BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES	**)**	
COMPANY FOR AN ADJUSTMENT OF	**)**	**CASE NO. 2014-00371**
ITS ELECTRIC RATES	**)**	

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND	**)**	
ELECTRIC COMPANY FOR AN	**)**	**CASE NO. 2014-00372**
ADJUSTMENT OF ITS ELECTRIC AND	**)**	
GAS RATES	**)**	

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

March 2015

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KENTUCKY PUBLIC SERVICE COMMISSION

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APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	)))	**CASE NO. 2014-00371**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	))))	**CASE NO. 2014-00372**

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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. 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 this proceeding are: Carbide Industries LLC, Cemex, Clopay Plastics Products Co., Inc., Corning Incorporated, Dow Corning Corporation, E.I. DuPont de Nemours & Co., Ford Motor Co., AAK, USA K2 LLC, Lexmark International, Inc., MeadWestvaco, NewPage Corp., North American Stainless, Solae, Schneider Electric USA, and Toyota Motor Engineering and Manufacturing North America, Inc.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to 1) address the magnitude of the Companies' rate increases within the context of the steady and significant increases in customer rates over the last ten years; 2) address the need for additional scrutiny of the Companies' claimed revenue deficiencies due to their use of forecast test years for the first time; 3) summarize the KIUC revenue requirement recommendations; 4) address specific issues that affect each Company's revenue requirement; and 5) quantify the effect on the revenue requirements of the cost of long term debt and return on equity recommendation of KIUC witness Mr. Richard Baudino.

Q. Please summarize your testimony.

A. The Companies' rates charged to customers have increased significantly over the last ten years. The Commission should carefully scrutinize the Companies' requests in these proceedings in order to minimize the increases. The Companies have filed their cases for the first time using a forecast test year. The forecast test year relies on models, assumptions, and estimates of the future. The Commission should carefully scrutinize these models, assumptions, and estimates to ensure that the costs are just and reasonable, and reflect efficient management, particularly compared to the actual costs incurred in prior periods.

I recommend that the Commission increase KU's base rates by no more than $48.081 million, a reduction of $105.363 million compared to its requested increase of $153.444 million. I recommend that the Commission decrease LG&E's electric base rates by at least $39.447 million, a reduction of $69.733 million compared to its requested increase of $30.286 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 retail jurisdictional basis and the amounts for LG&E are for electric only. I address in greater detail the reasons for each of the adjustments reflected in the table, except for the cost of long-term debt and the return on common equity, which are 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. 2014-00371 and 2014-00372
For the Test Year Ended June 30, 2016
($ Millions)

	KU Amount	LG&E Amount
Increase Requested by Company	153.444	30.286
KIUC Adjustments:		
Operating Income Issues		
Reduce Payroll and Related Benefits Expenses	(9.295)	(6.620)
Remove Nonrecurring O&M for the Retiring Green River 3 and 4 Units	(10.101)	
Remove Incentive Compensation Tied to Financial Performance	(5.863)	(4.961)
Reduce Pension Expense	(10.682)	(12.627)
Reduce Uncollectible Expense to 5-Year Average	(1.174)	(0.237)
Increase Late Payment Revenues	(2.533)	(2.007)
Remove Property Tax Expense Associated with CWIP	(2.067)	(2.343)
Extend Amortization Period on Deferred Costs	(1.183)	(0.809)
Reduce Cane Run 7 Depreciation Expense Related to Net Salvage	(0.514)	(0.164)
Revise Section 199 Income Tax Exp. Deduction for Bonus Depr. Extension	0.541	2.052
Reflect Other Operating Income Effects of Utilizing CWIP Slippage Factor	(0.247)	(0.170)
Cost of Capital Issues		
Reduce Capitalization for CWIP Slippage	(0.653)	(0.568)
Reduce Capitalization to Reflect 50% Bonus Depreciation Extension	(3.024)	(4.812)
Reduce Capitalization Associated With Paddy's Run Demolition Costs		(1.235)
Reduce Cost of Short Term Debt	(0.645)	(0.561)
Reduce Cost of Long Term Debt	(1.250)	(1.076)
Reflect Return on Equity of 8.6%	(56.674)	(33.596)
Total KIUC Adjustments to Company Request	(105.363)	(69.733)
KIUC Recommended Change in Base Rates	48.081	(39.447)

The amounts on the preceding table do not reflect the updates filed by the Companies on February 27, 2014, less than one week prior to the date for filing intervenor testimony. There was insufficient time and data to address the changes reflected in the updates. I reserve the right to update my recommendations to reflect the updated information.

In addition, the increase in rates described above for KU may be greater depending on whether the Commission directs KU to defer the nonrecurring operating expenses for Green River 3 and 4 for consideration in KU's next base rate case or adopts a new retirement rider to recover these expenses.

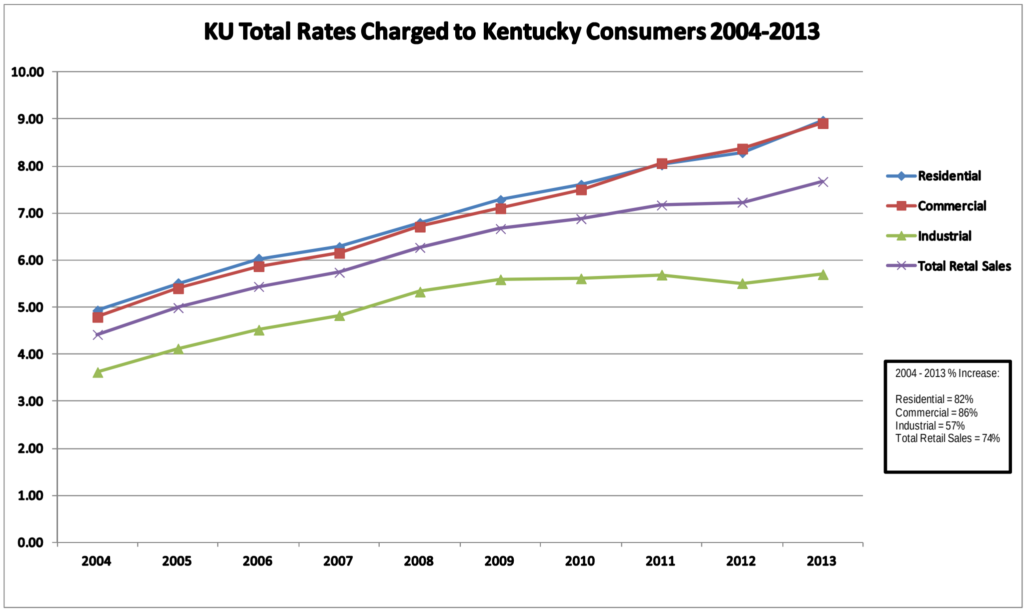
The revenue requirement effects of the expense adjustments shown on the preceding table are slightly greater than the amounts cited in my testimony because they reflect a gross-up due to uncollectible accounts expense and the Commission assessment.

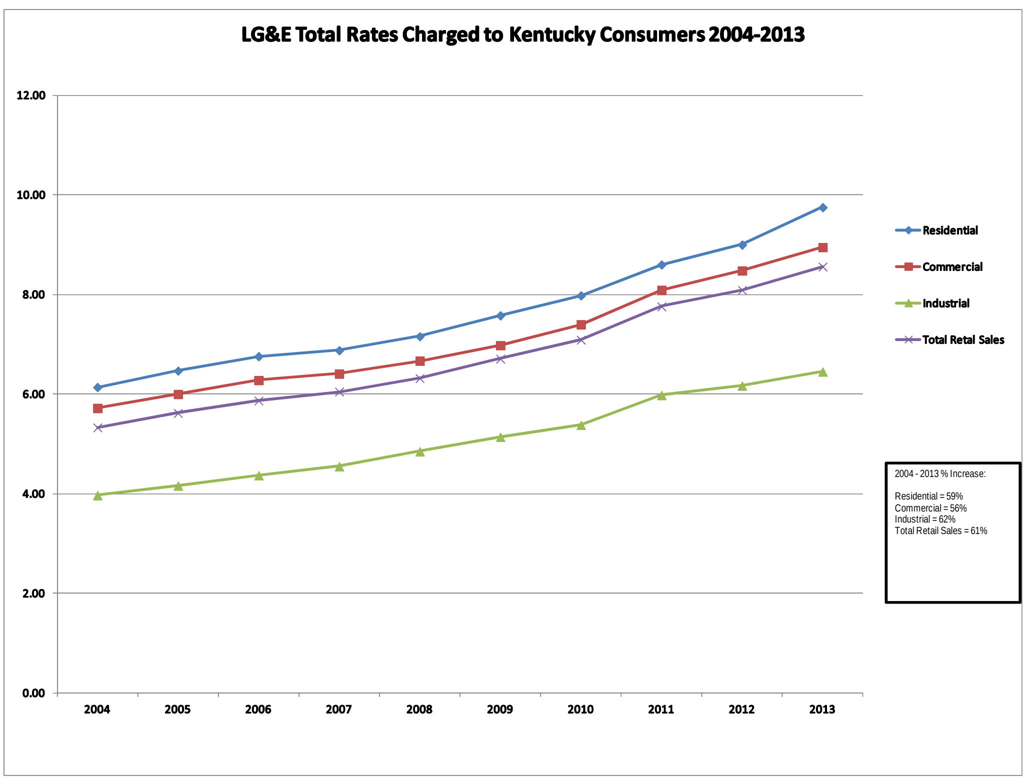
In the following sections of my testimony, I describe the significant increases in customer rates in the last ten years and the significant increases in KU's operation and maintenance expenses since 2013. I next address numerous adjustments that are necessary to ensure that the rates set in this proceeding are just and reasonable. I follow the sequence of the issues shown on the preceding table. Finally, I quantify the effects of Mr. Baudino's recommendations regarding the cost of long-term debt and the return on equity.

II. SIGNIFICANT INCREASES IN CUSTOMER RATES

Q. Please describe the significant increases in customer rates over the last ten years.

A. The Companies' rates have increased steadily and significantly over the last ten years. KU's rates have increased an average of 74% over all customer classes. LG&E's rates have increased an average of 61% over all customer classes. The following charts graphically portray these increases for each Company and each customer class from 2004 through 2013.


KU Total Rates Charged to Kentucky Consumers 2004-2013
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
Residential
Commercial
Industrial
Total Retal Sales
2004 - 2013 % Increase:
Residential = 82%
Commercial = 86%
Industrial = 57%
Total Retail Sales = 74%


LG&E Total Rates Charged to Kentucky Consumers 2004-2013
12.00
10.00
8.00
6.00
4.00
2.00
0.00
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
Residential
Commercial
Industrial
Total Retal Sales
2004 - 2013 % Increase:
Residential = 59%
Commercial = 56%
Industrial = 62%
Total Retail Sales = 61%

Q. Why are the historic increases in customer rates relevant in this proceeding?

A. First, they provide context for the increases that the Companies' seek in this proceeding. These rate increases impact real customers in residential households, schools and other government agencies, and small and large businesses. These customers need electric service and generally do not have economically realistic alternatives.

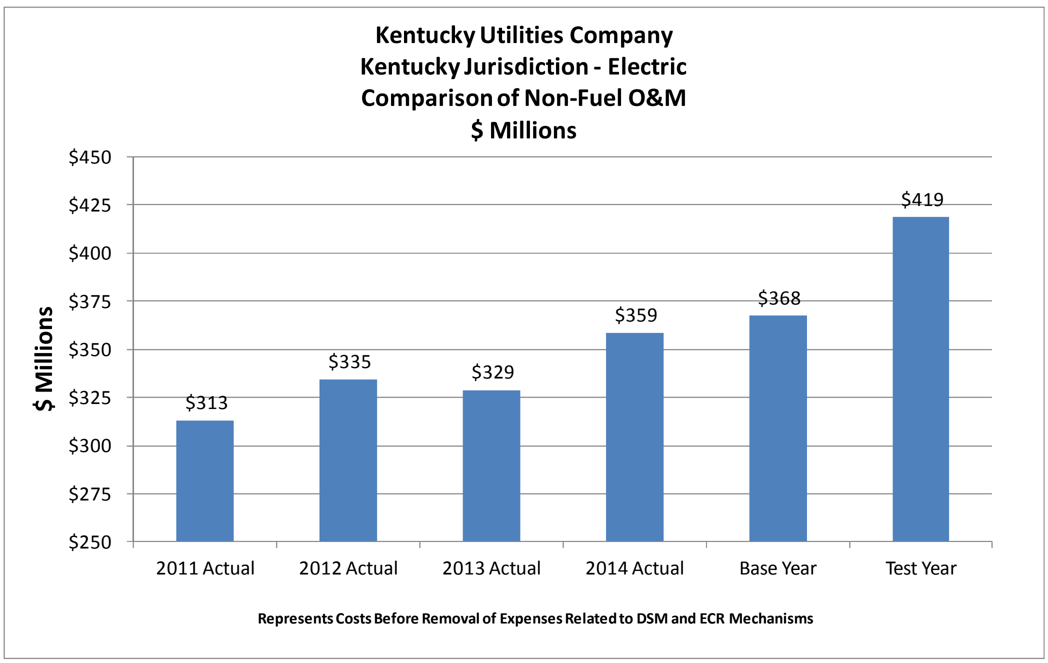
Second, these increases affect household budgets/expenses, government budgets/expenses, and business budgets/expenses, as well as business competitiveness and viability. Each of these customers must manage their income and expenses efficiently. The Commission should insist that the Companies are managed and operated efficiently to minimize their costs and that the costs allowed recovery reflect the least reasonable cost.

Third, the Companies' requested increases reflect projected costs in a forecast test year for the first time. Projected costs necessarily rely on models of the future based on assumptions and estimates, not the actual costs relied on in a historic test year. The use of a forecast test year is necessarily more subjective than the use of a historic test year. Thus, the Commission should carefully scrutinize the Companies' estimates and assumptions to ensure that they are not inefficient, unreasonable, excessive, or erroneous.

III. COSTS PROJECTED IN FORECAST TEST YEAR DESERVE CAREFUL SCRUTINY

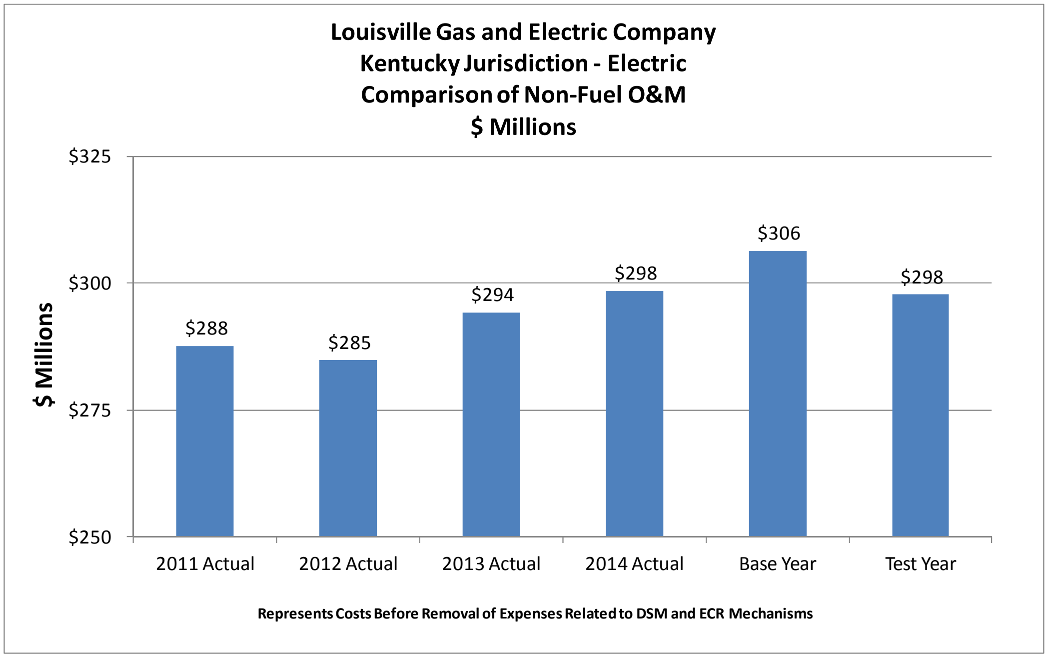
Q. How do the projected operation and maintenance expenses in the test year compare to the Companies' recent actual expenses?

A. KU's O&M expenses are substantially greater and demonstrate an exceptional rate of growth compared to actual historic levels. The following chart shows this graphically:[1]



[1]The data underlying this chart by FERC O&M and A&G expense accounts is provided in my Exhibit___(LK-2).

In contrast to KU, LG&E's O&M expenses have been relatively stable and show little growth compared to prior years. The following chart shows this graphically:[2]



Q. Do these comparisons of the test year to the actual O&M expenses in prior years demonstrate that KU's O&M expense is unreasonable or that LG&E's O&M expense is reasonable?

A. No. However, it does highlight the fact that projections in forecast test years deserve special scrutiny because they are based on projections and estimates, tend to reflect expenses that may not actually be incurred if they were restrained by the discipline of actual cost management, and can be used to increase the "ask" with

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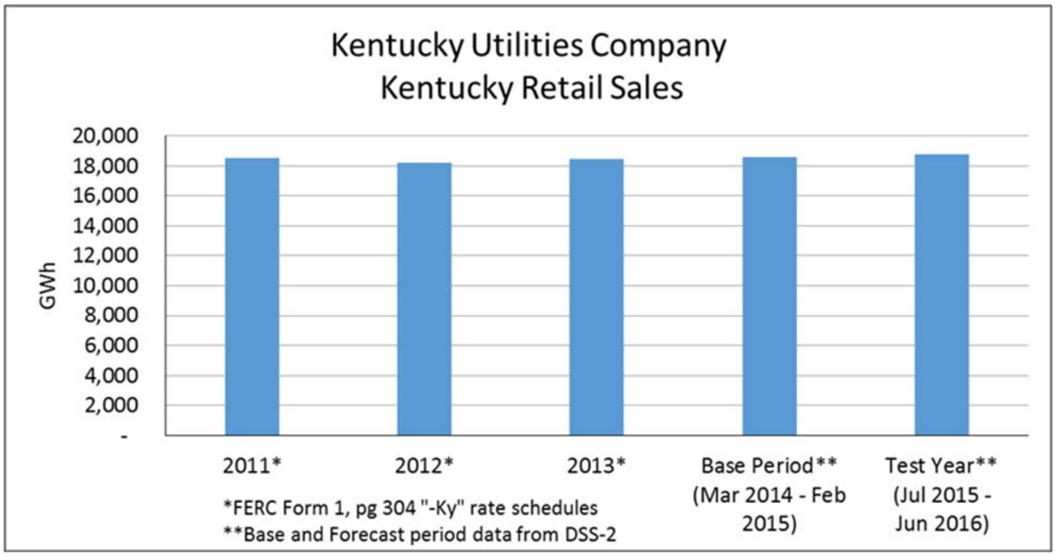
2 The data underlying this chart by FERC O&M and A&G expense accounts is provided in my Exhibit___(LK-3).

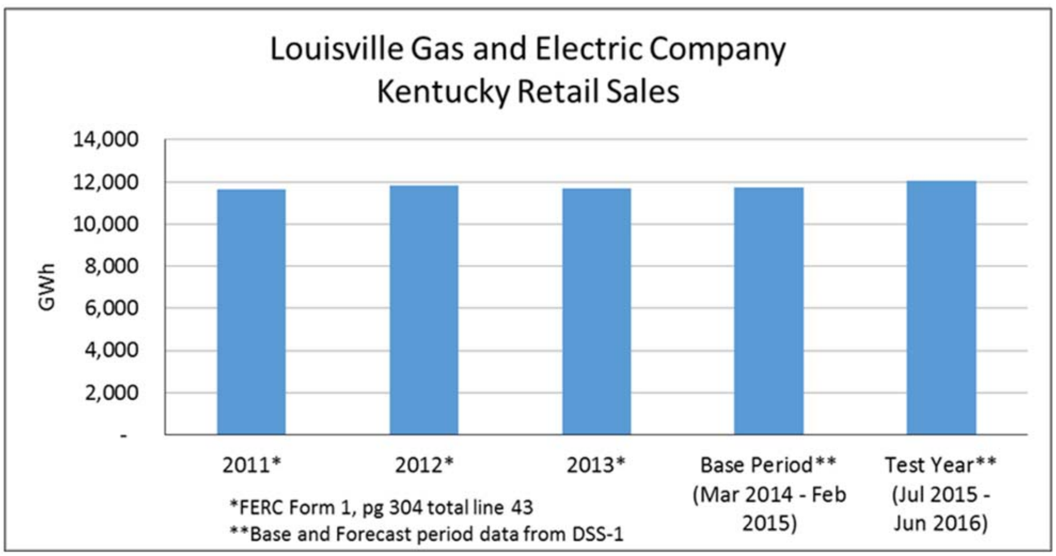
virtually no downside risk by utility management. After all, if the Commission does not authorize revenues based on the "ask," then the Companies may not actually incur the expenses they projected. If the Commission does authorize revenues based on the "ask," then the Companies still may not actually incur the expenses or incur them at the same level they projected.

Q. How do these increases in expense compare to the Companies' load growth?

A. The Companies' load growth has been flat and is projected to remain so. In his testimony, Mr. Staffieri cites the lack of load growth as a major factor in the need for the requested increases. Mr. Staffieri states that "the Companies continue to anticipate low growth in native system demand. In the past, the Companies have been able to rely on both off system sales and native load growth to defray the impact of rising costs between rate cases. Because this is no longer possible, the Companies must now adjust rates to earn a reasonable return"[3] The following graphs portray the Company's actual and projected test year load growth.

[3] Direct Testimony of Victor A. Staffieri at 11.





Q. What is the significance of the Companies' flat load growth?

A. It demonstrates that load growth is not the driver of the increases in O&M expense. Rather, other factors are driving these O&M expense increases, including management decisions.

It means that the increases in staffing levels and payroll and related expenses that I address in the next section of my testimony, were not and cannot be caused by actual or projected load growth. It also means that the Companies should be encouraged to operate more efficiently given their status as mature utilities with almost no load growth. In addition, it means that the Companies arguably should be limited to the same number of employees to achieve the same level of utility operations in the test year as in 2010, before the PPL acquisition, adjusted only for known and measurable changes in activities, such as KU's retirement of Green River 3 and 4 and LG&E's retirement of the coal-fired Cane Run generating units and the commercial operation of Cane Run 7.

Again, the Commission should ensure that the expenses in the test year are just and reasonable, prudent and necessary in order to minimize the impact on customers.

Q. What are some of the reasons for the increases in expenses that the Commission should carefully scrutinize?

A. The Companies have been engaged in a hiring frenzy since the end of the test year in their last base rate cases (March 31, 2012), as highlighted in Mr. Thompson's and other witnesses' testimony, even though the Companies have experienced almost no load growth. This increase in staffing results in significant inefficiencies and unnecessary payroll and related expenses. Adding duplicative employees is not a necessity; it is a luxury, the cost of which should not be imposed on customers.

The Companies have and are engaged in shutting down approximately 800 MW of coal-fired generation, which is labor-intensive. The shutdowns should result in significant expense reductions in the test year compared to prior years even with the commercial operation of Cane Run 7. Cane Run 7 is a natural gas-fired combined cycle facility, which is much less labor-intensive than coal-fired generation. Although the Companies have reflected some savings from the shutdown of the coal-fired generation, the reductions in KU's expenses from retiring Green River 3 and 4 have been offset by increases due to one-time expenses to shut down the units in the test year.

The Companies have significantly increased their pension expense to reflect recent changes to the mortality tables used to project their future pension payments and reductions in the discount rate used to calculate their pension benefit obligations.

The Companies have increased their uncollectible accounts expense and reduced their late payment revenues compared to recent actual expenses and revenues.

IV. OPERATING INCOME ISSUES

Reduce Payroll and Related Expenses To Reflect Efficient Staffing Levels

Q. Please describe the growth in staffing levels since 2010 and continuing through the test year.

A. The Companies have significantly increased employee staffing levels since 2010 and PPL's acquisition of the utility operations of E.ON U.S. and propose even greater staffing levels for the test year. The Companies not only incur the payroll and related costs for their own employees, but also incur payroll and related costs allocated from LG&E and KU Services Company ("LKS").

In January 2011, KU had 1,667 employees, including those allocated to KU from LKS. LG&E had 1,558 employees, including those allocated to LG&E from LKS.[4]

In their filings, in June 2016, KU projects that it will have 1,868 employees, including those allocated from LKS, which is an increase of 12.1% despite the reductions from retiring the Green River 3 and 4 generating units. LG&E projects that it will have 1,786 employees, including those allocated from LKS, which is an increase of 14.6% despite the reductions from retiring Tyrone and the coal-fired Cane Run generating units. As I noted previously, the Companies are significantly increasing employee levels despite the fact that their loads are barely growing.

The Companies quantified a net increase of 293 positions after March 31, 2012, the end of the test year in their last base rate cases, and June 30, 2016, the end of the test year in the pending cases.[5]

The following chart portrays the increase in staffing levels from 2008 through the test year (all historic years are at year end).[6]

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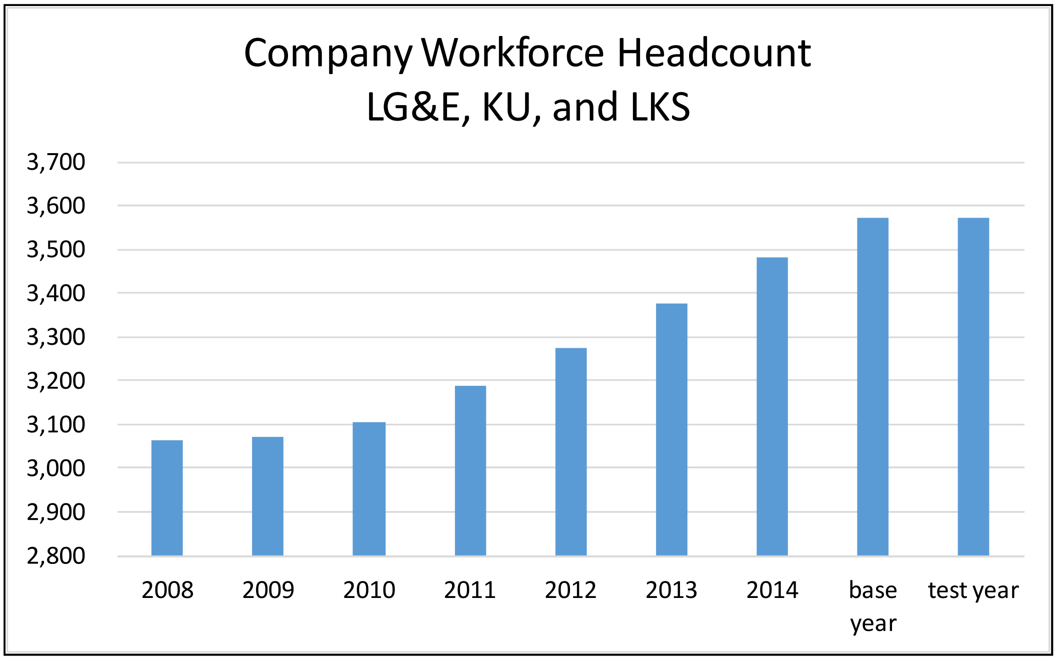
[4] KU's and LG&E's responses to Staff 1-32. I have attached a copy of KU's response as my Exhibit___(LK-4) and LG&E's response as my Exhibit___(LK-5).

[5] KU and LG&E Responses to KIUC 1-10. I have attached a copy of the KU response to KIUC 1-10 as my Exhibit___(LK-6).

[6] KU's and LG&E's responses to KIUC 1-9. I have attached a copy of KU's response to KIUC 1-9 as my Exhibit___(LK-7).



Q. What are the reasons cited by the Companies for the increases after March 31, 2012?

A. The primary reason cited by the Companies is "core skill building/knowledge retention and transfer." The Companies cited this as the reason for 200 of the 293 added positions. The other reasons cited include "capital projects," "regulatory compliance," "corporate reorganization," "plant retirement," and "customer service."[7]

Q. Does the addition of additional employees for "core skill building/knowledge retention and transfer" increase efficiency and productivity?

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[7] *Id.*

A. No. The contrary is true. First, the additional employees are duplicative, almost by definition. The Companies do not deny this. The employee increases for "core skill building/knowledge retention and transfer" do not displace existing staffing; they are in addition to the existing staffing. In other words, although the workload is unchanged, it now will take more employees to accomplish the same activities. This is the definition of negative productivity. Adding duplicative employees is not a necessity; it is a luxury, the cost of which should not be imposed on customers.

Second, these employees are being hired before there is an actual need for them to replace employees who will retire or otherwise leave the Companies. The Companies have failed to demonstrate that there is a need to hire these redundant employees so many years in advance of the retirement of older employees. The Companies have performed no workforce staffing study, other than a generalized study that highlights the need to plan for future retirements.

Third, the new employees are being hired outside of and in addition to the normal employee replenishment process. The normal process is to hire younger and less experienced employees to perform lower level jobs and then to promote them when they are more experienced and there are job openings. This is the normal process of knowledge building and skill retention as older and more experienced employees train and develop younger and less experienced employees. Instead, the Companies have overlaid another round of hiring in addition to the normal process. This is inefficient and results in excessive payroll and related expenses. It offsets and overwhelms any benefits the Companies actually achieved from additional investment to achieve efficiencies and to reduce staffing.

Fourth, the Companies have provided no evidence that hiring these additional employees is justified on the basis of cost savings or efficiency improvements.

Q. Is there any compelling need to accelerate hiring in the manner undertaken by the Companies and projected to extend into the test year?

A. No. The Companies have steadily increased their hiring since 2010 and in 2014 accelerated it even more. The Companies plan to stabilize their staffing in 2016 and future years, notably after the peak in staffing is reflected in the test year.

Q. Is there another staffing issue that the Commission should address?

A. Yes. KU proposes that 11 of the employees from the retiring Green River 3 and 4 generating units be added to staffing in the Metering department, ostensibly to replace contractor expense incurred for reading meters. While commendable, this unnecessarily adds additional expenses to the Companies' revenue requirement.

Q. What is your recommendation?

A. I recommend that the Commission disallow the payroll and related expenses for the positions added for "core skill building/knowledge retention and transfer" and disallow the payroll and related expenses for the 11 employees transferred from the Green River units offset by an increase in contractor expense. Such employee additions result in unnecessary and inefficient staffing. The Companies' business customers cannot afford the luxury of redundant employees. The Companies' customers have had to become more efficient and learn to do more with less. The Commission should hold KU and LG&E to no lower standard.

Q. What are the effects of your recommendation?

A. The effects are a reduction in KU's O&M expense of $9.247 million and a reduction in LG&E's O&M expense of $6.586 million.[8]

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

A. Yes. The Companies based their staffing levels on budgets and projections for the test year. However, their experience is that actual staffing always is less than their budgeted staffing. Over the three historical years (2011 – 2013), this slippage has averaged 2.01% for KU and 2.95% for LG&E.[9]

Q. Do you have an alternative recommendation if the Commission does not adopt your recommendation to disallow the payroll and related expenses for the added positions for "core skill building/knowledge retention and

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[8] The calculations and sources of data used for the calculations are provided for KU on my Exhibit___(LK-8) and for LG&E on my Exhibit___(LK-9).

[9] KU's and LG&E's responses to Staff 1-32. The responses provided actual and budgeted staffing levels by month for 2011 through October 2014. I have attached a copy of KU's response as my Exhibit___(LK-4) and LG&E's response as my Exhibit___(LK-5).

transfer" and for employees transferred from the Green River units to Metering?

A. Yes. I recommend that the Commission disallow the payroll and related expenses for the positions that the Companies' actual experience indicates will not be filled due to "slippage." If the positions are not filled, then the Companies will not incur the expenses.

Q. What are the effects of your alternative recommendation?

A. The effects are a reduction in the KU payroll and related expenses of $3.348 million and a reduction in the LG&E expenses of $3.688 million.[10]

<u>Remove Nonrecurring Operating Expenses for Retiring Generating Units from the Base Revenue Requirement</u>

Q. Please describe the Companies' plans to retire certain of their coal-fired generating units.

A. KU plans to retire Green River 3 and 4 in April 2016, although the retirement date may be extended to April 2017 under the Mercury and Air Toxics Standards if grid reliability concerns are present. The last operating unit at Tyrone was retired in 2013. LG&E plans to retire the coal-fired units at Cane Run in May 2015 when Cane Run 7 achieves commercial operation.[11]

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[10] The calculations and sources of data used for the calculations are provided for KU on my Exhibit___(LK-10) and for LG&E on my Exhibit___(LK-11).

[11] Thompson Direct at 22.

KU provided its actual and projected operating expenses (operation and maintenance expenses, administrative and general expenses and other taxes expense) for Green River 3, 4 and common in its response to KIUC 1-7.[12] Starting in January 2015, KU projected operating expenses for the units on a combined basis, except for severance expenses, which it projected for each unit. KU provided its actual and projected labor expenses for Green River 3 and 4 and common in its response to KIUC 1-8.[13]

LG&E provided its actual and projected operating expenses for Cane Run 4, 5, 6 and common in its response to KIUC 1-7.[14] Starting in May 2015, LG&E projected operating expenses for the units on a combined basis. LG&E provided its actual and projected labor expenses for Cane Run 4, 5, 6 and common in its response to KIUC 1-8.[15]

Q. Are the operating expenses for the retiring KU units in the test year recurring?

A. No. Except for nominal amounts for ongoing safety and site monitoring, the operating expenses no longer will be incurred after the facilities are shut down and the site is secured. KU projects that it will incur expenses through December

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[12] I have attached a copy of the KU's response to KIUC 1-7 as my Exhibit___(LK-12).

[13] I have attached a copy of KU's response to KIUC 1-8 as my Exhibit___(LK-13).

[14] I have attached a copy of LG&E's response to KIUC 1-7 as my Exhibit___(LK-14).

[15] I have attached a copy of LG&E's response to KIUC 1-8 as my Exhibit___(LK-15).

2016 to shutdown and secure the facilities, after which these expenses will drop to approximately $0.050 million per month for ongoing safety and site monitoring and maintenance.

Q. In contrast to the retiring KU units, are the operating expenses for the retiring LG&E units in the test year recurring?

A. It appears that they are. LG&E incurred expenses to shut down the facilities and secure the site prior to the test year.

Q. Are there specific one-time expenses related to the retirement of the retiring KU units included in the test year?

A. Yes. The expenses included in the test year include one-time expenses related to shutting down the facilities and securing the site and employee severance expenses.

Q. Please describe how the Companies reflected the operating expenses and capitalization of the retiring generating units in the test year revenue requirement.

A. The Companies included these operating expenses and all capital-related costs, including depreciation expense and the return on capitalization, in the test year revenue requirements

Q. Is it appropriate to include the retiring KU units' operating expenses in the base revenue requirement?

A. No. These are nonrecurring expenses and should be removed from the KU base revenue requirement. If the expenses are included in the base revenue requirement, then KU will continue to recover the expenses long after they no longer are incurred or are incurred at a much lower level. KU's rates will not be reasonable and it will obtain excessive recovery.

Q. If the retiring KU units' operating expenses are removed from the base revenue requirement, are there recovery alternatives available that are compensatory, but do not provide excessive recovery?

A. Yes. There are at least two alternatives available. The first alternative is to authorize KU to defer and amortize the operating expenses in excess of the approximately $0.050 million recurring expense. The deferral would be based on the actual operating expenses incurred, less the $0.050 million recurring expense, and would be subject to review and recovery through amortization expense in the Companies' next base rate cases. The amortization should be over a reasonably short time period, such as three to five years.

The second alternative is to authorize KU to implement a new retirement cost rider similar to the Big Sandy Retirement Rider authorized by the Commission for Kentucky Power Company in Case No. 2012-00578. KU would recover its actual operating expenses as incurred, except for one-time expenses, such as severance expenses, which should be deferred and amortized over three to five years, and except for the approximately $0.050 million recurring expense. By January 2017, the expenses recovered through the retirement cost rider would diminish to the amount of the amortization expense and after three to five years would diminish to $0 and be terminated.

Q. Should the Commission continue to allow recovery of the depreciation and return on both Companies' retiring units through the base revenue requirement?

A. Yes. The Commission should adopt the Companies' proposal to recover the remaining net book value of the retiring plants over the lives of their other coal-fired generating assets through depreciation expense included in the base revenue requirement.[16] This proposal is reasonable because it provides a lengthy recovery period and minimizes the impact on the revenue requirement. It also avoids any arguments or decisions in this proceeding as to the final disposition of the retired units, the potential costs of dismantling and site remediation if they are not retired in place, and the time period over and the manner in which such costs will be recovered.

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[16] The Companies will follow the FERC Uniform System of Accounts for retirements of plant costs, and debit the accumulated depreciation and credit the plant in service accounts by the amount of the gross plant that is retired. The remaining net book value of the retired units will be reflected in the net book value of the operating units in the next depreciation study and recovered over the remaining service lives of the operating units through slightly greater depreciation rates.

Q. Please summarize your recommendations regarding the retiring coal-fired generating units.

A. I recommend that the Commission remove the nonrecurring operating expenses for Green River 3 and 4 from KU's revenue requirement and either defer these expenses for consideration in KU's next base rate case or adopt a new retirement rider to recover these costs.

Eliminate Incentive Compensation Tied to Financial Performance

Q. Please describe the incentive compensation tied to financial performance included in the Companies' O&M expense and revenue requirements.

A. KU included $6.474 million (total Company) and LG&E included $5.967 million (total Company) in incentive compensation expense tied to PPL earnings per share ("EPS") and LKE net income, two of the four metrics pursuant to the PPL Team Incentive Award ("TIA").[17] These amounts were incurred to "motivate and direct employees toward the achievement of [PPL's] strategic goals." In a 2012 Employee Bulletin, Mr. Blake, a witness for the Companies in these two proceedings, stated: "EPS reflects an important part of PPL's mission, which includes providing shareholders with best-in-sector returns."[18]

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[17] Response to KIUC 2-14 for KU and LG&E in each case, respectively. Sum of the amounts expensed in the test year based on the Financial – PPL EPS and Financial – LKE Net Income metrics. A copy of each response is attached as Exhibit___(LK-16) and Exhibit___(LK-17), respectively. The Companies provided a copy of the TIA in response to AG 1-74 in each case, respectively. A copy of KU's response to AG 1-74 is attached as my Exhibit___(LK-18).

[18] Response to AG 1-74, page 9 of 11 in each case, respectively.

Q. Should the incentive compensation tied to financial performance be included in the Companies' revenue requirement?

A. No. First, the Commission precedent is to remove these expenses from the revenue requirement. In its order in Kentucky-American Water Company Case No. 2010-00036, the Commission disallowed incentive compensation expense tied to "financial goals that primarily benefited shareholders."[19] This expense falls clearly within that category and should be a shareholder cost, not a customer cost.

Second, this form of incentive compensation is directed toward achieving shareholder goals, not customer goals. In its order in Atmos Energy Corporation Case No. 2013-00148, the Commission stated "Incentive criteria based on a measure of EPS, with no measure of improvement in areas such as safety, service quality, call-center response, or other customer-focused criteria, are clearly shareholder-oriented. As noted in the hearing on this matter, the Commission has long held that ratepayers receive little, if any, benefit from these types of incentive plants. . . It has been the Commission's practice to disallow recovery of the cost of employee incentive plans that are tied to EPS or other earnings measures."[20] Thus, the cost should be borne by shareholders, not customers.

Third, this form of profit-maximizing incentive compensation incentivizes the Companies to seek greater rate increases from customers to improve PPL EPS and LKE net income. The greater the rate increases and revenues, the greater the

[19] Order in Kentucky American Water Company Case No. 2010-00036 at 14.
[20] Order in Atmos Energy Corporation Case No. 2013-00148 at 9.

PPL EPS and LKE net income and the greater the incentive compensation expense. There is an inherent conflict between lower rates to customers and greater financial performance for shareholders and incentive compensation for executives and other employees. This expense should be a shareholder cost.

Fourth, including incentive compensation expenses in the revenue requirement itself increases the PPL EPS and LKE net income and ensures that the incentive compensation expense will be incurred; essentially, it is a self-fulfilling expense, all else equal. If the Companies are ensured recovery of the expense from customers, then there is no performance that is at risk or that must be achieved in order to recover that expense. This expense should be a shareholder cost.

<u>Pension Expense to Reflect Amortization of Net Actuarial Loss Over A Longer Period</u>

Q. Please describe the Companies' request for pension expense.

A. The Companies seek significant increases in pension expense in the test year compared to calendar year 2014 and compared to the base year. KU seeks an increase of $15.316 million (total Company) compared to calendar year 2014 and of $12.467 million compared to the base year.[21] LG&E seeks an increase of $16.659 million (total Company) compared to calendar year 2014 and of $13.366 million compared to the base year.[22] These projected increases were based on

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[21] KU's Response to KIUC 1-20. I have attached a copy of this response as my Exhibit____(LK-19).

