BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

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

In the Matter of:

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

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**

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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

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[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.

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[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?

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[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?

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[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

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[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.

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[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.

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[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

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[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?

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[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

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[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

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[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?

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[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.

BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

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

In the Matter of:

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

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

March 3, 2017