GAS [3]	74,063	-	(16,769)	57,294	51,704	-	(16,769)	34,936
WIND STORM REGULATORY ASSET	10,396,980	-	(2,354,033)	8,042,947	7,258,269	-	(2,354,033)	4,904,236
2011 SUMMER STORM - ELECTRIC	2,952,446	-	(1,610,425)	1,342,021	805,212	-	(805,212)	-
INTEREST RATE SWAPS (Mark to Market, Wachovia Swap Termination and Bank of America Swap Termination) [4]	62,204,390	4,137,229	(7,690,057)	58,651,562	56,144,442	-	(7,435,413)	48,709,029
FORWARD STARTING SWAP LOSSES	42,672,761	-	(2,391,436)	40,281,325	39,481,996	-	(2,391,436)	37,090,560
RATE CASE EXPENSES - ELECTRIC [3]	884,683	846,887	(379,199)	1,352,370	1,428,408	50,609	(745,805)	733,213
RATE CASE EXPENSES - GAS [3]	221,177	222,060	(94,800)	348,437	373,130	14,073	(192,268)	194,935
CARBON MANAGEMENT RESEARCH GROUP	235,770	97,560	(97,560)	235,770	203,250	97,560	(97,560)	203,250
ASSET RETIREMENT OBLIGATION - ELECTRIC (ARO) [3,7] (b)	57,721,069	24,849,837	(271,422)	82,299,484	88,669,527	19,533,280	(1,104,229)	107,098,578
ASSET RETIREMENT OBLIGATION (ARO) - GAS [3]	3,750,562	1,320,393	-	5,070,955	5,491,969	1,296,608	-	6,788,578
ENVIRONMENTAL COST RECOVERY	7,525,000	26,890,807	(28,987,643)	5,428,164	5,336,518	89,426,584	(85,020,182)	9,742,920
FUEL ADJUSTMENT CLAUSE (FAC) [5]	-	(15,098,556)	14,491,615	(606,941)	(1,194,195)	(43,944,431)	42,892,028	(2,246,598)
GAS SUPPLY CLAUSE (GSC) [6]	314,000	1,303,711	(539,237)	1,078,474	718,983	-	(718,983)	-
GAS LINE TRACKER (GLT) [6]	1,464,570	(1,464,570)	-	-	-	-	-	-
OFF-SYSTEM TRACKER (OST) [6]	-	(370,701)	189,878	(180,823)	(17,127)	(1,059,270)	1,020,459	(55,937)
PERFORMANCE-BASED RATES	980,833	(980,833)	-	-	-	-	-	-
Total Regulatory Assets*	$ 438,917,227	$ 119,262,541	$ (49,451,663)	$ 508,728,106	$ 503,714,460	$ 72,843,664	$ (80,365,251)	$ 496,192,872

*Balances agree to monthly Total Company Balance Sheet provided in Attachment to LGE PSC1-59 (Supplemental) - LGE Electric Schedule B
The derivation of the calculations are from UIPlanner. For assumptions used and the Orders authorizing the assumptions as it relates to activity and amortization see response to KIUC 2-8(c)

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 1-28 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] = For the Base Period, the response to KIUC 1-28 inadvertently included the March 30, 2016, balance for the Postretirement instead of the March 1, 2016. For the Forecasted Test Period, the response to KIUC 1-28 inadvertently did not include the Postretirement beginning balance, activity nor the ending balance.

[3] = In the response KIUC 1-28 for the Electric and Gas balances we had inadvertently used the incorrect electric and gas percentage split, this schedule reflects the corrected split.

[4] = In the response to KIUC 1-28, these items were shown separately, to be consistent with the balance sheet presentation these are added together.

[5] = The response to KIUC 1-28 did not include the activity for the FAC because this is a regulatory liability. However, for the forecasted periods, the activity is recorded to the regulatory asset balance.

[6] = The response to KIUC 1-28 inadvertently reflected the net GSC, GLT balances and activity, this schedule reflects the regulatory asset balance only. The OST is a regulatory liability, the response to KIUC 1-28 reflected the net balances and activity, however for the forecasted periods the activity is recorded to the regulatory asset balance.

[7] = For the Forecasted Test Period, in the response to KIUC 1-28, we inadvertently used the incorrect month for the beginning balance which resulted in the incorrect activity total but the correct ending balance.

EXHIBIT ____ (LK-14)

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. 2

Responding Witness: John J. Spanos

Q.1-2. Refer to pages 10-1 1 of Mr. Spanos' Direct Testimony wherein he describes the "dismantlement component" added to the overall net salvage for each production facility. Refer also to pages VIII-2 and VIII-3 of Exhibit JJS-KU-l (Depreciation Study attached to Mr. Spanos' Direct Testimony).

a. Please describe and provide copies of all source documentation relied upon to determine that "the dismantlement or decommissioning costs for steam production facilities is best calculated at $40/KW of the assets subject to final retirement. The percentage for dismantlement of hydro and other production facilities is $ 10/KW of the assets surviving at final retirement with the exception of the combined facility which is $20/KW."

b. Please provide for each production facility the KWs utilized to calculate the "dismantlement component", the calculation of the "dismantlement component," and describe how that calculation was incorporated into the calculation of the net salvage component contained on pages VIII-2 and VIII-3 of Exhibit JJS-KU- 1. Provide all calculations if not provided in response to other requests for exhibits and workpapers in electronic format with all formulas intact.

c. At page 11 starting at line 9, Mr. Spanos states, "The current practice for LG&E includes a low level of terminal net salvage combined with the interim net salvage percentage. In this study, the methodology continues to advance to a more precise practice and is utilized by most utilities. The weighting of the interim and final net salvage by location establishes a more precise recovery pattern for each location." Please describe how the calculation of the overall net salvage percentage reflected in the approved depreciation rates differs from the calculation one in the new depreciation study other than the use of a lower level of terminal net salvage as part of current depreciation rates. Provide the calculations of the overall net salvage showing the interim and terminal net salvage components reflected in the approved depreciation rates and those proposed in this proceeding.

A.1-2.

a) The determination of the $/KW levels for dismantlement of generating facilities was based on numerous studies performed by engineering consulting firms that specialize in the dismantlement of generating facilities and an initial study performed and presented by the American Gas Association and Edison Electric Institute.