[22] LG&E's Response to KIUC 1-20. I have attached a copy of this response as my

preliminary estimates developed by Towers Perrin, an actuarial firm retained by the Companies.[23]

Q. What are the reasons for these significant increases?

A. The only witness who addressed these increases was Mr. Blake. The only reason cited by Mr. Blake was the presumed use by the Companies' actuaries of recently developed new mortality tables, which reflect "mortality improvements," or longer participant lives. Mr. Blake is not an actuary. Instead, he relied on preliminary estimates from Towers Perrin for the pension expenses included in the test year. These estimates were based on the new mortality tables as well as incorporating the effects of various other changes in assumptions. The result of the new mortality tables and other changes in assumptions is a huge increase in the Companies' future pension benefit obligations ("PBO") and the resulting net actuarial loss, a significant portion of which must be amortized and reflected in pension expense over some amortization period. The Companies amortized the net actuarial loss to expense using an extremely short year amortization period of less than 9 years.

Exhibit____(LK-20).

[23] Excerpts from the Towers Perrin report were provided in KU and LG&E's responses to KIUC 1-15 and 1-16. I have attached a copy of KU's response as my Exhibit___(LK-21).

Although it was not cited by Mr. Blake, another reason for the increase in pension expense is an increase in the PBO and the resulting net actuarial loss due to a reduction in the discount rate used to calculate the PBO. This reason is cited in the Towers Perrin report wherein it provided the preliminary estimates of pension expense relied on by the Companies in their filings. The discount rate is used to calculate the net present value of future pension payments to plan participants. The lower the discount rate, the greater the PBO, the greater the net actuarial loss, and the greater the pension expense, all else equal.

Q. How is the increase in the net actuarial loss reflected in the pension expense?

A. In addition to several other components, the pension expense calculation includes an amortization of a significant portion of the net actuarial loss in the 2015 and 2016 calendar years used to develop the pension expense for the test year. If the net actuarial loss increases, as it did from the use of the new mortality tables and the reduction in the discount rate, then the amortization included in the pension expense increases, all else equal. Similarly, if the amortization period is shortened, then the amortization included in the pension expense increases, all else equal. In future years, as the net actuarial loss is reduced, the amortization included in the pension expense will decline, all else equal.

Q. Is the essence of pension expense a statistical allocation of the future pension payments to plan participants over their lives?

A. Yes. Pension expense is nothing more than a statistical allocation of estimated future benefit payments. It requires estimates of the future pension payments, but is trued-up each year to reflect actual experience in the prior year and further adjusted to reflect changes in estimates of future payments to plan participants.

Consequently, the pension plan expense is properly viewed as a "self-truing" expense that is updated each year over the remaining lives of the plan participants. The estimates will change each year based on actual experience, the assumptions used and the allocation methods that are applied. Nevertheless, the sum of the pension expense necessarily will equal the sum of the pension benefit payments until the last plan participant or qualified dependent dies.

The Companies' defined benefit pension plans are now closed to new employees. The future pension payments to plan participants over their lives will not be known with certainty until the last plan participant dies and the plan is terminated. Until the termination of the plan, the pension expense each year requires an estimate of the future pension payments and an allocation of that expense over the remaining years of the plan.

This important point is confirmed in the Towers Perrin actuarial report provided in response to KIUC 1-16. Towers Perrin correctly notes that the variability in expense from estimate to estimate is due to changes in assumptions, but ultimately does not affect the pension expense incurred over time.

As an example of how assumptions can be used or changed to affect the pension expense calculated by the actuary for any year, the Companies successfully reduced their pension expense last year when they raised the discount rate by 90 basis points. Now they plan to reduce the discount rate by 50 basis points for the projected test year. If interest rates increase in future years, then the Companies will increase the discount rate again, which will reduce pension expense in those future years to levels below what their actuary projects today.

As another example of how the Companies used assumptions to increase pension expense in the projected test year in the pending cases, the Companies directed Towers Perrin to assume that there would be *no* earnings on the pension fund assets after March 31, 2014 until December 31, 2014. December 31, 2014 was the date used to value the pension assets and the PBO and the net actuarial loss used to calculate the pension expense for 2015. This assumption reduced the pension fund assets and increased the pension expense due to an increase in in the net actuarial loss for 2015 and all subsequent years that were projected. In effect, the Companies increased their pension expense in the test year through a apparently unsupported assumption.

Q. Have the Companies projected their pension expense after the end of the test year?

A. Yes. Towers Perrin projected the Companies' pension expense for each year 2015 through 2019.[24] After the increase in 2015, the projected expenses decline in each subsequent year 2016 through 2019. This occurs primarily because the amortization included in the pension expense declines as the funding deficiency and the net actuarial loss are reduced each year.

[24] KU's and LG&E's response to KIUC 1-16. I have attached a copy of KU's response as part of my Exhibit___(LK-21).

Q. What is the significance of the declines in pension expense after the test year?

A. If the Commission adopts the Companies' proposed pension expense, then the base revenue requirement will include pension expense at its peak and will not reflect the declines in each subsequent year. This will result in the Companies' recovering more than the pension expense they actually incur until their next base rate cases. This is inequitable and can and should be avoided.

Q. Is the Commission obligated to use the Companies' proposed pension expenses for ratemaking purposes?

A. No. The Commission is required to set the pension expense at a level that it determines is reasonable for ratemaking purposes. This may not be the same as the Companies' estimates for accounting and financial reporting purposes. As I noted previously, pension expense is an estimate that is self-truing over time. The pension expense estimates are extremely sensitive to the models and assumptions that are used to calculate the expenses. All of these assumptions are approved by the Companies.

Thus, if the Commission determines that different estimates are reasonable for ratemaking purposes based on different assumptions, such as a longer amortization period or higher discount rate, then those estimates can and will be trued up in subsequent rate cases.

To the extent that the Companies' pension expense allowed for ratemaking is different than it reports for accounting and financial reporting, it is considered a timing difference under Generally Accepted Accounting Principles ("GAAP") and the Companies can defer the difference (either as an asset or a liability). These deferrals will converge to $0 when the final pension expense is determined and the plan is terminated. The use of deferral accounting ensures that the Companies' earnings will not be affected if the Commission adopts a longer amortization period.

Q. What is your recommendation?

A. I recommend that the Commission set pension expense to reflect a 30 year amortization of the net acturarial losses rather than the less than 9 year amortization periods used by the Companies. The longer amortization more closely matches the period over which pension payments will be made (up to 60 or more years) than the unduly short amortization period reflected in the Companies' amortization. The longer amortization period will reduce the volatility caused by changes in the mortality tables, the discount rate, and market returns on pension assets, not only in the pending cases, but also in future cases. The longer amortization period also will levelize the pension expense over the life of the pension plan compared to the Companies' proposal, which front-loads the amortization and thus, the pension expense. Finally, the longer amortization period will minimize the excess recoveries from customers as the Companies' pension expense declines in future years.

Q. What are the effects of your recommendation?

A. The effects are a reduction in KU's pension expense of $10.627 million and a reduction in LG&E's electric expense of $12.562 million.[25]

<u>Reduce Uncollectible Expense to Reflect Recent Experience</u>

Q. How does the uncollectible accounts expense included by the Companies in the test year compare to their actual experience over the most recent five years?

A. KU included $6.441 million in uncollectible expense in the test year compared to a five year average for 2010 through 2014 of $5.273 million. The five year average was driven sharply upward by abnormally high residential accruals in 2010 and 2014.[26] KU claims that the test year uncollectible expense is 0.40% of total revenues, which it claims is "not unreasonable when compared to the five year average."[27]

LG&E included $4.028 million in uncollectible accounts expense in the test year compared to a five year average for 2010 through 2014 of $3.730 million. The five year average was driven sharply upward by abnormally high residential accruals in 2010 and 2014.[28] LG&E claims that the test year

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[25] The calculations for KU and LG&E are attached as Exhibit___(LK-22) and Exhibit___(LK-23), respectively.

[26] KU's response to AG 1-3. I have attached a copy of this response as my Exhibit___(LK-24).

[27] KU's response to AG 2-3. I have attached a copy of this response as my Exhibit___(LK-25).

[28] LG&E's response to AG 1-3. I have attached a copy of this response as my Exhibit___(LK-26).

uncollectible expense is 0.28% of total revenues, which it claims is "not unreasonable when compared to the five year average."[29]

Q. Is the uncollectible accounts expenses included by each Company in its revenue requirement excessive?

A. Yes. The Commission must determine what a reasonable level of expense is for the forecast test year. The best way to do that is to compare it to each Company's recent experience. A five year average provides the best evidence of each Company's actual experience, including the effects of any anomalies. As I noted previously, it is not appropriate to compare the test year level to the most recent calendar year alone because the residential expense accruals were abnormally high in 2014.

As to the Companies' claim that the projected test year expense "is not unreasonable compared to the five year average," the numbers do not support that claim. The Companies' projections are substantially in excess of the five year averages and they are not reasonable.

Q. What is your recommendation?

A. I recommend that the Commission use the five year average for each Company. The Companies have offered no justification to increase the projected test year

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[29] LG&E's response to AG 2-3. I have attached a copy of this response as my Exhibit___(LK-27).

expense to the proposed levels. The uncollectibles account expense is volatile and it should reflect each Company's average actual experience.

Q. What are the effects of your recommendation?

A. The effect is a reduction in KU's uncollectible accounts expense of $1.168 million and a reduction in LG&E's electric expense of $0.236 million.

<u>Increase Customer Late Payment Revenues to Reflect Recent Experience</u>

Q. Please describe the late payment revenues reflected by the Companies in the test year and how those "other revenues" compare to the Companies' recent actual five year experience.

A. KU reflected $3.786 million in the test year compared to a five year average for 2010 through 2014 of $6.306 million.[30] LG&E reflected $2.475 million (electric) in the test year compared to a five year average for 2010 through 2014 of $4.471 million.[31]

Q. Should the Commission use the five year average for late payment revenues in the same manner as you recommend for uncollectible accounts expense?

A. Yes, and for the same reasons.

[30] KU's response to AG 1-3. A copy of this response is attached as my Exhibit___(LK-24).

[31] LG&E's response to AG 1-3. A copy of this response is attached as my Exhibit___(LK-26).

Q. What are the effects of your recommendation?

A. The effect is an increase in KU's late payment revenues of $2.520 million and an increase in LG&E's revenues of $1.996 million.

<u>Remove Property Tax Expense on Construction Work In Progress and Direct the Companies to Capitalize the Expense</u>

Q. Did the Companies capitalize any property tax expense in the test year to construction work in progress ("CWIP")?

A. No. The Companies reflected all property tax expense as an operating expense in the revenue requirement. The Companies' calculations of property tax expense in included construction work in progress ("CWIP") as well as plant in service.[32]

Q. Please describe the Companies' property tax expense capitalization policy.

A. The Companies capitalize property tax expense only on the "original construction costs of coal-fired generating units."[33] There is no construction of new coal-fired generating units in the test year, so the Companies did not capitalize any of the projected property tax expense. However, there is significant other construction, some of which is reflected in base rates and some of which is reflected in the environmental surcharge.

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[32] KU's and LG&E's response to KIUC 1-36. I have attached a copy of the summary tabs from each Company's response to KIUC 1-36 as my Exhibit___(LK-28).

[33] KU's and LG&E's response to KIUC 2-10. I have attached a copy of the KU response as my Exhibit___(LK-29).

Q. Is this capitalization policy appropriate?

A. No. It is not appropriate for accounting or ratemaking purposes. There is no justification for the Companies to expense the property taxes on the construction costs of environmental and all other additions to coal-fired generating units, gas-fired generating units, transmission, and distribution assets. The property tax expense on these construction costs is a cost of construction, not a current period expense. In fact, the FERC Uniform System of Accounts ("USOA") requires that such taxes be capitalized during construction.[34] The property tax expense should be treated no differently than the cost of labor, materials, contractors, and other costs that are incurred to construct the assets and to prepare them for service.

In the past, prior to the Companies' massive environmental capital expenditures and prior to their construction of gas-fired generation units instead of new coal-fired units, there may have been little difference whether the property taxes on CWIP were capitalized or not. However, circumstances have changed significantly from those days and the accounting and ratemaking practices of the past should be updated to reflect present reality. The Companies' accounting practices also should be modified to conform with the requirements of the FERC USOA Plant Instructions.

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[34] FERC USOA Electric Plant Instructions #3A. *Components of Construction Cost* states that "For Major utilities, the cost of construction property includible in the electric plant accounts shall include, where applicable, the direct and overhead cost as listed and defined hereunder:" The list of such costs includes #16 *Taxes*, which states: "*Taxes* includes taxes on physical property (including land) during the period of construction and other taxes properly includible in construction costs before the facilities become available for service."

Further, it is particularly important to capitalize property tax expense on CWIP in a forecast test year. There may have been an argument in the past when using a historic test year that regulatory lag justified treating all property tax expense as a current period expense for ratemaking recovery, at least with respect to property tax expense on minor generating unit additions or short-term transmission and distribution construction projects. That argument is no longer relevant now that the Companies have switched to a forecast test year.

Q. What are the effects of your recommendation?

A. The effect is a reduction in KU's property tax expense of $2.056 million and a reduction in LG&E's electric expense of $2.331 million.[35]

<u>Extend The Amortization Period for Deferred Costs That Will Be Fully Amortized Shortly After The Test Year</u>

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.[36] For certain of these deferred costs, the amortization will be completed within one or two years after the end of the test year.

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[35] The calculation of the KU adjustment is shown on my Exhibit___(LK-30). The calculation of the LG&E adjustment is shown on my Exhibit___(LK-31).

[36] See KU's and LG&E's response to KIUC 1-29. I have attached a copy of each Company's response as my Exhibit___(LK-32) and Exhibit___(LK-33), respectively.

More specifically, KU's Mountain Storm deferred costs will be fully amortized in October 2016, a mere four months after the end of the test year. The amortization expense is $1.208 million. However, at the end of the test year, the unamortized cost is only $0.403 million. In other words, if this amortization expense is "baked-in" to the revenue requirement without modification, KU will recover $0.805 million more than the amortization expense in the twelve months after the test year and $1.208 million more than the amortization expense each year thereafter.

KU's MISO Exit Fee deferred costs will be fully amortized in June 2017, only twelve months after the end of the test year. The amortization expense is $0.484 million. However, at the end of the test year, the unamortized cost is only $0.482 million. In other words, if this amortization expense is "baked-in" to the revenue requirement without modification, KU will recover $0.484 million more than the amortization expense every twelve months starting in July 2017.

LG&E's 2011 Summer Storm will be fully amortized in December 2017, only 18 months after the end of the test year. The amortization expense is $1.610 million. However, at the end of the test year, the unamortized cost is only $2.416 million. In other words, LG&E will recover $1.610 million more than the amortization expense each year starting in January 2018.

Q. What is your recommendation to address this problem and the overrecovery that will occur within mere months after the end of the test year?

A. I recommend that the Commission reset the amortization period to five years for the deferred costs that I identified. This will reduce the likelihood that the Companies will overrecover, 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 $1.177 million for the Mountain Storm and MISO Exit Fee deferred costs.[37] LG&E's amortization expense will be reduced by $0.805 million for the 2011 Summer Storm deferred costs.[38]

<u>Eliminate Terminal Net Salvage from the Cane Run 7 Depreciation Rates</u>

Q. Please describe the net salvage that the Companies included in the proposed Cane Run 7 depreciation rates.

A. The Companies propose net salvage of negative 5% for plant accounts 342 and 343, negative 10% for account 344, and negative 5% for account 345[39] for Cane Run 7. Mr. Spanos developed these proposed net negative salvage rates by performing a statistical review of the historic *interim* retirements and *interim* net salvage of the Companies' other gas-fired generating units.[40] Mr. Spanos did not perform any review of *terminal* retirements or *terminal* net salvage for the Companies' other gas-fired generating units or for Cane Run 7 specifically and

[37] The calculations for KU are shown on my Exhibit___(LK-34).

[38] The calculations for LG&E are shown on my Exhibit___(LK-35).

[39] These net salvage rates for each plant account are shown on Exhibit JJS-1 attached to Mr. Spanos' Direct Testimony for each company. I have attached a copy of KU's and LG&E's schedule as my Exhibit___(LK-36) and Exhibit___(LK-37), respectively, for ease of reference.

[40] Spanos Direct at 5-6.

claims that he did not "include a terminal net salvage component in the proposed rates since no plans have been established for how the facility would be dismantled."[41]

Q. Please distinguish between net salvage on interim retirements and net salvage on terminal retirements.

A. The plant balances represent the cost of the assets, in this case the Cane Run 7 generating unit. Some of the components of the asset will be replaced and retired before the entire asset is retired. These retirements are considered to be *interim* retirements. The net cost to remove these *interim* retirements, offset by any salvage income, is referred to as net negative salvage on *interim* retirements.

However, the bulk of the components and the cost of the components will remain in service from the first day of operation to the last day when the generating unit is shut down and retired. These retirements are considered to be *terminal* retirements. If the facilities are retired in place, then there is no cost to remove those components, net of any salvage income. If the facilities are dismantled and the site is remediated, then there is a cost to remove these components and remediate the site. The net cost to do so is referred to as net negative salvage on *terminal* retirements.[42]

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[41] KU's and LG&E's responses to KIUC 2-12. A copy of these responses is attached as my Exhibit___(LK-38).

[42] Mr. Spanos provides a description of interim and terminal retirements in his Direct Testimony at 7-8.

The distinction between interim and terminal retirements and the net negative salvage related to each may be illustrated through an analogy to a car. Assume that Betty buys a new car. Over the years, she replaces the tires and some of the engine components, such as the alternator and the power steering pump. Those are analogous to the interim retirements that Cane Run 7 will experience over its life. The costs that she incurred to pay her mechanic to remove and replace these parts are considered net negative salvage on those interim retirements. Years later, the car reaches the end of its life and Betty decides to permanently retire it. She has the car towed to the salvage yard and is paid nothing for it. The costs that she paid the towing company are considered net negative salvage on terminal retirements. The terminal retirement of the car is analogous to Cane Run 7. At the end of its life, the entire remaining plant balances will be retired. There may be no net negative salvage if the unit is retired in place or there may be net negative salvage if it is dismantled and removed and the site is remediated.

Q. How did Mr. Spanos apply the net negative salvage that he developed for *interim* retirements when he calculated the depreciation rate for Cane Run 7?

A. Mr. Spanos applied the *interim* net negative salvage to the *entire* Cane Run plant balance rather than only the *interim* portion of the plant balance. He acknowledged that he did so in response to discovery.[43] Returning to my car analogy, he assumed that the roof, hood, trunk, and chassis of the car all would have to be replaced on the same regular basis as tires, the alternator and the power steering pump.

Q. What is the proportion of the plant balance for Cane Run 7 that is subject to interim retirements?

A. Mr. Spanos provided the Cane Run 7 plant balances by account that would be subject to interim retirements in response to discovery.[44] That response shows that only 25% (on average across all plant accounts) of the total plant balances for each Company will be subject to interim retirement.[45] Yet, Mr. Spanos applied the interim net salvage to 100% of the total plant balances, both the interim portion and the terminal portion.

Q. Was this a calculation error?

A. Yes. First, the Companies claim that they included ***NO*** terminal net salvage in the proposed Cane Run 7 depreciation rates. However, that claim is incorrect. By applying the interim net salvage rate to the terminal retirements in addition to the interim retirements, the Companies included net negative salvage on terminal

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[43] KU's and LG&E's responses to KIUC 2-13. I have attached a copy of these responses as my Exhibit___(LK-39).

[44] *Id.*

[45] The 25% is an average across all plant accounts. The responses to KIUC 2-13 indicate that interim retirements compared to total plant balances for both Companies are 18% for account 341, 16% for account 342, 19% for account 343, 30% for account 344, 33% for account 345, and 34% for account 346.

retirements, despite denying that they did so and denying that they even could do so.

Second, the Companies provided no estimate of terminal net salvage and no support for including terminal net salvage, let alone any evidence that terminal net salvage would be anything other than 0%. Mr. Spanos included the following Question and Answer in his testimony as follows:

Q. DID YOU INCLUDE A NET SALVAGE COMPONENT FOR DISMANTLEMENT IN THE DEPRECIATION CALCULATIONS?

A. No. Although it is important to establish the full service value of the facility at the early stages, including an amount at this time is premature. There is analysis of the facility and site that needs to be performed before an adequate estimate of dismantlement costs assigned for recovery. Once the study is completed, the dismantlement component will be included in future depreciation rates.

Mr. Spanos testified that not only had he ***NOT*** included terminal net salvage, but that he could not do so until he had "an adequate estimate of dismantlement costs."

In Case Nos. 2012-00221 and 2012-00222, the settlement adopted by the Commission limited terminal net salvage to negative 2% on all of the Companies' generating units.[46] Methodologically, the Companies weighted the interim and terminal net salvage by the interim and terminal portions of the plant balance.[47] If Mr. Spanos had done a similar weighting for Cane Run 7 with a 0% terminal net

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[46] In their responses to KIUC 2-12, the Companies provide the weighting of the interim and terminal net salvage rates into a combined net salvage rate applied to the entire plant balances. The terminal net salvage for all plant accounts is shown as negative 2% in accordance with the settlement term.

[47] *Id.*

salvage for the terminal portion of the plant balances, then the weighted net salvage would be one-fourth of the net salvage rate that he applied.

Q. What is your recommendation?

A. I recommend that the Commission correct this error in the Companies' calculation of the proposed Cane Run 7 depreciation rates and remove the terminal net salvage from the calculations.

Q. What are the effects of your recommendation?

A. The Cane Run 7 depreciation rates should be reduced to 2.62% for accounts 341 and 342, 2.68% for account 343, 2.91% for account 344, 2.88% for account 345, and 2.82% for account 346. KU's depreciation expense should be reduced by $0.511 million and LG&E's by $0.164 million.[48] I used the Companies' methodology for its other generating units to weight the interim net salvage and the terminal net salvage (using 0% for Cane Run 7) to develop the net salvage rate applied to the Cane Run 7 plant balances. These reductions to depreciation expense and the associated rate increases will not affect the earnings of the Companies.

[48] The calculations of the corrected depreciation rates and the corrections to the KU and LG&E depreciation expense are shown on my Exhibit___(LK-40) and Exhibit___(LK-41), respectively.

V. CAPITALIZATION ISSUES

<u>Reduce The Revenue Requirement to Reflect A “Slippage Factor” Applied to Construction Expenditures</u>

Q. The Staff asked the Companies to quantify a construction expenditure “slippage factor” and the resulting reduction in revenue requirements.[49] Please describe the concept of a “slippage factor” and the Companies’ responses.

A. A “slippage factor” in this context refers the percentage by which the actual construction expenditures tend to underrun the budgeted construction expenditures. The Commission has applied slippage factors in other utility base rate cases where there has been a forecast test year. In its order in Union Light, Heat and Power Company Case No. 2005-00042, the Commission adopted a “slippage factor” adjustment for the forecast test year, which it described 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

[49] KU’s response to Staff 2-75 and LG&E’s response to Staff 2-89.

> 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.[50] (footnote omitted).

Similarly, in its order in Case No. 2004-00103, the Commission adopted "slippage factor" adjustments for the forecast test year, which it described "as an indicator of Kentucky-American's accuracy in predicting the cost of its utility plant additions."[51]

In these proceedings, KU quantified a 97.803% slippage factor and a reduction of $0.900 million in its base revenue requirement if the slippage factor is applied to its projected construction expenditures.[52,53] LG&E quantified a 97.728% slippage factor and a reduction of $0.738 million in its electric base revenue requirement if the slippage factor is applied to its projected construction expenditures.[54,55]

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[50] Order in Union Light, Heat and Power Company Case No. 2005-00042 at 8.

[51] Order in Kentucky American Water Case No. 2004-00103 at 2.

[52] KU's responses to Staff 2-75. I have attached a copy of this response as my Exhibit___(LK-42).

[53] I have reflected the effects on capitalization of KU's calculations in Section II on my Exhibit___(LK-43) in order that the subsequent changes in capitalization and costs of each component will be properly calculated in a sequential manner. KU's calculation also affect operating income. I have included both effects on the same line item under Capitalization issues on the table in the Summary section of my testimony.

[54] LG&E's response to Staff 2-89. I have attached a copy of this response as my Exhibit___(LK-44).

[55] I have reflected the effects on capitalization of LG&E's calculations in Section II on my Exhibit___(LK-45) in order that the subsequent changes in capitalization and costs of each component will be properly calculated in a sequential manner. LG&E's calculation also affect operating income. I have included both effects on the same line item under Capitalization issues on the table in the Summary section of my testimony.

The quantifications provided by the Companies include not only the effect on capitalization, but also the capital-related effects on operating income.

Q. Should the Commission apply the slippage factors calculated by the Companies and reduce capitalization?

A. Yes. The Commission's precedent is to apply slippage factors, which the Companies have acknowledged.

<u>Reduce The Companies' Capitalization and Income Tax Expense to Reflect the Extension of Bonus Depreciation Enacted After the Companies Made Their Filings</u>

Q. Please describe the "tax extender" bill passed by the U.S. Congress in December 2014.

A. In December 2014, the Congress passed Public Law No. 113-295, entitled "The Tax Increase Prevention Act of 2014" ("Act"). The Act provided for the extension of 50% bonus tax depreciation in 2014 for qualified property while also providing 50% bonus tax depreciation in 2015 for long-production-period property.[56]

Under the law, the Companies may elect out of the bonus depreciation and instead use MACRS depreciation. If the Companies apply bonus depreciation on qualified property, they both will be able to deduct the additional bonus tax depreciation in excess of the MACRS tax depreciation. The additional tax

[56] KU's response to AG 1-27 and LG&E's response to AG 1-26.

depreciation will significantly increase their accumulated deferred income taxes ("ADIT").

Q. What are the implications of the Act in these proceedings?

A. The Act was passed and signed into law after the Companies made their filings in these proceedings. Consequently, the effects of the additional tax depreciation are not reflected in their filings.

The effects are two-fold. First, the Companies are able to deduct additional depreciation compared to the MACRS depreciation they reflected in their filings. However, they may elect out of the bonus depreciation and instead use MACRS depreciation if that results in a better outcome. Further, they may use bonus depreciation for 2014, but elect out for 2015. To the extent that the Companies use bonus depreciation, they will have greater accumulated deferred income taxes and reduced capitalization. This will result in a reduction in their revenue requirements, all else equal.

Second, the amount of bonus depreciation deducted results in lower taxable income and lower Section 199 deductions, which are based on taxable income. A reduction in the Section 199 deduction results in greater income tax expense and an increase in the revenue requirement, all else equal.

Thus, the Companies must optimize between the use of bonus depreciation in 2014 and 2015 and the potential loss of the Section 199 deduction in each of those years.

Q. Have the Companies each performed an analysis to optimize the revenue requirement benefit of the bonus depreciation against the loss of the Section 199 deduction?

A. Yes. The Companies each performed four analyses that included not only the effects on their base revenue requirements, but also on their environmental surcharge revenue requirements in order to optimize the effects of the Act. KU determined that its best option will be to utilize bonus depreciation for 2014, but to elect out of it 2015.[57] LG&E determined that its best option will be to utilize bonus depreciation for both 2014 and 2015.[58]

Q. Did the Companies quantify the effects on the Section 199 deduction and the capitalization (due to the greater ADIT) for the test year?

A. Yes. KU quantified a reduction in capitalization due to the additional ADIT of $28.234 million and a reduction in income tax expense due to an increase in the Section 199 deduction of $0.350 million. LG&E quantified a reduction in capitalization due to the additional ADIT of $54.238 million and an increase in income tax expense due to a reduction in the Section 199 deduction of $1.606 million, both total company.

Q. What is the effect of reflecting these changes in capitalization and income tax expense on each Company's revenue requirement?

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[57] KU's response to AG 1-27. See Tab 1 – Summary and Tab 3 – Opt Out 2015. I have attached a copy of the response and the relevant tabs as my Exhibit___(LK-46).

[58] LG&E's response to AG 1-26. See Tab 1 – Summary and Tab 4 – Elect Bonus w Rev. I have attached a copy of the response and the relevant tabs as my Exhibit___(LK-47).

A. The effect is a reduction in KU's base revenue requirement of $2.483 million and a reduction in LG&E's electric base revenue requirement of $2.760 million.[59] There also are significant effects of these changes on each Company's environmental surcharge revenue requirement, which the Commission should ensure are properly incorporated in each Company's environmental surcharge filings.

Reduce LG&E's Capitalization to Remove The Paddy's Run Demolition Costs

Q. Please describe LG&E's proposal to demolish the retired Paddy's Run generating plant.

A. LG&E proposes to demolish the retired Paddy's Run generating plant in the test year. It has been retired in place for many years. LG&E proposes to incur $11.5 million starting April 2015 and finishing in June 2016, all of which it included in the test year capitalization. The cost estimate was prepared by AMEC Environment & Infrastructure, Inc.[60]

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[59] The calculations for the effect on KU's revenue requirement due to the reduction in capitalization are shown on Section III of my Exhibit___(LK-43) and for the effect on LG&E's revenue requirement due to the reduction in capitalization are shown on Section III of my Exhibit___(LK-45). The effect on KU's base revenue requirement due to the increase in the Section 199 deduction is $0.541 million. The effect on LG&E's electric base revenue requirement due to the reduction in the Section 199 deduction is $2.052 million.

[60] LG&E's response to KIUC 1-6. The response to part (a) provides the projected expenditures by month. The responses to parts (b) through (d) provide other information on the status of the plant, the accounting for the demolition costs, and whether there is any legal obligation to demolish the plant. The response to part (e) provides a copy of the AMEC "Conceptual Phase Study Demolition with Clean Fill Option." I have attached a copy of the response as my Exhibit___(LK-48), although I have provided only the cover and table of contents of the AMEC study report.

Q. Is there any legal obligation to demolish Paddy's Run?

A. No.[61]

Q. Should the Commission include this proposed demolition cost in LG&E capitalization?

A. No. There is no legal obligation to incur the cost. The Company has not demonstrated that it is necessary to incur the cost in the test year.

Q. What is the effect of your recommendation?

A. The effect is a reduction in the LG&E revenue requirement of $1.235 million.[62]

VI. COST OF SHORT TERM DEBT

<u>Reduce the Cost of Short Term Debt to Reflect A More Reasonable Assumption About Future Interest Rates</u>

Q. Please describe the cost of short term debt proposed by the Companies in the test year.

A. The Companies propose a rate of 0.905%, which reflects a projected rate of 0.636% for the July 2015 through December 2015 portion of the test year and a rate of 1.585% for the January 2016 through June 2016 portion of the test year.

[61] *Id.*, response to part (d)(i): "There is no legal requirement to demolish the units."
[62] The calculations and sources of data used for the calculations are detailed in Section IV on my Exhibit___(LK-45).

Q. Are these rates reasonable?

A. No. They are excessive. The present rate for 90 day commercial paper is 0.15%. The present rates for 240 day to 270 day commercial paper range from 0.33% to 0.36%.[63]

Q. What is your recommendation?

A. I recommend that the Commission use a short term debt rate of 0.30%, near the top of the range, although a lower rate also would be reasonable.

Q. What is the effect of your recommendation?

A. The effect is a reduction in KU's revenue requirement of $0.645 million and a reduction in LG&E's revenue requirement of $0.561 million.[64]

VII. COST OF LONG TERM DEBT ISSUED AFTER DECEMBER 2014

Q. Have you quantified the effect of Mr. Baudino's recommendation to reduce the cost of the new debt issuances projected by the Companies?

A. Yes. I have used the long term debt interest rates proposed by Mr. Baudino for each Company's projected new debt issuances.

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[63] See attached excerpt from February 26, 2015 Wall Street Journal reflecting rates.

[64] The calculations for KU are detailed in Section IV on my Exhibit___(LK-43) and for LG&E in Section V on my Exhibit___(LK-45).

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

A. The effects are a reduction in KU's revenue requirement of $1.250 million and a reduction in LG&E's revenue requirement of $1.076 million.[65]

VIII. 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 8.6% compared to the Companies' requested return on equity of 10.50%. Mr. Baudino's recommended return on equity for KU is 13.69% when grossed up for income taxes, bad debt expense, and Commission assessment, compared to KU's requested return on equity of 16.71% when grossed-up for income taxes, bad debt expense, and Commission assessment. Mr. Baudino's recommended return on equity for LG&E is 13.83% when grossed up for income taxes, bad debt expense, and Commission assessment compared to LG&E's return on equity of 16.89% 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 $56.674 million and a reduction in LG&E's revenue requirement of $33.596 million.[66]

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[65] The calculations for KU are detailed in Section V on my Exhibit___(LK-43) and for LG&E in Section VI on my Exhibit___(LK-45).

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 $29.828 million in revenue requirements. For LG&E, each 1.0% return on equity equals $17.682 million in revenue requirements. These quantifications reflect the reductions in capitalization for each Company that I recommend.[67]

IX. OFF-SYSTEM SALES MARGIN RIDER

Q. Please describe the off-system sales ("OSS") margins included by the Companies in their revenue requirements?

A. KU reflected OSS margins of $0.5 million as a reduction to its revenue requirement and LG&E reflected $2.7 million in its revenue requirement. These margins are significantly lower than OSS margins reflected in the revenue requirement in prior cases and the actual OSS margins earned by the Companies.

Q. Are OSS margins subject to the same or greater volatility as fuel and purchased power expenses?

A. Yes. The same factors that affect fuel and purchased power expenses also affect OSS margins. In addition, there are many other factors that affect OSS margins, including market clearing prices, the availability of other parties' generation,

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[66] The calculations for KU are detailed in Section VI on my Exhibit___(LK-43) and for LG&E in Section VII on my Exhibit___(LK-45).

[67] The quantifications of each 1.0% change in the return on equity are shown for KU on my Exhibit___(LK-43) and for LG&E on my Exhibit___(LK-45).

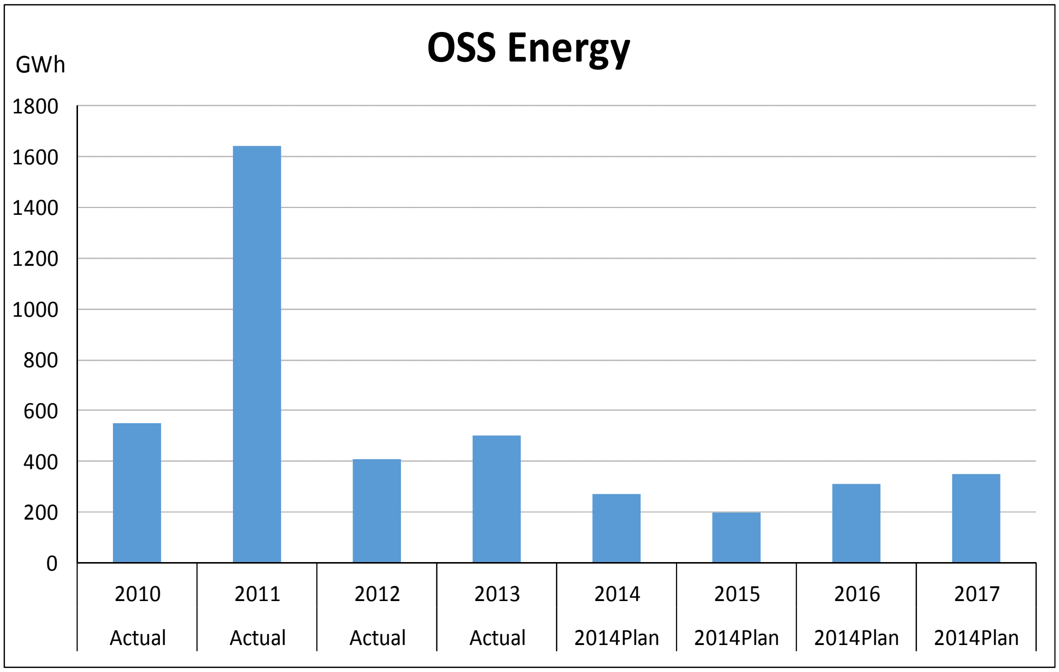
other parties' demand at the market clearing prices, the Companies' loads under unpredictable weather conditions, and the availability of the Companies' generating units, including the effects of planned, forced, and deration outages of generating units. Assumptions regarding the following factors must be made in order to predict OSS margins in a future test year:

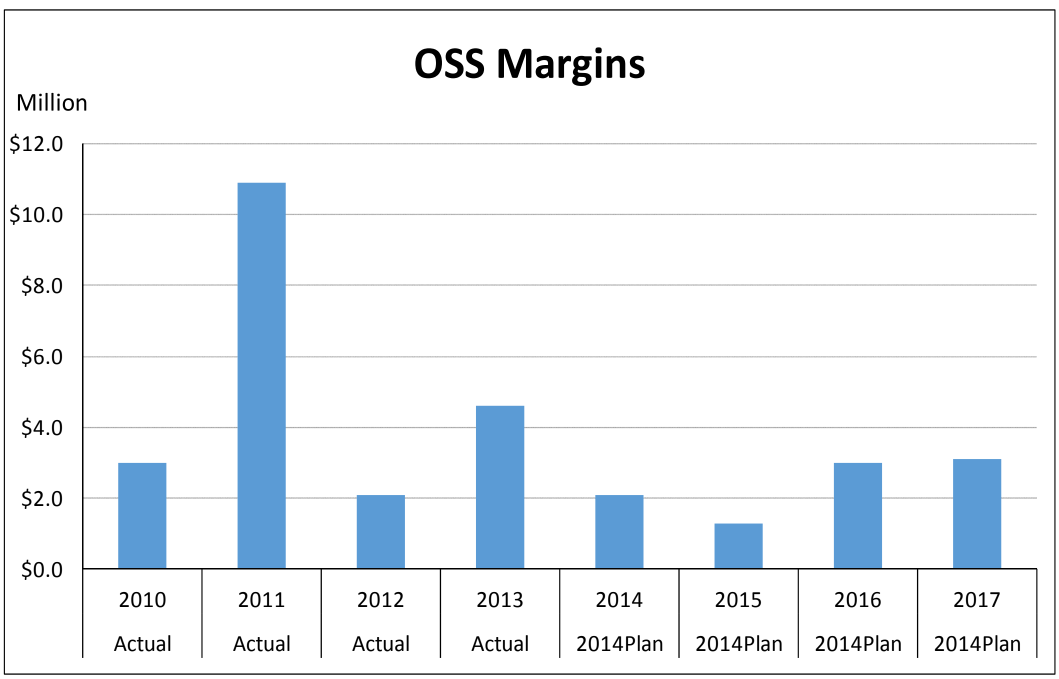
- Hourly dispatched generation by unit
- Hourly native load
- Hourly energy sales
- Hourly economic minimum and emergency minimum capacity levels
- Data required to calculate both incremental dispatch costs and actual dispatch costs include:
- Quadratic heat rate coefficients
- Fuel costs ($/MBTU)
- Fuel Handling Costs ($/MBTU or $/MWh)
- Other costs such as for lime ($/MBTU or $/Ton)
- Dispatch penalty factor
- Variable O&M costs ($/MWh)
- SO_2 and NO_X emissions costs ($/MWh)

Q. How have OSS and OSS margins varied in recent years?

A. The following charts show the volatility and variability of both OSS and OSS margins over the last five years.[68]

[68] OSS Energy obtained from page 2 of 71 in response to 807 KAR 5:001Section 16(7)(c) provided with each Company's filing. OSS Margins obtained from Thompson Direct in KU at 25.


OSS Energy
GWh
1800
1600
1400
1200
1000
800
600
400
200
0
2010 Actual
2011 Actual
2012 Actual
2013 Actual
2014 2014Plan
2015 2014Plan
2016 2014Plan
2017 2014Plan


OSS Margins
Million
$12.0
$10.0
$8.0
$6.0
$4.0
$2.0
$0.0
2010 Actual
2011 Actual
2012 Actual
2013 Actual
2014 2014Plan
2015 2014Plan
2016 2014Plan
2017 2014Plan

Q. Is it possible to accurately and reliably project OSS margins?

A. No. OSS margins are more difficult to project than fuel and purchased power expenses.

Q. Does the volatility and the inability to accurately and reliably project OSS margins indicate the need for an OSS tracker as a means of truing-up the OSS margins reflected in the base revenue requirement?

A. Yes. Fuel and purchased power expenses, although included in the base revenue requirement on a projected basis, are trued-up to actual costs through the Fuel Adjustment Clause ("FAC"). That true-up through the FAC is necessary because these expenses are volatile, vary considerably from month to month and from year to year, and cannot be accurately or reliably projected. Those same reasons argue for a true-up of the OSS margins through the FAC.

Q. Has the Commission previously approved an OSS tracker in the FAC for another utility?

A. Yes. The Commission authorized an OSS tracker in the FAC for Kentucky Power Company, which is identified as the System Sales Clause. It is used to true-up the OSS margins included in Kentucky Power Company's base rates and to share the true-up differences between Kentucky Power Company and its customers.

Q. Should the Commission adopt a similar OSS tracker in the FAC for KU and LG&E?

A. Yes. First, an OSS tracker will address the volatility and variability in OSS, and the inability to accurately or precisely project these expenses in an equitable and fair manner so that neither the Companies nor their customers are unduly harmed or benefitted from factors largely beyond their control.

Second, both KU and LG&E are planning to retire old and inefficient generating units in 2015 and 2016. They expect to commence operation of the new and highly efficient Cane Run 7 natural gas combined cycle plant in the next few months. These events will affect the availability of energy and the cost to sell energy off-system.

Third, an OSS tracker will mitigate the effects of disagreements on methodologies used to allocate fuel and purchased power expense between native load and OSS.

Q. What sharing factors should the Commission adopt?

A. I recommend that the Commission adopt 90% to customers and 10% to the Companies sharing factors for the differences between actual OSS margins and the OSS margins included in the base revenue requirement. For example, if actual OSS margins are $1 million more than included in the base revenue requirement, then customers would be allocated $900,000 and shareholders would be allocated $100,000. On the other hand, if OSS margins are $1 million less, then customers would "pay" $900,000 and shareholders effectively would "pay" $100,000.

The 90%/10% sharing percentages are appropriate for the following reasons:

- OSS margins are subject to greater volatility and variability than fuel and purchased power expenses.

- OSS margins are directly related to fuel and purchased power expense and should be allocated entirely to customers in the same manner that fuel and purchased power expenses are allocated entirely to customers.

- Customers pay all the fixed costs of the generating units, the dispatch organization, including affiliate charges, and all related overheads.

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
6th day of March 2015.

Jessica K. I

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
JULY 31, 2015
CHEROKEE COUNTY, GEORGIA

BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES	**)**	
COMPANY FOR AN ADJUSTMENT OF	**)**	**CASE NO. 2014-00371**
ITS ELECTRIC RATES	**)**	

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND	**)**	
ELECTRIC COMPANY FOR AN	**)**	**CASE NO. 2014-00372**
ADJUSTMENT OF ITS ELECTRIC AND	**)**	
GAS RATES	**)**	

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

March 2015

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

Expert Testimony Appearances
of
Lane Kollen
as of March 2015

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.

**Expert Testimony Appearances
of
Lane Kollen
as of March 2015**

Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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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.
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.

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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.
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 (Rebuttal)	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.

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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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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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.

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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.

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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.
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.

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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.
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.

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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.
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, 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.

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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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

Expert Testimony Appearances of Lane Kollen as of March 2015

Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

**Expert Testimony Appearances
of
Lane Kollen
as of March 2015**

Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.
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 Recover Company LLC	Public Service Company of Colorado	Line extension policies and refunds.

Expert Testimony Appearances
of
Lane Kollen
as of March 2015

Date	Case	Jurisdict.	Party	Utility	Subject
01/15	14-0702-E-42T 14-0701-E-D	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.
02/15	9400-YO-100 Rebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Energy Corporation	WEC acquisition of Integrys Energy Group, Inc.

EXHIBIT ____ (LK-2)

Kentucky Utilities Company
Kentucky Jurisdictional Comparison of O&M Expenses
Forecast Test Year vs Base Year vs 2011 through 2014 Actual
For the Test Year Ended June 30, 2016
($ Milllions)

Account	Twelve Months Ended 12/31/2011	Twelve Months Ended 12/31/2012	Twelve Months Ended 12/31/2013	Twelve Months Ended 12/31/2014	Unadjusted BASE	Adjusted BASE	Unadjusted TEST	Adjusted TEST	Unadjusted BASE vs 2013 Variance	Unadjusted TEST vs 2013 Variance
Total Fuel and Non Fuel										
Production Operation-Steam	473	454	497	487	496	453	497	429	(1)	(0)
Production Maintenance-Steam	57	72	55	70	70	69	70	67	15	15
Production - Hydraulic	0	0	0	1	1	1	0	0	0	(0)
Production - Other Power	31	37	29	72	69	69	156	156	41	127
Production - Other Power Supply	97	93	71	96	92	92	70	70	22	(1)
Transmission - Operation	18	19	17	19	19	19	20	20	2	3
Transmission - Maintenance	6	7	7	10	7	7	6	6	0	(1)
Regional Market Expenses	1	1	(0)	-	(0)	-	-	-	(0)	0
Distribution-Operation	19	20	19	23	21	21	21	21	2	1
Distribution-Maintenance	25	32	31	32	35	35	32	32	4	0
Customer Accounts Expenses	27	27	26	32	32	32	32	32	6	6
Customer Service & Informational	14	15	20	18	19	2	20	2	(0)	1
Sales	0	0	0	0	0	0	0	0	0	0
Administrative & General	93	89	96	93	100	100	123	123	4	27
Total O&M - Fuel and Non Fuel	862	867	868	952	962	900	1,047	957	95	179
Less: Fuel Accounts										
501	425	406	443	430	437	405	420	374	(7)	(23)
509	0	0	0	0	0	0	0	0	(0)	(0)
547	28	34	26	69	67	67	140	140	41	114
555	95	92	69	95	92	92	68	68	22	(1)
Total Fuel Accounts	548	532	539	594	595	563	629	582	56	90
Total Non-Fuel O&M	313	335	329	359	368	337	419	375	39	90
3 Yr Average			326							
Total Non Fuel										
Production Operation-Steam	47	48	54	57	60	47	77	55	6	23
Production Maintenance-Steam	57	72	55	70	70	69	70	67	15	15
Production - Hydraulic	0	0	0	1	1	1	0	0	0	(0)
Production - Other Power	3	3	3	3	3	3	16	16	(0)	13
Production - Other Power Supply	2	2	2	2	1	1	2	2	(1)	0
Transmission - Operation	18	19	17	19	19	19	20	20	2	3
Transmission - Maintenance	6	7	7	10	7	7	6	6	0	(1)
Regional Market Expenses	1	1	(0)	-	(0)	-	-	-	(0)	0
Distribution-Operation	19	20	19	23	21	21	21	21	2	1
Distribution-Maintenance	25	32	31	32	35	35	32	32	4	0
Customer Accounts Expenses	27	27	26	32	32	32	32	32	6	6
Customer Service & Informational	14	15	20	18	19	2	20	2	(0)	1
Sales	0	0	0	0	0	0	0	0	0	0
Administrative & General	93	89	96	93	100	100	123	123	4	27
Total Non Fuel O&M	313	335	329	359	368	337	419	375	39	90

Source: 2011, 2012, 2013, and Unadjusted Base - Response to PSC 1-29(b) pages 4 through 6 for KY jurisdictional amounts. Schedule C-2.1 for Unadjusted Base (Matches Response Above), Adjusted Base, Unadjusted Test and Adjusted Test. 2014 - Response to AG-2-20.

Note: See Schedule D-2 for Adjustments to Base and Forecast Years - Removal of expenses related to FAC, DSM and ECR Mechanisms.

EXHIBIT ____ (LK-3)

Louisville Gas and Electric Company
Kentucky Jurisdictional Comparison of O&M Expenses - Electric Only - 100% KY
Forecast Test Year vs Base Year vs 2011 through 2014 Actual
For the Test Year Ended June 30, 2016
($ Millions)

Account	Twelve Months Ended 12/31/2011	Twelve Months Ended 12/31/2012	Twelve Months Ended 12/31/2013	Twelve Months Ended 12/31/2014	Unadjusted BASE	Adjusted BASE	Unadjusted TEST	Adjusted TEST	Unadjusted BASE vs 2013 Variance	Unadjusted TEST vs 2013 Variance
Total Fuel and Non Fuel										
Production Operation-Steam	400	423	420	435	426	422	353	344	6	(68)
Production Maintenance-Steam	58	60	60	57	58	58	52	47	(2)	(8)
Production - Hydraulic	2	2	2	2	2	2	2	2	(0)	0
Production - Other Power	19	23	17	42	38	38	66	66	20	49
Production - Other Power Supply	79	55	50	51	47	47	70	70	(3)	20
Transmission - Operation	14	13	11	12	12	12	12	12	0	0
Transmission - Maintenance	3	2	3	3	3	3	4	4	0	1
Regional Market Expenses	1	1	(0)	-	-	-	-	-	0	0
Distribution-Operation	18	19	19	21	21	21	20	20	3	1
Distribution-Maintenance	25	24	26	29	28	28	28	28	2	1
Customer Accounts Expenses	12	10	10	13	13	13	13	13	2	3
Customer Service & Informational	11	12	15	15	15	1	16	1	0	1
Sales	0	0	0	0	0	0	0	0	(0)	0
Administrative & General	83	79	87	82	88	88	91	91	1	5
Total O&M - Fuel and Non Fuel	724	723	722	762	751	733	727	699	30	5
Less: Fuel Accounts										
501	344	365	363	375	363	362	299	302	0	(64)
509	0	0	0	0	0	0	0	0	0	(0)
547	17	21	16	40	36	36	61	61	20	45
555	75	52	48	48	46	46	68	68	(2)	20
Total Fuel Accounts	436	438	427	464	445	444	429	431	18	2
Total Non-Fuel O&M	288	285	294	298	306	289	298	267	12	3
3 Yr Average			289							
Total Non Fuel										
Production Operation-Steam	56	58	57	60	63	60	53	42	6	(4)
Production Maintenance-Steam	58	60	60	57	58	58	52	47	(2)	(8)
Production - Hydraulic	2	2	2	2	2	2	2	2	(0)	0
Production - Other Power	2	2	1	2	2	2	5	5	1	4
Production - Other Power Supply	4	2	2	3	2	2	2	2	(1)	(0)
Transmission - Operation	14	13	11	12	12	12	12	12	0	0
Transmission - Maintenance	3	2	3	3	3	3	4	4	0	1
Regional Market Expenses	1	1	(0)	-	-	-	-	-	0	0
Distribution-Operation	18	19	19	21	21	21	20	20	3	1
Distribution-Maintenance	25	24	26	29	28	28	28	28	2	1
Customer Accounts Expenses	12	10	10	13	13	13	13	13	2	3
Customer Service & Informational	11	12	15	15	15	1	16	1	0	1
Sales	0	0	0	0	0	0	0	0	(0)	0
Administrative & General	83	79	87	82	88	88	91	91	1	5
Total Non Fuel O&M	288	285	294	298	306	289	298	267	12	3

Source: 2011, 2012, 2013, and Unadjusted Base - Response to PSC 1-29(b) pages 4 through 6 for KY jurisdictional amounts. Schedule C-2.1 for Unadjusted Base (Matches Response Above), Adjusted Base, Unadjusted Test and Adjusted Test. 2014 - Response to AG-2-15.

Note: See Schedule D-2 for Adjustments to Base and Forecast Years - Removal of expenses related to FAC, DSM and ECR Mechanisms.

EXHIBIT ____ (LK-4)

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's First Request for Information
Dated November 14, 2014

Case No. 2014-00371

Question No. 32

Responding Witness: Paula H. Pottinger, Ph.D.

Q-32. List separately the budgeted and actual numbers of full- and part-time employees by employee group, by month and by year, for the three most recent calendar years, the base period, and the forecasted test period.

A-32. See attached.

Kentucky Utilities Company
Case No. 2014-00371
Question No. 32
Headcount by Employee Type by Month - Budget

2011	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Exempt	636	636	637	637	637	637	639	639	639	640	640	640
Non-exempt	392	392	392	392	392	392	392	392	392	393	393	384
Union-Hourly	621	621	621	621	621	621	621	621	621	621	621	620
Part-time Other	18	18	18	18	19	20	20	20	19	19	19	19
Total	1,667	1,667	1,668	1,668	1,669	1,670	1,673	1,673	1,671	1,673	1,673	1,663

2012	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Exempt	656	659	659	661	663	667	678	678	680	679	683	686
Non-exempt	415	419	426	427	433	433	437	437	445	445	445	445
Union-Hourly	605	605	606	606	606	606	608	608	608	608	608	608
Part-time Other	-	-	-	-	-	-	-	-	-	-	-	-
Total	1,676	1,683	1,692	1,694	1,702	1,705	1,723	1,723	1,732	1,732	1,736	1,739

2013	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Exempt	677	679	680	681	681	682	684	684	685	685	685	685
Non-exempt	440	440	440	440	440	440	444	444	444	444	444	444
Union-Hourly	599	600	600	600	600	600	611	610	610	610	611	611
Part-time Other	38	38	38	38	40	40	40	40	38	38	38	38
Total	1,754	1,757	1,759	1,759	1,761	1,762	1,778	1,777	1,776	1,776	1,777	1,778

Base Year: March 2014 - Feb 2015	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB
Exempt	717	716	716	716	719	721	720	725	725	725	740	740
Non-exempt	450	453	453	453	457	457	457	448	448	448	457	457
Union-Hourly	613	619	619	619	619	619	619	610	610	609	609	609
Part-time Other	37	37	39	39	40	40	38	38	38	39	49	49
Total	1,816	1,825	1,826	1,827	1,834	1,836	1,834	1,820	1,820	1,820	1,855	1,855

Forecast Test Year July 2015-June 2016	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
Exempt	756	756	755	755	755	755	757	757	760	760	767	767
Non-exempt	462	462	462	462	462	462	464	464	464	465	456	456
Union-Hourly	607	607	607	607	607	607	607	607	607	618	594	594
Part-time Other	52	52	50	49	49	50	49	49	49	49	52	52
Total	1,876	1,876	1,874	1,873	1,873	1,874	1,877	1,877	1,879	1,891	1,868	1,868

Kentucky Utilities Company
Case No. 2014-00371
Question No. 32
Headcount by Employee Type by Month Actuals

2011	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Exempt	598	597	600	602	605	605	605	608	609	616	621	623
Non-exempt	374	373	373	370	384	388	386	388	393	400	403	409
Union-Hourly	600	599	599	598	596	593	595	595	593	593	593	591
Part-time Other	20	20	21	20	28	27	25	23	23	22	21	20
Total	1,592	1,590	1,593	1,590	1,613	1,614	1,611	1,615	1,618	1,632	1,638	1,642

2012	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Exempt	622	625	626	630	634	634	635	635	638	641	644	647
Non-exempt	411	419	420	419	424	422	421	421	417	414	418	415
Union-Hourly	592	589	590	591	586	581	579	579	580	585	586	587
Part-time Other	23	24	23	23	30	32	33	33	26	24	24	27
Total	1,648	1,657	1,659	1,663	1,675	1,669	1,667	1,667	1,661	1,665	1,673	1,677

2013	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Exempt	652	652	657	658	667	665	668	668	670	675	677	683
Non-exempt	410	421	421	418	414	413	413	418	424	433	431	431
Union-Hourly	594	588	589	594	595	599	601	606	604	602	600	599
Part-time Other	39	40	38	38	48	48	48	44	44	44	45	45
Total	1,696	1,701	1,704	1,708	1,724	1,725	1,730	1,736	1,743	1,754	1,753	1,757

Base Year: March 2014 - Feb 2015	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB
Exempt	697	702	706	709	709	707	710	707				
Non-exempt	448	443	442	440	439	444	442	450				
Union-Hourly	598	600	599	603	606	598	596	596				
Part-time Other	45	44	48	55	55	50	46	44				
Total	1,787	1,789	1,795	1,806	1,810	1,799	1,794	1,797				

Forecast Test Year July 2015-June 2016	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
Exempt												
Non-exempt												
Union-Hourly												
Part-time Other												
Total												

EXHIBIT ____ (LK-5)

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's First Request for Information
Dated November 14, 2014

Case No. 2014-00372

Question No. 32

Responding Witness: Paula H. Pottinger, Ph.D.

Q-32. List separately the budgeted and actual numbers of full- and part-time employees by employee group, by month and by year, for the three most recent calendar years, the base period, and the forecasted test period.

A-32. See attached.

LOUISVILLE GAS AND ELECTRIC COMPANY
Case No. 2014-00372
Question No. 32
Headcount by Employee Type by Month - Budget

2011	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Exempt	670	670	672	672	672	673	673	673	673	674	674	674
Non-exempt	234	234	234	234	234	234	234	234	234	234	234	224
Union-Hourly	719	719	720	720	721	721	721	721	721	721	722	722
Part-time Other	20	20	20	20	21	22	22	22	20	20	20	20
Total	1,643	1,643	1,646	1,646	1,647	1,649	1,650	1,650	1,649	1,650	1,651	1,641

2012	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Exempt	696	698	699	703	705	709	718	718	722	722	726	729
Non-exempt	226	229	236	236	241	241	241	241	247	247	248	248
Union-Hourly	706	706	709	715	714	715	716	716	718	718	718	718
Part-time Other	-	-	-	-	-	-	-	-	-	-	-	-
Total	1,628	1,634	1,643	1,654	1,660	1,665	1,676	1,676	1,687	1,688	1,692	1,695

2013	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Exempt	701	702	703	708	708	709	710	710	711	711	711	712
Non-exempt	238	238	238	238	238	238	239	239	239	239	239	239
Union-Hourly	720	720	721	723	722	723	724	724	725	727	727	724
Part-time Other	38	38	38	38	38	38	38	38	37	37	37	37
Total	1,697	1,698	1,700	1,706	1,706	1,708	1,712	1,712	1,713	1,715	1,715	1,712

Base Year: March 2014 - Feb 2015	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB
Exempt	737	737	737	740	743	744	746	747	747	747	767	768
Non-exempt	250	253	253	253	254	254	254	254	254	254	248	248
Union-Hourly	746	751	754	754	752	752	751	752	752	752	736	736
Part-time Other	39	39	40	40	40	41	40	40	40	40	43	43
Total	1,773	1,781	1,785	1,788	1,789	1,791	1,792	1,793	1,793	1,793	1,795	1,796

Forecast Test Year July 2015-June 2016	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
Exempt	758	757	757	757	757	757	757	758	761	759	762	763
Non-exempt	248	248	248	248	248	248	249	249	249	249	249	249
Union-Hourly	726	726	726	725	724	724	725	725	728	732	732	732
Part-time Other	42	42	41	40	40	40	40	40	40	40	42	42
Total	1,775	1,774	1,772	1,771	1,770	1,770	1,772	1,773	1,780	1,782	1,785	1,786

LOUISVILLE GAS AND ELECTRIC COMPANY
Case No. 2014-00372
Question No. 32
Headcount by Employee Type by Month Actuals

2011	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Exempt	635	634	637	637	637	636	638	637	637	647	650	651
Non-exempt	210	208	208	207	202	207	204	202	208	214	215	217
Union-Hourly	690	695	691	690	689	689	686	685	687	683	683	686
Part-time Other	23	24	24	24	32	35	33	27	25	24	23	20
Total	1,558	1,561	1,561	1,558	1,560	1,566	1,561	1,551	1,558	1,568	1,571	1,574

2012	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Exempt	655	657	660	666	673	672	672	672	676	676	679	683
Non-exempt	223	233	230	230	233	229	228	228	224	228	233	232
Union-Hourly	688	682	688	691	688	689	692	692	694	696	697	698
Part-time Other	27	28	27	26	37	38	40	40	33	30	29	27
Total	1,593	1,600	1,606	1,613	1,630	1,629	1,632	1,632	1,628	1,630	1,638	1,640

2013	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Exempt	676	676	679	682	688	689	691	694	696	703	704	709
Non-exempt	220	228	227	225	223	222	223	227	227	234	233	233
Union-Hourly	700	695	696	705	709	705	705	707	707	702	702	701
Part-time Other	47	48	46	45	56	56	55	49	50	48	48	41
Total	1,642	1,646	1,648	1,657	1,676	1,672	1,674	1,677	1,680	1,686	1,687	1,685

Base Year: March 2014 - Feb 2015	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB
Exempt	713	718	726	731	735	737	741	741				
Non-exempt	239	233	234	236	236	237	238	244				
Union-Hourly	709	706	717	718	720	717	711	708				
Part-time Other	46	44	46	47	54	51	40	40				
Total	1,707	1,701	1,724	1,733	1,745	1,741	1,730	1,733				

Forecast Test Year July 2015-June 2016	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
Exempt												
Non-exempt												
Union-Hourly												
Part-time Other												
Total												

EXHIBIT ____ (LK-6)

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 8, 2015

Question No. 10

Responding Witness: Russel A. Hudson

Q.1-10. Please refer to Mr. Thompson's and Mr. Blake's Direct Testimonies for Kentucky Utilities ("KU"), discussing workforce additions for KU/LG&E (the "Companies"). Refer further to their discussion of the workforce and the reasons for increases in the number of employees for each of the Companies' functional departments since the end of their last test year, April 1, 2012, as follows:

	Increase in Number	**% Increase**
Mr. Thompson:		
Pages 23-24 – Generation	50	5%
Page 31 – Transmission	19	14%
Page 53 – Distribution	53	8%
Page 62 – Customer Service	93	16%
Page 67 – Safety & Technical Training	8	Not Provided
Mr. Blake:		
Pages 9-10 – Information Technology	53	Not Provided
Page 10 – Administrative	17	Not Provided
Total	293	

a. Please confirm that the Companies' total net forecasted gain in positions is 293, excluding LG&E's gas operations, for the end of the projected test period compared to the number of employees as of April 1, 2012. If the total and the breakdown of projected net addition employees are different than those listed above, please describe the differences.

b. Please provide a breakdown of the Company's net forecasted gains by department listed above.

c. Please provide the number of positions that have already been added since April 1, 2012 for each of the departments listed above separately for the Company.
d. Please provide the estimated annual reduction in contractor expense that has occurred since April 1, 2012 for each of the departments listed above for the Company.

e. Please provide the estimated annual reduction in contractor expense for the Company that will occur between now and the end of the projected test year for each of the departments listed above.

f. Please provide the estimated increase in wages expense and related benefits expense for the Company that has occurred since April 1, 2012 related to the employees already added for each of the departments listed above separately.

g. Please provide the estimated increase in wages expense and related benefits expense for the Company that will occur between now and the end of the projected test year related to the employees projected to be added for each of the departments listed above separately.

h. For each of the net employee position additions enumerated in the list above, please provide a listing and description of each position. For the generation department, please also provide a description of the positions that were reduced or are expected to be reduced due to generating unit retirements.

i. For each of the departments listed above, please provide the number of net employee additions for the Company that has already occurred related to compliance with the NERC's current or proposed Critical Infrastructure Protection ("CIP") standards.

j. For each of the departments listed above, please provide the number of net employee additions for the Company that is estimated to occur between now and the end of the projected test year related to compliance with the NERC's current or proposed CIP standards.

A.1-10. a-j. See attached.

LG&E

	Generation	Transmission	Distribution	Customer Service	Safety & Technical Training	Information Technology	Administrative	Total
a.	Yes	Yes	Yes	Yes	Yes	Yes	Yes	
b.	(14)	6	41	30	3	25	8	99
c.	23	4	19	24	3	17	6	96
d.	$ -	$ 88,503	$ 1,379,941	$ 246,063	$ -	$ -	$ -	$ 1,714,507
e.	$ -	$ 158,896	$ 1,476,493	$ 14,750	$ -	$ -	$ -	$ 1,650,139
f.	$ 3,411,104	$ 457,805	$ 1,551,163	$ 1,762,370	$ 420,989	$ 2,314,392	$ 646,799	$ 10,564,622
g.	$ (5,664,780)	$ 240,039	$ 1,867,740	$ 450,122	$ 89,103	$ 899,514	$ 321,381	$ (1,796,881)
h.	See pages 2 through 6							
i.	-	1	-	2	-	4	-	7
j.	-	-	-	-	-	-	-	-

KU

	Generation	Transmission	Distribution	Customer Service	Safety & Technical Training	Information Technology	Administrative	Total
a.	Yes	Yes	Yes	Yes	Yes	Yes	Yes	
b.	64	13	12	63	5	28	9	194
c.	47	8	5	32	5	18	6	121
d.	$ -	$ 197,079	$ 440,947	$ 188,137	$ -	$ -	$ -	$ 826,163
e.	$ -	$ 353,842	$ 310,687	$ 576,535	$ -	$ -	$ -	$ 1,241,064
f.	$ 4,254,608	$ 1,019,464	$ 352,626	$ 2,044,008	$ 571,560	$ 2,503,270	$ 731,252	$ 11,476,788
g.	$ 3,538,548	$ 534,526	$ 715,234	$ 2,380,574	$ 120,971	$ 972,929	$ 363,341	$ 8,626,123
h.	See pages 2 through 6							-
i.	2	3	-	2	-	5	1	13
j.	-	-	-	-	-	1	-	1

Combined Utilities

	Generation	Transmission	Distribution	Customer Service	Safety & Technical Training	Information Technology	Administrative	Total
a.	Yes	Yes	Yes	Yes	Yes	Yes	Yes	
b.	50	19	53	93	8	53	17	293
c.	70	12	24	56	8	35	12	217
d.	$ -	$ 285,582	$ 1,820,888	$ 434,200	$ -	$ -	$ -	$ 2,540,670
e.	$ -	$ 512,738	$ 1,787,180	$ 591,285	$ -	$ -	$ -	$ 2,891,203
f.	$ 7,665,712	$ 1,477,269	$ 1,903,789	$ 3,806,378	$ 992,549	$ 4,817,662	$ 1,378,051	$ 22,041,410
g.	$ (2,126,232)	$ 774,565	$ 2,582,974	$ 2,830,696	$ 210,074	$ 1,872,443	$ 684,722	$ 6,829,242
h.	See pages 2 through 4							
i.	2	4	-	4	-	9	1	20
j.	-	-	-	-	-	1	-	1

Note: $ amounts are annual totals

Dept	Title	# of positions	Business Need
Generation	Chemical Engineer	3	Capital Projects
Generation	Civil Engineer	1	Capital Projects
Generation	Electrical Engineer	3	Capital Projects
Generation	Mechanical Engineer	1	Capital Projects
Generation	Mgr Major Capital Projects	1	Capital Projects
Generation	Project Coordinator	9	Capital Projects
Generation	Boiler Welding QA/QC Specialist	1	Core Skill Building/Knowledge Retention and Transfer
Generation	Buyer	2	Core Skill Building/Knowledge Retention and Transfer
Generation	CCS Administrative Coordinator	1	Core Skill Building/Knowledge Retention and Transfer
Generation	Civil Engineer	4	Core Skill Building/Knowledge Retention and Transfer
Generation	Commercial Ops Analyst	1	Core Skill Building/Knowledge Retention and Transfer
Generation	Compliance Engineer	1	Core Skill Building/Knowledge Retention and Transfer
Generation	Consumer Behavioral Analyst	1	Core Skill Building/Knowledge Retention and Transfer
Generation	Contract Administrator	3	Core Skill Building/Knowledge Retention and Transfer
Generation	Dept/Div Secretary	1	Core Skill Building/Knowledge Retention and Transfer
Generation	Dir. Fleet Maint Perfm & Reliab	1	Core Skill Building/Knowledge Retention and Transfer
Generation	Drafter	1	Core Skill Building/Knowledge Retention and Transfer
Generation	E&I Technician	5	Core Skill Building/Knowledge Retention and Transfer
Generation	Electrical Engineer	3	Core Skill Building/Knowledge Retention and Transfer
Generation	Engineer	2	Core Skill Building/Knowledge Retention and Transfer
Generation	Group Leader - Engineering	1	Core Skill Building/Knowledge Retention and Transfer
Generation	I&E Maintenance Planner	1	Core Skill Building/Knowledge Retention and Transfer
Generation	I&E Technician (SAM)	1	Core Skill Building/Knowledge Retention and Transfer
Generation	Lab Assistant	1	Core Skill Building/Knowledge Retention and Transfer
Generation	Lab Tech	1	Core Skill Building/Knowledge Retention and Transfer
Generation	Maintenance Tech	10	Core Skill Building/Knowledge Retention and Transfer
Generation	Material Handling Leader	1	Core Skill Building/Knowledge Retention and Transfer
Generation	Mechanic	1	Core Skill Building/Knowledge Retention and Transfer
Generation	Mechanical Engineer	10	Core Skill Building/Knowledge Retention and Transfer
Generation	OF Turbine Mechanic	2	Core Skill Building/Knowledge Retention and Transfer
Generation	Operator/Production Leader	9	Core Skill Building/Knowledge Retention and Transfer
Generation	Production Leader	1	Core Skill Building/Knowledge Retention and Transfer
Generation	R&D Scientist	5	Core Skill Building/Knowledge Retention and Transfer
Generation	Service Shop Coordinator	1	Core Skill Building/Knowledge Retention and Transfer
Generation	Sourcing Assistant	1	Core Skill Building/Knowledge Retention and Transfer
Generation	Sr. Labor Distribution Clerk/Timekeeper	2	Core Skill Building/Knowledge Retention and Transfer
Generation	Supervisor - Maintenance	1	Core Skill Building/Knowledge Retention and Transfer
Generation	Supply Mkt and Inv Analyst	1	Core Skill Building/Knowledge Retention and Transfer
Generation	Technician/Mntc Leader	4	Core Skill Building/Knowledge Retention and Transfer
Generation	Trainer	2	Core Skill Building/Knowledge Retention and Transfer
Generation	Turbine Specialist	2	Core Skill Building/Knowledge Retention and Transfer

Dept	Title	# of positions	Business Need
Generation	Warehouse Supervisor	1	Core Skill Building/Knowledge Retention and Transfer
Generation	Dir ES Business Information	-1	Corporate Reorganization
Generation	ES SR. Business Info Analyst	-1	Corporate Reorganization
Generation	Mgr Eng Serv Business Info	-1	Corporate Reorganization
Generation	Mgr. Ops Analysis	-1	Corporate Reorganization
Generation	Chief Operating Officer	-2	Corporate Reorganization
Generation	Green River transfer to metering	-11	Plant retirement
Generation	Manager- Tyrone	-1	Plant retirement
Generation	Green River retirement	-15	Plant retirement
Generation	Cane Run Retirement	-25	Plant retirement
Generation	CCR Supervisor	1	Regulatory Compliance
Generation	CIP Clerk	1	Regulatory Compliance
Generation	CIP Control Specialist	1	Regulatory Compliance
Generation	Control Specialist	1	Regulatory Compliance
Transmission	Cascade Analyst	1	Core Skill Building/Knowledge Retention and Transfer
Transmission	Drafting Technician	3	Core Skill Building/Knowledge Retention and Transfer
Transmission	Electrical Engineer	1	Core Skill Building/Knowledge Retention and Transfer
Transmission	Group Leader Substation Asset Mgmt	1	Core Skill Building/Knowledge Retention and Transfer
Transmission	Lines Inspector	3	Core Skill Building/Knowledge Retention and Transfer
Transmission	Mgr Transmission Substation, Eng., Constr., Maint	1	Core Skill Building/Knowledge Retention and Transfer
Transmission	Planning Engineer	2	Core Skill Building/Knowledge Retention and Transfer
Transmission	Planning Engineer	1	Regulatory Compliance
Transmission	Project Coordinator	1	Capital Projects
Transmission	Protection/Relay Technician	3	Core Skill Building/Knowledge Retention and Transfer
Transmission	Protection/Relay Technician	1	Capital Projects
Transmission	Protection Engineer	2	Regulatory Compliance
Transmission	Substation Inspector	2	Core Skill Building/Knowledge Retention and Transfer
Transmission	System Control Engineer	1	Regulatory Compliance
Transmission	System Control Engineer	1	Core Skill Building/Knowledge Retention and Transfer
Transmission	System Administrator	-4	Corporate Reorganization
Transmission	Safety Coordinator	-1	Corporate Reorganization
Transmission	Contract Coordinator	-1	Position not backfilled
Transmission	Cascade Administrator	1	Core Skill Building/Knowledge Retention and Transfer
Distribution	Computer Graphics Technician	2	Core Skill Building/Knowledge Retention and Transfer
Distribution	Distribution operations Assistant	1	Core Skill Building/Knowledge Retention and Transfer
Distribution	Electrical Apprentice	6	Core Skill Building/Knowledge Retention and Transfer
Distribution	Electrical Engineer	1	Core Skill Building/Knowledge Retention and Transfer
Distribution	Electrical Engineer (Danville)	1	Core Skill Building/Knowledge Retention and Transfer
Distribution	Electrical Engineer (Maysville)	1	Core Skill Building/Knowledge Retention and Transfer
Distribution	Electrical Engineer (SC&M)	1	Core Skill Building/Knowledge Retention and Transfer
Distribution	Electrical Engineer (System Planning)	1	Core Skill Building/Knowledge Retention and Transfer

Dept	Title	# of positions	Business Need
Distribution	Engineer (Reliability)	1	Core Skill Building/Knowledge Retention and Transfer
Distribution	Engineer Design Tech	1	Core Skill Building/Knowledge Retention and Transfer
Distribution	Engineer Design Tech (Danville)	1	Core Skill Building/Knowledge Retention and Transfer
Distribution	Facility Records Technician	3	Core Skill Building/Knowledge Retention and Transfer
Distribution	Field Coordinator	3	Core Skill Building/Knowledge Retention and Transfer
Distribution	Line Technician (Greenville)	1	Core Skill Building/Knowledge Retention and Transfer
Distribution	Line Technician (Louisville)	19	Core Skill Building/Knowledge Retention and Transfer
Distribution	Line Technician (Pineville)	1	Core Skill Building/Knowledge Retention and Transfer
Distribution	Line Technician (Richmond)	1	Core Skill Building/Knowledge Retention and Transfer
Distribution	Mechanic Helper	1	Core Skill Building/Knowledge Retention and Transfer
Distribution	Network Technician	6	Core Skill Building/Knowledge Retention and Transfer
Distribution	Project Coordinator	1	Core Skill Building/Knowledge Retention and Transfer
Distribution	Records Coordinator	2	Core Skill Building/Knowledge Retention and Transfer
Distribution	Restoration Coordinator	2	Core Skill Building/Knowledge Retention and Transfer
Distribution	SC&M Coordinator Analyst	1	Core Skill Building/Knowledge Retention and Transfer
Distribution	Utility Arborist	1	Core Skill Building/Knowledge Retention and Transfer
Distribution	Sr. Distribution operations assistant	-1	Core Skill Building/Knowledge Retention and Transfer
Distribution	Substation Tech	-1	Core Skill Building/Knowledge Retention and Transfer
Distribution	Sys Admin	-3	Core Skill Building/Knowledge Retention and Transfer
Distribution	Team Leader (SC&M)	-1	Core Skill Building/Knowledge Retention and Transfer
Customer Services	AMR Tech	1	Regulatory Compliance
Customer Services	Area Retail Operations Manager	1	Customer Service
Customer Services	Billing Analysis Associate	1	Core Skill Building/Knowledge Retention and Transfer
Customer Services	Billing Analysis Associate	3	Customer Service
Customer Services	Call Center Business Analyst	2	Customer Service
Customer Services	Call Center Performance Operations rep	1	Customer Service
Customer Services	Call Center QA Rep	1	Customer Service
Customer Services	Call Center Representative (Morganfield)	20	Customer Service
Customer Services	CIP Associate	1	Regulatory Compliance
Customer Services	CIP Coordinator	1	Regulatory Compliance
Customer Services	Corp Security Secretary	1	Core Skill Building/Knowledge Retention and Transfer
Customer Services	Customer Care Coach	2	Customer Service
Customer Services	Customer Relations Associate	1	Core Skill Building/Knowledge Retention & Transfer
Customer Services	Customer Representative - Business Office	7	Customer Service
Customer Services	Customer Representatives	7	Customer Service
Customer Services	Customer Representatives - Residential Call Center	6	Customer Service
Customer Services	Dept/Div Secretary	2	Core Skill Building/Knowledge Retention and Transfer
Customer Services	Electric Meter Tech	2	Core Skill Building/Knowledge Retention and Transfer
Customer Services	Electrical Engineer	1	Core Skill Building/Knowledge Retention and Transfer
Customer Services	Energy Efficiency	4	Customer Service
Customer Services	Gas Meter Mechanic Helper	1	Core Skill Building/Knowledge Retention and Transfer

Dept	Title	# of positions	Business Need
Customer Services	Gas Meter Shop Supervisor	1	Core Skill Building/Knowledge Retention and Transfer
Customer Services	Manager Facilities Construction and Space Utilization	1	Core Skill Building/Knowledge Retention and Transfer
Customer Services	Manager ROW	1	Core Skill Building/Knowledge Retention and Transfer
Customer Services	Manager, Facility Services	1	Core Skill Building/Knowledge Retention and Transfer
Customer Services	Meter Reader	11	Regulatory Compliance
Customer Services	Meter Reading Process Analyst	1	Core Skill Building/Knowledge Retention and Transfer
Customer Services	Program Manager	1	Customer Service
Customer Services	ROW Agent	7	Core Skill Building/Knowledge Retention and Transfer
Customer Services	Security Technical Assistant	1	Regulatory Compliance
Customer Services	Supervisor Corp Facilitiy Services	1	Core Skill Building/Knowledge Retention and Transfer
Customer Services	Supervisor Facility Operations	2	Core Skill Building/Knowledge Retention and Transfer
Customer Services	Meter Tech	-1	NA
Safety & Technical training	Safety Specialist	3	Core Skill Building/Knowledge Retention and Transfer
Safety & Technical training	Fire and Security Investigator	1	Corporate Reorganization
Safety & Technical training	Manager, ED and Transmission Safety	1	Corporate Reorganization
Safety & Technical training	Manager, Gas Distribution Safety	1	Core Skill Building/Knowledge Retention and Transfer
Safety & Technical training	Safety Coordinator	1	Corporate Reorganization
Safety & Technical training	Training Consultant	1	Core Skill Building/Knowledge Retention and Transfer
Safety & Technical training	Safety Metrics Analyst	1	Core Skill Building/Knowledge Retention and Transfer
Safety & Technical training	Health and Safety Coordinator	-1	Core Skill Building/Knowledge Retention and Transfer
Information Technology	Business Relationship Manager	4	Corporate Reorganization
Information Technology	Computer Operator Associate	1	Core Skill Building/Knowledge Retention and Transfer
Information Technology	Data Architect	1	Regulatory Compliance
Information Technology	Database Administrator	1	Capital Projects
Information Technology	Enterprise Architect	1	Core Skill Building/Knowledge Retention and Transfer
Information Technology	Group Leader - Energy Mgmt	1	Corporate Reorganization
Information Technology	IT Systems Engineer	5	Corporate Reorganization
Information Technology	IT Technical Specialist	1	Corporate Reorganization
Information Technology	Manager, IT Development & Support	1	Corporate Reorganization
Information Technology	Manager, IT Requirement	1	Corporate Reorganization
Information Technology	Manager, IT Security Compliance	1	Regulatory Compliance
Information Technology	Manager, IT Security Operations	1	Regulatory Compliance
Information Technology	Network Engineer	5	Regulatory Compliance
Information Technology	Network Engineer	2	Customer Service
Information Technology	Network Systems Engineer	2	Core Skill Building/Knowledge Retention and Transfer
Information Technology	Network Systems Engineer	2	Capital Projects
Information Technology	Programmer Analyst	1	Core Skill Building/Knowledge Retention and Transfer
Information Technology	Programmer Analyst	1	Regulatory Compliance
Information Technology	Programmer Analyst	5	Capital Projects
Information Technology	Programmer Analyst	4	Customer Service
Information Technology	Project Manager	2	Customer Service

Dept	Title	# of positions	Business Need
Information Technology	Service Desk Analyst	1	Customer Service
Information Technology	Tech Support Analyst	2	Core Skill Building/Knowledge Retention and Transfer
Information Technology	Telecom Engineer	1	Core Skill Building/Knowledge Retention and Transfer
Information Technology	Telecom Engineer	1	Capital Projects
Information Technology	Telecom Technician	1	Regulatory Compliance
Information Technology	Telecom Technician	1	Capital Projects
Information Technology	Workstation System Support	3	Customer Service
Administrative	Environmental Scientist	2	Regulatory Compliance
Administrative	Air Emissions Testing Coordinator	1	Regulatory Compliance
Administrative	Air Emissions Test Scientist	1	Regulatory Compliance
Administrative	Manager, Compliance	1	Regulatory Compliance
Administrative	Sr. Oracle Business Support Analyst	2	Corporate Reorganization
Administrative	Web Specialist	1	Customer Service
Administrative	Director, Media Relations	1	Customer Service
Administrative	Community Relations Specialist	1	Customer Service
Administrative	Rates Analyst	2	Core Skill Building/Knowledge Retention and Transfer
Administrative	Manager, Corporate Responsibility	1	Core Skill Building/Knowledge Retention and Transfer
Administrative	Assistant to VP External Affairs	1	Core Skill Building/Knowledge Retention and Transfer
Administrative	Corporate Events Specialist	1	Core Skill Building/Knowledge Retention and Transfer
Administrative	HRIS Analyst	1	Core Skill Building/Knowledge Retention and Transfer
Administrative	Sourcing Leader	1	Core Skill Building/Knowledge Retention and Transfer
		293	

EXHIBIT ____ (LK-7)

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to First Set of Data Requests of Kentucky Industrial Utility Customers, Inc. Dated January 8, 2015

Question No. 9

Responding Witness: Russel A. Hudson

Q.1-9. Please provide a breakdown of the total headcount by department and in total for the Company as of: i) December 31 for each of the years 2009-2013; ii) April 1, 2012; iii) the most current date available; iv) the end of the forecasted base year ended February 28, 2015; and v) the end of forecasted test year.

A.1-9. The Companies' workforce includes LG&E and KU Services Company ("LKS"), LG&E and KU employees. For actuals, LKS employees' labor costs are allocated to LG&E or KU consistent with the Cost Allocation Manual ("CAM"). For purposes of this response, we have included headcount for each Company. See attached.