Decommissioning cost estimates are extensive studies performed by experts in the field that establish the cost to complete each task of the demolition and then net the scrap value to determine the overall decommissioning cost. The cost breakdown for these studies is based on returning the site to a brownfield condition. These costs are then converted to a $/KW value based on the MWs of each unit or location. The estimates of decommissioning costs range from $20/KW to $150/KW with a very high percentage around the $40/KW to $50/KW level. Thus, $40/KW was utilized for KU facilities. Similar analysis was performed for hydro, other production and combined cycle facilities.

b) The attached schedule KU-KIUC-1-2.xlsx sets forth the calculation of the percentage of the dismantlement costs to the assets to be retired on a terminal basis. These percentages are utilized in the determination of the weighted net salvage percentage as set forth on pages VIII-2 and VIII-3 of the Exhibit JJS-KU-1.

c) The currently approved net salvage was determined based on a settlement that was not a calculated or analyzed based on costs to dismantle. The amount of 2% of terminal net salvage per unit or location was agreed upon in settlement in order to establish an amount to include in depreciation rates.

KENTUCKY UTILITIES

DECOMMISSIONING COSTS RELATED TO GENERATING UNITS

UNIT	ESTIMATED RETIREMENT YEAR	MW	ESTIMATED DECOMMISSIONING COSTS ($/KW)	TOTAL DECOMMISSIONING COSTS (CURRENT $)	TOTAL DECOMMISSIONING COSTS (FUTURE $)	ESTIMATED TERMINAL RETIREMENTS
(1)	(2)	(3)	(4)	(5)=(3)*(4)	(6)	(7)
STEAM						
SYSTEM LABORATORY	2040	0	40	0	0	(3,981,926)
TRIMBLE COUNTY	2066	335	40	13,400,000	48,388,905	(590,869,790)
BROWN 1	2023	106	40	4,240,000	5,295,179	
BROWN 2	2029	166	40	6,640,000	9,616,700	
BROWN 3	2035	411	40	16,440,000	27,612,326	
TOTAL BROWN				27,320,000	42,524,205	(903,057,104)
GHENT 1	2034	493	40	19,720,000	32,313,516	
GHENT 2	2034	490	40	19,600,000	32,116,882	
GHENT 3	2037	454	40	18,160,000	32,045,330	
GHENT 4	2038	487	40	19,480,000	35,233,981	
TOTAL GHENT				76,960,000	131,709,709	(2,544,166,674)
TOTAL STEAM				117,680,000	222,622,819	(4,042,075,495)
HYDRO						
DIX DAM	2041	26	10	260,000	506,428	(35,425,875)
TOTAL HYDRO				260,000	506,428	(35,425,875)
OTHER						
CANE RUN	2055	660	20	13,200,000	36,328,914	(288,106,178)
HAEFLING 1, 2 AND 3	2020	36	10	360,000	417,490	(3,985,290)
PADDY'S RUN 13	2031	74	10	740,000	1,125,998	(27,330,118)
BROWN 5	2031	57	10	570,000	867,322	
BROWN 6	2029	91	10	910,000	1,317,951	
BROWN 7	2029	91	10	910,000	1,317,951	
BROWN 8	2025	121	10	1,210,000	1,587,625	
BROWN 9	2031	121	10	1,210,000	1,841,158	
BROWN 10	2031	121	10	1,210,000	1,841,158	
BROWN 11	2026	121	10	1,210,000	1,627,315	
BROWN GAS PIPELINE	2031	0	10	0	0	
TOTAL BROWN				7,230,000	10,400,480	(229,538,287)
TRIMBLE COUNTY 5	2032	114	10	1,140,000	1,778,011	
TRIMBLE COUNTY 6	2032	114	10	1,140,000	1,778,011	
TRIMBLE COUNTY GAS PIPELINE	2034		10	0	0	
TRIMBLE COUNTY 7	2034	101	10	1,010,000	1,655,003	
TRIMBLE COUNTY 8	2034	101	10	1,010,000	1,655,003	
TRIMBLE COUNTY 9	2034	101	10	1,010,000	1,655,003	
TRIMBLE COUNTY 10	2034	101	10	1,010,000	1,655,003	
TOTAL TRIMBLE COUNTY				6,320,000	10,176,034	(190,892,260)
TOTAL OTHER				27,850,000	58,448,916	(739,852,132)

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

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

Question No. 2

Responding Witness: John J. Spanos

Q.1-2. Refer to pages 10-11 of Mr. Spanos' Direct Testimony wherein he describes the "dismantlement component" added to the overall net salvage for each production facility. Refer also to pages VIII-2 and VIII-3 of Exhibit JJS-LGE-1 (Depreciation Study attached to Mr. Spanos' Direct Testimony).

a. Please describe and provide copies of all source documentation relied upon to determine that "the dismantlement or decommissioning costs for steam production facilities is best calculated at $40/KW of the assets subject to final retirement. The percentage for dismantlement of hydro and other production facilities is $10/KW of the assets surviving at final retirement with the exception of the combined facility which is $20/KW."

b. Please provide for each production facility the KWs utilized to calculate the "dismantlement component," the calculation of the "dismantlement component," and describe how that calculation was incorporated into the calculation of the net salvage component contained on pages VIII-2 and VIII-3 of Exhibit JJS-LGE-1. Provide all calculations if not provided in response to other requests for exhibits and workpapers in electronic format with all formulas intact.

c. At page 11 starting at line 9, Mr. Spanos states, "The current practice for LG&E includes a low level of terminal net salvage combined with the interim net salvage percentage. In this study, the methodology continues to advance to a more precise practice and is utilized by most utilities. The weighting of the interim and final net salvage by location establishes a more precise recovery pattern for each location." Please describe how the calculation of the overall net salvage percentage reflected in the approved depreciation rates differs from the calculation one in the new depreciation study other than the use of a lower level of terminal net salvage as part of current depreciation rates. Provide the calculations of the overall net salvage showing the interim and terminal net salvage components reflected in the approved depreciation rates and those proposed in this proceeding.

A.1-2.

a) The determination of the $/KW levels for dismantlement of generating facilities was based on numerous studies performed by engineering consulting firms that specialize in the dismantlement of generating facilities and an initial study performed and presented by the American Gas Association and Edison Electric Institute.

Decommissioning cost estimates are extensive studies performed by experts in the field that establish the cost to complete each task of the demolition and then net the scrap value to determine the overall decommissioning cost. The cost breakdown for these studies is based on returning the site to a brownfield condition. These costs are then converted to a $/KW value based on the MWs of each unit or location. The estimates of decommissioning costs range from $20/KW to $150/KW with a very high percentage around the $40/KW to $50/KW level. Thus, $40/KW was utilized for LGE facilities. Similar analysis was performed for hydro, other production and combined cycle facilities.

b) The attached schedule LGE-KIUC-1-2.xlsx sets forth the calculation of the percentage of the dismantlement costs to the assets to be retired on a terminal basis. These percentages are utilized in the determination of the weighted net salvage percentage as set forth on pages VIII-2 and VIII-3 of the Exhibit JJS-LGE-1.

c) The currently approved net salvage was determined based on a settlement that was not a calculated or analyzed based on costs to dismantle. The amount of 2% of terminal net salvage per unit or location was agreed upon in settlement in order to establish an amount to include in depreciation rates.

LOUISVILLE GAS AND ELECTRIC

DECOMMISSIONING COSTS RELATED TO GENERATING UNITS

UNIT	ESTIMATED RETIREMENT YEAR	MW	ESTIMATED DECOMMISSIONING COSTS ($/KW)	TOTAL DECOMMISSIONING COSTS (CURRENT $)	TOTAL DECOMMISSIONING COSTS (FUTURE $)	ESTIMATED TERMINAL RETIREMENTS
(1)	(2)	(3)	(4)	(5)=(3)*(4)	(6)	(7)
STEAM						
MILL CREEK 1	2032	303	40	12,120,000	18,903,064	
MILL CREEK 2	2034	301	40	12,040,000	19,728,942	
MILL CREEK 3	2038	391	40	15,640,000	28,288,474	
MILL CREEK 4	2042	477	40	19,080,000	38,093,125	
TOTAL MILL CREEK				58,880,000	105,013,605	(1,452,787,796)
TRIMBLE COUNTY 1	2050	383	40	15,320,000	37,266,441	
TRIMBLE COUNTY 2	2066	102	40	4,080,000	14,733,338	
TOTAL TRIMBLE COUNTY				19,400,000	51,999,779	(535,583,282)
TOTAL STEAM				**78,280,000**	**157,013,384**	**(1,988,371,079)**
HYDRO						
OHIO FALLS	2045	52	10	520,000	1,118,004	(92,590,980)
TOTAL HYDRO				**520,000**	**1,118,004**	**(92,590,980)**
OTHER						
CANE RUN 7	2055	31	20	620,000	1,706,358	
CANE RUN 11	2018	14	20	280,000	309,068	
TOTAL CANE RUN				900,000	2,015,426	(90,119,059)
ZORN AND RIVER ROAD GAS TURBINE	2019	14	10	140,000	158,397	(1,857,026)
PADDY'S RUN 11	2018	12	10	120,000	132,458	(36,704,237)
PADDY'S RUN 12	2018	23	10	230,000	253,877	
PADDY'S RUN 13	2031	84	10	840,000	1,278,159	
TOTAL PADDY'S RUN				1,190,000	1,664,494	(37,931,804)
BROWN 5	2031	65	10	650,000	989,052	
BROWN 6	2029	55	10	550,000	796,564	
BROWN 7	2029	55	10	550,000	796,564	
TOTAL BROWN				1,750,000	2,582,180	(60,738,943)
TRIMBLE COUNTY 5	2032	46	10	460,000	717,443	
TRIMBLE COUNTY 6	2032	46	10	460,000	717,443	
TRIMBLE COUNTY 7	2034	59	10	590,000	966,784	
TRIMBLE COUNTY 8	2034	59	10	590,000	966,784	
TRIMBLE COUNTY 9	2034	59	10	590,000	966,784	
TRIMBLE COUNTY 10	2034	59	10	590,000	966,784	
TOTAL TRIMBLE COUNTY				3,280,000	5,302,022	(100,724,301)
TOTAL OTHER				**7,260,000**	**11,722,519**	**(291,371,133)**

EXHIBIT ____ (LK-15)

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. 1

Responding Witness: John J. Spanos

Q.2-1. Refer to the response to KIUC 1-2(a), which requested a copy of all source documents relied on for the decommissioning cost estimates. No source documents were provided. Either provide the documents or indicate that they are not available and provide the reason why they are not available.

A.2-1. The documents supplied in response to KIUC 1-2 were the supporting documents that can be produced. In preparing the decommissioning cost estimates, Mr. Spanos relied upon proprietary studies for which he does not have necessary consents to disclose and his general knowledge of industry information on decommissioning costs. Attached is a file which shows the calculation of the decommissioning costs referenced in Mr. Spanos's depreciation study.

KENTUCKY UTILITIES

DECOMMISSIONING COSTS RELATED TO GENERATING UNITS

UNIT	ESTIMATED RETIREMENT YEAR	MW	ESTIMATED DECOMMISSIONING COSTS ($/KW)	TOTAL DECOMMISSIONING COSTS (CURRENT $)	TOTAL DECOMMISSIONING COSTS (FUTURE $)	ESTIMATED TERMINAL RETIREMENTS
(1)	(2)	(3)	(4)	(5)=(3)*(4)	(6)	(7)
STEAM						
SYSTEM LABORATORY	2040	0	40	0	0	(3,981,926)
TRIMBLE COUNTY	2066	335	40	13,400,000	48,388,905	(590,869,790)
BROWN 1	2023	106	40	4,240,000	5,295,179	
BROWN 2	2029	166	40	6,640,000	9,616,700	
BROWN 3	2035	411	40	16,440,000	27,612,326	
TOTAL BROWN				27,320,000	42,524,205	(903,057,104)
GHENT 1	2034	493	40	19,720,000	32,313,516	
GHENT 2	2034	490	40	19,600,000	32,116,882	
GHENT 3	2037	454	40	18,160,000	32,045,330	
GHENT 4	2036	487	40	19,480,000	35,233,981	
TOTAL GHENT				76,960,000	131,709,709	(2,544,166,674)
TOTAL STEAM				117,680,000	222,622,819	(4,042,075,495)
HYDRO						
DIX DAM	2041	26	10	260,000	506,428	(35,425,875)
TOTAL HYDRO				260,000	506,428	(35,425,875)
OTHER						
CANE RUN	2055	660	20	13,200,000	36,328,914	(288,106,178)
HAEFLING 1, 2 AND 3	2020	36	10	360,000	417,490	(3,985,290)
PADDYS RUN 13	2031	74	10	740,000	1,125,998	(27,330,118)
BROWN 5	2031	57	10	570,000	867,322	
BROWN 6	2029	91	10	910,000	1,317,951	
BROWN 7	2029	91	10	910,000	1,317,951	
BROWN 8	2025	121	10	1,210,000	1,587,625	
BROWN 9	2031	121	10	1,210,000	1,841,158	
BROWN 10	2031	121	10	1,210,000	1,841,158	
BROWN 11	2026	121	10	1,210,000	1,627,315	
BROWN GAS PIPELINE	2031	0	10	0	0	
TOTAL BROWN				7,230,000	10,400,480	(229,538,287)
TRIMBLE COUNTY 5	2032	114	10	1,140,000	1,778,011	
TRIMBLE COUNTY 6	2032	114	10	1,140,000	1,778,011	
TRIMBLE COUNTY GAS PIPELINE	2034		10	0	0	
TRIMBLE COUNTY 7	2034	101	10	1,010,000	1,655,003	
TRIMBLE COUNTY 8	2034	101	10	1,010,000	1,655,003	
TRIMBLE COUNTY 9	2034	101	10	1,010,000	1,655,003	
TRIMBLE COUNTY 10	2034	101	10	1,010,000	1,655,003	
TOTAL TRIMBLE COUNTY				6,320,000	10,176,034	(150,692,260)
TOTAL OTHER				27,850,000	58,448,916	(739,852,132)

Attachment to Response to KIUC-2 Question No. 1

Spanos

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Second Set of Data Requests of Kentucky Industrial Utility Customers, Inc. Dated February 7, 2017

Question No. 1

Responding Witness: John J. Spanos

Q.2-1. Refer to the response to KIUC 1-2(a), which requested a copy of all source documents relied on for the decommissioning cost estimates. No source documents were provided. Either provide the documents or indicate that they are not available and provide the reason why they are not available.