KENTUCKY UTILITIES COMPANY

Breakdown of total headcount, by department as of i) 12/31/2009, 12/31/2010, 12/31/2011, 12/31/2012, 12/31/2013

KU Headcount

Business Area	12/31/2008	12/31/2009	12/31/2010	12/31/2011	12/31/2012	12/31/2013
CEO	-	-	-	-	-	-
CAO (exclusive of IT)	8	8	8	8	8	8
IT	23	10	10	10	11	11
CFO	-	2	3	2	3	3
COO department only	-	-	-	-	-	-
Generation / Project Engineering	406	402	406	399	387	406
Energy Supply & Analysis	-	-	-	-	-	-
Transmission	-	-	-	-	-	-
Electric Distribution	372	365	368	371	372	365
Gas Distribution	-	-	-	-	-	-
Customer Service	168	175	176	149	150	151
Safety / Technical Training	-	-	-	-	-	-
TOTAL	**977**	**962**	**971**	**939**	**931**	**944**

LGE Headcount

Business Area	12/31/2008	12/31/2009	12/31/2010	12/31/2011	12/31/2012	12/31/2013
CEO	-	-	-	-	-	-
CAO (exclusive of IT)	-	-	-	-	-	-
IT	10	9	10	10	10	10
CFO	-	3	3	3	3	3
COO department only	-	-	-	-	-	-
Generation / Project Engineering	460	461	476	476	485	495
Energy Supply & Analysis	-	-	-	-	-	-
Transmission	-	-	-	-	-	-
Electric Distribution	199	202	205	202	214	203
Gas Distribution	210	211	215	217	218	224
Customer Service	100	104	104	57	59	62
Safety / Technical Training	1	1	1	1	1	1
TOTAL	**980**	**991**	**1,014**	**966**	**990**	**998**

LKS Headcount

Business Area	12/31/2008	12/31/2009	12/31/2010	12/31/2011	12/31/2012	12/31/2013
CEO	2	2	3	3	3	3
CAO (exclusive of IT)	167	167	166	176	180	187
IT	217	220	222	230	249	265
CFO	131	136	135	132	133	131
COO department only	-	-	-	-	-	2
Generation / Project Engineering	90	88	94	93	112	118
Energy Supply & Analysis	75	76	67	68	65	60
Transmission	102	109	117	134	137	140
Electric Distribution	64	61	63	72	61	86
Gas Distribution	1	1	1	1	1	4
Customer Service	241	241	235	358	396	419
Safety / Technical Training	18	17	17	18	18	19
TOTAL	**1,108**	**1,118**	**1,120**	**1,285**	**1,355**	**1,434**

KENTUCKY UTILITIES COMPANY

Breakdown of total headcount, by department as of ii) April 1, 2012; iii) 12/31/2014; iv) base year ended 2/28/15; and v) forecast test year ending 6/30/16

KU Headcount

Business Area	3/31/2012	12/31/2014	2/28/2015	6/30/2016
CEO	-	-	-	-
CAO (exclusive of IT)	8	8	9	9
IT	11	11	11	11
CFO	3	3	3	3
COO department only	-	-	-	-
Generation / Project Engineering	397	408	424	397
Energy Supply & Analysis	-	-	-	-
Transmission	-	-	-	-
Electric Distribution	369	367	373	375
Gas Distribution	-	-	-	-
Customer Service	150	152	152	167
Safety / Technical Training	-	-	-	-
TOTAL	**938**	**949**	**972**	**962**

LGE Headcount

Business Area	3/31/2012	12/31/2014	2/28/2015	6/30/2016
CEO	-	-	-	-
CAO (exclusive of IT)	-	-	-	-
IT	10	10	10	10
CFO	3	3	3	3
COO department only	-	-	-	-
Generation / Project Engineering	476	498	512	489
Energy Supply & Analysis	-	-	-	-
Transmission	-	-	-	-
Electric Distribution	210	215	229	235
Gas Distribution	216	239	244	255
Customer Service	57	63	66	66
Safety / Technical Training	1	1	1	1
TOTAL	**973**	**1,029**	**1,065**	**1,059**

LKS Headcount

Business Area	3/31/2012	12/31/2014	2/28/2015	6/30/2016
CEO	3	2	2	2
CAO (exclusive of IT)	178	190	193	194
IT	237	272	290	290
CFO	136	136	136	136
COO department only	-	2	2	2
Generation / Project Engineering	94	135	127	135
Energy Supply & Analysis	67	63	64	63
Transmission	135	147	149	154
Electric Distribution	72	93	94	94
Gas Distribution	1	4	4	4
Customer Service	386	434	451	453
Safety / Technical Training	18	26	25	26
TOTAL	**1,327**	**1,504**	**1,537**	**1,553**

EXHIBIT ____ (LK-8)

Kentucky Utilities Company
KIUC Adjustment to Reduce Payroll and Related Benefits Expenses
For the Test Year Ended June 30, 2016
$ Millions

Sources: Responses to KIUC 2-20

Core Skill Building /Knowledge Retention and Transfer - Payroll Expense		8.086
Core Skill Building /Knowledge Retention and Transfer - Benefits and Taxes Expense		2.701
Core Skill Building /Knowledge Retention and Transfer - Total Expense		10.787
(Includes Transfers to Headquarters and Mill Creek - See AG 2-18)		
Green River Employees Transferred to Metering (11) - Payroll Expense		0.712
Green River Employees Transferred to Metering (11) - Benefits and Taxes Expense		0.267
Green River Employees Transferred to Metering (11) - Total Expense		0.979
Annual Estimated Decrease in Contractor Expense - Total KU		(2.067)
Core Skill Building /Knowledge Retention and Transfer - Number of Employees	202	
Green River Employees Transferred to Metering	11	
Total Employees Being Removed	213	
Total Employee Additions	293	
Percentage of Employee Additions Being Removed		72.7%
Annual Estimated Decrease in Contractor Expense Related to Employee Cost Removals		(1.503)
Total Reduction to Payroll and Benefits Expense Net of Contractor Expense Savings - Tot Co		(10.263)
KY Jurisdiction Allocation % - Forecast Test Year for Labor		90.10%
Total Reduction to Payroll and Benefits Expense Net of Contractor Expense Savings - KY Jur		(9.247)

EXHIBIT ____ (LK-9)

Louisville Gas and Electric Company
KIUC Adjustment to Reduce Payroll and Related Benefits Expenses
For the Test Year Ended June 30, 2016
$ Millions

Sources: Responses to KIUC 2-20

Core Skill Building /Knowledge Retention and Transfer - Payroll Expense		7.696
Core Skill Building /Knowledge Retention and Transfer - Benefits and Taxes Expense		2.722
Core Skill Building /Knowledge Retention and Transfer - Total Expense		10.418
(Includes Transfers to Headquarters and Mill Creek - See AG 2-18)		
Annual Estimated Decrease in Contractor Expense - Total KU		(3.365)
Core Skill Building /Knowledge Retention and Transfer - Number of Employees	202	
Green River Employees Transferred to Metering	11	
Total Employees Being Removed	213	
Total Employee Additions	293	
Percentage of Employee Additions Being Removed		72.7%
Annual Estimated Decrease in Contractor Expense Related to Employee Cost Removals		(2.446)
Total Reduction to Payroll and Benefits Expense Net of Contractor Expense Savings - Tot Co		(7.972)
Electric Only Allocation - Based on As-Filed Capitalization and Rate Base %		82.61%
Total Reduction to Payroll and Benefits Expense Net of Contractor Expense Savings - Electric		(6.586)

EXHIBIT ____ (LK-10)

Kentucky Utilities Company
KIUC Adjustment to Reduce Payroll and Related Benefits Expense for Employee Slippage
For the Test Year Ended June 30, 2016
$ Millions

Sources: Responses to Staff 1-32, AG 1-50, Sch C-2.1

	Budgeted	Actual	Difference	% Slippage
Employees at the End of 2011	1,663	1,642	21	1.26%
Employees at the End of 2012	1,739	1,677	62	3.57%
Employees at the End of 2013	1,778	1,757	21	1.18%
Average Employees	1,727	1,692	35	2.01%

	Amount
Test Year Budgeted Payroll Expense (Base Pay + Overtime and Other Pay + Incentive Compensation)	142.483
Less: Incentive Compensation Removed in Separate KIUC Adjustment	(6.474)
Test Year Budgeted Payroll Expense As Adjusted by KIUC	136.008
Test Year Budgeted Pensions and Benefits Expense	51.092
Less: Pension Expense Removed in Separate KIUC Adjustment	(11.795)
Test Year Budgeted Pensions and Benefits Expense As Adjusted by KIUC	39.297
Payroll Taxes Budgeted After Adjustment for Incentive Compensation	9.780
Test Year Payroll Expense and Pensions and Benefits Expense As Adjusted by KIUC	185.085
Average Employee Slippage Factor From Above	2.01%
KIUC Recommended Reduction in Payroll & Related Pensions and Benefits Expense	(3.716)
KY Jurisdiction Allocation % - Forecast Test Year for Labor	90.10%
KIUC Recommended Reduction in Payroll & Related Pensions and Benefits Expense	(3.348)

EXHIBIT ____ (LK-11)

Louisville Gas and Electric Company
KIUC Adjustment to Reduce Payroll and Related Benefits Expense for Employee Slippage
For the Test Year Ended June 30, 2016
$ Millions

Sources: Responses to Staff 1-32, AG 1-50, Sch C-2.1

	Budgeted	Actual	Difference	% Slippage
Employees at the End of 2011	1,641	1,574	67	4.08%
Employees at the End of 2012	1,695	1,640	55	3.24%
Employees at the End of 2013	1,712	1,685	27	1.58%
Average Employees	1,683	1,633	50	2.95%

	Amount
Test Year Budgeted Payroll Expense (Base Pay + Overtime and Other Pay + Incentive Compensation)	123.799
Electric Only Allocation - Based on As-Filed Capitalization and Rate Base %	82.61%
Test Year Budgeted Payroll Expense - Electric Only	102.270
Less: Incentive Compensation Removed in Separate KIUC Adjustment	(4.935)
Test Year Budgeted Payroll Expense As Adjusted by KIUC	97.335
Test Year Budgeted Pensions and Benefits Expense - Electric Only	32.172
Less: Pension Expense Removed in Separate KIUC Adjustment	(12.562)
Test Year Budgeted Pensions and Benefits Expense As Adjusted by KIUC	19.610
Payroll Taxes Budgeted After Adjustment for Incentive Compensation	8.005
Test Year Payroll Expense and Pensions and Benefits Expense As Adjusted by KIUC	124.950
Average Employee Slippage Factor From Above	2.95%
KIUC Recommended Reduction in Payroll & Related Pensions and Benefits Expense	(3.688)

EXHIBIT ____ (LK-12)

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to First Set of Data Requests of Kentucky Industrial Utility Customers, Inc. Dated January 8, 2015

Question No. 7

Responding Witness: Russel A. Hudson

Q.1-7. Please provide in an Excel spreadsheet the operating expenses by FERC O&M and A&G and other expense accounts by month from January 2013 through December 2017 for each generating unit that the Company has retired or plans to retire during that five-year period. Provide a copy of all assumptions, data, and calculations, including electronic spreadsheets with all formulas intact

A.1-7. See attachment being provided in Excel format. The Tyrone steam plant was retired on February 28, 2013. Continuing costs charged and forecasted attributable to Tyrone are related to ongoing costs to oversee maintenance of the structures at the site. The assumption included in base and test year periods is that the Green River Coal Steam plant will retire on April 16, 2016. O&M costs remaining in the plans past the retirement date are related to five employees remaining at the plant to provide supervisory oversight over maintenance of remaining structures and to monitor environmental needs.

Operating Expenses by FERC (excl Fuel)
KU Retired and/or Retiring Units
2013-2017
Case No. 2014-00371
KIUC Q. 1-7

		Actuals											
	FERC	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
Green River 3	408	461	629	402	58	191	282	98	607	388	1,021	301	309
	500	16,935	13,161	14,138	19,294	15,009	12,194	12,816	16,621	17,861	46,520	5,462	16,064
	501	29,759	26,358	31,880	30,186	36,487	28,985	25,550	28,418	33,034	27,241	26,019	34,795
	502	51,375	34,199	38,491	71,873	52,647	41,532	51,086	29,217	40,300	40,427	51,313	45,125
	505	17,091	19,124	25,886	64,808	37,431	24,813	47,252	14,063	34,196	22,915	50,937	25,196
	506	25,971	27,217	21,898	32,667	26,415	26,611	24,799	25,836	24,503	31,215	27,334	35,289
	509	2,702	2,836	1,570	2,452	2,278	1,682	2,257	1,011	1,568	1,634	2,840	6,033
	510	39,497	80,427	38,800	48,469	31,030	34,319	36,123	37,850	39,687	43,586	93,872	35,126
	511	41,111	30,029	25,889	15,483	21,993	39,707	23,663	31,107	22,046	31,900	30,029	21,283
	512	54,232	57,602	30,672	28,362	30,910	33,664	34,372	68,135	49,037	241,323	60,011	40,414
	513	19,926	5,924	67,624	16,825	12,052	69,355	20,774	8,799	11,750	26,146	12,923	15,125
	514	4,806	3,515	5,151	2,435	17,546	12,754	4,093	5,540	2,682	11,864	37,480	5,609
	925	57	71	50	8	20	29	14	57	46	(10)	(6)	(21)
	926	1,918	2,412	2,055	330	830	1,211	555	2,346	1,876	2,820	1,769	1,621
Total Green River 3		305,841	303,504	304,506	333,249	284,839	327,140	283,451	269,609	278,974	528,602	400,285	281,970
Green River 4	408	797	404	838	1,799	293	344	230	288	530	362	382	463
	500	25,402	19,742	48,769	538,391	(421,717)	18,291	19,224	24,931	26,792	30,608	23,967	24,096
	501	44,639	39,536	47,820	45,280	54,730	43,478	38,325	42,627	49,550	40,862	39,029	52,193
	502	91,293	99,220	100,037	47,026	103,306	96,001	88,105	109,524	88,458	112,141	94,347	110,080
	505	30,371	55,485	68,412	42,404	73,449	57,356	81,491	52,717	75,061	63,566	93,656	61,465
	506	38,957	40,826	32,847	49,001	39,622	39,917	37,199	38,755	36,755	46,823	41,001	52,934
	509	2,824	2,659	2,983	1,234	3,161	2,746	2,800	2,784	2,494	3,354	4,087	9,775
	510	59,984	43,178	58,200	72,703	46,545	51,478	54,185	56,776	59,530	65,379	140,808	52,690
	511	59,940	44,488	44,906	30,311	38,020	52,562	36,755	30,264	31,610	48,529	37,950	30,148
	512	165,594	347,894	169,884	442,243	485,897	93,208	96,842	85,512	133,339	89,174	54,635	164,388
	513	45,484	32,151	63,949	47,598	52,913	18,806	35,438	34,615	19,369	20,679	25,592	26,992
	514	7,521	5,677	8,247	4,773	42,979	19,131	6,139	8,858	4,023	17,979	56,220	8,413
	925	59	38	72	153	29	43	26	38	46	(7)	(6)	(34)
	926	2,004	1,276	2,906	6,289	1,201	1,761	1,067	1,559	1,897	1,928	1,663	2,646
Total Green River 4		574,867	732,573	649,869	1,329,206	520,428	495,122	497,825	489,246	529,455	541,376	613,331	596,248

Operating Expenses by FERC (excl Fuel)
KU Retired and/or Retiring Units
2013-2017
Case No. 2014-00371
KIUC Q. 1-7

		Actuals											
	FERC	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
Green River Common	408	28,751	25,259	29,296	31,056	26,961	26,268	27,595	27,570	27,088	29,808	27,387	27,649
	426	-	-	55	(5)	-	-	307	-	-	-	-	515
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	-	-	-	-	-	-	-	-	-	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	3,158	2,731	3,053	3,236	2,985	2,646	2,809	3,000	2,649	(455)	(412)	(1,591)
	926	106,791	93,820	125,595	135,377	122,810	109,078	115,343	123,739	108,756	131,046	116,256	124,348
Total Green River Common		138,700	121,810	157,999	169,663	152,757	137,992	146,055	154,309	138,493	160,399	143,231	150,922
Tyrone 3	408	1,092	1,097	2,295	1,754	1,781	1,803	1,379	1,947	1,033	1,601	1,278	876
	500	19,822	13,162	(2,674)	-	-	844	5,859	1,283	5,594	-	-	-
	501	3,054	8,700	42,000	19,109	6,694	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	506	21,619	28,637	35,934	35,336	24,918	32,312	43,723	41,571	37,299	16,624	23,756	14,424
	510	8,758	189	-	-	-	-	-	130	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	-	(1,007)	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	(1,551)	-	-	-	-	-	-
	925	148	148	314	243	237	249	179	269	136	(33)	(25)	(64)
	926	4,993	5,013	12,701	9,960	9,710	10,238	7,358	11,027	5,595	9,274	7,440	4,966
Total Tyrone 3		59,486	56,946	89,564	66,401	43,340	43,894	58,498	56,227	49,657	27,467	32,450	20,202
Tyrone Common	408	1,093	969	(195)	-	-	49	440	107	422	-	-	-
	426	-	-	-	-	-	-	12	-	116	-	243	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	925	151	132	(27)	-	-	7	61	14	58	-	-	-
	926	5,103	4,513	(913)	-	-	278	2,498	598	2,394	-	-	-
Total Tyrone Common		6,347	5,615	(1,136)	-	-	333	3,011	719	2,990	-	243	-

Operating Expenses by FERC (e:
KU Retired and/or Retiring Unit
2013-2017
Case No. 2014-00371
KIUC Q. 1-7

		Actuals											
	FERC	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
Green River 3	408	347	303	406	217	436	698	445	247	651	1,587	998	763
	500	27,000	18,742	20,380	20,948	18,187	16,115	16,509	18,980	19,156	25,735	23,521	28,064
	501	32,724	26,654	36,748	26,744	36,794	35,178	34,571	41,071	35,347	40,436	35,815	34,450
	502	48,555	36,474	46,168	55,623	43,957	58,480	59,634	48,579	48,977	35,571	52,031	54,243
	505	27,059	22,459	35,764	38,452	50,852	21,270	27,874	27,722	43,118	20,520	50,109	29,243
	506	27,696	26,776	31,160	34,974	29,949	27,704	28,957	58,822	33,397	83,069	43,737	34,334
	509	1,664	1,427	1,900	1,957	1,522	1,776	1,817	1,917	2,231	1,197	1,798	1,736
	510	32,905	28,124	32,523	31,748	29,357	32,600	37,861	34,095	36,312	46,165	19,947	42,772
	511	20,819	16,482	17,581	21,157	41,091	28,056	25,877	24,477	28,707	25,077	52,752	26,141
	512	51,299	34,911	74,217	42,531	106,198	88,082	89,493	99,165	119,570	659,645	54,057	156,535
	513	8,924	12,419	18,331	11,074	17,945	21,056	21,371	19,963	41,264	55,528	61,304	68,057
	514	1,996	1,194	1,805	8,789	2,744	20,726	3,723	3,423	5,565	6,466	11,046	(1,960)
	925	49	40	53	31	43	39	47	24	49	97	68	(102)
	926	1,788	1,480	1,642	963	1,329	1,078	1,312	682	1,368	3,159	1,896	2,235
Total Green River 3		282,824	227,486	318,679	295,209	380,404	352,858	349,492	379,168	415,712	1,004,252	409,079	476,511
Green River 4	408	524	623	370	1,015	822	719	643	562	395	346	353	661
	500	40,500	28,113	30,570	31,422	27,280	24,172	24,763	28,470	28,734	38,603	35,282	42,096
	501	49,085	39,982	55,122	40,116	55,191	52,767	51,857	61,607	53,021	60,654	53,723	51,675
	502	97,333	82,265	93,777	59,430	104,779	88,696	103,178	89,869	84,598	110,891	104,120	109,044
	505	54,243	50,655	72,985	41,084	121,216	32,261	48,228	51,284	74,477	63,969	100,274	58,787
	506	41,544	40,164	46,740	52,460	44,924	41,556	43,435	88,233	50,096	124,603	65,605	51,501
	509	2,584	2,369	3,076	1,838	2,675	2,197	2,500	2,820	3,137	2,623	2,674	2,133
	510	49,358	42,186	48,785	47,622	44,036	48,900	56,791	51,142	54,468	69,248	29,920	64,159
	511	30,480	22,139	26,763	29,689	122,875	77,602	43,847	38,554	41,520	37,688	78,254	34,972
	512	190,250	94,477	145,341	789,223	176,030	169,581	165,278	82,100	125,322	141,990	195,641	227,465
	513	12,358	20,560	10,008	41,153	48,038	32,067	26,573	42,184	26,685	48,295	43,688	73,200
	514	3,267	1,791	2,708	16,167	5,112	31,065	5,858	5,148	8,347	9,700	16,568	(2,941)
	925	53	60	48	94	61	71	52	55	36	26	38	(95)
	926	1,938	2,189	1,493	3,097	1,911	1,963	1,450	1,696	1,011	723	1,061	2,084
Total Green River 4		573,517	427,572	537,786	1,154,410	754,951	603,617	574,454	543,725	551,848	709,358	727,202	714,740

Operating Expenses by FERC (e:
KU Retired and/or Retiring Unit
2013-2017
Case No. 2014-00371
KIUC Q. 1-7

		Actuals											
	FERC	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
Green River Common	408	26,388	24,479	27,237	26,334	25,766	22,916	24,372	24,260	24,076	28,333	23,545	43,498
	426	-	-	-	-	-	4,900	721	(13)	-	250	-	4,253
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	-	-	-	-	-	-	-	-	-	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	2,974	2,874	2,883	2,716	2,671	1,972	2,031	2,227	2,092	2,260	1,874	(4,916)
	926	107,870	102,179	90,239	84,802	83,293	55,135	56,548	62,047	58,544	63,135	52,289	107,618
Total Green River Common		137,232	129,532	120,358	113,852	111,729	84,924	83,671	88,520	84,712	93,978	77,709	150,453
Tyrone 3	408	(6)	13	13	13	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	9,216	6,036	100	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	187	-	-	-
	506	28,393	25,304	27,899	28,439	30,223	35,748	29,782	71,291	25,983	19,671	14,498	7,859
	510	-	-	7,685	-	-	404	-	-	-	-	4,730	-
	511	-	195	(195)	-	-	-	-	-	-	-	-	-
	512	-	-	-	-	1,363	1,318	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	12	2	2	2	-	-	-	-	-	-	-	-
	926	(140)	68	59	59	864	-	-	-	-	-	-	-
Total Tyrone 3		28,259	25,582	35,463	28,513	32,450	37,470	29,782	80,507	32,206	19,771	19,228	7,859
Tyrone Common	408	1,410	1,516	1,467	1,534	1,639	1,812	1,211	1,125	1,138	622	327	615
	426	-	-	-	-	-	-	-	-	-	-	419	341
	506	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	925	176	212	205	218	233	211	138	133	127	72	39	(91)
	926	7,427	7,805	6,397	6,780	7,261	5,881	3,843	3,693	3,592	2,040	1,073	1,993
Total Tyrone Common		9,013	9,533	8,069	8,531	9,134	7,904	5,192	4,950	4,857	2,734	1,857	2,859

Operating Expenses by FERC (e:
KU Retired and/or Retiring Unit
2013-2017
Case No. 2014-00371
KIUC Q. 1-7

		Budget											
	FERC	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
Green River 3	408	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	-	-	-	-	-	-	-	-	300,000	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
Total Green River 3		-	-	-	-	-	-	-	-	-	300,000	-	-
Green River 4	408	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	-	1,000,000	-	-	-	-	-	-	-	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
Total Green River 4		-	-	1,000,000	-	-	-	-	-	-	-	-	-

Operating Expenses by FERC (e:
KU Retired and/or Retiring Unit
2013-2017
Case No. 2014-00371
KIUC Q. 1-7

	FERC	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
		Budget											
Green River Common	408	30,438	26,864	29,975	28,398	28,264	29,154	29,943	29,887	30,478	31,447	26,783	28,146
	426	4,080	-	-	1,020	-	-	1,020	-	-	4,080	-	1,020
	500	19,588	18,385	19,937	19,317	19,317	19,937	20,557	19,937	19,937	20,557	18,698	19,937
	501	105,599	102,169	107,993	152,599	152,827	156,564	154,221	229,512	158,258	155,966	101,441	105,306
	502	170,798	158,226	168,645	163,366	162,270	165,042	132,226	132,709	135,038	138,034	121,855	125,445
	505	118,068	97,850	114,837	105,990	104,819	109,403	86,498	87,147	90,776	95,767	69,797	76,215
	506	41,771	53,935	41,771	41,411	41,771	41,411	41,771	41,771	41,411	41,771	41,411	41,771
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	6,335	6,335	6,335	6,335	6,335	6,335	6,335	6,335	6,335	6,335	6,335	6,335
	510	82,749	76,379	83,197	79,841	79,674	82,001	107,120	106,417	106,998	113,703	102,654	104,234
	511	62,372	62,372	65,131	62,372	62,372	95,731	84,572	84,572	107,531	84,572	84,572	87,331
	512	38,992	38,992	222,592	54,292	55,822	66,992	79,192	79,192	259,732	111,322	79,192	79,192
	513	49,621	49,622	51,661	64,922	49,621	73,809	77,920	77,920	79,961	77,920	88,120	79,962
	514	71,891	71,891	85,846	81,188	75,906	89,861	24,740	24,740	38,695	24,740	20,725	34,680
	925	4,163	3,674	4,100	3,884	3,866	3,987	4,095	4,088	4,169	4,301	3,663	3,850
	926	167,892	148,177	165,337	156,639	155,902	160,806	165,160	164,849	168,111	173,455	147,729	155,248
Total Green River Common		974,357	914,871	1,167,356	1,021,575	998,767	1,101,033	1,015,370	1,089,077	1,247,431	1,083,971	912,976	948,671
Tyrone 3	408	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
Total Tyrone 3		-	-	-	-	-	-	-	-	-	-	-	-
Tyrone Common	408	351	312	347	320	314	323	336	339	346	354	301	308
	426	-	-	-	-	3,000	3,000	3,000	3,000	3,000	-	-	-
	506	15,012	13,927	14,956	14,425	14,541	14,462	14,819	14,855	14,748	15,051	14,179	14,472
	510	-	-	-	-	-	-	-	510	510	6,120	4,080	1,020
	925	48	43	47	44	43	44	46	46	47	48	41	42
	926	1,936	1,721	1,912	1,767	1,731	1,783	1,852	1,868	1,907	1,953	1,659	1,702
Total Tyrone Common		17,346	16,002	17,261	16,556	19,629	19,612	20,053	20,618	20,557	23,527	20,260	17,545

Operating Expenses by FERC (e:
KU Retired and/or Retiring Unit
2013-2017
Case No. 2014-00371
KIUC Q. 1-7

		Budget											
	FERC	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
Green River 3	408	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	-	-	-	-	-	-	-	-	-	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
Total Green River 3		-	-	-	-	-	-	-	-	-	-	-	-
Green River 4	408	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	300,000	-	-	-	-	-	-	-	-	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
Total Green River 4		-	300,000	-	-	-	-	-	-	-	-	-	-

Operating Expenses by FERC (e:
KU Retired and/or Retiring Unit
2013-2017
Case No. 2014-00371
KIUC Q. 1-7

		Budget											
	FERC	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
Green River Common	408	30,408	29,643	33,191	27,870	3,541	3,467	1,567	1,825	1,666	1,650	1,567	1,506
	426	-	-	-	1,200	-	-	-	-	-	-	-	-
	500	20,349	20,349	22,032	20,059	1,869,731	10,994	5,208	5,489	5,301	5,301	5,208	5,208
	501	135,525	135,392	166,244	129,541	-	10,000	-	-	-	-	-	-
	502	134,588	131,762	143,215	127,828	5,399	5,547	5,227	6,069	5,517	5,517	5,227	4,995
	505	87,659	82,085	102,669	73,807	10,248	10,396	10,076	10,918	10,366	10,366	10,076	9,844
	506	42,487	55,258	42,487	42,119	55,166	29,798	30,166	30,166	29,798	30,166	29,798	30,166
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	6,462	6,462	6,462	6,462	267	267	267	267	267	267	267	267
	510	108,170	107,516	115,136	103,062	25,868	24,582	6,911	8,950	8,243	12,465	10,032	7,110
	511	84,623	84,623	87,437	84,623	70,000	2,814	-	-	2,814	-	-	2,814
	512	79,691	79,691	259,691	104,893	10,000	16,500	-	-	-	16,500	-	-
	513	78,070	78,071	80,151	93,676	-	-	-	-	-	-	-	-
	514	14,836	14,836	16,065	24,319	200,000	206,000	200,000	200,000	200,000	200,000	200,000	200,000
	925	4,159	4,054	4,540	3,812	484	474	214	250	228	226	214	206
	926	167,724	163,508	183,078	153,727	19,532	19,125	8,645	10,067	9,187	9,100	8,645	8,305
Total Green River Common		994,751	993,251	1,262,398	996,998	2,270,236	339,963	268,280	274,000	273,387	291,559	271,033	270,420
Tyrone 3	408	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
Total Tyrone 3		-	-	-	-	-	-	-	-	-	-	-	-
Tyrone Common	408	343	339	375	311	341	332	308	386	356	346	328	298
	426	-	-	-	-	3,000	3,000	3,000	3,000	3,000	-	-	-
	506	15,136	14,689	15,540	14,529	15,112	14,796	14,698	15,678	15,094	15,169	14,746	14,564
	510	-	-	-	-	-	-	-	520	520	6,242	4,162	1,040
	925	47	46	51	43	47	45	42	53	49	47	45	41
	926	1,892	1,871	2,067	1,716	1,882	1,832	1,702	2,128	1,961	1,906	1,810	1,644
Total Tyrone Common		17,417	16,946	18,033	16,599	20,382	20,005	19,750	21,764	20,979	23,710	21,090	17,587

Operating Expenses by FERC (e:
KU Retired and/or Retiring Unit
2013-2017
Case No. 2014-00371
KIUC Q. 1-7

		Budget											
	FERC	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
Green River 3	408	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	-	-	-	-	-	-	-	-	-	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
Total Green River 3		-	-	-	-	-	-	-	-	-	-	-	-
Green River 4	408	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	-	-	-	-	-	-	-	-	-	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
Total Green River 4		-	-	-	-	-	-	-	-	-	-	-	-

Operating Expenses by FERC (e:
KU Retired and/or Retiring Unit
2013-2017
Case No. 2014-00371
KIUC Q. 1-7

	FERC	Budget											
		Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
Green River Common	408	1,355	1,212	1,448	1,157	1,448	1,375	1,303	1,520	1,303	1,448	1,303	2,829
	426	-	-	-	-	-	-	-	-	-	-	-	-
	500	5,316	5,093	5,427	4,982	5,426	5,316	5,204	5,538	5,204	5,426	5,204	5,093
	501	-	-	-	2,500	2,500	2,500	2,500	-	-	-	-	-
	502	4,282	6,319	4,649	3,696	7,149	4,411	4,173	7,387	4,173	4,649	6,673	3,934
	505	8,615	8,152	8,982	8,029	8,982	8,744	8,506	9,220	8,506	8,982	8,506	8,267
	506	15,810	15,058	15,810	15,436	15,810	15,436	15,810	15,811	15,436	15,811	15,436	15,811
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	278	278	278	278	278	278	278	278	278	278	278	278
	510	6,518	5,853	6,850	5,517	6,849	6,518	6,185	7,978	6,981	12,155	9,369	26,682
	511	-	-	2,927	-	-	22,927	-	-	2,927	-	-	2,927
	512	-	-	-	-	-	21,500	-	-	-	21,500	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	6,000	-	6,000	-	-	-	-	-	-
	925	185	166	198	158	198	188	178	208	178	198	178	387
	926	7,473	6,686	7,985	6,384	7,985	7,586	7,185	8,384	7,185	7,985	7,185	15,602
Total Green River Common		49,832	48,818	54,554	54,137	56,625	102,778	51,322	56,324	52,170	78,432	54,131	81,809
Tyrone 3	408	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
Total Tyrone 3		-	-	-	-	-	-	-	-	-	-	-	-
Tyrone Common	408	372	330	386	301	369	341	317	396	346	374	337	286
	426	-	-	-	-	3,000	3,000	3,000	3,000	3,000	-	-	-
	506	15,719	14,786	15,894	14,614	15,685	15,123	15,018	16,029	15,189	15,748	15,070	14,632
	510	-	-	-	-	-	-	-	531	531	6,367	4,245	1,061
	925	51	45	53	41	51	47	43	54	47	51	46	39
	926	2,051	1,823	2,128	1,661	2,037	1,882	1,747	2,187	1,911	2,064	1,859	1,580
Total Tyrone Common		18,193	16,984	18,461	16,618	21,142	20,393	20,126	22,197	21,025	24,605	21,557	17,599

EXHIBIT ____ (LK-13)

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to First Set of Data Requests of Kentucky Industrial Utility Customers, Inc. Dated January 8, 2015

Question No. 8

Responding Witness: Russel A. Hudson

Q.1-8. Please provide in an Excel spreadsheet the FTE staffing levels and related payroll (direct and burdens) by month from January 2013 through December 2017 at each generating unit/plant that the Company has retired or plans to retire during that five-year period.

A.1-8. See the response to Question No. 7. See tab labeled "Q.8 KU labor."

Retired and/or Retiring Units
Staffing Levels and Payroll
2013-2017
Case No. 2014-00371
KIUC Q. 1-8

	Actuals											
	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
Labor $												
Green River 3	75,205	67,995	78,066	83,225	63,805	61,807	60,454	76,467	66,414	85,283	63,596	67,734
Green River 4	320,560	279,044	330,267	348,338	299,853	289,284	303,840	302,148	299,413	325,086	301,835	341,149
Green River Common	138,700	121,810	157,944	169,668	152,757	137,992	145,748	154,309	138,493	160,399	143,231	150,406
Green River Total	534,464	468,849	566,277	601,232	516,414	489,083	510,042	532,925	504,319	570,768	508,662	559,290
Tyrone 3	41,585	32,308	41,770	34,098	34,079	35,665	31,718	39,180	25,033	31,023	24,650	17,837
Tyrone Common	6,347	5,615	(1,136)	-	-	333	2,999	719	2,874	-	-	-
Total Tyrone*	47,932	37,923	40,634	34,098	34,079	35,998	34,717	39,899	27,907	31,023	24,650	17,837
Staffing Levels**												
Green River	41	41	41	41	41	41	41	41	41	41	41	41
Tyrone	3	3	3	3	3	3	3	3	3	3	3	3

* Beginning in January 2014, there are no employees physically located at Tyrone. However, there are minimal labor costs originating from the EW Brown plant to maintain the retired plar

** Staffing levels are not divided by unit

Retired and/or Retirii
Staffing Levels and Pa
2013-2017
Case No. 2014-00371
KIUC Q. 1-8

	Actuals											
	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
Labor $												
Green River 3	72,580	66,828	74,423	70,851	67,529	69,972	74,251	68,947	75,554	107,442	75,807	83,970
Green River 4	314,877	295,793	326,205	317,142	316,010	304,008	316,705	318,425	310,332	349,339	300,342	370,471
Green River Common	137,232	129,532	120,358	113,852	111,729	80,024	82,951	88,534	84,712	93,728	77,709	146,200
Green River Total	524,689	492,153	520,986	501,845	495,268	454,004	473,907	475,906	470,598	550,509	453,858	600,640
Tyrone 3	18,935	20,696	20,026	20,971	23,014	26,586	17,715	16,534	16,578	9,124	4,805	6,044
Tyrone Common	9,013	9,533	8,069	8,531	9,134	7,904	5,192	4,950	4,857	2,734	1,439	2,518
Total Tyrone*	27,948	30,229	28,096	29,502	32,148	34,489	22,907	21,485	21,434	11,858	6,244	8,562
Staffing Levels**												
Green River	40	40	40	40	40	40	40	40	40	40	40	40
Tyrone	0	0	0	0	0	0	0	0	0	0	0	0

* Beginning in January 2014t.
** Staffing levels are not di

Retired and/or Retiri
Staffing Levels and Pa
2013-2017
Case No. 2014-00371
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	Budget											
	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
Labor $												
Green River 3	-	-	-	-	-	-	-	-	-	-	-	-
Green River 4	-	-	-	-	-	-	-	-	-	-	-	-
Green River Common	578,022	510,451	569,687	538,762	535,667	552,561	568,109	567,071	578,230	596,420	507,850	533,099
Green River Total	578,022	510,451	569,687	538,762	535,667	552,561	568,109	567,071	578,230	596,420	507,850	533,099
Tyrone 3	-	-	-	-	-	-	-	-	-	-	-	-
Tyrone Common	6,791	6,037	6,706	6,198	6,074	6,254	6,498	6,553	6,689	6,852	5,822	5,970
Total Tyrone*	6,791	6,037	6,706	6,198	6,074	6,254	6,498	6,553	6,689	6,852	5,822	5,970
Staffing Levels**												
Green River	40	40	40	40	40	40	40	40	40	40	40	40
Tyrone	0	0	0	0	0	0	0	0	0	0	0	0

* Beginning in January 201
** Staffing levels are not di

Retired and/or Retiri
Staffing Levels and Pa
2013-2017
Case No. 2014-00371
KIUC Q. 1-8

	Budget											
	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
Labor $												
Green River 3	-	-	-	-	-	-	-	-	-	-	-	-
Green River 4	-	-	-	-	-	-	-	-	-	-	-	-
Green River Common	577,663	563,391	631,065	528,787	1,926,886	66,667	29,930	34,870	31,810	31,507	29,930	28,736
Green River Total	577,663	563,391	631,065	528,787	1,926,886	66,667	29,930	34,870	31,810	31,507	29,930	28,736
Tyrone 3	-	-	-	-	-	-	-	-	-	-	-	-
Tyrone Common	6,637	6,564	7,253	6,020	6,602	6,426	5,970	7,464	6,880	6,688	6,349	5,767
Total Tyrone*	6,637	6,564	7,253	6,020	6,602	6,426	5,970	7,464	6,880	6,688	6,349	5,767
Staffing Levels**												
Green River	40	40	40	40	5	5	5	5	5	5	5	5
Tyrone	0	0	0	0	0	0	0	0	0	0	0	0

* Beginning in January 201
** Staffing levels are not di

Retired and/or Retiri
Staffing Levels and Pa
2013-2017
Case No. 2014-00371
KIUC Q. 1-8

	Budget											
	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
Labor $												
Green River 3	-	-	-	-	-	-	-	-	-	-	-	-
Green River 4	-	-	-	-	-	-	-	-	-	-	-	-
Green River Common	26,220	23,458	28,015	22,399	28,013	26,613	25,210	29,415	25,210	28,013	25,210	54,739
Green River Total	26,220	23,458	28,015	22,399	28,013	26,613	25,210	29,415	25,210	28,013	25,210	54,739
Tyrone 3	-	-	-	-	-	-	-	-	-	-	-	-
Tyrone Common	7,198	6,395	7,466	5,828	7,147	6,603	6,131	7,672	6,704	7,242	6,523	5,542
Total Tyrone*	7,198	6,395	7,466	5,828	7,147	6,603	6,131	7,672	6,704	7,242	6,523	5,542
Staffing Levels**												
Green River	5	5	5	5	5	5	5	5	5	5	5	5
Tyrone	0	0	0	0	0	0	0	0	0	0	0	0

* Beginning in January 201
** Staffing levels are not di

EXHIBIT ____ (LK-14)

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2014-00372

Response to First Set of Data Requests of Kentucky Industrial Utility Customers, Inc. Dated January 8, 2015

Question No. 7

Responding Witness: Russel A. Hudson

Q.1-7. Please provide in an Excel spreadsheet the operating expenses by FERC O&M and A&G and other expense accounts by month from January 2013 through December 2017 for each generating unit that the Company has retired or plans to retire during that five-year period. Provide a copy of all assumptions, data, and calculations, including electronic spreadsheets with all formulas intact

A.1-7. See attachment being provided in Excel format. The assumption included in base and test year periods is that the Cane Run Coal Steam plant will retire on April 30, 2015. O&M costs remaining in the plans past the retirement date is for maintenance of remaining structures at the plant to keep it secure and in a "dry" state.