A.2-1. The documents supplied in response to KIUC 1-2 were the supporting documents that can be produced. In preparing the decommissioning cost estimates, Mr. Spanos relied upon proprietary studies for which he does not have necessary consents to disclose and his general knowledge of industry information on decommissioning costs. Attached is a file which shows the calculation of the decommissioning costs referenced in Mr. Spanos's depreciation study.

LOUISVILLE GAS AND ELECTRIC

DECOMMISSIONING COSTS RELATED TO GENERATING UNITS

UNIT (1)	ESTIMATED RETIREMENT YEAR (2)	MW (3)	ESTIMATED DECOMMISSIONING COSTS ($/KW) (4)	TOTAL DECOMMISSIONING COSTS (CURRENT $) (5)=(3)*(4)	TOTAL DECOMMISSIONING COSTS (FUTURE $) (6)	ESTIMATED TERMINAL RETIREMENTS (7)
STEAM						
MILL CREEK 1	2032	303	40	12,120,000	18,903,064	
MILL CREEK 2	2034	301	40	12,040,000	19,728,942	
MILL CREEK 3	2038	391	40	15,640,000	28,288,474	
MILL CREEK 4	2042	477	40	19,080,000	38,093,125	
TOTAL MILL CREEK				58,880,000	105,013,605	(1,452,787,796)
TRIMBLE COUNTY 1	2050	383	40	15,320,000	37,266,441	
TRIMBLE COUNTY 2	2066	102	40	4,080,000	14,733,338	
TOTAL TRIMBLE COUNTY				19,400,000	51,999,779	(535,583,282)
TOTAL STEAM				78,280,000	157,013,384	(1,988,371,079)
HYDRO						
OHIO FALLS	2045	52	10	520,000	1,118,004	(92,590,980)
TOTAL HYDRO				520,000	1,118,004	(92,590,980)
OTHER						
CANE RUN 7	2055	31	20	620,000	1,706,358	
CANE RUN 11	2018	14	20	280,000	309,068	
TOTAL CANE RUN				900,000	2,015,426	(90,119,059)
ZORN AND RIVER ROAD GAS TURBINE	2019	14	10	140,000	158,397	(1,857,026)
PADDY'S RUN 11	2018	12	10	120,000	132,458	
PADDY'S RUN 12	2018	23	10	230,000	253,877	
PADDY'S RUN 13	2031	84	10	840,000	1,278,159	
TOTAL PADDY'S RUN				1,190,000	1,664,494	(37,931,604)
BROWN 5	2031	65	10	650,000	989,052	
BROWN 6	2029	55	10	550,000	796,564	
BROWN 7	2029	55	10	550,000	796,564	
TOTAL BROWN				1,750,000	2,582,180	(60,738,943)
TRIMBLE COUNTY 5	2032	46	10	460,000	717,443	
TRIMBLE COUNTY 6	2032	46	10	460,000	717,443	
TRIMBLE COUNTY 7	2034	59	10	590,000	966,784	
TRIMBLE COUNTY 8	2034	59	10	590,000	966,784	
TRIMBLE COUNTY 9	2034	59	10	590,000	966,784	
TRIMBLE COUNTY 10	2034	59	10	590,000	966,784	
TOTAL TRIMBLE COUNTY				3,280,000	5,302,022	(100,724,301)
TOTAL OTHER				7,260,000	11,722,519	(291,371,133)

Attachment to Response to KIUC-2 Question No. 1
Page 1 of 1
Spanos

EXHIBIT ____ (LK-16)

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

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

Question No. 180

Responding Witness: John J. Spanos

Q-180. If not provided elsewhere, provide all workpapers supporting terminal net salvage (decommissioning) estimates for each account for which terminal net salvage is a factor. Include any decommissioning studies relied upon, and explain how the results of those studies were incorporated into the net salvage estimate proposed by KU. Include all calculations in electronic format (Excel), with all formulae intact.

A-180. See the responses to KIUC 1-3 and KIUC 1-6.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

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

Question No. 180

Responding Witness: John J. Spanos

Q-180. If not provided elsewhere, provide all workpapers supporting terminal net salvage (decommissioning) estimates for each account for which terminal net salvage is a factor. Include any decommissioning studies relied upon, and explain how the results of those studies were incorporated into the net salvage estimate proposed by LG&E. Include all calculations in electronic format (Excel), with all formulae intact.

A-180. See the response to KIUC 1-3 and KIUC 1-6.

EXHIBIT ____ (LK-17)

KENTUCKY UTILITIES COMPANY

LOUISVILLE, KENTUCKY

2015 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUALS RELATED TO ELECTRIC PLANT
AS OF DECEMBER 31, 2015

Gannett Fleming

Excellence Delivered As Promised

A summary of the year in service, life span and probable retirement year for each power production unit follows:

Depreciable Group	Major Year in Service	Probable Retirement Year	Life Span
Steam Production Plant			
Tyrone Unit 3	1947,1953	2015	68,62
Tyrone Units 1 & 2	1947,1948	2015	68,67
Green River Unit 3	1954	2015	61
Green River Unit 4	1959	2015	56
Green River Units 1 & 2	1950	2015	65
Brown Unit 1	1956	2023	67
Brown Unit 2	1963	2029	66
Brown Unit 3	1971	2035	64
Pineville Unit 3	1951	2015	64
Ghent Unit 1	1974	2034	60
Ghent Unit 2	1977	2034	57
Ghent Unit 3	1981	2037	56
Ghent Unit 4	1984	2038	54
System Laboratory	1989	2040	51
Trimble County Unit 2	1990,2011	2066	76,55
Hydro Plant			
Dix Dam	1941	2041	100
Other Production Plant			
Paddy's Run Generator 13	2001	2031	30
Brown Unit 5	2001	2031	30
Brown Unit 6	1999	2029	30
Brown Unit 7	1999	2029	30
Brown Unit 8	1995	2025	30
Brown Unit 9	1994	2031	37
Brown Unit 10	1995	2031	36
Brown Unit 11	1996	2026	30
Trimble County Unit 5	2002	2032	30
Trimble County Unit 6	2002	2032	30
Trimble County Unit 7	2004	2034	30
Trimble County Unit 8	2004	2034	30
Trimble County Unit 9	2004	2034	30

Trimble County Unit 10	2004	2034	30
Haefling Units 1, 2, & 3	1970	2020	50
Cane Run Unit 7	2015	2055	40

Similar studies were performed for the remaining plant accounts. Each of the judgments represented a consideration of statistical analyses of aged plant activity, management's outlook for the future, and the typical range of lives used by other electric companies.

The selected amortization periods for other General Plant accounts are described in the section "Calculated Annual and Accrued Amortization."

LOUISVILLE GAS AND ELECTRIC COMPANY

LOUISVILLE, KENTUCKY

2015 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUALS RELATED TO ELECTRIC, GAS AND
COMMON PLANT AS OF DECEMBER 31, 2015

Gannett Fleming

Excellence Delivered As Promised

1954 through 2015 for steam, 1934 through 2015 for hydro, and 1963 through 2015 for other production.

The depreciable life span estimates for power generating stations were the result of considering experienced life spans of similar generating units, the age of surviving units, general operating characteristics of the units, major refurbishing, and discussions with management personnel concerning the probable long-term outlook for the units, and observed features and conditions at the time of the field visit. These life spans represent the expected depreciable life of each facility under their current configuration. Future capital expenditures can extend a facility's depreciable life, however, such changes to depreciable life would not be prudent until the capital expenditures are actually put into plant in service.

The life span estimate for most steam, base-load units is 55 to 60 years, which is within the typical range of life spans for such units. The 111-year life span for the hydro production facility is within the typical range. Life spans of 30 to 48 years were estimated for the majority of combustion turbines. These life span estimates are typical for combustion turbines which are used primarily as peaking units.

A summary of the year in service, life span and probable retirement year for each power production unit follows:

Depreciable Group	Major Year in Service	Probable Retirement Year	Life Span
Steam Production Plant			
Cane Run Unit 1	1954	2002	48
Cane Run Unit 2	1956	2002	46
Cane Run Unit 3	1958	2002	44
Cane Run Unit 4	1962	2015	53
Cane Run Unit 5	1966	2015	49
Cane Run Unit 6	1969	2015	46

Mill Creek Unit 1	1972	2032	60
Mill Creek Unit 2	1974	2034	60
Mill Creek Unit 3	1978	2038	60
Mill Creek Unit 4	1982	2042	60
Trimble County Unit 1	1990	2050	60
Trimble County Unit 2	1990,2011	2066	76,55
Hydro Plant			
Ohio Falls	1934	2045	111
Other Production Plant			
Cane Run GT 11	1970	2018	48
Cane Run CC 7	2015	2055	40
Zorn and River Road Gas Turbine	1970	2019	49
Paddy's Run Generator 11	1970	2018	48
Paddy's Run Generator 12	1970	2018	48
Paddy's Run Generator 13	2001	2031	30
Brown CT 5	2001	2031	30
Brown CT 6	1999	2029	30
Brown CT 7	1999	2029	30
Trimble County CT 5	2002	2032	30
Trimble County CT 6	2002	2032	30
Trimble County CT 7	2004	2034	30
Trimble County CT 8	2004	2034	30
Trimble County CT 9	2004	2034	30
Trimble County CT 10	2004	2034	30

Similar studies were performed for the remaining plant accounts. Each of the judgments represented a consideration of statistical analyses of aged plant activity, management's outlook for the future, and the typical range of lives used by other electric and gas companies.

The selected amortization periods for other General Plant accounts are described in the section "Calculated Annual and Accrued Amortization."

EXHIBIT ____ (LK-18)

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. 9

Responding Witness: John J. Spanos / Lonnie E. Bellar

Q.1-9. Please provide the probable retirement dates used for each of the Company's generating units and the source documents relied on for this purpose. Identify the Company witness, other than Mr. Spanos, who provided and can testify as to the probable retirement dates.

A.1-9. The Company does not assign retirement dates to its generating units, however, probable retirement dates are projected in order to calculate depreciation based on a concurrent retirement of assets. See also the Company's response to AG 1-193 and 1-194. Concerning the second part of the request, please see the "Responding Witness" line above.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

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

Question No. 10

Responding Witness: John J. Spanos / Lonnie E. Bellar

Q.1-10. Please provide the probable retirement dates used for each of the Company's generating units and the source documents relied on for this purpose. Identify the Company witness, other than Mr. Spanos, who provided and can testify as to the probable retirement dates.

A.1-10. The Company does not assign retirement dates to its generating units, however, probable retirement dates are projected in order to calculate depreciation based on a concurrent retirement of assets. See also the Company's response to AG 1-193 and 1-194. Concerning the second part of the request, please see the "Responding Witness" line above.

EXHIBIT ____ (LK-19)

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

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

Question No. 193

Responding Witness: Lonnie E. Bellar

Q-193. Identify and explain all Company programs which might affect plant lives.

A-193. The Company performs routine maintenance, inspections and scheduled overhauls on its generating units to maintain the units' reliable and efficient operation throughout their useful lives. All of these programs help the Company to monitor, maintain and address issues that may impact the lives of the Company's units. See pages 16-22 of Mr. Thompson's testimony for further information about programs that impact generation reliability, cost savings, and efficiency.

KU believes that continuing a prudent level of ongoing maintenance and investment at its remaining generating units will ensure the ongoing reliable operation of the units and minimize the potential for a significant mechanical failure. Consistent with information provided to the Commission in previous IRP and other proceedings, KU has informally grouped units into categories for guiding investment decisions that ensure the remaining useful life is maintained. The expected remaining useful life of each coal unit is discussed below:

- With respect to Trimble County 2, the new unit is expected to have a life expectancy of approximately 60 years.
- With respect to Cane Run 7, the new unit is expected to have a life expectancy of approximately 40 years.
- With respect to Brown Units and Ghent 1-2, KU will maintain the units in such a way as to ensure that, year over year, a minimum 20-year remaining useful life is expected. In other words, for each year KU operates and maintains these units, KU expects to have at least a 20-year remaining useful life commencing in that year.
- With respect to Ghent Units 3-4, KU expects the units to have, year over year, a minimum of 30-years remaining useful life. Prudent investments will continue to be made to ensure operation of these units into the future.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

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

Question No. 193

Responding Witness: Lonnie E. Bellar

Q-193. Identify and explain all Company programs which might affect plant lives.

A-193. The Company performs routine maintenance, inspections and scheduled overhauls on its generating units to maintain the units' reliable and efficient operation throughout their useful lives. All of these programs help the Company to monitor, maintain and address issues that may impact the lives of the Company's units. See pages 16-22 of Mr. Thompson's testimony for further information about programs that impact generation reliability, cost savings, and efficiency.