Operating Expenses by FERC (excl Fuel)
LG&E Retired and/or Retiring Units
2013-2017
Case No. 2014-00371
KIUC Q. 1-7

		Actuals											
	FERC	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
Cane Run 4	408	2,423	3,226	2,618	2,301	2,256	3,735	3,744	2,683	2,132	3,115	2,118	2,926
	500	15,030	16,862	21,133	19,447	20,419	17,898	21,156	20,650	20,075	23,369	16,222	20,933
	501	88,319	139,012	100,655	115,676	79,807	142,737	115,524	126,688	148,808	111,184	134,047	98,037
	502	451,082	301,325	382,734	560,855	403,769	107,196	(16,095)	428,451	363,913	432,222	431,503	461,938
	505	2,547	2,246	980	3,505	3,019	236	0	1,239	2,169	1,928	1,289	1,296
	506	128,180	137,655	124,879	102,069	124,205	127,720	131,056	122,419	131,113	122,220	120,740	133,013
	507	-	-	230	230	230	230	230	230	230	230	230	230
	509	1,430	3,459	74	52	75	61	54	77	74	67	3,582	4,725
	510	24,987	21,278	29,911	31,184	25,008	26,179	24,049	31,246	34,307	69,404	11,885	10,945
	511	16,898	28,186	13,678	456	14,751	8,824	13,156	11,568	9,580	6,994	12,993	13,713
	512	60,504	177,251	134,905	171,114	166,025	122,296	274,304	121,348	76,284	329,653	29,223	126,336
	513	70,035	13,078	20,750	118,046	26,964	31,102	36,588	103,584	111,368	37,094	85,261	62,062
	514	13,057	19,338	12,269	13,015	12,062	10,097	13,191	14,979	10,558	12,776	15,077	32,248
	925	295	316	319	205	250	514	479	310	257	(275)	(162)	144
	926	8,956	9,618	12,915	8,329	10,135	21,417	19,452	12,600	10,420	12,259	7,178	10,081
Total Cane Run 4		883,743	872,851	858,050	1,146,482	888,974	620,242	636,888	998,071	921,286	1,162,240	871,185	978,627
Cane Run 5	408	2,604	2,379	3,219	8,940	2,835	2,122	2,368	1,984	1,240	4,613	2,941	1,902
	426	-	-	-	-	-	-	-	-	-	-	-	-
	500	16,700	18,736	23,482	21,608	22,688	19,887	23,507	22,944	22,305	25,966	18,025	23,259
	501	81,473	51,861	94,261	82,733	85,273	100,818	51,313	63,820	63,161	102,197	107,514	143,476
	502	504,212	406,849	410,214	124,781	413,060	527,731	520,294	464,284	493,894	414,771	410,522	450,794
	505	2,946	3,107	1,081	535	3,156	1,837	2,764	1,397	3,044	1,970	1,251	1,311
	506	145,368	151,385	133,491	126,244	148,102	139,857	142,327	134,602	145,603	136,361	158,483	159,066
	507	-	-	255	255	255	255	255	255	255	255	255	255
	509	2	65	83	56	83	70	62	87	84	74	3,981	5,249
	510	27,763	23,642	33,235	34,649	27,787	29,088	26,721	34,717	38,119	77,116	13,206	12,162
	511	33,936	31,994	21,839	11,156	32,875	30,434	17,257	31,332	10,411	14,330	19,463	23,982
	512	147,069	132,791	289,403	1,018,291	69,961	113,622	99,327	103,129	43,650	321,916	186,055	195,208
	513	62,916	101,142	32,049	153,722	117,509	53,445	47,477	26,750	13,551	33,497	43,498	96,266
	514	14,508	21,487	13,632	14,461	13,402	11,219	14,657	16,643	11,731	14,195	16,753	35,831
	925	343	340	353	724	410	278	357	292	169	(358)	(274)	125
	926	10,425	10,331	14,330	29,372	16,648	11,286	14,489	11,837	6,879	15,824	12,102	8,007
Total Cane Run 5		1,050,266	956,108	1,070,928	1,627,526	954,044	1,041,950	963,175	914,072	854,096	1,162,727	993,774	1,156,892

Operating Expenses by FERC (excl Fuel)
LG&E Retired and/or Retiring Units
2013-2017
Case No. 2014-00371
KIUC Q. 1-7

		Actuals											
	FERC	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
Cane Run 6	408	4,606	3,057	4,285	5,783	3,103	1,771	2,774	4,275	2,014	2,299	3,304	2,228
	500	23,937	26,855	33,657	30,971	92,705	(31,682)	33,693	32,886	31,971	37,217	25,835	33,338
	501	181,267	113,500	114,544	114,049	124,005	68,405	71,349	136,551	54,749	115,386	120,300	99,658
	502	664,251	473,286	679,267	742,763	508,714	747,097	709,446	473,895	649,975	770,109	624,733	688,535
	505	2,809	2,696	1,519	3,942	2,765	2,138	2,979	1,045	2,957	2,861	1,462	1,475
	506	206,755	256,143	192,636	169,060	228,956	217,049	204,801	206,898	228,469	216,162	190,049	225,346
	507	-	-	366	366	366	366	366	366	366	366	366	366
	509	3	93	119	81	117	99	88	121	119	106	5,704	7,523
	510	39,794	33,887	47,636	49,663	39,828	41,692	38,300	49,761	54,637	110,532	18,928	17,432
	511	12,085	12,222	13,740	(1,622)	18,032	13,865	20,481	18,534	17,221	11,135	22,055	22,602
	512	450,133	24,011	234,395	330,384	228,838	228,913	140,625	420,345	179,435	240,749	165,610	210,802
	513	297,965	148,026	29,684	181,232	39,840	60,669	42,947	108,357	2,688	57,596	43,397	8,710
	514	20,794	30,798	19,539	20,728	19,210	16,081	21,008	23,855	16,815	20,346	24,012	51,358
	925	552	346	360	572	385	217	375	521	204	(196)	(275)	132
	926	16,784	10,506	14,632	23,547	15,621	8,820	15,237	21,544	8,264	8,685	12,189	8,802
Total Cane Run 6		1,921,734	1,135,425	1,386,379	1,671,519	1,322,487	1,375,501	1,304,468	1,498,954	1,249,882	1,593,352	1,257,668	1,378,306
Cane Run Common	408	68,489	62,366	65,236	66,889	60,442	67,193	66,495	67,497	68,185	72,337	55,447	64,496
	426	2,132	1,242	551	4,573	14,483	9,733	1,320	1,800	1,680	4,000	115,588	24,441
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	(14,804)	1	(401)	-	-	-	(2,946)
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	(27)	-	-	-	(19,310)	-	(6,901)	-	-	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	921	333	-	130	35	165	-	660	-	-	-	130	140
	925	9,353	8,194	8,399	8,225	8,068	8,921	8,718	8,959	8,345	(8,414)	(6,487)	3,251
	926	278,928	250,769	339,541	336,693	332,495	364,312	358,192	369,429	340,200	375,275	289,447	270,349
	930	-	390	-	172	1,166	-	-	75	-	-	-	-
Total Cane Run Common		359,235	322,933	413,858	416,588	416,818	416,046	435,387	440,456	418,411	443,197	454,124	359,732

Operating Expenses by FERC
LG&E Retired and/or Retirin
2013-2017
Case No. 2014-00371
KIUC Q. 1-7

		Actuals											
	FERC	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
Cane Run 4	408	2,334	2,113	2,225	7,981	2,125	2,223	2,409	2,251	2,883	2,530	1,594	4,951
	500	23,369	18,982	21,643	20,718	19,806	19,324	20,145	17,864	19,828	18,495	15,851	23,257
	501	79,178	128,469	92,047	106,166	130,546	75,440	113,997	124,962	57,423	76,056	56,461	42,367
	502	487,424	391,800	579,652	211,992	364,109	426,336	446,966	299,709	503,000	495,377	498,907	591,635
	505	2,233	1,064	3,317	1,205	1,393	2,782	2,747	745	1,501	2,092	1,561	3,999
	506	106,906	132,851	122,207	169,308	122,314	155,375	141,704	158,032	165,543	108,130	121,008	103,420
	507	230	-	-	-	-	1,148	-	459	230	230	230	230
	509	356	343	235	2,649	1,077	1,115	4,442	2,576	4,466	1,793	2,440	1,877
	510	21,763	24,264	29,942	28,212	25,489	16,097	24,804	12,657	15,830	56,978	(6,572)	5,313
	511	15,860	14,077	14,640	6,363	10,509	12,223	10,030	14,681	6,656	9,318	9,002	29,746
	512	98,683	131,666	56,326	653,378	118,027	108,658	144,860	161,136	289,888	197,063	142,550	113,197
	513	50,815	23,542	36,897	81,449	29,268	29,412	35,412	19,679	21,303	36,656	14,710	34,179
	514	10,670	10,213	17,241	19,646	6,626	(3,736)	19,005	12,616	12,743	15,159	1,345	8,563
	925	198	188	208	601	225	153	136	168	187	179	103	(409)
	926	6,014	5,848	5,712	16,928	6,160	4,635	4,247	5,242	5,977	5,659	3,129	10,478
Total Cane Run 4		906,035	885,422	982,292	1,326,595	837,674	851,183	970,902	832,777	1,107,458	1,025,714	862,319	972,803
Cane Run 5	408	3,021	3,812	7,401	3,158	2,381	2,119	2,377	2,350	2,342	2,214	1,049	2,790
	426	-	-	-	-	-	-	-	-	-	-	-	-
	500	25,966	21,091	24,048	23,020	22,007	21,471	22,383	19,849	22,031	20,550	17,613	25,841
	501	62,434	103,909	99,554	84,414	114,817	109,421	117,989	137,184	72,920	73,529	46,486	45,708
	502	620,009	511,873	521,374	678,528	508,270	477,876	517,324	411,159	539,901	555,799	523,241	660,338
	505	2,957	1,443	3,089	3,882	1,957	3,076	3,240	1,019	1,577	2,396	1,715	4,590
	506	139,979	155,976	127,035	195,904	121,620	153,633	151,205	197,172	176,246	112,633	153,661	108,291
	507	255	-	-	-	-	1,275	-	510	255	255	255	255
	509	395	381	261	2,944	1,196	1,239	4,935	2,863	4,962	1,992	2,711	2,086
	510	24,182	26,960	33,269	31,347	28,321	17,885	27,560	14,063	17,589	63,309	(7,302)	5,904
	511	17,735	15,381	19,022	9,018	8,167	15,422	14,914	17,657	12,398	13,384	21,424	46,032
	512	147,555	207,961	454,726	264,021	163,607	196,411	175,465	202,166	216,860	206,798	208,827	223,070
	513	51,900	19,971	59,635	77,859	61,627	24,117	60,413	80,006	39,238	52,422	35,854	23,858
	514	11,856	11,348	19,157	21,829	7,362	(4,151)	21,117	14,018	14,159	16,843	1,495	9,515
	925	287	407	486	222	298	171	184	203	199	183	87	(268)
	926	9,031	12,535	13,404	6,094	8,177	5,380	5,908	6,306	6,116	5,565	2,659	6,698
Total Cane Run 5		1,117,560	1,093,050	1,382,461	1,402,240	1,049,808	1,025,344	1,125,015	1,106,524	1,126,794	1,127,872	1,009,776	1,164,707

Operating Expenses by FERC
LG&E Retired and/or Retirin
2013-2017
Case No. 2014-00371
KIUC Q. 1-7

		Actuals											
	FERC	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
Cane Run 6	408	4,653	4,323	11,160	4,167	4,044	4,139	2,621	2,295	2,360	2,087	2,073	4,160
	500	37,218	30,231	34,469	32,996	31,543	30,775	32,083	28,451	31,578	29,455	25,245	37,039
	501	155,401	107,270	139,804	118,936	149,761	105,840	111,697	98,078	59,006	48,111	72,574	57,899
	502	743,757	742,144	508,023	630,638	605,310	659,467	805,046	744,907	448,013	6,768	337,114	25,286
	505	2,747	1,741	2,442	2,830	1,874	3,456	3,962	1,469	1,007	-	808	-
	506	214,251	254,263	192,283	286,022	362,559	229,988	214,153	239,398	259,042	161,580	203,430	170,488
	507	366	-	-	-	-	1,828	-	731	366	366	366	366
	509	566	546	374	4,219	1,715	1,776	7,074	4,103	7,112	2,855	3,886	2,990
	510	34,660	38,643	47,685	44,931	40,594	25,635	39,502	20,157	25,211	90,742	(10,467)	8,462
	511	24,876	21,083	35,940	15,910	11,311	17,271	16,274	27,927	7,020	12,162	13,568	37,180
	512	253,372	246,379	462,259	507,568	267,247	231,623	252,488	180,633	124,670	92,175	80,507	71,332
	513	113,450	114,197	504,521	(325,916)	24,492	36,940	53,233	27,622	17,950	5,700	23,594	3,556
	514	16,993	16,266	27,458	31,288	10,553	(5,950)	30,268	20,092	20,295	24,141	2,142	13,638
	925	426	382	724	384	415	290	245	176	212	148	159	(323)
	926	13,419	12,534	20,088	10,607	11,504	10,175	7,258	5,340	6,515	4,479	4,829	7,951
Total Cane Run 6		1,616,155	1,590,001	1,987,230	1,364,579	1,522,921	1,353,252	1,575,902	1,401,379	1,010,358	480,769	759,828	440,023
Cane Run Common	408	86,947	75,595	88,285	75,663	72,580	66,197	71,078	69,993	69,286	56,455	52,088	118,007
	426	6,860	3,837	1,781	3,403	1,821	9,525	1,230	5,026	2,031	4,294	7,502	7,437
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	(1,847)	-	1,847	(12,224)	(2,865)	(8,617)	(14,466)	(5,328)
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	(27)	-	-	(5,657)	-	5,657	(165)	2,972	(18,375)	(3,464)	(21,693)
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	921	231	110	-	-	150	-	150	-	-	50	-	305
	925	10,085	8,972	10,074	8,834	8,301	5,755	6,069	6,095	5,888	4,963	3,713	(8,722)
	926	315,607	279,536	278,517	243,905	231,433	178,290	187,517	186,739	180,671	151,720	113,678	210,761
	930	417	-	-	-	-	(417)	-	-	-	-	-	-
Total Cane Run Common		420,146	368,023	378,657	331,804	306,780	259,351	273,548	255,463	257,984	190,489	159,051	300,766

Operating Expenses by FERC
LG&E Retired and/or Retirin;
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		Budget											
	FERC	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
Cane Run 4	408	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	153,069	126,244	165,864	190,135	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	1,994	8,629	22,022	9,193	-	-	-	-	-	-	-	-
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	5,573	8,657	-	-	-	-	-	-	-	-
	512	7,022	12,224	12,745	23,363	-	-	-	-	-	-	-	-
	513	574	574	5,880	574	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
Total Cane Run 4		162,659	147,671	212,084	231,922	-	-	-	-	-	-	-	-
Cane Run 5	408	-	-	-	-	-	-	-	-	-	-	-	-
	426	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	279,544	207,874	289,133	299,100	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	9,237	18,544	9,800	-	-	-	-	-	-	-	-
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	17,725	9,208	13,327	8,361	-	-	-	-	-	-	-	-
	513	718	718	718	718	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
Total Cane Run 5		297,987	227,037	321,722	317,979	-	-	-	-	-	-	-	-

Operating Expenses by FERC
LG&E Retired and/or Retirin;
2013-2017
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		Budget											
	FERC	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
Cane Run 6	408	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	2,477	4,529	1,126	-	-	-	-	-	-	-	-
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	988	988	13,228	16,288	-	-	-	-	-	-	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
Total Cane Run 6		988	3,465	17,757	17,414	-	-	-	-	-	-	-	-
Cane Run Common	408	60,530	58,849	64,349	60,777	-	-	-	-	-	-	-	-
	426	219	-	1,639	1,912	-	-	-	-	-	-	-	-
	500	15,000	15,000	15,000	2,515,261	-	-	-	-	-	-	-	-
	501	104,501	145,878	104,351	158,095	-	-	-	-	-	-	-	-
	502	478,786	468,050	512,475	506,675	46,590	16,590	16,590	16,590	16,590	-	-	-
	505	5,231	5,231	9,165	5,231	-	-	-	-	-	-	-	-
	506	484,428	489,265	528,407	696,390	103,986	103,296	103,986	103,986	103,296	103,986	103,296	103,986
	507	836	836	836	836	-	-	-	-	-	-	-	-
	509	20	16	15	9	21	21	29	29	23	12	16	17
	510	78,961	70,323	76,983	115,449	-	10,000	-	1,530	1,530	8,160	6,120	1,020
	511	71,489	84,926	72,272	71,911	-	-	-	-	-	-	-	-
	512	406,113	380,171	509,689	491,581	-	-	-	-	-	-	-	-
	513	68,690	61,294	74,977	64,432	-	-	-	-	-	-	-	-
	514	20,994	20,994	20,994	8,999,395	-	-	-	-	-	-	-	-
	921	-	-	-	-	-	-	-	-	-	-	-	-
	925	10,377	10,089	11,032	10,420	-	-	-	-	-	-	-	-
	926	378,600	368,089	402,493	380,150	-	-	-	-	-	-	-	-
	930	-	-	-	-	-	-	-	-	-	-	-	-
Total Cane Run Common		2,184,775	2,179,010	2,404,676	14,078,523	150,597	129,907	120,605	122,135	121,439	112,158	109,432	105,023

Operating Expenses by FERC
LG&E Retired and/or Retirin
2013-2017
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		Budget											
	FERC	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
Cane Run 4	408	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	-	-	-	-	-	-	-	-	-	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
Total Cane Run 4		-	-	-	-	-	-	-	-	-	-	-	-
Cane Run 5	408	-	-	-	-	-	-	-	-	-	-	-	-
	426	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	-	-	-	-	-	-	-	-	-	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
Total Cane Run 5		-	-	-	-	-	-	-	-	-	-	-	-

Operating Expenses by FERC
LG&E Retired and/or Retirin;
2013-2017
Case No. 2014-00371
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		Budget											
	FERC	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
Cane Run 6	408	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	-	-	-	-	-	-	-	-	-	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
Total Cane Run 6		-	-	-	-	-	-	-	-	-	-	-	-
Cane Run Common	408	-	-	-	-	-	-	-	-	-	-	-	-
	426	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	99,903	98,494	99,903	99,198	99,903	99,198	99,903	99,903	99,198	99,903	99,197	99,902
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	10,200	-	1,561	1,561	8,323	6,242	1,040
	511	-	-	-	-	-	150,000	-	-	-	-	-	150,000
	512	-	-	-	-	-	-	-	-	-	-	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	921	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
	930	-	-	-	-	-	-	-	-	-	-	-	-
Total Cane Run Common		99,903	98,494	99,903	99,198	99,903	259,398	99,903	101,464	100,759	108,226	105,439	250,942

Operating Expenses by FERC
LG&E Retired and/or Retirin
2013-2017
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		Budget											
	FERC	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
Cane Run 4	408	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	-	-	-	-	-	-	-	-	-	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
Total Cane Run 4		-	-	-	-	-	-	-	-	-	-	-	-
Cane Run 5	408	-	-	-	-	-	-	-	-	-	-	-	-
	426	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	-	-	-	-	-	-	-	-	-	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
Total Cane Run 5		-	-	-	-	-	-	-	-	-	-	-	-

Operating Expenses by FERC
LG&E Retired and/or Retirin
2013-2017
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		Budget											
	FERC	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
Cane Run 6	408	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	-	-	-	-	-	-	-	-	-	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
Total Cane Run 6		-	-	-	-	-	-	-	-	-	-	-	-
Cane Run Common	408	-	-	-	-	-	-	-	-	-	-	-	-
	426	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	92,304	90,867	92,304	91,585	92,304	91,585	92,304	92,304	91,585	92,304	91,586	92,305
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	10,404	-	1,592	1,592	8,490	6,367	1,061
	511	-	-	-	-	-	153,000	-	-	-	-	-	153,000
	512	-	-	-	-	-	-	-	-	-	-	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	921	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
	930	-	-	-	-	-	-	-	-	-	-	-	-
Total Cane Run Common		92,304	90,867	92,304	91,585	92,304	254,989	92,304	93,896	93,177	100,794	97,953	246,366

EXHIBIT ____ (LK-15)

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2014-00372

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 8, 2015

Question No. 8

Responding Witness: Russel A. Hudson

Q.1-8. Please provide in an Excel spreadsheet the FTE staffing levels and related payroll (direct and burdens) by month from January 2013 through December 2017 at each generating unit/plant that the Company has retired or plans to retire during that five-year period.

A.1-8. See the response to Question No. 7. See tab labeled "Q.8 LGE labor."

Operating Expenses by FERC (excl Fuel)
LG&E Retired and/or Retiring Units
2013-2017
Case No. 2014-00371
KIUC Q. 1-7

		Actuals											
	FERC	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
Cane Run 4	408	2,423	3,226	2,618	2,301	2,256	3,735	3,744	2,683	2,132	3,115	2,118	2,926
	500	15,030	16,862	21,133	19,447	20,419	17,898	21,156	20,650	20,075	23,369	16,222	20,933
	501	88,319	139,012	100,655	115,676	79,807	142,737	115,524	126,688	148,808	111,184	134,047	98,037
	502	451,082	301,325	382,734	560,855	403,769	107,196	(16,095)	428,451	363,913	432,222	431,503	461,938
	505	2,547	2,246	980	3,505	3,019	236	0	1,239	2,169	1,928	1,289	1,296
	506	128,180	137,655	124,879	102,069	124,205	127,720	131,056	122,419	131,113	122,220	120,740	133,013
	507	-	-	230	230	230	230	230	230	230	230	230	230
	509	1,430	3,459	74	52	75	61	54	77	74	67	3,582	4,725
	510	24,987	21,278	29,911	31,184	25,008	26,179	24,049	31,246	34,307	69,404	11,885	10,945
	511	16,898	28,186	13,678	456	14,751	8,824	13,156	11,568	9,580	6,994	12,993	13,713
	512	60,504	177,251	134,905	171,114	166,025	122,296	274,304	121,348	76,284	329,653	29,223	126,336
	513	70,035	13,078	20,750	118,046	26,964	31,102	36,588	103,584	111,368	37,094	85,261	62,062
	514	13,057	19,338	12,269	13,015	12,062	10,097	13,191	14,979	10,558	12,776	15,077	32,248
	925	295	316	319	205	250	514	479	310	257	(275)	(162)	144
	926	8,956	9,618	12,915	8,329	10,135	21,417	19,452	12,600	10,420	12,259	7,178	10,081
Total Cane Run 4		883,743	872,851	858,050	1,146,482	888,974	620,242	636,888	998,071	921,286	1,162,240	871,185	978,627
Cane Run 5	408	2,604	2,379	3,219	8,940	2,835	2,122	2,368	1,984	1,240	4,613	2,941	1,902
	426	-	-	-	-	-	-	-	-	-	-	-	-
	500	16,700	18,736	23,482	21,608	22,688	19,887	23,507	22,944	22,305	25,966	18,025	23,259
	501	81,473	51,861	94,261	82,733	85,273	100,818	51,313	63,820	63,161	102,197	107,514	143,476
	502	504,212	406,849	410,214	124,781	413,060	527,731	520,294	464,284	493,894	414,771	410,522	450,794
	505	2,946	3,107	1,081	535	3,156	1,837	2,764	1,397	3,044	1,970	1,251	1,311
	506	145,368	151,385	133,491	126,244	148,102	139,857	142,327	134,602	145,603	136,361	158,483	159,066
	507	-	-	255	255	255	255	255	255	255	255	255	255
	509	2	65	83	56	83	70	62	87	84	74	3,981	5,249
	510	27,763	23,642	33,235	34,649	27,787	29,088	26,721	34,717	38,119	77,116	13,206	12,162
	511	33,936	31,994	21,839	11,156	32,875	30,434	17,257	31,332	10,411	14,330	19,463	23,982
	512	147,069	132,791	289,403	1,018,291	69,961	113,622	99,327	103,129	43,650	321,916	186,055	195,208
	513	62,916	101,142	32,049	153,722	117,509	53,445	47,477	26,750	13,551	33,497	43,498	96,266
	514	14,508	21,487	13,632	14,461	13,402	11,219	14,657	16,643	11,731	14,195	16,753	35,831
	925	343	340	353	724	410	278	357	292	169	(358)	(274)	125
	926	10,425	10,331	14,330	29,372	16,648	11,286	14,489	11,837	6,879	15,824	12,102	8,007
Total Cane Run 5		1,050,266	956,108	1,070,928	1,627,526	954,044	1,041,950	963,175	914,072	854,096	1,162,727	993,774	1,156,892

Operating Expenses by FERC (excl Fuel)
LG&E Retired and/or Retiring Units
2013-2017
Case No. 2014-00371
KIUC Q. 1-7

		Actuals											
	FERC	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
Cane Run 6	408	4,606	3,057	4,285	5,783	3,103	1,771	2,774	4,275	2,014	2,299	3,304	2,228
	500	23,937	26,855	33,657	30,971	92,705	(31,682)	33,693	32,886	31,971	37,217	25,835	33,338
	501	181,267	113,500	114,544	114,049	124,005	68,405	71,349	136,551	54,749	115,386	120,300	99,658
	502	664,251	473,286	679,267	742,763	508,714	747,097	709,446	473,895	649,975	770,109	624,733	688,535
	505	2,809	2,696	1,519	3,942	2,765	2,138	2,979	1,045	2,957	2,861	1,462	1,475
	506	206,755	256,143	192,636	169,060	228,956	217,049	204,801	206,898	228,469	216,162	190,049	225,346
	507	-	-	366	366	366	366	366	366	366	366	366	366
	509	3	93	119	81	117	99	88	121	119	106	5,704	7,523
	510	39,794	33,887	47,636	49,663	39,828	41,692	38,300	49,761	54,637	110,532	18,928	17,432
	511	12,085	12,222	13,740	(1,622)	18,032	13,865	20,481	18,534	17,221	11,135	22,055	22,602
	512	450,133	24,011	234,395	330,384	228,838	228,913	140,625	420,345	179,435	240,749	165,610	210,802
	513	297,965	148,026	29,684	181,232	39,840	60,669	42,947	108,357	2,688	57,596	43,397	8,710
	514	20,794	30,798	19,539	20,728	19,210	16,081	21,008	23,855	16,815	20,346	24,012	51,358
	925	552	346	360	572	385	217	375	521	204	(196)	(275)	132
	926	16,784	10,506	14,632	23,547	15,621	8,820	15,237	21,544	8,264	8,685	12,189	8,802
Total Cane Run 6		1,921,734	1,135,425	1,386,379	1,671,519	1,322,487	1,375,501	1,304,468	1,498,954	1,249,882	1,593,352	1,257,668	1,378,306
Cane Run Common	408	68,489	62,366	65,236	66,889	60,442	67,193	66,495	67,497	68,185	72,337	55,447	64,496
	426	2,132	1,242	551	4,573	14,483	9,733	1,320	1,800	1,680	4,000	115,588	24,441
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	(14,804)	1	(401)	-	-	-	(2,946)
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	(27)	-	-	-	(19,310)	-	(6,901)	-	-	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	921	333	-	130	35	165	-	660	-	-	-	130	140
	925	9,353	8,194	8,399	8,225	8,068	8,921	8,718	8,959	8,345	(8,414)	(6,487)	3,251
	926	278,928	250,769	339,541	336,693	332,495	364,312	358,192	369,429	340,200	375,275	289,447	270,349
	930	-	390	-	172	1,166	-	-	75	-	-	-	-
Total Cane Run Common		359,235	322,933	413,858	416,588	416,818	416,046	435,387	440,456	418,411	443,197	454,124	359,732

Operating Expenses by FERC
LG&E Retired and/or Retirin
2013-2017
Case No. 2014-00371
KIUC Q. 1-7

		Actuals											
	FERC	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
Cane Run 4	408	2,334	2,113	2,225	7,981	2,125	2,223	2,409	2,251	2,883	2,530	1,594	4,951
	500	23,369	18,982	21,643	20,718	19,806	19,324	20,145	17,864	19,828	18,495	15,851	23,257
	501	79,178	128,469	92,047	106,166	130,546	75,440	113,997	124,962	57,423	76,056	56,461	42,367
	502	487,424	391,800	579,652	211,992	364,109	426,336	446,966	299,709	503,000	495,377	498,907	591,635
	505	2,233	1,064	3,317	1,205	1,393	2,782	2,747	745	1,501	2,092	1,561	3,999
	506	106,906	132,851	122,207	169,308	122,314	155,375	141,704	158,032	165,543	108,130	121,008	103,420
	507	230	-	-	-	-	1,148	-	459	230	230	230	230
	509	356	343	235	2,649	1,077	1,115	4,442	2,576	4,466	1,793	2,440	1,877
	510	21,763	24,264	29,942	28,212	25,489	16,097	24,804	12,657	15,830	56,978	(6,572)	5,313
	511	15,860	14,077	14,640	6,363	10,509	12,223	10,030	14,681	6,656	9,318	9,002	29,746
	512	98,683	131,666	56,326	653,378	118,027	108,658	144,860	161,136	289,888	197,063	142,550	113,197
	513	50,815	23,542	36,897	81,449	29,268	29,412	35,412	19,679	21,303	36,656	14,710	34,179
	514	10,670	10,213	17,241	19,646	6,626	(3,736)	19,005	12,616	12,743	15,159	1,345	8,563
	925	198	188	208	601	225	153	136	168	187	179	103	(409)
	926	6,014	5,848	5,712	16,928	6,160	4,635	4,247	5,242	5,977	5,659	3,129	10,478
Total Cane Run 4		906,035	885,422	982,292	1,326,595	837,674	851,183	970,902	832,777	1,107,458	1,025,714	862,319	972,803
Cane Run 5	408	3,021	3,812	7,401	3,158	2,381	2,119	2,377	2,350	2,342	2,214	1,049	2,790
	426	-	-	-	-	-	-	-	-	-	-	-	-
	500	25,966	21,091	24,048	23,020	22,007	21,471	22,383	19,849	22,031	20,550	17,613	25,841
	501	62,434	103,909	99,554	84,414	114,817	109,421	117,989	137,184	72,920	73,529	46,486	45,708
	502	620,009	511,873	521,374	678,528	508,270	477,876	517,324	411,159	539,901	555,799	523,241	660,338
	505	2,957	1,443	3,089	3,882	1,957	3,076	3,240	1,019	1,577	2,396	1,715	4,590
	506	139,979	155,976	127,035	195,904	121,620	153,633	151,205	197,172	176,246	112,633	153,661	108,291
	507	255	-	-	-	-	1,275	-	510	255	255	255	255
	509	395	381	261	2,944	1,196	1,239	4,935	2,863	4,962	1,992	2,711	2,086
	510	24,182	26,960	33,269	31,347	28,321	17,885	27,560	14,063	17,589	63,309	(7,302)	5,904
	511	17,735	15,381	19,022	9,018	8,167	15,422	14,914	17,657	12,398	13,384	21,424	46,032
	512	147,555	207,961	454,726	264,021	163,607	196,411	175,465	202,166	216,860	206,798	208,827	223,070
	513	51,900	19,971	59,635	77,859	61,627	24,117	60,413	80,006	39,238	52,422	35,854	23,858
	514	11,856	11,348	19,157	21,829	7,362	(4,151)	21,117	14,018	14,159	16,843	1,495	9,515
	925	287	407	486	222	298	171	184	203	199	183	87	(268)
	926	9,031	12,535	13,404	6,094	8,177	5,380	5,908	6,306	6,116	5,565	2,659	6,698
Total Cane Run 5		1,117,560	1,093,050	1,382,461	1,402,240	1,049,808	1,025,344	1,125,015	1,106,524	1,126,794	1,127,872	1,009,776	1,164,707

Operating Expenses by FERC
LG&E Retired and/or Retirin;
2013-2017
Case No. 2014-00371
KIUC Q. 1-7

		Actuals											
	FERC	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
Cane Run 6	408	4,653	4,323	11,160	4,167	4,044	4,139	2,621	2,295	2,360	2,087	2,073	4,160
	500	37,218	30,231	34,469	32,996	31,543	30,775	32,083	28,451	31,578	29,455	25,245	37,039
	501	155,401	107,270	139,804	118,936	149,761	105,840	111,697	98,078	59,006	48,111	72,574	57,899
	502	743,757	742,144	508,023	630,638	605,310	659,467	805,046	744,907	448,013	6,768	337,114	25,286
	505	2,747	1,741	2,442	2,830	1,874	3,456	3,962	1,469	1,007	-	808	-
	506	214,251	254,263	192,283	286,022	362,559	229,988	214,153	239,398	259,042	161,580	203,430	170,488
	507	366	-	-	-	-	1,828	-	731	366	366	366	366
	509	566	546	374	4,219	1,715	1,776	7,074	4,103	7,112	2,855	3,886	2,990
	510	34,660	38,643	47,685	44,931	40,594	25,635	39,502	20,157	25,211	90,742	(10,467)	8,462
	511	24,876	21,083	35,940	15,910	11,311	17,271	16,274	27,927	7,020	12,162	13,568	37,180
	512	253,372	246,379	462,259	507,568	267,247	231,623	252,488	180,633	124,670	92,175	80,507	71,332
	513	113,450	114,197	504,521	(325,916)	24,492	36,940	53,233	27,622	17,950	5,700	23,594	3,556
	514	16,993	16,266	27,458	31,288	10,553	(5,950)	30,268	20,092	20,295	24,141	2,142	13,638
	925	426	382	724	384	415	290	245	176	212	148	159	(323)
	926	13,419	12,534	20,088	10,607	11,504	10,175	7,258	5,340	6,515	4,479	4,829	7,951
Total Cane Run 6		1,616,155	1,590,001	1,987,230	1,364,579	1,522,921	1,353,252	1,575,902	1,401,379	1,010,358	480,769	759,828	440,023
Cane Run Common	408	86,947	75,595	88,285	75,663	72,580	66,197	71,078	69,993	69,286	56,455	52,088	118,007
	426	6,860	3,837	1,781	3,403	1,821	9,525	1,230	5,026	2,031	4,294	7,502	7,437
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	(1,847)	-	1,847	(12,224)	(2,865)	(8,617)	(14,466)	(5,328)
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	(27)	-	-	(5,657)	-	5,657	(165)	2,972	(18,375)	(3,464)	(21,693)
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	921	231	110	-	-	150	-	150	-	-	50	-	305
	925	10,085	8,972	10,074	8,834	8,301	5,755	6,069	6,095	5,888	4,963	3,713	(8,722)
	926	315,607	279,536	278,517	243,905	231,433	178,290	187,517	186,739	180,671	151,720	113,678	210,761
	930	417	-	-	-	-	(417)	-	-	-	-	-	-
Total Cane Run Common		420,146	368,023	378,657	331,804	306,780	259,351	273,548	255,463	257,984	190,489	159,051	300,766

Operating Expenses by FERC
LG&E Retired and/or Retirin;
2013-2017
Case No. 2014-00371
KIUC Q. 1-7

		Budget											
	FERC	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
Cane Run 4	408	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	153,069	126,244	165,864	190,135	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	1,994	8,629	22,022	9,193	-	-	-	-	-	-	-	-
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	5,573	8,657	-	-	-	-	-	-	-	-
	512	7,022	12,224	12,745	23,363	-	-	-	-	-	-	-	-
	513	574	574	5,880	574	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
Total Cane Run 4		162,659	147,671	212,084	231,922	-	-	-	-	-	-	-	-
Cane Run 5	408	-	-	-	-	-	-	-	-	-	-	-	-
	426	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	279,544	207,874	289,133	299,100	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	9,237	18,544	9,800	-	-	-	-	-	-	-	-
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	17,725	9,208	13,327	8,361	-	-	-	-	-	-	-	-
	513	718	718	718	718	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
Total Cane Run 5		297,987	227,037	321,722	317,979	-	-	-	-	-	-	-	-

Operating Expenses by FERC
LG&E Retired and/or Retirin
2013-2017
Case No. 2014-00371
KIUC Q. 1-7

		Budget											
	FERC	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
Cane Run 6	408	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	2,477	4,529	1,126	-	-	-	-	-	-	-	-
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	988	988	13,228	16,288	-	-	-	-	-	-	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
Total Cane Run 6		988	3,465	17,757	17,414	-	-	-	-	-	-	-	-
Cane Run Common	408	60,530	58,849	64,349	60,777	-	-	-	-	-	-	-	-
	426	219	-	1,639	1,912	-	-	-	-	-	-	-	-
	500	15,000	15,000	15,000	2,515,261	-	-	-	-	-	-	-	-
	501	104,501	145,878	104,351	158,095	-	-	-	-	-	-	-	-
	502	478,786	468,050	512,475	506,675	46,590	16,590	16,590	16,590	16,590	-	-	-
	505	5,231	5,231	9,165	5,231	-	-	-	-	-	-	-	-
	506	484,428	489,265	528,407	696,390	103,986	103,296	103,986	103,986	103,296	103,986	103,296	103,986
	507	836	836	836	836	-	-	-	-	-	-	-	-
	509	20	16	15	9	21	21	29	29	23	12	16	17
	510	78,961	70,323	76,983	115,449	-	10,000	-	1,530	1,530	8,160	6,120	1,020
	511	71,489	84,926	72,272	71,911	-	-	-	-	-	-	-	-
	512	406,113	380,171	509,689	491,581	-	-	-	-	-	-	-	-
	513	68,690	61,294	74,977	64,432	-	-	-	-	-	-	-	-
	514	20,994	20,994	20,994	8,999,395	-	-	-	-	-	-	-	-
	921	-	-	-	-	-	-	-	-	-	-	-	-
	925	10,377	10,089	11,032	10,420	-	-	-	-	-	-	-	-
	926	378,600	368,089	402,493	380,150	-	-	-	-	-	-	-	-
	930	-	-	-	-	-	-	-	-	-	-	-	-
Total Cane Run Common		2,184,775	2,179,010	2,404,676	14,078,523	150,597	129,907	120,605	122,135	121,439	112,158	109,432	105,023

Operating Expenses by FERC
LG&E Retired and/or Retirin
2013-2017
Case No. 2014-00371
KIUC Q. 1-7

		Budget											
	FERC	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
Cane Run 4	408	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	-	-	-	-	-	-	-	-	-	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
Total Cane Run 4		-	-	-	-	-	-	-	-	-	-	-	-
Cane Run 5	408	-	-	-	-	-	-	-	-	-	-	-	-
	426	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	-	-	-	-	-	-	-	-	-	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
Total Cane Run 5		-	-	-	-	-	-	-	-	-	-	-	-

Operating Expenses by FERC
LG&E Retired and/or Retirin
2013-2017
Case No. 2014-00371
KIUC Q. 1-7

		Budget											
	FERC	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
Cane Run 6	408	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	-	-	-	-	-	-	-	-	-	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
Total Cane Run 6		-	-	-	-	-	-	-	-	-	-	-	-
Cane Run Common	408	-	-	-	-	-	-	-	-	-	-	-	-
	426	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	99,903	98,494	99,903	99,198	99,903	99,198	99,903	99,903	99,198	99,903	99,197	99,902
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	10,200	-	1,561	1,561	8,323	6,242	1,040
	511	-	-	-	-	-	150,000	-	-	-	-	-	150,000
	512	-	-	-	-	-	-	-	-	-	-	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	921	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
	930	-	-	-	-	-	-	-	-	-	-	-	-
Total Cane Run Common		99,903	98,494	99,903	99,198	99,903	259,398	99,903	101,464	100,759	108,226	105,439	250,942

Operating Expenses by FERC
LG&E Retired and/or Retirin
2013-2017
Case No. 2014-00371
KIUC Q. 1-7

		Budget											
	FERC	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
Cane Run 4	408	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	-	-	-	-	-	-	-	-	-	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
Total Cane Run 4		-	-	-	-	-	-	-	-	-	-	-	-
Cane Run 5	408	-	-	-	-	-	-	-	-	-	-	-	-
	426	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	-	-	-	-	-	-	-	-	-	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
Total Cane Run 5		-	-	-	-	-	-	-	-	-	-	-	-

Operating Expenses by FERC
LG&E Retired and/or Retirin
2013-2017
Case No. 2014-00371
KIUC Q. 1-7

		Budget											
	FERC	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
Cane Run 6	408	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	-	-	-	-	-	-	-	-	-	-	-	-
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-	-	-	-	-
	512	-	-	-	-	-	-	-	-	-	-	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
Total Cane Run 6		-	-	-	-	-	-	-	-	-	-	-	-
Cane Run Common	408	-	-	-	-	-	-	-	-	-	-	-	-
	426	-	-	-	-	-	-	-	-	-	-	-	-
	500	-	-	-	-	-	-	-	-	-	-	-	-
	501	-	-	-	-	-	-	-	-	-	-	-	-
	502	-	-	-	-	-	-	-	-	-	-	-	-
	505	-	-	-	-	-	-	-	-	-	-	-	-
	506	92,304	90,867	92,304	91,585	92,304	91,585	92,304	92,304	91,585	92,304	91,586	92,305
	507	-	-	-	-	-	-	-	-	-	-	-	-
	509	-	-	-	-	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	10,404	-	1,592	1,592	8,490	6,367	1,061
	511	-	-	-	-	-	153,000	-	-	-	-	-	153,000
	512	-	-	-	-	-	-	-	-	-	-	-	-
	513	-	-	-	-	-	-	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-	-	-	-	-
	921	-	-	-	-	-	-	-	-	-	-	-	-
	925	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-
	930	-	-	-	-	-	-	-	-	-	-	-	-
Total Cane Run Common		92,304	90,867	92,304	91,585	92,304	254,989	92,304	93,896	93,177	100,794	97,953	246,366

EXHIBIT ____ (LK-16)

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 6, 2015

Question No. 2-14

Responding Witness: Kent W. Blake / Paula H. Pottinger, Ph.D. / Counsel

Q.2-14. Refer to the Company's response to KIUC 1-12. The question asked the following:

> *Please provide the incentive compensation expense for 2013, 2014, the base year, and the test year by incentive compensation plan and by goal or target for each plan. This includes incentive compensation expense assigned and allocated to the Company as well as incentive compensation expense incurred directly by the Company.*

The Company's response referred to its response to AG 1-150. The response to AG 1-150 does not provide the information requested in KIUC 1-12 by plan and by goal or target for each plan. It also does not provide the information for LKS charged to the Company.

a. Please provide the information requested in KIUC 1-12. To be clear, this request also includes all stock-based compensation awards, and is not limited only to incentive compensation with cash or deferred payouts.

b. Please provide the calculation of incentive compensation expense in the historic year, the base year and the test year in electronic format with all formulas intact. This calculation should reflect all performance metrics and goals, the achieved metric or goal, and the calculation of the cost, including the allocation between expense and capital.

A.2-14. a. See the Company's Objection filed on February 16, 2015. The Team Incentive Award (TIA) is the only plan with payments included in the cost of service. Information by goal and by target for the TIA is provided in response to AG 1-76. None of the costs of stock-based compensation or other incentive plans, beyond the TIA, were incurred by Kentucky Utilities Company, nor were any such costs allocated to Kentucky Utilities Company by any other entity.

b. The attached information is from the Company's financial system and provides incentive compensation expense for 2013, 2014, the base year and the test year. Incentive compensation expense is determined at the beginning of the year, reviewed quarterly and adjusted, if appropriate. Incentive compensation expense is based on labor allocations from the Company's financial system and assumes on-target financial, customer satisfaction and team performance. Individual performance is assumed at 120%. When actual incentive payouts are made during the first quarter of the following year, true-up entries are made to allocate the incentive expense to the appropriate companies and FERC accounts.