LG&E believes that continuing a prudent level of ongoing maintenance and investment at its remaining generating units will ensure the ongoing reliable operation of the units and minimize the potential for a significant mechanical failure. Consistent with information provided to the Commission in previous IRP and other proceedings, LG&E has informally grouped units into categories for guiding investment decisions that ensure the remaining useful life is maintained. The expected remaining useful life of each coal unit is discussed below:

- With respect to the Trimble County 1 and Mill Creek 3-4 Units, LG&E will maintain these units in such a way as to ensure that, year over year, a minimum 30-year remaining useful life is expected. In other words, for each year LG&E operates and maintains these units, LG&E expects to have at least a 30-year remaining useful life commencing in that year.

- With respect to Trimble County 2, the new unit is expected to have a life expectancy of approximately 60 years.

- With respect to Cane Rune 7, the new unit is expected to have a life expectancy of approximately 40 years.

- With respect to the Mill Creek 1-2 Units, LG&E will maintain these units in such a way as to ensure that, year over year, a minimum 20-year remaining useful life is expected. In other words, for each year LG&E

operates and maintains these units, LG&E expects to have at least a 20-year remaining useful life commencing in that year.

EXHIBIT ____ (LK-20)

This Integrated Resource Plan represents a snapshot of an ongoing resource planning process using current business assumptions. The planning process is constantly evolving and may be revised as conditions change and as new information becomes available. Before embarking on any final strategic decisions or physical actions, the Companies will continue to evaluate alternatives for providing reliable energy while complying with all regulations in a least-cost manner. Such decisions or actions will be supported by specific analyses and will be subject to the appropriate regulatory approval processes.

significant amount of load is gained. Compared to the Base load scenario, peak demand in the High load scenario is approximately 300 MWs higher in 2014.

DSM Implementation

Due to the voluntary nature of the DSM/EE programs offered by the Companies, the amount of customer participation directly impacts the energy and demand reduction of the designed programs. The enhanced programming in their Demand Side Management/Energy Efficiency filing attempts to address instances where customer participation has fallen below projected levels by including modification of financial incentives and additional opportunities for customers to participate in programming that provide the most energy and demand savings for the Companies. However, for purposes of preparing the IRP, there is no additional uncertainty related to the achievement of DSM expect as reflected in the overall load forecast uncertainty described above.

Aging Units

Post 2015, the two oldest steam generating units in the system are Brown Units 1 and 2. Each of these units is over 50 years old. Some of the oldest combustion turbines are the smaller LG&E combustion turbines and the KU Haefling combustion turbines ("CTs"). Each of these units is over 30 years of age, which is considered the typical design life for small frame combustion turbines. Table 5.(6)-3 lists the ages of the oldest units.

Table 5.(6)-3
Aging Units

Fuel	Plant Name	Unit	Summer Net Capacity	In Service Year	Age (2014)
Coal	Brown	1	106	1957	57
Coal	Brown	2	166	1963	51
Gas	Cane Run	11	14	1968	46
Gas	Paddy's Run	11	12	1968	46
Gas	Paddy's Run	12	23	1968	46
Gas	Zorn	1	14	1969	45
Gas	Haefling	1,2	24	1970	44

The Companies periodically perform high-level condition and performance assessments on their generating units. Additionally, the Black and Veatch performed a remaining life assessment on Brown 1 and 2 in 2012. The assessment concluded that these units could operate reliably for the foreseeable future provided that the units continued to be appropriately operated and maintained.

The economics surrounding the continued operation of the Companies' older units will continue to be reviewed periodically to ensure the efficiency of the overall system. More stringent environmental regulations could result in the retirement of these units even without a significant mechanical failure.

Table 8.(3)(b) 1-11
KU and LG&E Existing and Planned Electric Generation Facilities

1	2	3	4	5	6	7		8		9	10	11
Plant Name	Unit No.	Location in Kentucky	Status	Operation Date	Facility Type	Net Capability (MW)* 2014/15 Winter	2014 Summer	Entitlement KU	LGE	Fuel Type	Fuel Storage Cap/SO, Content	Scheduled Upgrades Derates, Retirements
Cane Run	4	Louisville	Existing	1962	Steam	155	155		100%	Coal (Rail)	350,000 Tons (6.0# SO2)	Assumed to retire 2015
	5			1966		168	168					
	6			1969		240	240					
	11			1968	Turbine	14	14			Gas / Oil	50,000 Gals	None
Dix Dam	1-3	Burgin	Existing	1925	Hydro	24	24	100%		Water	None	None
E. W. Brown Coal	1	Burgin	Existing	1957	Steam	107	106	100%		Coal (Rail)	360,000 Tons (6# SO2)	None
	2			1963		168	166					None
	3			1971		414	410					Baghouse Derate 2015
E.W. Brown-ABB 11N2	5			2001	Turbine	130	133	47%	53%	Gas	2,200,000 Gals	None
E.W. Brown-ABB GT24	6			1999		171	146	62%	38%	Gas / Oil		
	7			1999		171	146					
E.W. Brown-ABB 11N2	8			1995		128	121	100%				
	9			1994		138	121					
	10			1995		138	121					
	11			1996		128	121					
Ghent	1	Ghent	Existing	1974	Steam	481	479	100%		Coal (Barge)	1,300,000 Tons (6# SO2)	Baghouse Derate 2015
	2			1977		477	495					Baghouse Derate 2015
	3			1981		482	489					Baghouse Derate 2014
	4			1984		491	469					Baghouse Derate 2014
Green River	3	Central City	Existing	1954	Steam	71	68	100%		Coal	150,000 Tons (4.5# SO2)	Assumed to retire 2015
	4			1959		98	93					
Haefling	1	Lexington	Existing	1970	Turbine	14	12	100%		Gas / Oil	130,000 Gals	None
	2			1970		14	12					
Mill Creek	1	Louisville	Existing	1972	Steam	303	303		100%	Coal (Barge & Rail)	1,000,000 Tons (6# SO2)	Baghouse Derate 2015
	2			1974		299	301					Baghouse Derate 2015
	3			1978		394	391					Baghouse Derate 2016
	4			1982		486	477					Baghouse Derate 2014
Ohio Falls	1-8	Louisville	Existing	1928	Hydro	Run of River (35/54)			100%	Water	None	10 MW upgrade 2014-2017
Paddy's Run	11	Louisville	Existing	1968	Turbine	13	12		100%	Gas	None	None
	12			1968		28	23					
Paddy's Run- Siem/West V84.3a	13			2001		175	147	47%	53%			
Trimble County Coal (75%)	1	Near Bedford	Existing	1990	Steam	511 (383)	511 (383)	0%	75%	Coal (Barge)	1,000,000 Tons (6.0# SO2)	Baghouse Derate 2015
	2			2011		760 (570)	732 (549)	61%	14%		150,000 Tons (0.6# SO2)	None
Trimble County-GE7FA	5			2002	Turbine	176	157	71%	29%	Gas	None	None
	6			2002		176	157					
	7			2004		176	157	63%	37%			
	8			2004		176	157					
	9			2004		176	157					
	10			2004		176	157					
Zorn	1	Louisville	Existing	1969	Turbine	16	14		100%	Gas	None	None
Future Units												
Cane Run	7	Louisville	Under Const.	2015	Turbine	652	640	78%	22%	Gas	None	None
E.W. Brown Solar	1	Burgin	Proposed	2016	Solar	0	9	64%	36%	Solar	None	None
Green River	5	Central City	Proposed	2018	Turbine	657	670	60%	40%	Gas	None	None