While the Company does not report incentive expense by performance goal, 2013's expense is provided below by financial, customer, individual and team performance goals. 2014 incentive expense by performance goal will be available mid-March. See the response to AG 1-76 for details on measure weightings.

Performance Measure	Capitalized	Expensed	Other Balance Sheet	Total
Financial - PPL EPS	30,600	128,213	16,755	175,568
Financial - LKE Net Income	1,514,625	6,346,183	829,312	8,690,120
Customer Satisfaction	352,541	1,477,125	193,029	2,022,696
Individual/Team Effectiveness	739,397	3,098,026	404,847	4,242,269
Total	2,637,163	11,049,547	1,443,943	15,130,652

Kentucky Utilities
Case No. 2014-00371
Incentive Compensation Expense for 2013, 2014, Base Year and Test Year

KU

Company Allocated from	Capitalized	Expensed	Other Balance Sheet	Total
2013				
Servco	932,862	6,224,626	558,715	7,716,203
LGE	72,010	590,166	4,098	666,274
KU	1,632,290	4,234,754	881,130	6,748,175
	2,637,163	11,049,547	1,443,943	15,130,652
2014				
Servco	897,388	6,707,097	638,069	8,242,553
LGE	136,308	662,181	1,997	800,487
KU	1,531,086	3,921,890	939,384	6,392,360
	2,564,782	11,291,168	1,579,450	15,435,400
Base Period				
Servco	638,433	6,013,104	486,415	7,137,953
LGE	57,100	348,698	2,565	408,363
KU	1,485,327	4,294,301	392,326	6,171,954
	2,180,860	10,656,104	881,306	13,718,270
Forecasted Test Period				
Servco	764,253	6,523,127	629,908	7,917,288
LGE	9,117	27,117	-	36,234
KU	1,326,217	4,423,194	304,422	6,053,834
	2,099,587	10,973,438	934,331	14,007,355

EXHIBIT ____ (LK-17)

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2014-00372

**Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 6, 2015**

Question No. 2-14

Responding Witness: Kent W. Blake / Paula H. Pottinger, Ph.D. / Counsel

Q.2-14. Refer to the Company's response to KIUC 1-12. The question asked the following:

Please provide the incentive compensation expense for 2013, 2014, the base year, and the test year by incentive compensation plan and by goal or target for each plan. This includes incentive compensation expense assigned and allocated to the Company as well as incentive compensation expense incurred directly by the Company.

The Company's response referred to its response to AG 1-150. The response to AG 1-150 does not provide the information requested in KIUC 1-12 by plan and by goal or target for each plan. It also does not provide the information for LKS charged to the Company.

a. Please provide the information requested in KIUC 1-12. To be clear, this request also includes all stock-based compensation awards, and is not limited only to incentive compensation with cash or deferred payouts.

b. Please provide the calculation of incentive compensation expense in the historic year, the base year and the test year in electronic format with all formulas intact. This calculation should reflect all performance metrics and goals, the achieved metric or goal, and the calculation of the cost, including the allocation between expense and capital.

A.2-14. a. See the Company's Objection filed on February 16, 2015. The Team Incentive Award (TIA) is the only plan with payments included in the cost of service. Information by goal and by target for the TIA is provided in response to AG-1 Question 75. None of the costs of stock-based compensation or other incentive plans, beyond the TIA, were incurred by the Louisville Gas and Electric Company, nor were any such costs allocated to Louisville Gas and Electric Company by any other entity.

b. The attached information is from the Company's financial system and provides incentive compensation expense for 2013, 2014, the base year and the test year. Incentive compensation expense is determined at the beginning of the year, reviewed quarterly and adjusted, if appropriate. Incentive compensation expense is based on labor allocations from the Company's financial system and assumes on-target financial, customer satisfaction and team performance. Individual performance is assumed at 120%. When actual incentive payouts are made during the first quarter of the following year, true-up entries are made to allocate the incentive expense to the appropriate companies and FERC accounts.

While the Company does not report incentive expense by performance goal, 2013's expense is provided below by financial, customer, individual and team performance goals. 2014 incentive expense by performance goal will be available mid-March. See the response to AG 1-75 for details on measure weightings.

Performance Measure	Capitalized	Expensed	Other Balance Sheet	Total
Financial - PPL EPS	23,233	118,308	13,043	154,584
Financial - LKE Net Income	1,149,986	5,855,895	645,579	7,651,460
Customer Satisfaction	267,669	1,363,007	150,264	1,780,939
Individual/Team Effectiveness	561,391	2,858,681	315,153	3,735,225
Total	2,002,279	10,195,891	1,124,038	13,322,208

Louisville Gas and Electric Company
Case No. 2014-00372
Incentive Compensation Expense for 2013, 2014, Base Year and Test Year

LGE

Company Allocated from	Capitalized	Expensed	Other Balance Sheet	Total
2013				
Servco	747,474	5,332,386	387,392	6,467,253
LGE	1,245,402	4,800,507	736,437	6,782,347
KU	9,402	62,998	208	72,608
	2,002,279	10,195,891	1,124,038	13,322,208
2014				
Servco	812,954	5,662,348	438,861	6,914,163
LGE	1,367,206	4,634,350	927,773	6,929,329
KU	7,925	42,654	(0)	50,579
	2,188,086	10,339,352	1,366,634	13,894,071
Base Period				
Servco	603,244	4,977,410	342,211	5,922,865
LGE	1,417,270	5,537,539	526,211	7,481,020
KU	13,209	38,691	-	51,901
	2,033,724	10,553,640	868,422	13,455,786
Forecasted Test Period				
Servco	546,333	5,407,473	399,224	6,353,030
LGE	1,084,276	5,573,371	388,069	7,045,716
KU	17,915	29,124	10,722	57,761
	1,648,524	11,009,967	798,015	13,456,506

EXHIBIT ____ (LK-18)

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Attorney General's Initial Requests for Information
Dated January 8, 2015

Question No. 75

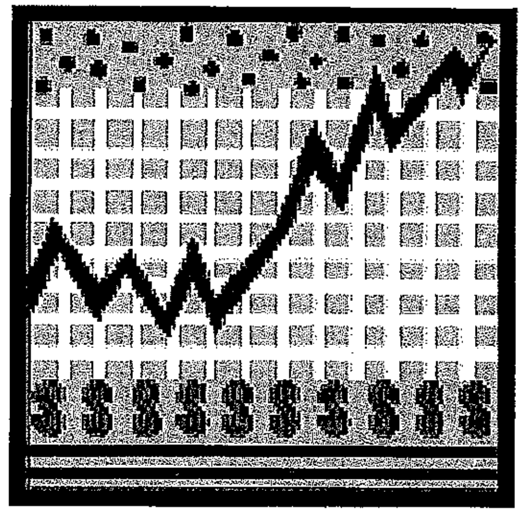
Responding Witness: Paula H. Pottinger, Ph.D.

Q-75. Incentive Programs. Please provide complete copies of any incentive compensation plan, bonus programs or other incentive award programs in effect at the Company for each year 2010 through 2014.

A-75. See attached for the incentive programs which are included in the cost to provide service in this case.

TEAM INCENTIVE AWARD (TIA) PLAN

- ☑ Financial Performance
- ☑ Customer Satisfaction
- ☑ Individual and Team Contributions



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

Revised 6-9-2014

TIA AND BUSINESS STRATEGY

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

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

There are several basic TIA concepts:

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

With these concepts in mind, the TIA was designed:

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

TIA PLAN

Key elements of the TIA are as follows:

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

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

Target Award Participation

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

3. Performance objectives are established annually to support the Company's business strategies. The size of the awards will depend upon the degree to which these objectives are achieved.

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

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

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

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

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

ELIGIBILITY

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

FINANCIAL PERFORMANCE OBJECTIVES

The financial performance objective is determined annually by the parent company. This performance measure is also used for the executive annual incentive to provide direct alignment and common performance objectives with the TIA.

INDIVIDUAL PERFORMANCE

OBJECTIVES

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

TIA COMMUNICATION

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

CONCLUSION

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

TIA FORMULA

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

TIA CALCULATION

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

Step 2: Target Award x Financial Performance Objective Weight x Financial Performance % Earned = Financial Performance Earned Award

Step 3: Target Award x Customer Satisfaction Objective Weight x Customer Satisfaction Performance % Earned = Customer Satisfaction Earned Award

Step 4: Target Award x Individual Performance Objective Weight x Individual Effectiveness % Earned = Individual Performance Earned Award

Step 5: Financial Performance Earned Award + Customer Satisfaction Earned Award + Individual Performance Earned Award = Total Earned TIA

TIA CALCULATION EXAMPLE

Annual Base Pay Earnings = $40,000
Target Award Percent = 9%
Financial Performance % Earned = 105%
Customer Satisfaction % Earned = 100%
Individual Performance % Earned = 110%

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

Step 2: $3,600 x 55% x 105% = $2,079

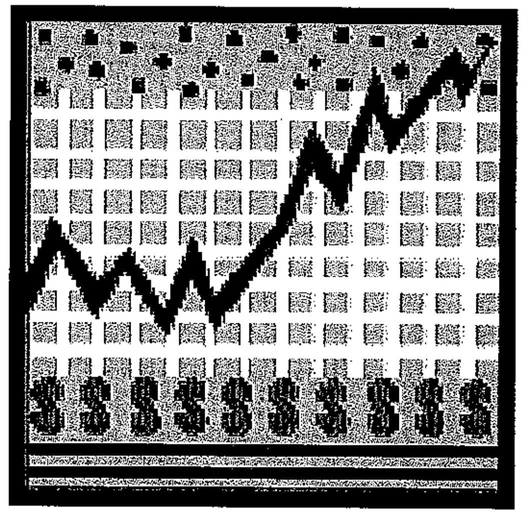
Step 3: $3,600 x 15% x 100% = $540

Step 4: $3,600 x 30% x 110% = $1,188

Step 5: $2,079 + $540 + 1,188 = $3,807

TEAM INCENTIVE AWARD (TIA) PLAN

- Financial Performance
- Customer Satisfaction
- Individual Contributions To The Team



TIA

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

TIA AND BUSINESS STRATEGY

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

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

There are several basic TIA concepts:

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

With these concepts in mind, the TIA was designed:

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

TIA PLAN

Key elements of the TIA are as follows:

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

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

<u>Target Award Participation</u>	
Non-Exempt & Hourly	6% of annual earnings
Exempt	
Individual Contributors	9% of base salary
Managers	14% of base salary
Senior Managers	25% of base salary

3. Performance objectives are established annually to support the Company's business strategies. The size of the awards will depend upon the degree to which these objectives are achieved.

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

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

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

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

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

ELIGIBILITY

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

FINANCIAL PERFORMANCE OBJECTIVES

The financial performance objective is determined annually by the LG&E and KU Finance department. This performance measure is also used for the officer annual incentives as part of the LG&E and KU Short Term Incentive Plan to provide direct alignment and common performance objectives with the TIA. In 2000, we began combining the averages for LG&E and KU Customer Satisfaction into one financial performance objective.

INDIVIDUAL PERFORMANCE OBJECTIVES

The individual performance objective links an individual employee's performance and contributions to the Company and their work group to the TIA award. The individual performance objective can be combined with performance objectives for small teams as well as with key objectives from the Performance Excellence Process. Individual performance objectives should align with, and support, strategic business goals to drive business success.

TIA COMMUNICATION

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

CONCLUSION

The Team Incentive Award Plan is designed to strengthen the connection between pay and performance. It will direct a portion of total pay to awards based on financial, operational and individual achievements. TIA focuses eligible salaried and hourly employee's attention on the company's business goals. It shares the added value created by success and provides everyone a powerful incentive to do his or her very best.

TIA FORMULA

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

TIA CALCULATION

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

Step 2: Target Award x Financial Performance Objective Weight x Financial Performance % Earned = Financial Performance Earned Award

Step 3: Target Award x Customer Satisfaction Objective Weight x Customer Satisfaction Performance % Earned = Customer Satisfaction Earned Award

Step 4: Target Award x Individual Performance Objective Weight x Individual Effectiveness % Earned = Individual Performance Earned Award

Step 5: Financial Performance Earned Award + Customer Satisfaction Earned Award + Individual Performance Earned Award = Total Earned TIA

TIA CALCULATION EXAMPLE

Annual Base Pay Earnings = $40,000
Target Award Percent = 9%
Financial Performance % Earned = 105%
Customer Satisfaction % Earned = 100%
Individual Performance % Earned = 110%

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

Step 2: $3,600 x 45% x 105% = $1,701

Step 3: $3,600 x 15% x 100% = $540

Step 4: $3,600 x 40% x 110% = $1,584

Step 5: $1,701 + $540 + 1,584 = $3,825

2012 Employee Bulletin
LG&E and KU Team Incentive Award measures, weightings announced for 2012

Program to include new PPL "Earnings per Share" minimum performance requirement

LG&E and KU's Team Incentive Award has been a core feature of the company's employee rewards philosophy since the 1990s. While the specific measures and weightings have varied over the years to reflect strategic emphasis, the TIA rewards financial, customer, and individual or team accomplishments. The financial measures have varied — based on the strategy of LG&E and KU's parent company — and have included internal operating profit, Earnings Before Interest and Taxes ("EBIT"), adjusted EBIT and, most recently, net income. The primary financial measure continues to be LKE net income in 2012.

What is "EPS"?
"Earnings per Share" or "EPS" is a carefully scrutinized metric that is often used to gauge a company's profitability per share of stock and is a key driver of share prices. EPS is calculated by dividing net income by the total number of shares outstanding.

For example, if a company's net income is $5 million, and there are 10 million shares outstanding, the EPS would be $0.50:

$5 million/10 million shares = **$0.50**

In terms of the standard performance measures and weightings for LG&E and KU employees, the following table outlines TIA components for 2012.

2012 TIA Measures and Weightings
• 55% – LKE Net Income • 15% – Customer Satisfaction • 30% – Individual/Team Objectives

Managers will be notified via email when PeopleSoft is available to review and approve individual TIA targets, measures and weightings. Managers can then print individual letters for salaried employees. Union and hourly employees will be informed of TIA targets, measures and weightings during a team briefing or in a bulletin board posting.

Also in 2012, LG&E and KU are aligning more closely with PPL's incentive structure by implementing a minimum PPL EPS —"Earnings per Share" — requirement.

The minimum EPS reflects PPL's commitment to align compensation with shareholder interests. PPL has achieved the minimum EPS requirement every year since its inception.

According to Chief Financial Officer, **Kent Blake**, achieving the minimum EPS reflects an important part of PPL's mission, which includes providing shareholders with best-in-sector returns. "Shareholders carefully consider EPS as a way to gauge a company's profitability. EPS is a key driver of share price," he said.

To support our commitment to shareholders, the minimum EPS performance requirement must be achieved before *any* part of the TIA can be paid. If the EPS is not achieved, no TIA payments will be made regardless of LKE financial, customer satisfaction, team or individual performance. While past performance is no indication of future performance, the minimum EPS performance requirement has been achieved every year since it was instituted.

If you have specific questions about TIA measures please contact your Human Resources representative.

Frequently Asked Questions

Are LG&E and KU's standard TIA measures and weightings changing in 2012?
No. The standard TIA measures and weightings are the same as 2011: 55 percent for LG&E and KU net income; 15 percent for customer satisfaction; and 30 percent for individual or team effectiveness.

What is Net Income?
Net Income is LKE's primary financial measure. Net Income is the company's income after all expenses and taxes have been deducted.

How is Customer Satisfaction measured?
Our market research vendor, Bellomy Research, calls randomly selected LG&E and KU customers as well as customers from each peer group company and asks them to take a survey about their satisfaction with their respective utility company. The scores are compiled quarterly, and those results are used to rank the utility companies.

If LKE's overall satisfaction score is above the peer competitive range, we earn 6 points; if within the peer competitive range, we earn 3 points. Two bonus points can be earned if LKE is first in the absolute ranking; one point is earned if we are second in the absolute ranking.

What are Individual Objectives and Team Effectiveness Measures?
Individual objectives and team effectiveness measures are established each year to ensure we are collectively working to achieve strategic business goals. Individual goals vary by individual and by department and support respective department and line of business objectives. Team effectiveness measures are specific to each line of business and reflect key performance indicators.

What is EPS?
EPS is a carefully scrutinized metric that is often used to gauge a company's profitability per share of stock and is a key driver of share prices. EPS is calculated by dividing net income by the total number of shares outstanding.

Who is affected by the EPS minimum performance requirement?
All employees — including executives, senior managers, managers, salaried, hourly and union employees — are affected by the EPS requirement. PPL must achieve the minimum performance requirement in order for *any incentive* program to be funded.

Why are we making this change now?
The Earnings per Share (EPS) minimum performance requirement was in place at PPL prior to the LG&E and KU acquisition. Adoption of this feature of PPL's incentive plan at LKE, as a PPL company, aligns our program with PPL shareholder interests.

What happens if PPL EPS falls below the level required for payments?
No incentives will be paid to any employee in the PPL family of companies. Specifically, for the TIA at LG&E and KU, this means that no payment will be made for LG&E and KU financial, customer satisfaction, team or individual measures, regardless of performance.

What is the specific minimum EPS performance requirement?
PPL, as a publically traded company, must remain vigilant in minimizing the risk of selective disclosure of financial information. As such, internal disclosure of financial targets and goals would create the potential for disclosure outside the company. Best practice is to not provide the specific EPS requirement.

How can LG&E and KU employees impact PPL EPS?
LG&E and KU employees impact PPL's EPS by focusing on their respective budgets which influence LG&E and KU's net income results. The LG&E and KU business segment represents 15 percent of PPL's 2012 EPS total.

Has the minimum requirement for PPL EPS been achieved in the past?
Yes. While past performance is no indication of future performance, the EPS minimum performance requirement has been achieved every year since it was instituted. PPL has paid incentives to employees since the 1990s.

EXHIBIT ____ (LK-19)

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to First Set of Data Requests of Kentucky Industrial Utility Customers, Inc. Dated January 8, 2015

Question No. 20

Responding Witness: Daniel K. Arbough

Q.1-20. Please provide the Company's pension cost calculations for each year 2008 through 2014, the base year, and the test year, showing for each of those years the vintage year gains and losses and the calculation of the amortization of the gains and losses associated with each of those vintage years.

A.1-20. See attached schedule of the Company's pension cost for each year 2008 through 2014, the base year, and the test year.

Kentucky Utilities' Pension Costs

	2008	2009	2010	2011	2012	2013	2014	Base Year	Test Year
Service cost	9,824,728	10,846,457	11,923,065	13,536,659	12,807,482	15,161,440	12,693,955	13,213,077	16,010,380
Interest cost	24,376,281	25,078,862	26,933,197	28,077,257	26,828,995	26,697,750	28,532,418	29,001,705	32,023,655
Expected return on assets	(26,591,898)	(19,387,235)	(23,058,517)	(27,060,946)	(29,578,243)	(36,389,398)	(37,479,393)	(37,549,333)	(39,223,867)
Amortizations:									
Transition	-	-	-	-	-	-	-	-	-
Prior service cost	2,098,821	2,054,315	2,114,733	2,011,865	1,995,945	2,033,254	2,049,822	2,049,390	1,704,173
(Gain)/loss	373,365	11,125,390	9,055,256	12,475,354	9,379,726	17,029,468	4,890,168	6,821,354	15,488,751
ASC 715 NPBC	**10,081,297**	**29,717,790**	**26,967,734**	**29,040,188**	**21,433,905**	**24,532,514**	**10,686,969**	**13,536,192**	**26,003,091**

EXHIBIT ____ (LK-20)

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2014-00372

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 8, 2015

Question No. 20

Responding Witness: Daniel K. Arbough

Q.1-20. Please provide the Company's pension cost calculations for each year 2008 through 2014, the base year, and the test year, showing for each of those years the vintage year gains and losses and the calculation of the amortization of the gains and losses associated with each of those vintage years.

A.1-20. See attached schedule of the Company's pension cost for each year 2008 through 2014, the base year, and the test year.

Louisville Gas and Electric's Pension Costs

	2008	2009	2010	2011	2012	2013	2014	Base Year	Test Year
Service cost	7,879,130	8,189,129	8,454,895	9,358,414	8,700,412	9,968,160	7,854,643	8,186,474	9,821,355
Interest cost	31,393,743	31,758,234	32,883,611	33,621,614	32,396,917	31,199,114	33,269,413	33,685,157	35,927,834
Expected return on assets	(37,404,737)	(26,815,372)	(30,549,918)	(35,447,526)	(38,273,402)	(43,158,195)	(43,575,784)	(43,592,951)	(44,772,026)
Amortizations:									
Transition	-	-	-	-	-	-	-	-	-
Prior service cost	6,812,422	6,683,590	6,297,938	5,307,007	5,625,835	5,160,010	5,153,432	5,341,298	5,955,669
(Gain)/loss	1,526,257	14,602,369	12,561,515	18,397,507	16,084,885	24,174,580	9,555,061	11,930,480	21,983,270
ASC 715 NPBC	**10,206,815**	**34,417,949**	**29,648,041**	**31,237,016**	**24,534,647**	**27,343,668**	**12,256,765**	**15,550,457**	**28,916,101**

EXHIBIT ____ (LK-21)

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 8, 2015

Question No. 15

Responding Witness: Daniel K. Arbough

Q.1-15. Please provide the Company's 2013 and 2014 pension and OPEB actuarial reports as well as the actuarial cost projections for the base year and the test year in a comparable format.

A.1-15. See attachments 1-5 for the 2013 and 2014 actuarial reports.

See the response to Question No. 20 for pension actuarial cost projections for the base year and test year.

See attachment 6 for the OPEB actuarial cost projections for the base year and test year.

Linda C. Myers, F.S.A.
Principal

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MERCER

Private & Confidential
Ms. Kelli Higdon
LG&E and KU Energy LLC
220 West Main Street
Louisville, KY 40202

March 4, 2013

Dear Kelli:

Enclosed are exhibits illustrating the 2013 accounting expense (for both financial and regulatory accounting purposes) for the Qualified Retirement Plans [redacted] of LG&E and KU Energy LLC for the fiscal year ending December 31, 2013.

Compared to the 2013 projections prepared on May 18, 2012, the net periodic pension cost for financial accounting purposes decreases from $12.5 million to $7.8 million, the regulatory accounting expense increases from $36.1 million to $56.9 million and the consolidated financial statement accounting expense increases from $30.8 million to $44.3 million. Please see the attached analysis for the change in net periodic pension cost relative to the estimate provided on May 18, 2012.

A measurement date of December 31, 2012 was used in these calculations. Plan liabilities were based on census data collected as of September 30, 2012. A summary of the participant data is attached. All other methods, assumptions, plan provisions and assets used in calculating the 2013 accounting expense are the same as those used in the December 31, 2012 disclosures, dated January 17, 2013 with the exception that the expected return on assets assumption was lowered from 7.25% to 7.10%.

In addition, we assumed the following contributions were made to the Plans on January 15, 2013:

Plan	Amount (In Millions)
LG&E Union	$10.6
Non-Union	
— LG&E	30.9
— KU	59.4
— ServCo	48.3
— [redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

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If you have any questions or need anything else, please give me a call.

Mercer has prepared this report exclusively for LG&E and KU Energy LLC; subject to this limitation, LG&E and KU Energy LLC may direct that this report be provided to its auditors in connection with the audit of its financial statements. Mercer is not responsible for use of this report by any other party.

The only purpose of this report is to provide an actuarial estimate of the net periodic benefit cost for defined benefit plans relating to the LG&E and KU Energy LLC Retirement Plans for the fiscal year ending December 31, 2013.

This report may not be used for any other purpose. Mercer is not responsible for the consequences of any unauthorized use. Its content may not be modified, incorporated into or used in other material, sold or otherwise provided, in whole or in part, to any other person or entity, without Mercer's permission.

All parts of this report, including any documents incorporated by reference, are integral to understanding and explaining its contents, no part may be taken out of context, used or relied upon without reference to the report as a whole.

Decisions about benefit changes, granting new benefits, investment policy, funding policy, benefit security and/or benefit-related issues should not be made on the basis of this valuation, but only after careful consideration of alternative economic, financial, demographic and societal factors, including financial scenarios that assume future sustained investment losses.

To prepare this report Mercer has used and relied on participant data as of September 30, 2012 as summarized herein. LG&E and KU Energy LLC is responsible for ensuring that such participant data provides an accurate description of all persons who are participants under the terms of the plan or otherwise entitled to benefits that is sufficiently comprehensive and accurate for the purposes of this report. If the data supplied are not sufficiently comprehensive and accurate for the purposes of this report, the valuation results may differ significantly from the results that would be obtained with such data; this may require a later revision of this report. Although Mercer has reviewed the data in accordance with Actuarial Standards of Practice No. 23, Mercer has not verified or audited any of the data or information provided.

Mercer has used and relied on the plan documents, including amendments, and interpretations of plan provisions, as summarized in the Plan Provisions section of the 2012 accounting valuation report. LG&E and KU Energy LLC is solely responsible for the validity, accuracy and comprehensiveness of this information. If any data or plan provisions supplied are not accurate

MERCER

and complete, the valuation results may differ significantly from the results that would be obtained with accurate and complete information; this may require a later revision of this report. Moreover, plan documents may be susceptible to different interpretations, each of which could be reasonable, and that the different interpretations could lead to different valuation results.

This report is based on our understanding of applicable law and regulations as of the valuation date. Mercer is not an accountant or auditor and is not responsible for the interpretation of, or compliance with, accounting standards; citations to, and descriptions of accounting standards provided in this report are for reference purposes only. Mercer is not engaged in the practice of law. This report does not constitute and is not a substitute for legal advice.

The plan sponsor is ultimately responsible for selecting the plan's accounting policies, methods and assumptions. The policies, methods, and assumptions used in this valuation are described in the valuation report. The plan sponsor is solely responsible for communicating to Mercer any changes required to those policies, methods and assumptions.

A valuation report is only a snapshot of a plan's estimated financial condition at a particular point in time; it does not predict the plan's future financial condition or its ability to pay benefits in the future and does not provide any guarantee of future financial soundness of the plan. Over time, a plan's total cost will depend on a number of factors, including the amount of benefits the plan pays, the number of people paid benefits, the period of time over which benefits are paid, plan expenses and the amount earned on any assets invested to pay benefits. These amounts and other variables are uncertain and unknowable at the valuation date.

Because modeling all aspects of a situation is not possible or practical, we may use summary information, estimates, or simplifications of calculations to facilitate the modeling of future events in an efficient and cost-effective manner. We may also exclude factors or data that, if used, in our judgment, would not have significantly affected our results. Use of such simplifying techniques does not, in our judgment, affect the reasonableness of valuation results for the plan.

Valuations do not affect the ultimate cost of the plan, only the timing of when benefit costs are recognized. Cost recognition occurs over time. If the costs recognized over a period of years are lower or higher than necessary, for whatever reason, normal and expected practice is to adjust future expense levels with a view to recognizing the entire cost of the plan over time.

To prepare the valuation report, assumptions are used in a forward looking financial and demographic model to present a single scenario from a wide range of possibilities; the results based on that single scenario are included in the valuation. The future is uncertain and the plan's

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actual experience will differ from those assumptions; these differences may be significant or material because these results are very sensitive to the assumptions made and, in some cases, to the interaction between the assumptions.

Different assumptions or scenarios within the range of possibilities may also be reasonable and results based on those assumptions would be different. As a result of the uncertainty inherent in a forward looking projection over a very long period of time, no one projection is uniquely "correct" and many alternative projections of the future could also be regarded as reasonable. Two different actuaries could, quite reasonably, arrive at different results based on the same data and different views of the future. A "sensitivity analysis" shows the degree to which results would be different if you substitute alternative assumptions within the range of possibilities for those utilized in this report. We have not been engaged to perform such a sensitivity analysis and thus the results of such an analysis are not included in this report. At LG&E and KU Energy LLC's request, Mercer is available to perform such a sensitivity analysis.

Assumptions may also be changed from one valuation to the next because of changes in mandated requirements, plan experience, changes in expectations about the future and other factors. A change in assumptions is not an indication that prior assumptions were unreasonable when made.

This report was prepared in accordance with generally accepted actuarial principles and procedures. Based on the information provided to us, we believe that the actuarial assumptions are reasonable for the purposes described in this report.

LG&E and KU Energy LLC should notify Mercer promptly after receipt of the report if LG&E and KU Energy LLC disagrees with anything contained in the report or is aware of any information that would affect the results of the report that has not been communicated to Mercer or incorporated therein. The report will be deemed final and acceptable to LG&E and KU Energy LLC unless LG&E and KU Energy LLC promptly provides such notice to Mercer.

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I am available to answer any questions on the material contained in the report, or to provide explanations or further details as may be appropriate. The undersigned credentialed actuary meets the Qualification Standards of the American Academy of Actuaries to render the actuarial opinion contained in this report. I am not aware of any direct or material indirect financial interest or relationship, including investments or other services that could create a conflict of interest, that would impair the objectivity of this work.

Linda C. Myers

Linda C. Myers, F.S.A.
Enrolled Actuary (No. 11-04846)

3/4/2013
Date

Copy:
Dan Arbough, Kent Blake, Chris Garrett, Elliott Horne, Greg Meiman, Heather Metts, Vaneeca Mottley, Ken Mudd, Lesley Pienaar, Valerie Scott, Cathy Shultz, Jeanne Wright, Henry Erk, Marcie Gunnell, Patrick Baker

Enclosure

The information contained in this document (including any attachments) is not intended by Mercer to be used, and it cannot be used, for the purpose of avoiding penalties under the Internal Revenue Code that may be imposed on the taxpayer.

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2013 Net Periodic Pension Cost for Qualified Plans

Regulatory Accounting Purposes

	LG&E Union	NonUnion Retirement Plan LG&E	ServCo	KU	WKE	Total	WKE-Union
1. Service cost	$ 2,009,930	$ 2,135,701	$ 12,932,918	$ 8,228,879	$ [redacted]		
2. Interest cost	13,564,734	9,688,835	17,648,530	17,237,432			
3. Expected return on assets	(19,750,316)	(13,542,925)	(21,911,895)	(24,643,746)			
4. Amortizations:							
a. Transition	0	0	0	0			
b. Prior service cost	2,118,027	1,915,245	2,502,694	691,710			
c. Gain/loss	13,633,023	6,931,648	8,018,278	12,731,350			
5. Net periodic pension cost	**$ 11,575,398**	**$ 7,128,504**	**$ 19,190,525**	**$ 14,245,625**	**$**		

Financial Accounting Purposes

	LG&E Union	NonUnion Retirement Plan LG&E	ServCo	KU	WKE	Total	WKE-Union
1. Service cost	$ 2,009,930	$ 2,135,701	$ 12,932,918	$ 8,228,879	$ [redacted]		
2. Interest cost	13,564,734	9,688,835	17,648,530	17,237,432			
3. Expected return on assets	(19,750,316)	(13,542,925)	(21,911,895)	(24,643,746)			
4. Amortizations:							
a. Transition	0	0	0	0			
b. Prior service cost	778,382	0	0	0			
c. Gain/loss	492,338	231,849	0	0			
5. Net periodic pension cost	**$ (2,904,932)**	**$ (1,486,540)**	**$ 8,669,553**	**$ 822,565**	**$**		

2013 Net Periodic Pension Cost for Non-Qualified Plans

Regulatory Accounting Purposes

		Officer SERP			Restoration Plan					Qualified and Non-Qualified Plans
	[redacted]SERP	LG&E	ServCo	Total	LG&E	ServCo	KU	WKE	Total	Grand Total
1. Service cost	[redacted]									
2. Interest cost										
3. Expected return on assets										
4. Amortizations:										
a. Transition										
b. Prior service cost										
c. Gain/loss										
5. Net periodic pension cost										

Financial Accounting Purposes

		Officer SERP			Restoration Plan					
	[redacted]SERP	LG&E	ServCo	Total	LG&E	ServCo	KU	WKE	Total	
1. Service cost	[redacted]									
2. Interest cost										
3. Expected return on assets										
4. Amortizations:										
a. Transition										
b. Prior service cost										
c. Gain/loss										
5. Net periodic pension cost										

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LG&E and KU ENERGY LLC RETIREMENT PLANS

COMPARISON OF PROJECTED 2013 EXPENSE CALCULATED ON MAY 18, 2012 TO ACTUAL 2013 EXPENSE (In Millions)

	Financial Accounting Purposes	Regulatory Accounting Purposes	Consolidated Financial Statement Purposes*
2013 Projected Expense calculated on May 18, 2012**	$12.5	$36.1	$30.8
Increase due to updating of mortality table	0.1	0.4	0.3
Increase due to reduction in discount rates	2.3	27.6	20.0
Decrease due to favorable investment experience for 2012 (assets earned approximately 12.5% compared to 7.25% assumed)	(1.3)	(2.4)	(2.1)
Increase due to reduction in expected return on assets assumption from 7.25% to 7.10%	1.7	1.7	1.7
Decrease due to additional $96.4 million contribution made on January 15, 2013	(6.6)	(6.6)	(6.6)
Increase/(decrease) due to updated data***	(0.9)	0.1	0.2
2013 Actual Expense	$7.8	$56.9	$44.3

* Consolidated Financial Statement Purposes is Regulatory accounting expense for LG&E Union Plan, LG&E division of Non-Union Plan and KU division of Non-Union Plan and Financial accounting expense for all else.

** Please note that the discount rates used in the May 18, 2012 Projected 2013 Expense were 44 basis points higher than the December 31, 2011 discount rates.

*** Service cost was approximately $0.9 million less than expected; however amortization of losses under regulatory accounting and consolidated financial statement purposes were higher than expected.

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LG&E AND KU ENERGY LLC RETIREMENT PLANS

SUMMARY OF PARTICIPANT DATA AS OF SEPTEMBER 30, 2012

	Qualified Plans		
	LG&E Union	Non-Union	WKE Union
Participants included in valuation			[redacted]
• Active	515	1,836	
• Inactive with deferred benefits	679	1,104	
• Inactive with immediate benefits	1,564	2,337	
• Total (includes QDRO beneficiaries	2,758	5,277	
Active Statistics			
• Average age	51.3	51.7	
• Average years of service	25.9	24.2	
Inactive deferred statistics			
• Average age	55.0	52.7	
• Total annual benefits	$7,610,076	$11,126,544	
• Average annual benefits	$11,208	$10,078	
Inactive immediate statistics			
• Average age	68.0	71.3	
• Total annual benefits	$13,789,956	$31,644,264	
• Average annual benefits	$8,817	$13,541	

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LG&E AND KU ENERGY LLC RETIREMENT PLANS

SUMMARY OF PARTICIPANT DATA AS OF SEPTEMBER 30, 2012

	Non-Qualified Plans		
	Officer's SERP	Restoration Plan	[redacted] SERP
Participants included in valuation	[redacted]	[redacted]	[redacted]
• Active			
• Inactive with deferred benefits			
• Inactive with immediate benefits			
• Total			
Active Statistics			
• Average age			
• Average years of service			
Inactive deferred statistics			
• Average age			
• Total annual benefits			
• Average annual benefits			
Inactive immediate statistics			
• Average age			
• Total annual benefits			
• Average annual benefits			

Marcie S. Gunnell, A.S.A., M.A.A.A.
Principal

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Private & Confidential
Ms. Kelli Higdon
LG&E and KU Energy LLC
220 West Main Street
Louisville, KY 40202

March 4, 2013

Subject: 2013 Net Periodic Benefit Cost for Postretirement Benefit Plan

Dear Kelli:

Enclosed are exhibits illustrating the 2013 net periodic benefit cost for financial and regulatory accounting purposes for the Postretirement Benefit Plans of LG&E and KU Energy LLC. The figures in the exhibits may be revised if assets and/or liabilities are remeasured during the year due to a plan amendment, curtailment, settlement or other significant event.

A measurement date of December 31, 2012 was used in these calculations. Plan liabilities were based on census data collected as of September 30, 2012 and claims costs and the expected return on assets (from 7.25% to 7.10%) assumptions were updated. The market values of assets as of December 31, 2012 were provided by LG&E and KU Energy LLC. All other methods, assumptions and plan provisions used in calculating the 2013 net periodic benefit costs were the same as those used in the December 31, 2012 disclosures, including a 3.99% discount rate.

We have assumed no contributions to the 401(h) for 2013.

Compared to the 2013 net periodic benefit cost projections provided on May 18, 2012, the net periodic benefit cost increased. The financial accounting expense increased from $7.5 million to $10.1 million and the regulatory accounting expense increased from $8.8 million to $10.9 million and the consolidated financial statement accounting expense increased from $8.6 million to $10.9 million. Consolidated financial statement accounting includes the expense amounts under regulatory accounting for KU and LG&E (Union and Non-union) and expense amounts under financial accounting for ServCo, WKE (Union and Non-union) and International. The increase was primarily due to losses generated by the decrease in discount rate (from 5.22% to 3.99%), updated per capita claims cost and a lower expected return on 401(h) assets, partially offset by gains generated by updated participant data.

Based on our discussions, we have assumed that LG&E and KU Energy LLC will apply for and receive the subsidy available under Medicare in 2013 for the grandfathered pre-2000 Kentucky Utilities retirees that have post-65 drug coverage. The full amount of the reduction in expense has

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been applied to Kentucky Utilities. The following assumptions were used with the Medicare Modernization Act calculations:

- LG&E and KU Energy LLC will determine actuarial equivalence by benefit option. Testing by benefit option, the grandfathered pre-2000 Kentucky Utilities post-65 retiree medical drug plan is projected to meet the definition of actuarial equivalence indefinitely.
- LG&E and KU Energy LLC will apply for and receive the subsidy available under Medicare indefinitely for all pre-2000 Kentucky Utilities retirees that have post-65 drug coverage.
- Retirees do not elect the Medicare Part D benefit.

The estimated subsidy was based on Mercer's understanding of the Medicare Reform legislation based on the final Center for Medicare Services (CMS) regulations issued in January 2005 and on the provided claims information from the medical plan administrator.

Mercer has prepared this report exclusively for LG&E and KU Energy LLC; subject to this limitation, LG&E and KU Energy LLC may direct that this report be provided to its auditors in connection with the audit of its financial statements. Mercer is not responsible for use of this report by any other party.

The only purpose of this report is to present Mercer's actuarial estimate of net periodic benefit cost for the fiscal year ending December 31, 2013 for other postretirement benefit plans relating to LG&E and KU Energy LLC, for LG&E and KU Energy LLC to incorporate, as LG&E and KU Energy LLC deems appropriate, in its financial statements under US accounting standards.

This report may not be used for any other purpose. Mercer is not responsible for the consequences of any unauthorized use. Its content may not be modified, incorporated into or used in other material, sold or otherwise provided, in whole or in part, to any other person or entity, without Mercer's permission.

All parts of this report, including any documents incorporated by reference, are integral to understanding and explaining its contents, no part may be taken out of context, used or relied upon without reference to the report as a whole.

Decisions about benefit changes, granting new benefits, investment policy, funding policy, benefit security and/or benefit-related issues should not be made on the basis of this valuation, but only after careful consideration of alternative economic, financial, demographic and societal factors, including financial scenarios that assume future sustained investment losses.

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To prepare this report Mercer has used and relied on participant data as provided by LG&E and KU Energy LLC to Mercer Outsourcing as summarized on the attached exhibits. LG&E and KU Energy LLC is responsible for ensuring that such participant data provides an accurate description of all persons who are participants under the terms of the plan or otherwise entitled to benefits that is sufficiently comprehensive and accurate for the purposes of this report. If the data supplied are not sufficiently comprehensive and accurate for the purposes of this report, the valuation results may differ significantly from the results that would be obtained with such data; this may require a later revision of this report. Although Mercer has reviewed the data in accordance with Actuarial Standards of Practice No. 23, Mercer has not verified or audited any of the data or information provided.

Mercer has used and relied on the plan documents, including amendments, and interpretations of plan provisions provided by LG&E and KU Energy LLC. The plan provisions used in this valuation are described in the December 31, 2012 year end disclosure report, dated January 18, 2013. LG&E and KU Energy LLC is solely responsible for the validity, accuracy and comprehensiveness of this information. If any data or plan provisions supplied are not accurate and complete, the valuation results may differ significantly from the results that would be obtained with accurate and complete information; this may require a later revision of this report. Moreover, plan documents may be susceptible to different interpretations, each of which could be reasonable, and that the different interpretations could lead to different valuation results.

This report is based on our understanding of applicable law and regulations as of the valuation date. Mercer is not an accountant or auditor and is not responsible for the interpretation of, or compliance with, accounting standards; citations to, and descriptions of accounting standards provided in this report are for reference purposes only. Mercer is not engaged in the practice of law. This report does not constitute and is not a substitute for legal advice.

The plan sponsor is ultimately responsible for selecting the plan's accounting policies, methods and assumptions. The policies, methods, and assumptions used in this valuation are described in herein. The plan sponsor is solely responsible for communicating to Mercer any changes required to those policies, methods and assumptions.