* The ratings for Dix Dam, Ohio Falls, and E. W. Brown Solar reflect the assumed output for these facilities during the summer and winter peak demands.

system to again challenge the new rule and possibly delay implementation deadlines. The regulations will address both impingement and entrainment issues, thus affecting the Companies' facilities, including those already equipped with closed cycle cooling (cooling towers). Possible requirements within the rule could include: cooling towers on all active units, "helper" towers on once-thru cooling units for use during spawning season and low flow periods, fine mesh screens (1-2 mm) for water intake, fish return systems associated with the screens, and/or annual in-stream fish studies. These potential capital investments could be required within the time period of this IRP document. The Companies will continue to review this issue.

Aging Generating Units

The two oldest steam generating units in the system are Brown Units 1 and 2, each over 50 years old. Some of the oldest combustion turbines are the smaller LG&E combustion turbines and the KU Haefling combustion turbines ("CTs"). Each of these units is over 30 years of age, which is considered the typical design life for small frame combustion turbines. Table 8.5(b)-2 lists the ages of the oldest units.

Table 8.5(b)-2
Aging Units

Fuel	Plant Name	Unit	Summer Net Capacity	In Service Year	Age (2014)
Coal	Brown	1	106	1957	57
Coal	Brown	2	166	1963	51
Gas	Cane Run	11	14	1968	46
Gas	Paddy's Run	11	12	1968	46
Gas	Paddy's Run	12	23	1968	46
Gas	Zorn	1	14	1969	45
Gas	Haefling	1,2	28	1970	44

The Companies periodically perform high-level condition and performance assessments on their generating units. Additionally, the Black and Veatch performed a remaining life assessment on Brown 1 and 2 in 2012. The assessment concluded that these units could operate reliably for the foreseeable future provided that the units continued to be appropriately operated and maintained.

The economics surrounding the continued operation of the Companies' older units will continue to be periodically reviewed to ensure the efficiency of the overall system. More stringent environmental regulations could result in the retirement of these units even without a significant mechanical failure.

Key Uncertainties

The Companies evaluate long-term resource decisions under a number of possible futures to ensure that customers' energy needs are reliably met at the lowest reasonable cost. While there are a number of uncertainties that could have some impact on the Companies' resource decisions, the uncertainties in native load (demand and energy), natural gas prices, and GHG regulations are the most important to consider when evaluating long-term generating resources. Each of these uncertainties is discussed in the subsections that follow.

Native Load Requirements

The only reason for the Companies to acquire new supply-side or demand-side resources is to reliably meet customers' future energy needs at the lowest reasonable cost. Therefore, the forecast of customers' future demand and energy needs has a significant impact on the Companies' optimal expansion plan. The volume of future load (demand and energy) is driven by future economic activity, the adoption rate of new and existing DSM programs, and the development of new electric end-uses (e.g., consumer electronics, electric vehicles, etc.). The Companies utilize the best information available to develop a reasonable long-term load forecast. As with any long-term forecast, the uncertainty associated with it tends to grow through time. Therefore, "High" and "Low" load forecasts were also developed which reflect the statistical

Table 8.(3)(b)12(a)-1
Capacity Factors

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-Low Load-Zero Carbon																
E.W. Brown 1	40.6%	7.0%	6.2%	7.5%	9.0%	3.8%	5.7%	4.1%	5.0%	4.8%	7.4%	8.0%	11.4%	14.6%	15.8%	23.6%
E.W. Brown 10	0.1%	0.3%	0.3%	0.4%	0.4%	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.3%
E.W. Brown 11	0.1%	0.2%	0.3%	0.3%	0.3%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.2%	0.2%
E.W. Brown 2	59.9%	14.9%	13.6%	14.0%	12.0%	6.0%	8.0%	5.9%	6.7%	7.7%	18.0%	15.6%	26.8%	35.8%	36.3%	38.3%
E.W. Brown 3	44.1%	32.9%	30.2%	33.0%	34.3%	32.8%	29.5%	32.8%	34.2%	32.9%	34.4%	33.1%	34.5%	29.9%	34.6%	33.5%
E.W. Brown 5	0.3%	0.5%	0.6%	0.6%	0.6%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.3%	0.3%	0.3%	0.3%	0.4%
E.W. Brown 6	3.6%	1.1%	1.2%	1.1%	1.2%	0.4%	0.4%	0.4%	0.4%	0.4%	0.5%	0.5%	0.5%	0.6%	0.6%	0.7%
E.W. Brown 7	3.1%	1.4%	1.5%	1.4%	1.5%	0.5%	0.6%	0.5%	0.6%	0.6%	0.6%	0.7%	0.7%	0.8%	0.8%	0.9%
E.W. Brown 8	0.3%	0.3%	0.3%	0.3%	0.4%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.2%	0.2%	0.2%
E.W. Brown 9	0.5%	0.4%	0.4%	0.5%	0.5%	0.1%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.3%	0.3%	0.3%	0.3%
Cane Run 11	0.1%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
Cane Run 4	51.3%	22.5%	10.1%													
Cane Run 5	58.7%	73.7%	37.3%													
Cane Run 6	47.3%	40.6%	23.4%													
Dix Dam 1-3	50.7%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%
Ghent 1	79.3%	73.8%	57.3%	60.0%	61.3%	44.7%	54.8%	46.7%	55.4%	65.3%	75.2%	73.8%	76.4%	74.8%	76.7%	75.6%
Ghent 2	82.5%	87.3%	77.5%	82.4%	84.1%	81.7%	69.7%	80.9%	81.0%	83.9%	82.9%	85.0%	83.4%	75.1%	85.7%	83.5%
Ghent 3	77.5%	47.9%	53.2%	43.0%	45.7%	24.3%	25.4%	25.5%	36.8%	52.1%	64.5%	65.5%	60.4%	67.9%	68.7%	69.0%
Ghent 4	71.6%	55.7%	42.9%	34.3%	29.3%	12.7%	18.5%	12.5%	16.9%	33.7%	54.9%	58.0%	62.6%	65.8%	62.5%	58.0%
Green River 3	51.1%	12.4%	3.6%													
Green River 4	76.4%	88.2%	88.7%													
Haefling 1-2	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Mill Creek 1	55.3%	87.5%	70.2%	80.5%	76.2%	79.7%	78.4%	83.2%	72.3%	85.1%	80.6%	85.0%	81.5%	86.6%	80.6%	86.4%
Mill Creek 2	72.2%	83.9%	74.6%	77.1%	84.2%	76.9%	85.9%	76.7%	88.7%	83.6%	89.3%	84.1%	89.5%	84.0%	89.3%	77.2%
Mill Creek 3	64.3%	85.6%	87.2%	49.8%	61.8%	58.0%	57.7%	72.0%	70.9%	77.3%	73.0%	77.4%	73.8%	78.0%	67.8%	79.0%
Mill Creek 4	64.2%	68.3%	61.8%	71.4%	80.0%	69.2%	81.0%	77.5%	84.9%	73.0%	86.9%	81.6%	87.6%	82.3%	88.1%	82.9%
Ohio Falls 1-8	51.3%	45.2%	46.3%	45.5%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%
Paddy's Run 11	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
Paddy's Run 12	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
Paddy's Run 13	2.1%	13.6%	12.1%	9.9%	8.6%	3.2%	4.3%	3.4%	3.7%	3.4%	3.7%	3.4%	3.6%	3.8%	3.4%	4.6%
Trimble County CT 10	1.8%	2.6%	2.5%	2.4%	2.8%	0.8%	1.0%	0.8%	0.9%	0.9%	1.0%	0.9%	1.1%	1.2%	1.2%	1.4%
Trimble County CT 5	4.6%	16.1%	13.4%	11.2%	9.2%	3.8%	5.6%	3.5%	4.1%	3.6%	4.8%	3.7%	4.4%	4.7%	4.3%	5.6%
Trimble County CT 6	6.1%	11.9%	9.9%	7.9%	9.3%	2.8%	4.1%	2.7%	2.7%	3.1%	3.7%	2.9%	3.5%	3.7%	3.4%	4.4%
Trimble County CT 7	4.9%	8.5%	7.2%	6.1%	6.8%	1.9%	2.8%	1.9%	2.4%	2.3%	2.6%	2.1%	2.6%	2.8%	2.5%	3.3%
Trimble County CT 8	1.9%	5.7%	5.2%	4.6%	4.6%	1.5%	2.0%	1.4%	1.7%	1.7%	1.9%	1.6%	2.0%	2.0%	2.0%	2.5%
Trimble County CT 9	5.8%	3.9%	3.7%	3.4%	3.7%	1.0%	1.4%	1.1%	1.3%	1.2%	1.4%	1.3%	1.5%	1.6%	1.6%	1.9%
Trimble County 1 (75%)	77.3%	88.4%	82.9%	88.4%	75.9%	88.4%	82.8%	88.4%	83.1%	88.4%	83.1%	88.4%	75.9%	88.4%	83.1%	88.4%
Trimble County 2 (75%)	64.1%	61.9%	81.6%	82.1%	82.1%	75.0%	82.1%	82.1%	82.1%	82.1%	82.1%	82.1%	82.1%	75.0%	82.1%	82.1%
Zorn 1	0.1%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
Cane Run 7			63.6%	95.0%	90.6%	91.1%	76.4%	85.5%	75.6%	60.7%	33.2%	35.9%	37.5%	40.1%	33.5%	31.7%
Brown Solar				10.6%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%
Green River 5						65.8%	66.3%	53.3%	45.3%	28.7%	17.4%	13.9%	15.2%	14.5%	12.4%	15.4%

Note: 2013 values are actual values.

EXHIBIT ____ (LK-21)

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. 8

Responding Witness: John P. Malloy / John J. Spanos

Q.1-8. Please provide the Companies' estimated remaining service life for the SAP CCS as of December 31, 2015. Is it the Companies' plan to retire the CCS in mid-2019? If not, then what is the expected retirement date of the CCS? Provide a copy of all support for your response, including a copy of all documents that address the timeline and upgrade schedule for the CCS and its ultimate retirement and replacement. If none, then please so state.

A.1-8. As of December 31, 2015, the CCS system had been in place since April 2009, 6+ years of a 10 year asset life cycle. An upgrade to the system began in early 2016 and will be installed mid-2017. Therefore the new asset life will be 10 years from 2017 to 2027. The mid-term IT plan is to upgrade the system over the 2021 and 2022 timeframe. There are no current plans to replace the CCS system.

The support for the original 10 year CCS life can be found at KU in Case No. 2012-00221, KU_Direct_Testimony_All, John J Spanos Testimony, Schedule III-4. The support for the 10 year CCS life extension can be found at Spanos Testimony, Exhibit JJS-KU-1, Page 54. The testimony of Mr. Spanos is available at: http://psc.ky.gov/pscecf/2012-00221/rick.lovekamp%40lge-ku.com/06292012/KU_Direct_Testimony_-_All.pdf.

For the timeline and upgrade schedule, see attached, which is being filed under seal pursuant to a Petition for Confidential Protection. The Current SAP Upgrade is denoted as "SAP – CRM/ECC Upgrade" and the future upgrade is denoted as "SAP HANA Upgrade."

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

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

Question No. 9

Responding Witness: John P. Malloy / John J. Spanos

Q.1-9. Please provide the Companies' estimated remaining service life for the SAP CCS as of December 31, 2015. Is it the Companies' plan to retire the CCS in mid-2019? If not, then what is the expected retirement date of the CCS? Provide a copy of all support for your response, including a copy of all documents that address the timeline and upgrade schedule for the CCS and its ultimate retirement and replacement. If none, then please so state.

A.1-9. As of December 31, 2015, the CCS system had been in place since April 2009, 6+ years of a 10 year asset life cycle. An upgrade to the system began in early 2016 and will be installed mid-2017. Therefore the new asset life will be 10 years from 2017 to 2027. The mid-term IT plan is to upgrade the system over the 2021 and 2022 timeframe. There are no current plans to replace the CCS system.

The support for the original 10 year CCS life can be found at LG&E in Case No. 2012-00222, LGE_Direct_Testimony_All, John J Spanos Testimony, Schedule III-13. The support for the 10 year CCS life extension can be found at Spanos Testimony, Exhibit JJS-LGE-1, Page 65. The testimony of Mr. Spanos is available at: http://psc.ky.gov/pscecf/2012-00222/rick.lovekamp%40lge-ku.com/06292012/LGE_Direct_Testimony_-_All.pdf.

For the timeline and upgrade schedule, see attached, which is being filed under seal pursuant to a Petition for Confidential Protection. The Current SAP Upgrade is denoted as "SAP – CRM/ECC Upgrade" and the future upgrade is denoted as "SAP HANA Upgrade."