A valuation report is only a snapshot of a plan's estimated financial condition at a particular point in time; it does not predict the plan's future financial condition or its ability to pay benefits in the future and does not provide any guarantee of future financial soundness of the plan. Over time, a plan's total cost will depend on a number of factors, including the amount of benefits the plan

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pays, the number of people paid benefits, the period of time over which benefits are paid, plan expenses and the amount earned on any assets invested to pay benefits. These amounts and other variables are uncertain and unknowable at the valuation date.

Because modeling all aspects of a situation is not possible or practical, we may use summary information, estimates, or simplifications of calculations to facilitate the modeling of future events in an efficient and cost-effective manner. We may also exclude factors or data that, if used, in our judgment, would not have significantly affected our results. Use of such simplifying techniques does not, in our judgment, affect the reasonableness of valuation results for the plan.

Valuations do not affect the ultimate cost of the plan, only the timing of when benefit costs are recognized. Cost recognition occurs over time. If the costs recognized over a period of years are lower or higher than necessary, for whatever reason, normal and expected practice is to adjust future expense levels with a view to recognizing the entire cost of the plan over time.

To prepare the valuation report, assumptions are used in a forward looking financial and demographic model to present a single scenario from a wide range of possibilities; the results based on that single scenario are included in the valuation. The future is uncertain and the plan's actual experience will differ from those assumptions; these differences may be significant or material because these results are very sensitive to the assumptions made and, in some cases, to the interaction between the assumptions.

Different assumptions or scenarios within the range of possibilities may also be reasonable and results based on those assumptions would be different. As a result of the uncertainty inherent in a forward looking projection over a very long period of time, no one projection is uniquely "correct" and many alternative projections of the future could also be regarded as reasonable. Two different actuaries could, quite reasonably, arrive at different results based on the same data and different views of the future. A "sensitivity analysis" shows the degree to which results would be different if you substitute alternative assumptions within the range of possibilities for those utilized in this report. We have not been engaged to perform such a sensitivity analysis and thus the results of such an analysis are not included in this report. At LG&E and KU Energy LLC's request, Mercer is available to perform such a sensitivity analysis.

Assumptions may also be changed from one valuation to the next because of changes in mandated requirements, plan experience, changes in expectations about the future and other factors. A change in assumptions is not an indication that prior assumptions were unreasonable when made.

MERCER

This report was prepared in accordance with generally accepted actuarial principles and procedures. Based on the information provided to us, we believe that the actuarial assumptions are reasonable for the purposes described in this report.

LG&E and KU Energy LLC should notify Mercer promptly after receipt of the valuation report if LG&E and KU Energy LLC disagrees with anything contained in the valuation report or is aware of any information that would affect the results of the valuation report that has not been communicated to Mercer or incorporated therein. The valuation report will be deemed final and acceptable to LG&E and KU Energy LLC unless LG&E and KU Energy LLC promptly provides such notice to Mercer.

Professional qualifications

We are available to answer any questions on the material contained in the report, or to provide explanations or further details as may be appropriate. Collectively, the credentialed actuaries Marcie Gunnell and Linda Myers meet the Qualification Standards of the American Academy of Actuaries to render the actuarial opinion contained in this report. We are not aware of any direct or material indirect financial interest or relationship, including investments or other services that could create a conflict of interest, that would impair the objectivity of our work.

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Please distribute copies of this letter to the appropriate parties. If you have any questions, please call me at 502 561 4622 or Patrick Baker at 502 561 4504.

Sincerely,

Marcie S. Gunnell

Marcie S. Gunnell, A.S.A., M.A.A.A.
Principal

Linda C. Myers

Linda C. Myers, F.S.A., M.A.A.A
Principal

Copy:
Dan Arbough, Kent Blake, Chris Garrett, Elliott Horne, Greg Meiman, Heather Metts, Vaneeca Mottley, Ken Mudd, Lesley Pienaar, Valerie Scott, Cathy Shultz, Jeanne Wright, Henry Erk, Linda Myers, Patrick Baker, Ryan Sloat

Enclosure

The information contained in this document (including any attachments) is not intended by Mercer to be used, and it cannot be used, for the purpose of avoiding penalties under the Internal Revenue Code that may be imposed on the taxpayer.

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LG&E and KU Energy LLC
2013 Net Periodic Benefit Cost For Postretirement Benefit Plans
December 31, 2012 Measurement Date
Financial Accounting

	Non-Union								
	LG&E	KU	ServCo	WKE	International	Total	LG&E Union	WKE Union	Grand Total
Service cost	$558,714	$1,627,357	$1,948,537	[redacted]	[redacted]	[redacted]	$543,711	[redacted]	[redacted]
Interest cost	1,401,064	3,144,110	1,467,859	[redacted]	[redacted]	[redacted]	2,166,007	[redacted]	[redacted]
Expected return on assets	(514,386)	(1,976,373)	(1,963,676)	[redacted]	[redacted]	[redacted]	0	[redacted]	[redacted]
Amortizations:									
Transition	0	0	0	[redacted]	[redacted]	[redacted]	0	[redacted]	[redacted]
Prior service cost	283,863	586,092	512,905	[redacted]	[redacted]	[redacted]	375,701	[redacted]	[redacted]
Gain/loss	0	0	0	[redacted]	[redacted]	[redacted]	0	[redacted]	[redacted]
Net periodic benefit cost	$1,729,255	$3,381,186	$1,965,625	[redacted]	[redacted]	[redacted]	$3,085,419	[redacted]	[redacted]

Regulatory Accounting

	Non-Union								
	LG&E	KU	ServCo	WKE	International	Total	LG&E Union	WKE Union	Grand Total
Service cost	$558,714	$1,627,357	$1,948,537	[redacted]	[redacted]	[redacted]	$543,711	[redacted]	[redacted]
Interest cost	1,401,064	3,144,110	1,467,859	[redacted]	[redacted]	[redacted]	2,166,007	[redacted]	[redacted]
Expected return on assets	(514,386)	(1,976,373)	(1,963,676)	[redacted]	[redacted]	[redacted]	0	[redacted]	[redacted]
Amortizations:									
Transition	0	0	0	[redacted]	[redacted]	[redacted]	0	[redacted]	[redacted]
Prior service cost	419,309	749,385	602,613	[redacted]	[redacted]	[redacted]	1,118,030	[redacted]	[redacted]
Gain/loss	0	0	0	[redacted]	[redacted]	[redacted]	(198,854)	[redacted]	[redacted]
Net periodic benefit cost	$1,864,701	$3,544,479	$2,055,333	[redacted]	[redacted]	[redacted]	$3,628,894	[redacted]	[redacted]
Accumulated Postretirement Benefit Obligation (APBO) as of December 31, 2012	36,513,343	81,394,201	37,280,350	[redacted]	[redacted]	[redacted]	55,914,515	[redacted]	[redacted]

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LG&E and KU ENERGY LLC RETIREMENT PLANS

COMPARISON OF PROJECTED 2013 EXPENSE CALCULATED ON May 18, 2012 TO ACTUAL 2013 EXPENSE (In Millions)

	Financial Accounting Purposes	Regulatory Accounting Purposes	Consolidated Financial Statement Purposes[1]
2013 Projected Expense calculated on May 18, 2012	$7.5	$8.8	$8.6
Decrease due to change in updating of mortality table	(0.1)	(0.1)	(0.1)
Increase due to reduction in discount rates	2.1	2.0	2.0
Increase due to not funding 401(h) account in 2012	0.4	0.4	0.4
Increase due to updated projected medical costs	0.9	0.9	0.9
Increase due to lower return on assets assumption (from 7.25% to 7.10%)	0.1	0.1	0.1
Decrease due to demographic and other gains / losses	(0.8)	(1.2)	(1.0)
2013 Actual Expense	10.1	$10.9	$10.9

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[1] Consolidated Financial Statement Purposes is Regulatory accounting expense for LG&E (Union and Non-Union) and KU (Union and Non-Union) and Financial accounting expense for all else.

LG&E and KU Energy LLC
Summary of Participant Data and Per Capita Claims Costs

	9/30/2012	9/30/2011
Active participants	3,228	3,120
Average age	47.4	47.5
Average service	18.8	19.2
Inactive participants		
Retirees	2,621	2,635
Spouses of retirees	1,198	1,233
Surviving spouses	292	295
Disableds	119	122
Total	4,230	4,285

	Fiscal Year Ending December 31, 2013	Fiscal Year Ending December 31, 2012
Annual average per capita claims cost		
LG&E, Kentucky Utilities post-1999 and WKE Union average pre-Medicare	$8,640	$7,805
Kentucky Utilities pre-1993 average cost per person (pre and post Medicare)	$6,255	$5,950
Kentucky Utilities 1993-1999 average cost per person (pre and post Medicare)	$4,141	$3,987
Annual average expected Medicare Part D subsidy		
Kentucky Utilities pre-1993	$806	$734
Kentucky Utilities 1993-1999	$740	$682

LG&E and KU Energy LLC ("LKE")
2014 Net Periodic Pension Cost
Qualified Pension Plans - Revised to reflect original non-union inactive division codes

	Regulatory	Regulatory	Financial	Regulatory	Financial		Financial	Consolidated	Regulatory
		Non-Union Retirement Plan							Non-Union
	LG&E Union	LG&E	ServCo	KU	WKE	Non-Union Total	WKE Union	Total Qualified US GAAP	ServCo
Funded Status									
ABO	291,960,791	181,895,592	314,238,243	319,364,020	[redacted]				314,238,243
PBO	291,960,791	203,826,984	382,044,504	358,066,243					382,044,504
Fair value of assets	281,471,417	193,333,088	324,413,186	354,179,143					324,413,186
Funded status	(10,489,374)	(10,493,896)	(57,631,318)	(3,887,100)					(57,631,318)
Amounts recognized in accumulated other comprehensive income consist of:									
Net actuarial loss/(gain)	90,205,599	49,955,184	(15,372,183)	79,418,733					56,237,829
Prior service cost/(credit)	15,386,016	7,097,210	-	1,451,525					11,455,908
Transition obligation/(asset)	-	-	-	-					-
Total	105,591,615	57,052,394	(15,372,183)	80,870,258					67,693,737
Market related value of assets	284,346,002	196,254,558	327,456,800	359,368,151					327,456,800
2014 Net Periodic Pension Cost									
Service cost	1,326,414	1,679,175	10,833,938	6,814,810					10,833,938
Interest cost	14,383,940	10,170,845	19,470,548	17,966,530					19,470,548
Expected return on assets	(19,094,174)	(13,714,725)	(24,055,778)	(24,425,285)					(24,055,778)
Amortization of:									
Transition obligation (asset)	-	-	-	-					-
Prior service cost (credit)	2,118,027	1,915,249	-	691,710					2,502,695
Actuarial (gain) loss	6,041,249	2,807,143	-	4,033,380					1,578,867
Net periodic pension cost	4,775,456	2,857,687	6,248,708	5,081,145					10,330,270
Key assumptions:									
Discount rate	5.13%	5.20%	5.20%	5.20%					5.20%
Expected return on plan assets	7.00%	7.00%	7.00%	7.00%					7.00%
Rate of compensation increase	N/A	4.00%	4.00%	4.00%					4.00%
Mortality		2014 IRS-prescribed RP-2000 tables. Includes projection for 7 years beyond valuation date for annuitants; 15 years for non-annuitants.							

The results contained in this document are based on the data provided by Mercer Outsourcing as of January 1, 2014. All other assumptions, methods, and plan provisions are the same as those used for the year-end 2013 financial statement fisclosures provided on January 22, 2014. The descriptions of the assumptions, methods, plan provisions, and limitations as set forth in the year-end 2013 financial statement disclosure letter should be considered part of these results.

The results above have been revised to reflect the non-union plan division codes used for Mercer's 2013 accounting valuation, which were provided to us in the 2013 actuarial transition data. 95 inactive participants were reverted back to their original division. In addition, two deceassed participants provided by LKE on 6/20/2014 were removed from the results.

Attachment #3 to Response to KU KIUC-1 Question No. 15
Page 1 of 1
Arbough

TOWERS WATSON

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April 30, 2014

Ms. Kelli Higdon
Senior Accounting Analyst
LG&E and KU Energy LLC
220 West Main Street
Louisville, KY 40202

Dear Kelli:

2014 ASC 715 ACOUNTING RESULTS FOR QUALIFIED PENSION PLANS

LG&E and KU Energy LLC ("LKE" or "the Company") engaged Towers Watson Delaware, Inc. ("Towers Watson") to determine the Net Periodic Pension Cost/Income ("Expense") for its qualified pension plans, in accordance with FASB Accounting Standards Codification Topic 715 ("ASC 715") for the fiscal year beginning January 1, 2014. The exhibits that follow provide results on a plan by plan basis, with allocations as requested by LKE.

The benefit obligations were measured as of LKE's fiscal year begin date of January 1, 2014, and are based on January 1, 2014 census data collected from the plan administrator for the following valuations:

- LG&E and KU Retirement Plan
- Louisville Gas and Electric Company Bargaining Employees' Retirement Plan
- [redacted]

We have reviewed the census information for reasonableness and consistency, but have neither audited nor independently verified this information. Based on discussions with and concurrence by the plan sponsor, assumptions or estimates may have been made if data were not available. We are not aware of any errors or omissions in the data that would have a significant effect on the results of our calculations.

Please note the following regarding these results:

1. As of January 1, 2014, LG&E and KU Energy LLC has selected the following economic assumptions:

   Discount rate:

	January 1, 2014
LG&E and KU Retirement Plan	5.20%
Louisville Gas and Electric Company Bargaining Employees' Retirement Plan	5.13%
[redacted]	[redacted]

   All discount rates are based on the results of the Towers Watson BOND:Link model. At December 31, 2013, cash flows by plan were provided by the prior actuary and used to develop individual discount rates. Further information regarding the BOND:Link model parameters chosen by LKE can be found in our e-mail correspondence from January 7, 2014.

Rate of compensation increase:

The January 1, 2014 rate of compensation increase assumption for all LKE plans is a flat 4% at all ages.

Expected return on assets (EROA):

	January 1, 2014
LG&E and KU Retirement Plan	7.00%
Louisville Gas and Electric Company Bargaining Employees' Retirement Plan	7.00%
[redacted]	[redacted]

2. All demographic assumptions are the same as those selected by LKE at January 1, 2013 with the exception of the mortality assumption. The mortality assumption has been changed from the optional combined 2013 mortality table with static mortality improvement published by the IRS to separate 2014 IRS rates for non-annuitants (based on RP-2000 "Employees" table without collar or amount adjustments, projected 15 beyond the valuation) and annuitants (based on RP-2000 "Healthy Annuitants" table without collar or amount adjustments, projected 7 years beyond the valuation date). The optional combined table used for the 2013 valuation is a blended table with a single mortality assumption for non-annuitants and annuitants based on similar mortality tables and mortality improvement projections. A summary of all assumptions can be found in the Assumption Setting Presentation provided to LKE on January 7, 2014. Detailed descriptions of these assumptions will be included in the actuarial valuation reports for the fiscal year ending December 31, 2014 (to be published during the coming months).

3. All plan provisions are the same as those valued at January 1, 2013, updated at January 1, 2014 to reflect scheduled increases in the dollar per month multiplier, if applicable.

   Detailed descriptions of the plan provisions will be included in the actuarial valuation reports for the fiscal year ending December 31, 2014 (to be published during the coming months).

4. The expected contributions for 2014 were set equal to the actual contributions made on January 14, 2014, specifically according to the table below:

	Contribution (in $millions)
LG&E and KU Retirement Plan	
LG&E non-union	$8.2
ServCo	$24.7
KU	$2.2
[redacted]	[redacted]
Louisville Gas and Electric Company Bargaining Employees' Retirement Plan	$0.0
[redacted]	[redacted]
	[redacted]

TOWERS WATSON

Ms. Kelli Higdon
April 30, 2014

Reconciliation to February 21, 2014 Budget Projections

The preliminary 2014 consolidated US GAAP expense for the three pension plans of $17.9 million compares to the projected 2014 consolidated expense of $24.6 million provided in our February 21, 2014 e-mail as follows:

	Consolidated US GAAP Expense (in $millions)
2014 Projected Expense provided on February 21, 2014	$24.6*
5% load on service cost and interest cost included in 2014 budgets	(4.2)
Demographic gains due to updated data	(2.7)
[redacted]	
Difference between expected and actual 2014 bulk lump sum amounts	0.1
2014 Preliminary Expense	$17.9

*Estimated expense provided on February 21, 2014 did not include the WKE non-union portion of the LG&E and KU Retirement Plan on a Financial basis or the Western Kentucky Energy Corp. Bargaining Employees' Retirement Plan on a Financial basis.

Actuarial Certification

In preparing the results presented in this letter (including attached exhibits), we have relied upon information regarding plan provisions, participants, assets and sponsor accounting policies and methods provided by LKE and other persons or organizations designated by LKE. We have relied on all the data and information provided as complete and accurate. We have reviewed this information for overall reasonableness and consistency, but have neither audited nor independently verified this information. Based on discussions with and concurrence by the plan sponsor, assumptions or estimates may have been made if data were not available. We are not aware of any errors or omissions in the data that would have a significant effect on the results of our calculations. The results presented in this report are directly dependent upon the accuracy and completeness of the underlying data and information. Any material inaccuracy in the data, assets, plan provisions or other information provided to us may have produced results that are not suitable for the purposes of this report and such inaccuracies, as corrected by LKE, may produce materially different results that could require that a revised report be issued.

The measurement date is January 1, 2014. The benefit obligations were measured as of January 1, 2014 and are based on participant data as of the census data, January 1, 2014.

Information about the fair value of plan assets was furnished to us by BNY Mellon. LKE also provided information about the general ledger account balances for the pension plan costs at December 31, 2013, which reflect the expected funded status of the plans before adjustment to reflect the plans' funded status based on the year-end measurements. Towers Watson used information supplied by LKE regarding amounts recognized in accumulated other comprehensive income as of December 31, 2013. This data was reviewed for reasonableness and consistency, but no audit was performed.

As required by U.S. GAAP, the actuarial assumptions and the accounting policies and methods employed in the development of the pension cost have been selected by LKE. Towers Watson has concurred with these assumptions and methods. ASC 715-30-35 requires that each significant assumption "individually represent the best estimate of a particular future event."

The results shown in this report have been developed based on actuarial assumptions that, to the extent evaluated by Towers Watson, we consider to be reasonable and within the "best-estimate range" as described by the Actuarial Standards of Practice. Other actuarial assumptions could also be considered to be reasonable and within the best-estimate range. Thus, reasonable results differing from those presented in this report could have been developed by selecting different points within the best-estimate range for various assumptions.

The results shown in this report are estimates based on data that may be imperfect and on assumptions about future events that cannot be predicted with any certainty. The effects of certain plan provisions may be approximated, or determined to be insignificant and therefore not valued. Reasonable efforts were made in preparing this valuation to confirm that items that are significant in the context of the actuarial liabilities or costs are treated appropriately, and are not excluded or included inappropriately. The numbers shown in this report are not rounded, but this is for convenience and should not implay precision, which is not a characteristic of actuarial calculations.

If overall future plan experience produces higher benefit payments or lower investment returns than assumed, the relative level of plan costs reported in this valuation will likely increase in future valuations (and vice versa). Future actuarial measurements may differ significantly from the current measurements presented in this report due to many factors, including: plan experience differing from the anticipated by the economic or demographic assumptions, increases or decreases expected as part of the natural operation of the methodology used for the measurements (such as the end of an amortization period), and changes in plan provisions or applicable law.

The information contained in this report was prepared for the internal use of LKE and its auditors in connection with our actuarial valuations of the qualified pension plans. It is neither intended for and may not be used for other purposes, and we accept no responsibility or liability in this regard. LKE may distribute this actuarial valuation report to the appropriate authorities who have the legal right to require LKE to provide them this report, in which case LKE will use best efforts to notify Towers Watson in advance of this distribution. Further distribution to, or use by, other parties of all or part of this document is expressly prohibited without Towers Watson's prior written consent. Towers Watson accepts no responsibility for any consequences arising from any other party relying on this report or any advice relating to its contents.

The undersigned consulting actuaries are members of the Society of Actuaries and meet the "Qualification Standards for Actuaries Issuing Statements of Actuarial Opinion in the United States" relating to pension plans. Our objectivity is not impaired by any relationship between the plan sponsor and our employer, Towers Watson Delaware Inc.

* * * * *

Please do not hesitate to call if you have any questions.

Sincerely,

Jennifer A. Della Pietra

Jennifer A. Della Pietra, ASA, EA

Senior Consulting Actuary
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Royce Kosoff

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cc: George Sunder – PPL Corporation
Dan Arbough – LG&E and KU Energy LLC
Karla Durn – PPL Corporation
Kristin May, FSA, EA – Towers Watson

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TOWERS WATSON

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May 16, 2014

Ms. Kelli Higdon
Senior Accounting Analyst
LG&E and KU Energy LLC
220 West Main Street
Louisville, KY 40202

Dear Kelli:

2014 ASC 715 ACOUNTING RESULTS FOR THE POSTRETIREMENT BENEFIT PLAN

LG&E and KU Energy LLC ("LKE" or "the Company") engaged Towers Watson Delaware, Inc. ("Towers Watson") to determine the Net Periodic Benefit Cost/Income ("Expense") for the LG&E and KU Energy Postretirement Benefit Plan, in accordance with FASB Accounting Standards Codification Topic 715 ("ASC 715") for the fiscal year beginning January 1, 2014. The exhibits that follow provide results for the plan, with allocations as requested by LKE.

Please note the following regarding these results:

1. As of January 1, 2014, LG&E and KU Energy LLC has selected the following economic assumptions:

   Discount rate:

   The discount rate of 4.91% is based on the results of the Towers Watson BOND:Link model. At December 31, 2013, cash flows by plan were provided by the prior actuary and used to develop individual discount rates. Further information regarding the BOND:Link model parameters chosen by LKE can be found in our e-mail correspondence from January 7, 2014.

   Rate of compensation increase:

   The January 1, 2014 rate of compensation increase assumption for the plan is a flat 4% at all ages.

   Expected return on assets (EROA):

   The January 1, 2014 EROA assumption for the plan is 7.00% for the 401(h) account and 0.00% for the Union and Non-union VEBAs.

   Health care cost trend:

	December 31, 2013
2014	7.6%
2015	7.2%
2016	6.8%
2017	6.4%
2018	6.0%
2019	5.5%
2020+	5.0%

Per capita claims cost:

The per capita claims costs and employee contribution amounts for 2014 were provided by Mercer. We have reviewed the claims information for reasonableness and consistency, but have neither audited nor independently verified this information.

2. All demographic assumptions are the same as those selected by LKE at January 1, 2013 with the exception of the mortality assumption. The mortality assumption has been changed from the optional combined 2013 mortality table with static mortality improvement published by the IRS to separate 2014 IRS rates for non-annuitants (based on RP-2000 "Employees" table without collar or amount adjustments, projected 15 beyond the valuation) and annuitants (based on RP-2000 "Healthy Annuitants" table without collar or amount adjustments, projected 7 years beyond the valuation date). The optional combined table used for the 2013 valuation is a blended table with a single mortality assumption for non-annuitants and annuitants based on similar mortality tables and mortality improvement projections. A summary of all assumptions can be found in the Assumption Setting Presentation provided to LKE on January 7, 2014. Detailed descriptions of these assumptions will be included in the actuarial valuation reports for the fiscal year ending December 31, 2014 (to be published during the coming months).

3. All plan provisions are the same as those valued at January 1, 2013. Detailed descriptions of the plan provisions will be included in the actuarial valuation reports for the fiscal year ending December 31, 2014 (to be published during the coming months).

4. The expected contributions to the 401(h) sub-account are assumed to be contributed on December 31st, 2014 and, therefore, have no impact on the calculation of the expected return on assets. The expected contributions to the Union and Non-union VEBAs are assumed to be made monthly equal to the amounts paid out of the VEBA account each month.

5. Under PPACA, the Transitional Reinsurance Fee ("TRF") is scheduled to be collected from both self-insured employer medical plans and fully insured medical plans beginning in 2014 and continuing through 2016 as a means to help stabilize premiums for coverage in the individual market (inside and outside the exchanges). Consistent with the prior year, the TRF will be accounted for outside of the plan, and therefore, the 2014 postretirement benefit obligations have not been adjusted to reflect the expected cost of the TRF.

TOWERS WATSON

Reconciliation to February 21, 2014 Budget Projections

The preliminary 2014 consolidated US GAAP expense for the postretirement benefit plan of $10.4 million compares to the projected 2014 consolidated expense of $10.7 million provided in our February 21, 2014 e-mail as follows:

	Consolidated US GAAP Expense (in $millions)
2014 Projected Expense provided on February 21, 2014	$10.7*
Demographic gains due to updated data	(0.1)
[redacted]	
Reflection of updated per capita claims data	0.6
5% load on service cost and interest cost included in 2014 budgets	(0.7)
2014 Preliminary Expense	$10.4

*Estimated expense provided on February 21, 2014 did not include the International, WKE non-union and WKE Union portions of the plan on a Financial basis.

Retiree Drug Subsidy under the Medicare Modernization Act

2014 Net Periodic Benefit Cost ($) (Regulatory Accounting Basis)	With Subsidy	Effect of Subsidy	Without Subsidy
Service cost	4,332,469	-	4,332,469
Interest cost	9,283,250	178,329	9,461,579
Expected return on assets	(5,016,620)	-	(5,016,620)
Amortization of:	-		
Transition obligation (asset)	-	-	-
Prior service cost (credit)	2,486,179	-	2,486,179
Actuarial (gain) loss	(731,851)	258,487	(473,364)
Net periodic benefit cost	$ 10,353,427	$ 436,816	$ 10,790,243

The present value of the Medicare Retiree Drug Subsidy for the pre-2000 Kentucky Utilities retirees, measured as of January 1, 2014, using the assumptions outlined in this letter is $3,804,507.

Actuarial Certification

In preparing the results presented in this letter (including the attached exhibit), we have relied upon information regarding plan provisions, participants, assets and sponsor accounting policies and methods provided by LKE and other persons or organizations designated by LKE. We have relied on all the data and information provided as complete and accurate. We have reviewed this information for overall reasonableness and consistency, but have neither audited nor independently verified this information. Based on discussions with and concurrence by the plan sponsor, assumptions or estimates may have been made if data were not available. We are not aware of any errors or omissions in the data that would have a significant effect on the results of our calculations. The results presented in this report are directly dependent upon the accuracy and completeness of the underlying data and information. Any material inaccuracy in the data, assets, plan provisions or other information provided to us may have produced results that are not suitable for the purposes of this report and such inaccuracies, as corrected by LKE, may produce materially different results that could require that a revised report be issued.

The measurement date is January 1, 2014. The benefit obligations were measured as of January 1, 2014 and are based on participant data as of the census date, January 1, 2014.

Information about the fair value of plan assets was furnished to us by LKE. LKE also provided information about the general ledger account balances for the postretirement benefit plan cost at December 31, 2013, which reflect the expected funded status of the plans before adjustment to reflect the plans' funded status based on the year-end measurements, and differences between the expected Medicare Part D subsidies and amounts received during the year. Towers Watson used information supplied by LKE regarding postretirement benefit asset, postretirement liability and amounts recognized in accumulated other comprehensive income as of December 31, 2013. This data was reviewed for reasonableness and consistency, but no audit was performed.

Accumulated other comprehensive (income)/loss amounts shown in this letter are shown prior to adjustment for deferred taxes. Any deferred tax effects in AOCI should be determined in consultation with LKE's tax advisors and auditors.

As required by U.S. GAAP, the actuarial assumptions and the accounting policies and methods employed in the development of the postretirement benefit cost and financial reporting have been selected by LKE. Towers Watson has concurred with these assumptions and methods. ASC 715-30-35 requires that each significant assumption "individually represent the best estimate of a particular future event."

The results shown in this report have been developed based on actuarial assumptions that, to the extent evaluated by Towers Watson, we consider to be reasonable and within the "best-estimate range" as described by the Actuarial Standards of Practice. Other actuarial assumptions could also be considered to be reasonable and within the best-estimate range. Thus, reasonable results differing from those presented in this report could have been developed by selecting different points within the best-estimate range for various assumptions.

The results shown in this report are estimates based on data that may be imperfect and on assumptions about future events that cannot be predicted with any certainty. The effects of certain plan provisions may be approximated, or determined to be insignificant and therefore not valued. Reasonable efforts were made in preparing this valuation to confirm that items that are significant in the context of the actuarial liabilities or costs are treated appropriately, and are not excluded or included inappropriately. The numbers shown in this report are not rounded, but this is for convenience and should not imply precision, which is not a characteristic of actuarial calculations.

If overall future plan experience produces higher benefit payments or lower investment returns than assumed, the relative level of plan costs reported in this valuation will likely increase in future valuations (and vice versa). Future actuarial measurements may differ significantly from the current measurements presented in this report due to many factors, including: plan experience differing from that anticipated by the economic or demographic assumptions, increases or decreases expected as part of the natural operation of the methodology used for the measurements (such as the end of an amortization period), and changes in plan provisions or applicable law.

The information contained in this report was prepared for the benefit of LKE and its auditors in connection with our actuarial valuation of the postretirement benefit plan. This letter should not be used for other purposes, and Towers Watson accepts no responsibility for any such use. It should not be relied upon by any other person without Towers Watson's prior written consent.

The undersigned consulting actuaries are members of the Society of Actuaries and meet the "Qualification Standards for Actuaries Issuing Statements of Actuarial Opinion in the United States" relating to other postretirement benefit plans. Our objectivity is not impaired by any relationship between the plan sponsor and our employer, Towers Watson Delaware Inc.

*   *   *   *   *

Please do not hesitate to call if you have any questions.

Sincerely,

Jennifer A. Della Pietra

Jennifer A. Della Pietra, ASA, EA

Senior Consulting Actuary
Direct Dial: 215-246-6861

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Royce S. Kosoff, FSA, EA, CFA

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William Loth

William R. Loth, FSA, EA
Consulting Actuary
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cc: George Sunder – PPL Corporation
Dan Arbough – LG&E and KU Energy LLC
Karla Durn – PPL Corporation
Kristin May, FSA, EA – Towers Watson

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LG&E and KU Energy LLC ("LKE")
2014 Net Periodic Benefit Cost
Post Retirement Welfare Plans (Regulatory)

	Regulatory	Financial	Financial	Regulatory	Financial		Regulatory	Financial	Consolidated	Regulatory
	LG&E Non-union	ServCo	[redacted]	KU	[redacted]	[redacted]	LG&E Union	[redacted]	[redacted]	ServCo
Funded Status										
APBO	32,626,922	38,254,043	[redacted]	70,611,930	[redacted]	[redacted]	52,652,997	[redacted]	[redacted]	38,254,043
Fair Value of Assets	8,981,980	30,849,603	[redacted]	31,115,600	[redacted]	[redacted]	807,256	[redacted]	[redacted]	30,849,603
Funded Status	(23,644,942)	(7,404,440)	[redacted]	(39,496,330)	[redacted]	[redacted]	(51,845,741)	[redacted]	[redacted]	(7,404,440)
Amounts recognized in accumulated other comprehensive income consist of:										
Net actuarial loss/(gain)	11,140,595	623,646	[redacted]	(29,920,615)	[redacted]	[redacted]	(9,887,860)	[redacted]	[redacted]	5,347,850
Prior service cost/(credit)	851,587	1,538,715	[redacted]	1,758,273	[redacted]	[redacted]	4,329,552	[redacted]	[redacted]	1,538,716
Transition obligation/(asset)	-	-	[redacted]	-	[redacted]	[redacted]	-	[redacted]	[redacted]	-
Total	11,992,182	2,162,361	[redacted]	(28,162,342)	[redacted]	[redacted]	(5,558,308)	[redacted]	[redacted]	6,886,566
2014 Net Periodic Benefit Cost										
Service cost	455,921	1,878,366	[redacted]	1,545,624	[redacted]	[redacted]	452,558	[redacted]	[redacted]	1,878,366
Interest cost	1,534,039	1,842,064	[redacted]	3,343,811	[redacted]	[redacted]	2,495,154	[redacted]	[redacted]	1,842,064
Expected return on assets	(595,499)	(2,159,472)	[redacted]	(2,082,994)	[redacted]	[redacted]	-	[redacted]	[redacted]	(2,159,472)
Amortization of:										
Transition obligation (asset)	-	-	[redacted]	-	[redacted]	[redacted]	-	[redacted]	[redacted]	-
Prior service cost (credit)	283,863	512,905	[redacted]	586,092	[redacted]	[redacted]	1,096,964	[redacted]	[redacted]	512,905
Actuarial (gain) loss	-	(82,087)	[redacted]	(258,487)	[redacted]	[redacted]	(374,721)	[redacted]	[redacted]	-
Net periodic benefit cost	1,678,324	1,991,776	[redacted]	3,134,046	[redacted]	[redacted]	3,669,955	[redacted]	[redacted]	2,073,863
Key assumptions:										
Discount Rate	4.91%	4.91%	[redacted]	4.91%	[redacted]	[redacted]	4.91%	[redacted]	[redacted]	4.91%
Expected return on 401(h) assets	7.00%	7.00%	[redacted]	7.00%	[redacted]	[redacted]	7.00%	[redacted]	[redacted]	7.00%
Rate of compensation increase	4.00%	4.00%	[redacted]	4.00%	[redacted]	[redacted]	4.00%	[redacted]	[redacted]	4.00%
Mortality	2014 IRS-prescribed RP-2000 tables. Includes projection for 7 years beyond valuation date for annuitants; 15 years for non-annuitants.									
Health care cost trend rate										
Initial rate	7.60%	7.60%	[redacted]	7.60%	[redacted]	[redacted]	7.60%	[redacted]	[redacted]	7.60%
Ultimate rate	5.00%	5.00%	[redacted]	5.00%	[redacted]	[redacted]	5.00%	[redacted]	[redacted]	5.00%
Years to ultimate	6	6	[redacted]	6	[redacted]	[redacted]	6	[redacted]	[redacted]	6

The results contained in this document are based on the individual participant data provided by Mercer and LKE as of January 1, 2014. 2014 per capita claim cost assumptions were provided by Mercer Health and Welfare actuaries. All other assumptions, methods, and plan provisions are the same as those used for the year-end 2013 financial statement disclosures provided on January 22, 2014. The descriptions of the assumptions, methods, plan provisions, and limitations as set forth in the year-end 2013 financial statement disclosure letter should be considered part of these results.

Kentucky Utilities' OPEB Costs

	Base Year	Test Year
Service cost	2,638,417	3,080,539
Interest cost	4,385,681	4,638,513
Expected return on assets	(3,303,053)	(3,862,134)
Amortizations:		
Transition	-	-
Prior service cost	864,425	868,378
(Gain)/loss	(214,544)	-
ASC 715 NPBC	**4,370,926**	**4,725,296**

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 8, 2015

Question No. 16

Responding Witness: Daniel K. Arbough

Q.1-16. Please provide the Company's 2015, 2016, and 2017 pension actuarial cost projections using the same pension methodology and mortalities that were used in 2013 and 2014.

A.1-16. See attached. Towers Watson, KU's actuary, has not calculated the pension actuarial cost projections for 2015, 2016 and 2017 using the methodology and mortalities used in the 2013 and 2014 cost calculations. The 2015, 2016 and 2017 pension actuarial cost projections are based on calculations provided by Towers Watson on May 30, 2014. On the last page of the attached report in Note 2, the actuary compares the consolidated 2014 expense for the qualified plans ($18.7M), which was based on the RP-2000 scale AA mortality table, to the projected expense for 2015, which was based on the RP-2014 scale BB mortality table. Note 2 indicates that the expense projection is $31.2 million higher than the 2014 expense primarily due to the change in the mortality assumption. Preparation of actuarial cost projections for 2015, 2016, and 2017 using the same pension methodology and mortalities that were used in 2013 and 2014 would require original work, significant time and additional cost.

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May 30, 2014

Ms. Kelli Higdon
Senior Accounting Analyst
LG&E and KU Energy LLC
220 West Main Street
Louisville, KY 40202

Dear Kelli:

2015-2019 FINANCIAL PROJECTIONS OF PENSION AND POSTRETIREMENT WELFARE PLANS

Towers Watson Delaware, Inc. ("Towers Watson") was engaged by LG&E and KU Energy LLC ("LKE" or "the Company") to provide 5-year projections of the Financial Accounting Standards Codification ("ASC") Topic 715 accounting cost for the following pension and postretirement welfare plans with allocations as requested by LKE:

- LG&E and KU Retirement Plan
- Louisville Gas and Electric Company Bargaining Employees' Retirement Plan

[redacted]

- LG&E and KU Postretirement Benefit Plan

The exhibits for the years 2015-2019 are as follows:

- Estimated ASC 715 accounting cost
- Estimated cash contributions to the pension plan trusts for the LG&E and KU Retirement Plan, the Louisville Gas and Electric Company Bargaining Employees' Retirement Plan, and the Western Kentucky Energy Corp. Bargaining Employees' Retirement Plan
- Expected cash flows for the LG&E and KU Postretirement Benefit Plan
- Expected employer contributions to the 401(h) account of the LG&E and KU Postretirement Benefit Plan

The projections are based on the 2014 actuarial valuation results provided to you on April 30 (qualified pension plans), May 16 (LG&E and KU Postretirement Benefit Plan), and May 23 (nonqualified pension plans). Except where otherwise noted, the assumptions, methods, data, and plan provisions used to develop these projections are the same as those used to develop the 2014 actuarial valuation results

TOWERS WATSON

Ms. Kelli Higdon
May 30, 2014

1. These projections reflect the following key economic assumptions:

Discount rate:

	December 31, 2014 and all subsequent years	December 31, 2013
LG&E and KU Retirement Plan	4.70%	5.20%
Louisville Gas and Electric Company Bargaining Employees' Retirement Plan	4.63%	5.13%
[redacted]		
LG&E and KU Postretirement Benefit Plan	4.41%	4.91%

All discount rates are based on the results of the Towers Watson BOND:Link model as of April 30, 2014, which resulted in a 50 basis point reduction from the discount rates at December 31, 2013 [redacted] Cash flows by plan are based on the results of the 2014 actuarial valuation results.

Rate of compensation increase:

The projected rates of compensation increase for all legacy LKE plans are flat at all ages.

	December 31, 2014 and all subsequent years	December 31, 2013
All legacy LKE plans	4.00%	4.00%

Expected return on assets (EROA):

	December 31, 2014 and all subsequent years	December 31, 2013
LG&E and KU Retirement Plan	7.00%	7.00%
Louisville Gas and Electric Company Bargaining Employees' Retirement Plan	7.00%	7.00%
[redacted]	[redacted]	[redacted]
LG&E Energy LLC Postretirement Benefit Plan - Union VEBA* - Nonunion VEBA* - 401(h) sub-account	 0.00% 0.00% 7.00%	 0.00% 0.00% 7.00%

* Historically used as a short-term payment vehicle, not long-term investment trust

Service cost growth:

The service cost is expected to grow at varying rates, depending on whether the plan is open or closed as well as the type of benefits provided by the plan.

	All projection years
LG&E and KU Retirement Plan	2.00%
Louisville Gas and Electric Company Bargaining Employees' Retirement Plan	2.00%
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
LG&E and KU Postretirement Benefit Plan	4.41%

Actual return on assets:

The actual return on assets during 2014 is assumed to be equal to the actual return through March 31, 2014 and a 0% return for the remainder of 2014.

	2015 and all subsequent years	2014
LG&E and KU Retirement Plan	7.00%	5.26%
Louisville Gas and Electric Company Bargaining Employees' Retirement Plan	7.00%	5.37%
[redacted]	[redacted]	[redacted]
LG&E Energy LLC Postretirement Benefit Plan - Union VEBA* - Nonunion VEBA* - 401(h) sub-account	 0.00% 0.00% 7.00%	 0.00% 0.00% 5.23%

Health care cost trend:

	December 31, 2014 and all subsequent years	December 31, 2013
2014	N/A	7.6%
2015	7.2%	7.2%
2016	6.8%	6.8%
2017	6.4%	6.4%
2018	6.0%	6.0%
2019	5.5%	5.5%
2020+	5.0%	5.0%

2. All demographic assumptions are the same as those selected by LKE at December 31, 2013 with the exception of the mortality assumption. Projections include the estimated impact for the potential mortality assumption change to the fully generational RP-2014 mortality table with MP-2014 projection scale with white collar adjustment (no collar adjustment for the Louisville Gas and Electric

Company Bargaining Employees' Retirement Plan [redacted] at fiscal year-end 2014. A summary of all other assumptions can be found in the Assumption Setting Presentation provided to LKE on January 7, 2014. Detailed descriptions of these assumptions will be included in the actuarial valuation reports for the fiscal year ending December 31, 2014 (to be published during the coming months).

3. All plan provisions are the same as those valued at January 1, 2014 with the exception of the dollar per month multiplier for the Louisville Gas and Electric Company Bargaining Employees' Retirement Plan, which is assumed to increase 3% per year throughout the projection period.

   Detailed descriptions of the plan provisions will be included in the actuarial valuation reports for the fiscal year ending December 31, 2014 (to be published during the coming months).

4. For the Louisville Gas and Electric Company Bargaining Employees' Retirement Plan, the increases in benefit multipliers are assumed to be collectively bargained and reflected every three years. The increase in Prior Service Cost for the increases in the benefit multipliers for 2015-2017 is assumed to be reflected at December 31, 2014, and the increase in Prior Service Cost for the increase in the benefit multipliers for 2018-2020 is assumed to be reflected at December 31, 2017.

5. The expected future service to retirement age (expected future lifetime of the plan population for the [redacted] the LG&E and KU Supplemental Executive Plan for [redacted], each of which have no active plan participants) used in the development of the unrecognized (gain) / loss amortization is equal to the amount developed in the January 1, 2014 actuarial valuation results and is assumed to decrease 0.5 per year for most plans to reflect the aging of the closed populations. The LG&E and KU Non-Executive Pension Restoration Plan and the LG&E and KU Postretirement Benefit Plan are not closed, so they have no assumed decrease in the amortization period. [redacted]

6. The projections for the LG&E and KU Retirement Plan and the Louisville Gas and Electric Company Bargaining Employees' Retirement reflect the actual lump sum payments made to terminated vested participants during the first half of 2014.

7. All contributions are assumed to be made at the end of the year. The projections reflect no prefunding for the Non-union and Union VEBAS.

8. Under the Affordable Care Act, the Transitional Reinsurance Fee ("TRF") is scheduled to be collected from both self-insured employer medical plans and fully insured medical plans beginning in 2014 and continuing through 2016 as a means to help stabilize premiums for coverage in the individual market (inside and outside the exchanges). Consistent with the 2014 valuation, the TRF will be accounted for outside of the plan, and therefore, the projected postretirement benefit obligations have not been adjusted to reflect the expected cost of the TRF.

9. Administrative expenses of the qualified pension plans were assumed to remain level with 2014 during the projection period and are allocated based on actual administrative expenses in 2013. Postretirement Benefit Plan administrative expenses were kept consistent with 2013 actual expenses during the projection period.

Actuarial certification

In preparing the calculations contained in this letter, Towers Watson has used information and data provided to us by LKE and other persons or organizations designated by LKE. We have relied on all the data and information provided, including plan provisions and asset information, as being complete and accurate. We have reviewed this information for overall reasonableness and consistency but have neither audited nor independently verified this information.

As required by ASC 715, the actuarial assumptions and methods employed in the development of the pension and postretirement plan obligations have been selected by the plan sponsor. Towers Watson has concurred with these assumptions and methods. ASC 715 requires that each significant assumption "individually represent the best estimate of a particular future event."

The results documented in this letter are estimates based on data that may be imperfect and on assumptions about future events that cannot be predicted with any certainty. Certain plan provisions may be approximated or determined to be immaterial and therefore not valued. Assumptions may be made about participant data or other factors. We have made reasonable efforts to ensure that items that are material in the context of the actuarial liabilities or costs are treated appropriately, and not excluded or included inappropriately.

Actual future experience will differ from the assumptions used in our calculations. As these differences arise, contributions or the cost for accounting purposes will be adjusted in future valuations to take changes into account. If these adjustments become material, they may result in future adjustments to the valuation model.

The results shown in this letter have been developed based on actuarial assumptions that, to the extent evaluated or selected by Towers Watson, we consider to be reasonable. Other actuarial assumptions could also be considered to be reasonable. Thus, reasonable results differing from those presented in this report could have been developed by selecting different reasonable assumptions.

The numbers in this letter are not rounded, but this is for convenience only and should not imply precision, which is not a characteristic of actuarial calculations.

The calculations provided in this letter have been prepared solely for the benefit of LKE for budgeting purposes. This letter should not be used for other purposes, and we accept no responsibility for any such use. It should not be relied upon by, or shared with, any third parties without Towers Watson's prior written consent.

This letter is provided subject to the terms set out herein and in our engagement letter dated March 28, 2013 and any accompanying or referenced terms and conditions.

This letter provides actuarial calculations. It does not constitute legal, accounting, tax or investment advice. We encourage you to consult with qualified advisors with respect to those matters.

The undersigned consulting actuaries are members of the Society of Actuaries and other professional actuarial organizations and meet the "Qualification Standards for Actuaries Issuing Statements of Actuarial Opinion in the United States" relating to retirement plans. Our objectivity is not impaired by any relationship between the plan sponsor and our employer, Towers Watson.

* * * * *

Please do not hesitate to call if you have any questions.

Sincerely,

Royce Kosoff

Royce S. Kosoff, FSA, EA, CFA

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cc: David Crosby – LG&E and KU Energy LLC
Dan Arbough – LG&E and KU Energy LLC
George Sunder – PPL Corporation
Karla Durn – PPL Corporation
Kristin May, FSA, EA, MAAA – Towers Watson

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LG&E & KU Energy LLC
Estimated ASC 715 Net Periodic Pension Cost ("NPPC") For Qualified Pension Plans
2015 Fiscal Year

	Regulatory	Regulatory	Financial	Financial		Regulatory	Financial	Consolidated	Regulatory
	LG&E and KU Retirement Plan								
	LG&E Non-union	KU	Servco	WKE Non-union	Non-union Total	LG&E Union	WKE Union	US GAAP	Servco
Service cost	2,155,220	8,410,431	13,520,777	[redacted]	[redacted]	1,599,741	[redacted]	[redacted]	13,520,777
Interest cost	10,551,938	19,171,202	22,337,611	[redacted]	[redacted]	15,165,158	[redacted]	[redacted]	22,337,611
Expected return on assets	(13,641,272)	(24,458,474)	(24,752,753)	[redacted]	[redacted]	(18,956,655)	[redacted]	[redacted]	(24,752,753)
Amortizations:									
Transition	-	-	-	[redacted]	[redacted]	-	[redacted]	[redacted]	-
Prior service cost	1,815,457	691,706	-	[redacted]	[redacted]	3,325,004	[redacted]	[redacted]	2,498,015
(Gain)/loss	6,901,548	10,935,346	2,085,458	[redacted]	[redacted]	12,243,026	[redacted]	[redacted]	9,793,863
ASC 715 NPBC	7,782,891	14,750,211	13,191,094	[redacted]	[redacted]	13,376,274	[redacted]	[redacted]	23,397,513

LG&E & KU Energy LLC
Estimated ASC 715 Net Periodic Pension Cost ("NPPC") For Qualified Pension Plans
2016 Fiscal Year

	Regulatory	Regulatory	Financial	Financial		Regulatory	Financial	Consolidated	Regulatory
	LG&E and KU Retirement Plan								
	LG&E Non-union	KU	Servco	WKE Non-union	Non-union Total	LG&E Union	WKE Union	US GAAP	Servco
Service cost	2,198,325	8,578,640	13,791,192	-	[redacted]	1,631,736	[redacted]	[redacted]	13,791,192
Interest cost	10,637,140	19,621,767	23,548,502	[redacted]	[redacted]	15,243,630	[redacted]	[redacted]	23,548,502
Expected return on assets	(14,261,169)	(25,741,568)	(26,572,160)	[redacted]	[redacted]	(20,026,033)	[redacted]	[redacted]	(26,572,160)
Amortizations:									
Transition	-	-	-	[redacted]	[redacted]	-	[redacted]	[redacted]	-
Prior service cost	1,287,626	26,068	-	[redacted]	[redacted]	3,325,004	[redacted]	[redacted]	2,390,646
(Gain)/loss	5,986,095	9,630,885	1,868,345	[redacted]	[redacted]	10,484,456	[redacted]	[redacted]	9,122,994
ASC 715 NPBC	5,848,016	12,115,792	12,635,880	[redacted]	[redacted]	10,658,793	[redacted]	[redacted]	22,281,175

Notes

1. These accounting projections are based on the January 1, 2014 valuation results provided on April 30, 2014. The description of the data, assumptions, methods, plan provisions, and limitations as set forth in the accounting valuation results cover letter should be considered part of these results. Please see the attached letter for a description of all other assumptions and methods used in this analysis, including a discount rate of [redacted], 4.63% for LG&E union plan, and 4.70% for the nonunion plans.
2. Projections reflect the actual impact of the Terminated Vested (TV) lump sum windows phased between 2013 and 2014.
3. Fair value of assets is assumed to earn [redacted] 7.00% each year for all others. However, in 2014, the fair value of assets is assumed to earn [redacted] 5.37% for LG&E union plan, and 5.26% for all others (based on actual return from January 1, 2014 through March 31, 2014 and 0% return for the remainder of 2014).
4. Service cost is assumed to grow by 2% annually.
5. RP-2014 mortality with MP-2014 projection has been reflected in each projection year (no collar adjustment for union plans and white collar for non-union plans).

LG&E & KU Energy LLC
Estimated ASC 715 Net Periodic Pension Cost ("NPPC") For Qualified Pension Plans
2017 Fiscal Year

	Regulatory	Regulatory	Financial	Financial		Regulatory	Financial	Consolidated	Regulatory
	LG&E and KU Retirement Plan								
	LG&E Non-union	KU	Servco	WKE Non-union	Non-union Total	LG&E Union	WKE Union	US GAAP	Servco
Service cost	2,242,291	8,750,213	14,067,016	[redacted]	[redacted]	1,664,371	[redacted]	[redacted]	14,067,016
Interest cost	10,718,015	20,070,290	24,745,247	[redacted]	[redacted]	15,297,267	[redacted]	[redacted]	24,745,247
Expected return on assets	(14,784,541)	(26,903,275)	(28,371,007)	[redacted]	[redacted]	(20,947,423)	[redacted]	[redacted]	(28,371,007)
Amortizations:									
Transition	-	-	-	[redacted]	[redacted]	-	[redacted]	[redacted]	-
Prior service cost	1,154,543	23,744	-	[redacted]	[redacted]	3,325,004	[redacted]	[redacted]	2,282,700
(Gain)/loss	5,497,877	9,230,455	1,626,773	[redacted]	[redacted]	8,916,672	[redacted]	[redacted]	8,427,667
ASC 715 NPBC	4,828,185	11,171,427	12,068,030	[redacted]	[redacted]	8,255,892	[redacted]	[redacted]	21,151,623

LG&E & KU Energy LLC
Estimated ASC 715 Net Periodic Pension Cost ("NPPC") For Qualified Pension Plans
2018 Fiscal Year

	Regulatory	Regulatory	Financial	Financial		Regulatory	Financial	Consolidated	Regulatory
	LG&E and KU Retirement Plan								
	LG&E Non-union	KU	Servco	WKE Non-union	Non-union Total	LG&E Union	WKE Union	US GAAP	Servco
Service cost	2,287,137	8,925,217	14,348,356	[redacted]	[redacted]	1,697,658	[redacted]	[redacted]	14,348,356
Interest cost	10,790,593	20,510,646	25,921,046	[redacted]	[redacted]	15,858,595	[redacted]	[redacted]	25,921,046
Expected return on assets	(15,261,483)	(28,041,350)	(30,135,227)	[redacted]	[redacted]	(21,730,052)	[redacted]	[redacted]	(30,135,227)
Amortizations:									
Transition	-	-	-	[redacted]	[redacted]	-	[redacted]	[redacted]	-
Prior service cost	924,330	18,294	-	[redacted]	[redacted]	4,837,907	[redacted]	[redacted]	1,781,848
(Gain)/loss	5,292,482	8,800,029	1,363,907	[redacted]	[redacted]	8,074,468	[redacted]	[redacted]	7,711,044
ASC 715 NPBC	4,033,059	10,212,836	11,498,082	[redacted]	[redacted]	8,738,576	[redacted]	[redacted]	19,627,067

Notes

1. These accounting projections are based on the January 1, 2014 valuation results provided on April 30, 2014. The description of the data, assumptions, methods, plan provisions, and limitations as set forth in the accounting valuation results cover letter should be considered part of these results. Please see the attached letter for a description of all other assumptions and methods used in this analysis, including a discount rate of 4.42% for the WKE union plan, 4.63% for LG&E union plan, and 4.70% for the nonunion plans.
2. Projections reflect the actual impact of the Terminated Vested (TV) lump sum windows phased between 2013 and 2014.
3. Fair value of assets is assumed to earn 0% each year for the WKE union plan and 7.00% each year for all others. However, in 2014, the fair value of assets is assumed to earn 0% for the WKE union plan, 5.37% for LG&E union plan, and 5.26% for all others (based on actual return from January 1, 2014 through March 31, 2014 and 0% return for the remainder of 2014).
4. Service cost is assumed to grow by 2% annually.
5. RP-2014 mortality with MP-2014 projection has been reflected in each projection year (no collar adjustment for union plans and white collar for non-union plans).

Attachment to Response to KU KIUC-1 Question No. 16
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Arbough

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5/30/2014

LG&E & KU Energy LLC
Estimated ASC 715 Net Periodic Pension Cost ("NPPC") For Qualified Pension Plans
2019 Fiscal Year

	Regulatory	Regulatory	Financial	Financial		Regulatory	Financial	Consolidated	Regulatory
	LG&E and KU Retirement Plan								
	LG&E Non-union	KU	Servco	WKE Non-union	Non-union Total	LG&E Union	WKE Union	US GAAP	Servco
Service cost	2,332,880	9,103,721	14,635,323	[redacted]	[redacted]	1,731,611	[redacted]	[redacted]	14,635,323
Interest cost	10,851,525	20,943,964	27,054,810	[redacted]	[redacted]	15,881,545	[redacted]	[redacted]	27,054,810
Expected return on assets	(15,698,596)	(29,152,709)	(31,830,055)	[redacted]	[redacted]	(22,562,274)	[redacted]	[redacted]	(31,830,055)
Amortizations:									
Transition	-	-	-	[redacted]	[redacted]	-	[redacted]	[redacted]	-
Prior service cost	5	3	-	[redacted]	[redacted]	4,674,242	[redacted]	[redacted]	4
(Gain)/loss	5,074,844	8,343,445	1,085,946	[redacted]	[redacted]	7,708,180	[redacted]	[redacted]	6,979,327
ASC 715 NPBC	2,560,657	9,238,425	10,946,024	[redacted]	[redacted]	7,433,305	[redacted]	[redacted]	16,839,410

Notes

1. These accounting projections are based on the January 1, 2014 valuation results provided on April 30, 2014. The description of the data, assumptions, methods, plan provisions, and limitations as set forth in the accounting valuation results cover letter should be considered part of these results. Please see the attached letter for a description of all other assumptions and methods used in this analysis, including a discount rate of [redacted], 4.63% for LG&E union plan, and 4.70% for the nonunion plans.
2. Projections reflect the actual impact of the Terminated Vested (TV) lump sum windows phased between 2013 and 2014.
3. Fair value of assets is assumed to earn [redacted] 7.00% each year for all others. However, in 2014, the fair value of assets is assumed to earn [redacted] 5.37% for LG&E union plan, and 5.26% for all others (based on actual return from January 1, 2014 through March 31, 2014 and 0% return for the remainder of 2014).
4. Service cost is assumed to grow by 2% annually.
5. RP-2014 mortality with MP-2014 projection has been reflected in each projection year (no collar adjustment for union plans and white collar for non-union plans).

LG&E & KU Energy LLC
Estimated Cash Contributions for Plan Years 2014-2019 ($ millions)

	LG&E and KU Retirement Plan							
	LG&E Nonunion	KU	Servco	WKE Nonunion	Nonunion Total	LG&E Union	WKE Union	Grand Total
1/14/2014 actual	8,200,000	2,200,000	24,700,000	[redacted]	[redacted]	-	[redacted]	[redacted]
12/31/2015	7,782,891	14,750,211	13,191,094	[redacted]	[redacted]	13,376,274	[redacted]	[redacted]
12/31/2016	5,848,016	12,115,792	12,635,880	[redacted]	[redacted]	10,658,793	[redacted]	[redacted]
12/31/2017	4,828,185	11,171,427	12,068,030	[redacted]	[redacted]	8,255,892	[redacted]	[redacted]
12/31/2018	4,033,059	10,212,836	11,498,082	[redacted]	[redacted]	8,738,576	[redacted]	[redacted]
12/31/2019	2,560,657	9,238,425	10,946,024	[redacted]	[redacted]	7,433,305	[redacted]	[redacted]

LG&E & KU Energy LLC
Estimated ASC 715 Net Periodic Pension Cost ("NPPC") For Non-qualified Pension Plans
Financial Accounting Basis
2015 Fiscal Year

	Officers SERP	Restoration Plan	[redacted] SERP	Non-qualifed Total
Service cost	[redacted]	[redacted]	[redacted]	[redacted]
Interest cost				
Expected return on assets				
Amortizations:				
Transition				
Prior service cost				
(Gain)/loss				
ASC 715 NPBC				

LG&E & KU Energy LLC
Estimated ASC 715 Net Periodic Pension Cost ("NPPC") For Non-qualified Pension Plans
Financial Accounting Basis
2016 Fiscal Year

	Officers SERP	Restoration Plan	[redacted] SERP	Non-qualifed Total
Service cost	[redacted]	[redacted]	[redacted]	[redacted]
Interest cost				
Expected return on assets				
Amortizations:				
Transition				
Prior service cost				
(Gain)/loss				
ASC 715 NPBC				

Notes

[redacted]

LG&E & KU Energy LLC
Estimated ASC 715 Net Periodic Pension Cost ("NPPC") For Non-qualified Pension Plans
Financial Accounting Basis
2017 Fiscal Year

	Officers SERP	Restoration Plan	[redacted] SERP	Non-qualifed Total
Service cost	[redacted]			
Interest cost				
Expected return on assets				
Amortizations:				
Transition				
Prior service cost				
(Gain)/loss				
ASC 715 NPBC				

LG&E & KU Energy LLC
Estimated ASC 715 Net Periodic Pension Cost ("NPPC") For Non-qualified Pension Plans
Financial Accounting Basis
2018 Fiscal Year

	Officers SERP	Restoration Plan	[redacted] SERP	Non-qualifed Total
Service cost	[redacted]			
Interest cost				
Expected return on assets				
Amortizations:				
Transition				
Prior service cost				
(Gain)/loss				
ASC 715 NPBC				

Notes

[redacted]

LG&E & KU Energy LLC
Estimated ASC 715 Net Periodic Pension Cost ("NPPC") For Non-qualified Pension Plans
Financial Accounting Basis
2019 Fiscal Year

	Officers SERP	Restoration Plan	[redacted] SERP	Non-qualifed Total
Service cost	[redacted]			
Interest cost				
Expected return on assets				
Amortizations:				
Transition				
Prior service cost				
(Gain)/loss				
ASC 715 NPBC				

[redacted]

LG&E & KU Energy LLC
Estimated ASC 715 Net Periodic Benefit Cost ("NPBC") For Postretirement Benefit Plan
2015 Fiscal Year

	Regulatory	Regulatory	Financial	Financial	Financial		Regulatory	Financial	Consolidated	Regulatory
	Non-Union									
	LG&E	KU	ServCo	WKE	International	Total	LG&E Union	WKE Union	US GAAP	ServCo
Service cost	537,410	1,806,997	2,193,217	[redacted]	[redacted]	[redacted]	524,683	[redacted]	[redacted]	2,193,217
Interest cost	1,482,491	3,537,211	1,943,715	[redacted]	[redacted]	[redacted]	2,465,236	[redacted]	[redacted]	1,943,715
Expected return on assets	(584,205)	(2,200,366)	(2,465,664)	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]	(2,465,664)
Amortizations:										
Transition	-	-	-	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]	-
Prior service cost	283,863	586,092	512,905	[redacted]	[redacted]	[redacted]	1,064,718	[redacted]	[redacted]	512,905
(Gain)/loss	-	-	-	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]	-
ASC 715 NPBC	1,719,560	3,729,934	2,184,173	[redacted]	[redacted]	[redacted]	4,054,637	[redacted]	[redacted]	2,184,173

LG&E & KU Energy LLC
Estimated ASC 715 Expense For Postretirement Benefit Plans
2016 Fiscal Year

	Regulatory	Regulatory	Financial	Financial	Financial		Regulatory	Financial	Consolidated	Regulatory
	Non-Union									
	LG&E	KU	ServCo	WKE	International	Total	LG&E Union	WKE Union	US GAAP	ServCo
Service cost	561,110	1,886,686	2,289,938	[redacted]	[redacted]	[redacted]	547,822	[redacted]	[redacted]	2,289,938
Interest cost	1,452,466	3,546,221	2,041,955	[redacted]	[redacted]	[redacted]	2,434,631	[redacted]	[redacted]	2,041,955
Expected return on assets	(690,389)	(2,564,982)	(2,910,574)	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]	(2,910,574)
Amortizations:										
Transition	-	-	-	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]	-
Prior service cost	283,861	586,089	512,905	[redacted]	[redacted]	[redacted]	665,070	[redacted]	[redacted]	512,905
(Gain)/loss	-	-	-	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]	-
ASC 715 NPBC	1,607,048	3,454,014	1,934,224	[redacted]	[redacted]	[redacted]	3,647,522	[redacted]	[redacted]	1,934,224

Notes

1. These accounting projections are based on the January 1, 2014 valuation results provided on May 16, 2014. The description of the data, assumptions, methods, plan provisions, and limitations as set forth in the accounting valuation results cover letter should be considered part of these results. Please see the attached letter for a description of all other assumptions and methods used in this analysis, including a discount rate of 4.41%.
2. Non-union and Union VEBA amounts are assumed to remain level over the projection period (i.e., contributions equal disbursements and a 0.00% actual return on assets). 401(h) amounts are assumed to earn 7.00% each year, and contributions to the 401(h) account are assumed to be equal to the maximum deductible amount, starting in 2014 and are expected to be contributed at year-end. However, in 2014, the fair value of 401(h) assets is assumed to earn 5.23% (based on actual return from January 1, 2014 through March 31, 2014 and 0% return for the remainder of 2014).
3. We have assumed service cost growth equal to the discount rate (4.41% per year).
4. As instructed by LKE, historical allocation methodology has been followed (specifically, the calculation of the loss/(gain) amortization).
5. RP-2014 mortality with MP-2014 projection has been reflected in each projection year (white collar).

LG&E & KU Energy LLC
Estimated ASC 715 Expense For Postretirement Benefit Plans
2017 Fiscal Year

	Regulatory	Regulatory	Financial	Financial	Financial		Regulatory	Financial	Consolidated	Regulatory
	Non-Union									
	LG&E	KU	ServCo	WKE	International	Total	LG&E Union	WKE Union	US GAAP	ServCo
Service cost	585,855	1,969,889	2,390,924	[redacted]	[redacted]	[redacted]	571,981	[redacted]	[redacted]	2,390,924
Interest cost	1,425,610	3,550,969	2,135,829	[redacted]	[redacted]	[redacted]	2,401,000	[redacted]	[redacted]	2,135,829
Expected return on assets	(822,724)	(3,005,922)	(3,454,578)	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]	(3,454,578)
Amortizations:										
Transition	-	-	-	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]	-
Prior service cost	-	-	1	[redacted]	[redacted]	[redacted]	375,701	[redacted]	[redacted]	1
(Gain)/loss	-	-	-	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]	-
ASC 715 NPBC	1,188,741	2,514,936	1,072,176	[redacted]	[redacted]	[redacted]	3,348,682	[redacted]	[redacted]	1,072,176

LG&E & KU Energy LLC
Estimated ASC 715 Expense For Postretirement Benefit Plans
2018 Fiscal Year

	Regulatory	Regulatory	Financial	Financial	Financial		Regulatory	Financial	Consolidated	Regulatory
	Non-Union									
	LG&E	KU	ServCo	WKE	International	Total	LG&E Union	WKE Union	US GAAP	ServCo
Service cost	611,691	2,056,761	2,496,364	[redacted]	[redacted]	[redacted]	597,205	[redacted]	[redacted]	2,496,364
Interest cost	1,401,936	3,551,831	2,226,928	[redacted]	[redacted]	[redacted]	2,363,243	[redacted]	[redacted]	2,226,928
Expected return on assets	(917,584)	(3,331,269)	(3,853,454)	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]	(3,853,454)
Amortizations:										
Transition	-	-	-	[redacted]			-	[redacted]	[redacted]	-
Prior service cost	-	-	-				375,701	[redacted]	[redacted]	-
(Gain)/loss	-	-	-				-	[redacted]	[redacted]	-
ASC 715 NPBC	1,096,043	2,277,322	869,838				3,336,149	[redacted]	[redacted]	869,838

Notes

1. These accounting projections are based on the January 1, 2014 valuation results provided on May 16, 2014. The description of the data, assumptions, methods, plan provisions, and limitations as set forth in the accounting valuation results cover letter should be considered part of these results. Please see the attached letter for a description of all other assumptions and methods used in this analysis, including a discount rate of 4.41%.
2. Non-union and Union VEBA amounts are assumed to remain level over the projection period (i.e., contributions equal disbursements and a 0.00% actual return on assets). 401(h) amounts are assumed to earn 7.00% each year, and contributions to the 401(h) account are assumed to be equal to the maximum deductible amount, starting in 2014 and are expected to be contributed at year-end. However, in 2014, the fair value of 401(h) assets is assumed to earn 5.23% (based on actual return from January 1, 2014 through March 31, 2014 and 0% return for the remainder of 2014).
3. We have assumed service cost growth equal to the discount rate (4.41% per year).
4. As instructed by LKE, historical allocation methodology has been followed (specifically, the calculation of the loss/(gain) amortization).
5. RP-2014 mortality with MP-2014 projection has been reflected in each projection year (white collar).

LG&E & KU Energy LLC
Estimated ASC 715 Expense For Postretirement Benefit Plans
2019 Fiscal Year

	Regulatory	Regulatory	Financial	Financial	Financial		Regulatory	Financial	Consolidated	Regulatory
	Non-Union									
	LG&E	KU	ServCo	WKE	International	Total	LG&E Union	WKE Union	US GAAP	ServCo
Service cost	638,667	2,147,464	2,606,454	[redacted]	[redacted]	[redacted]	623,542	[redacted]	[redacted]	2,606,454
Interest cost	1,379,251	3,552,117	2,313,805	[redacted]	[redacted]	[redacted]	2,318,606	[redacted]	[redacted]	2,313,805
Expected return on assets	(976,211)	(3,537,094)	(4,103,588)	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]	(4,103,588)
Amortizations:										
Transition	-	-	-	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]	-
Prior service cost	-	-	-	[redacted]	[redacted]	[redacted]	375,701	[redacted]	[redacted]	-
(Gain)/loss	-	-	-	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted])	-
ASC 715 NPBC	1,041,707	2,162,488	816,670	[redacted]	[redacted]	[redacted]	3,317,849	[redacted]	[redacted]	816,670

Notes

1. These accounting projections are based on the January 1, 2014 valuation results provided on May 16, 2014. The description of the data, assumptions, methods, plan provisions, and limitations as set forth in the accounting valuation results cover letter should be considered part of these results. Please see the attached letter for a description of all other assumptions and methods used in this analysis, including a discount rate of 4.41%.
2. Non-union and Union VEBA amounts are assumed to remain level over the projection period (i.e., contributions equal disbursements and a 0.00% actual return on assets). 401(h) amounts are assumed to earn 7.00% each year, and contributions to the 401(h) account are assumed to be equal to the maximum deductible amount, starting in 2014 and are expected to be contributed at year-end. However, in 2014, the fair value of 401(h) assets is assumed to earn 5.23% (based on actual return from January 1, 2014 through March 31, 2014 and 0% return for the remainder of 2014).
3. We have assumed service cost growth equal to the discount rate (4.41% per year).
4. As instructed by LKE, historical allocation methodology has been followed (specifically, the calculation of the loss/(gain) amortization).
5. RP-2014 mortality with MP-2014 projection has been reflected in each projection year (white collar).

PLAN PROVISION CHANGES FOR POSTRETIREMENT BENEFIT PLAN USED IN 2015-2019 PROJECTIONS

Effective Date for Projection Purposes	Non-Union and LG&E Union Plans
January 1, 2015	no change
January 1, 2016	no change
January 1, 2017	no change
January 1, 2018	no change
January 1, 2019	no change

LG&E & KU Energy LLC
Estimated Benefit Payments For Postretirement Benefit Plans

Fiscal Year	Non-Union						LG&E Union	WKE Union	Grand Total
	LG&E	KU	ServCo	WKE	International	Total			
2014	2,767,532	5,019,751	1,474,912	[redacted]	[redacted]	[redacted]	3,670,387	[redacted]	[redacted]
2015	2,716,609	5,054,889	1,725,205	[redacted]	[redacted]	[redacted]	3,649,465	[redacted]	[redacted]
2016	2,684,553	5,226,755	2,097,331	[redacted]	[redacted]	[redacted]	3,719,108	[redacted]	[redacted]
2017	2,559,185	5,425,895	2,311,469	[redacted]	[redacted]	[redacted]	3,771,568	[redacted]	[redacted]
2018	2,537,176	5,578,363	2,613,809	[redacted]	[redacted]	[redacted]	3,887,965	[redacted]	[redacted]
2019	2,518,654	5,626,336	2,895,839	[redacted]	[redacted]	[redacted]	4,059,141	[redacted]	[redacted]

Estimated Year End Contributions to 401(h) Account

Fiscal Year	401(h) Account
2014	7,696,655
2015	8,594,692
2016	10,466,377
2017	5,183,709
2018	-
2019	-

Notes

1. These accounting projections are based on the January 1, 2014 valuation results provided on May 16, 2014. The description of the data, assumptions, methods, plan provisions, and limitations as set forth in the accounting valuation results cover letter should be considered part of these results. Please see the attached letter for a description of all other assumptions and methods used in this analysis, including a discount rate of 4.41%.
2. Non-union and Union VEBA amounts are assumed to remain level over the projection period (i.e., contributions equal disbursements and a 0.00% actual return on assets). 401(h) amounts are assumed to earn 7.00% each year, and contributions to the 401(h) account are assumed to be equal to the maximum deductible amount, starting in 2014 and are expected to be contributed at year-end. However, in 2014, the fair value of 401(h) assets is assumed to earn 5.23% (based on actual return from January 1, 2014 through March 31, 2014 and 0% return for the remainder of 2014).
3. We have assumed service cost growth equal to the discount rate (4.41% per year).
4. As instructed by LKE, historical allocation methodology has been followed (specifically, the calculation of the loss/(gain) amortization).
5. RP-2014 mortality with MP-2014 projection has been reflected in each projection year (white collar).
6. The 401(h) contribution is assumed to be made at the end of the calendar year. The expected 401(h) contribution amount for 2014 may change when the actual 2014 ERISA funding valuation for the LG&E and KU Retirement Plan is completed.

($ in millions)

1. Qualified Pension Plans: Reconciliation of 2015 Budgets	Consolidated US GAAP Expense
2015 Budget provided September 12, 2013	35.7
Demographic gains: Reflection of updated data as of January 1, 2014	(3.7)
Mortality: Incremental increase from RP-2000 / Scale BB to RP-2014 / MP-2014*	13.9
Discount Rates: Approximately 30-40 basis point decrease	4.2
Plan changes: Reflection of anticipated Dollar Per Month increase in LG&E Bargaining Plan	1.7
Contributions: Actual 2014 funding higher than expected	(2.0)
Asset returns: Assumed January 1, 2015 values higher than previous projections	(0.7)
Updated 2015 Budget provided May 30, 2014	49.1

***Note that the mortality assumption change is preliminary at this point, and will be reviewed with LKE and PPL in the coming months. Actual table and projection scale used at year-end 2014 may differ from the assumption used in these forecasts.**

2. All Plans: Comparison of 2014 actual expense to updated 2015 budgets

-Qualified plans: consolidated expense projection for 2015 is $31.2 million higher than 2014 expense primarily due to the change in the mortality assumption (LKE did not move to the scale BB projection at year-end 2013, so unlike impact above, impact from 2014 to 2015 is not incremental). The 50 basis point decrease in assumed discount rate, as well as the plan change, also increased the 2015 expense projection.

-Postretirement Benefit Plan: consolidated expense projection for 2015 is $1.2 million higher than 2014 expense predominantly due to the change in the mortality assumption (where retiree medical losses are offset by life insurance gains) and the 50 basis point decrease in assumed discount rate.

[redacted]

3. Nonqualified Plan: Comparison of 2015 budgets

[redacted]

4. Postretirement Benefit Plan: Comparison of 2015 budgets

- The consolidated US GAAP expense for the Postretirement Benefit Plan 2015 budget increased from $10.3 million in May 2013 to $11.6 million primarily due to the reflection of updated per capita claim costs as of January 1, 2014 and the mortality change, offset by the 42 basis point increase in assumed discount rate.

5. Qualified Pension Plans: Comparison of 2016 budgets

-The 2016 budget increase for the qualified plans is $6.8 million. The key drivers are consistent with the reconciliation above (i.e. mortality assumption change, discount rate decrease, and plan change).

EXHIBIT ____ (LK-22)

Kentucky Utilities Company
KIUC Adjustment to Reduce Pension Expense to Reflect Reduced Amortization of Net Actuarial (Gain)/Loss for Test Year
For the Test Year Ended June 30, 2016
$ Millions

Source: KIUC 2-6 (Supplemental)

2015	As-Filed Amortization Gain/Loss Result	Average Years of Future Service	Loss to Amortize	Adjusted Years of Future Service	KIUC Adjusted Amortization Gain/Loss Result
KU					
Unrecognized Gain/Loss					
Amortization 10%	9.887	8.930	88.289	30.000	2.943
Amortization 30%	2.575	4.465	11.496	30.000	0.383
Total KU	12.462				3.326
ServCo					
Unrecognized Gain/Loss					
Amortization 10%	10.171	8.930	90.827	30.000	3.028
KU % of ServCo	55.037%				55.037%
KU Portion of ServCo	5.598				1.666
Total KU	18.059				4.992

2016	As-Filed Amortization Gain/Loss Result	Average Years of Future Service	Loss to Amortize	Average Years of Future Service	KIUC Adjusted Amortization Gain/Loss Result
KU					
Unrecognized Gain/Loss					
Amortization 10%	9.826	8.430	82.829	30.000	2.761
Amortization 30%	-		-	30.000	-
Total KU	9.826				2.761
ServCo					
Unrecognized Gain/Loss					
Amortization	8.742	8.430	73.698	30.000	2.457
KU % of ServCo	55.037%				55.037%
KU Portion of ServCo	4.812				1.352
Total KU	14.637				4.113

Kentucky Utilities Company
KIUC Adjustment to Reduce Pension Expense to Reflect Reduced Amortization of Net Actuarial (Gain)/Loss for Test Year
For the Test Year Ended June 30, 2016
$ Millions

Source: KIUC 2-6 (Supplemental)

	As-Filed Amortization Gain/Loss Result	KIUC Adjusted Amortization Gain/Loss Result
Test Year Amortization		
50% of 2015	9.030	2.496
50% of 2016	7.319	2.057
Test Year Amortization	16.348	4.553

KIUC Recommended Reduction in Pension Expense to Reflect Reduced Amortization of Net Actuarial (Gain)/Loss for Test Year - Total Co.	(11.795)
KY Jurisdiction Allocation % - Forecast Test Year for Labor	90.097%
KIUC Recommended Reduction in Pension Expense to Reflect Reduced Amortization of Net Actuarial (Gain)/Loss for Test Year - Total Co.	(10.627)

EXHIBIT ____ (LK-23)

Louisville Gas and Electric Company
KIUC Adjustment to Reduce Pension Expense to Reflect Reduced Amortization of Net Actuarial (Gain)/Loss for Test Year
For the Test Year Ended June 30, 2016
$ Millions

Source: KIUC 2-6 (Supplemental)

2015	As-Filed Amortization Gain/Loss Result	Average Years of Future Service	Loss to Amortize	Adjusted Years of Future Service	KIUC Adjusted Amortization Gain/Loss Result
LG&E					
Unrecognized Gain/Loss					
Amortization 10%	5.382	8.930	48.062	30.000	1.602
Amortization 30%	2.397	4.465	10.702	30.000	0.357
Total KU	7.779				1.959
LG&E Union					
Unrecognized Gain/Loss					
Amortization 10%	7.784	8.482	66.020	30.000	2.201
Amortization 30%	3.270	4.241	13.867	30.000	0.462
Total KU	11.053				2.663
ServCo					
Unrecognized Gain/Loss					
Amortization 10%	10.171	8.930	90.827	30.000	3.028
LG&E % of ServCo	44.148%				44.148%
LG&E Portion of ServCo	4.490				1.337
Total LG&E	23.323				5.958

Louisville Gas and Electric Company
KIUC Adjustment to Reduce Pension Expense to Reflect Reduced Amortization of Net Actuarial (Gain)/Loss for Test Year
For the Test Year Ended June 30, 2016
$ Millions

Source: KIUC 2-6 (Supplemental)

2016	As-Filed Amortization Gain/Loss Result	Average Years of Future Service	Loss to Amortize	Average Years of Future Service	KIUC Adjusted Amortization Gain/Loss Result
LG&E					
Unrecognized Gain/Loss					
Amortization 10%	5.726	8.430	48.274	30.000	1.609
Amortization 30%	0.152	4.215	0.639	30.000	0.021
Total KU	5.878				1.630
LG&E Union					
Unrecognized Gain/Loss					
Amortization 10%	8.211	7.982	65.540	30.000	2.185
Amortization 30%	-	3.991	-	30.000	-
Total KU	8.211				2.185
ServCo					
Unrecognized Gain/Loss					
Amortization 10%	8.742	8.430	73.698	30.000	2.457
LG&E % of ServCo	44.148%				44.148%
LG&E Portion of ServCo	3.860				1.085
Total LG&E	17.948				4.900
Test Year Amortization					
50% of 2015	11.661				2.979
50% of 2016	8.974				2.450
Test Year Amortization	20.636				5.429

KIUC Recommended Reduction in Pension Expense to Reflect Reduced Amortization of Net Actuarial (Gain)/Loss for Test Year - Total Co.	(15.207)
Electric Only Allocation - Based on As-Filed Capitalization and Rate Base %	82.61%
KIUC Recommended Reduction in Pension Expense to Reflect Reduced Amortization of Net Actuarial (Gain)/Loss for Test Year - Total Co.	(12.562)

EXHIBIT ____ (LK-24)

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Attorney General's Initial Requests for Information
Dated January 8, 2015

Question No. 3

Responding Witness: Christopher M. Garrett

Q-3. Please provide the following amounts by class or rate schedule as available, for the years 2010-2014, and projected figures for the fully forecasted test period:

a. Late payment charges,

b. Customer deposits,

c. Customer advances, and,

d. Uncollectibles expense.

A-3.

a. See attached.

b. See attached.

c. See attached.

d. See attached.

Kentucky Utilities Company
Case No. 2014-00371
Late Payment Charges by Revenue Class - Kentucky Only
For the Calendar Years 2010 through 2014, plus Fully Forecasted Test Period

Revenue Class	2010	2011	2012	2013	2014	Forecasted Test Period
Residential	$ 7,483,736	$ 5,627,356	$ 5,264,201	$ 2,611,518	$ 2,969,039	$ 2,947,965
Commercial	2,040,872	1,482,281	1,268,337	642,356	615,199	669,283
Industrial	343,025	316,142	246,620	116,550	128,461	138,964
Public Authority	119,169	28,112	162,621	29,503	23,401	27,775
Street Lights	1,524	1,993	2,529	1,911	2,775	2,211
Total Late Payment Charges	$ 9,988,326	$ 7,455,884	$ 6,944,308	$ 3,401,838	$ 3,738,875	$ 3,786,198

Kentucky Utilities Company Case No. 2014-00371 Customer Deposits - Kentucky Only For the Calendar Years 2010 through 2014, plus Fully Forecasted Test Period	
As of	Balance
December 31, 2010	$ 22,314,681.28
December 31, 2011	22,288,183.17
December 31, 2012	23,939,104.39
December 31, 2013	24,741,289.73
December 31, 2014	25,921,051.52
Forecasted Test Period Ended June 30, 2016	25,392,252.01

KU does not maintain Customer Deposits by class or rate schedule.

Kentucky Utilities Company Case No. 2014-00371 Customer Advances - Kentucky Only For the Calendar Years 2010 through 2014, plus Fully Forecasted Test Period	
As of	Balance
December 31, 2010	$ 2,869,273.92
December 31, 2011	3,155,939.30
December 31, 2012	2,985,264.42
December 31, 2013	2,882,357.12
December 31, 2014	2,189,028.23
Forecasted Test Period Ended June 30, 2016	2,442,711.15

KU does not maintain Customer Advances by class or rate schedule.

Kentucky Utilities Company Case No. 2014-00371 Uncollectibles Expense by Revenue Class - Kentucky Only For the Calendar Years 2010 through 2014, plus Fully Forecasted Test Period						
Revenue Class	2010	2011	2012	2013	2014	Forecasted Test Period
Residential	$ 5,831,197	$ 4,716,971	$ 2,687,526	$ 2,836,501	$ 6,513,911	
Commercial	558,043	502,576	377,435	260,746	593,662	
Industrial	92,630	464,211	634,195	89,135	201,816	
Public Authority	146	43	328	841	1,966	
Street Lights	1,290	1,620	268	543	(798)	
Total Uncollectibles Expense	$ 6,483,306	$ 5,685,421	$ 3,699,752	$ 3,187,766	$ 7,310,557	$ 6,441,434

For the actuals, the accrual for bad debt is not recorded by revenue class; therefore, for the purposes of this response, the accrual has been allocated to each revenue class based on the actual write-offs.

For the forecasted test period, uncollectibles expense is not forecasted by revenue class.

EXHIBIT ____ (LK-25)

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Attorney General's Supplemental Requests for Information Dated February 6, 2015

Question No. 3

Responding Witness: Christopher M. Garrett

Q-3. Reference the responses to AG 1-2 and AG 1-3(d). Confirm that while KU seeks $6,441,434 in uncollectible expense in the forecasted test period, the uncollectible average from 2010-2014 is $4,249,960 and from 2011-2014 is $2,953,299.

A-3. KU has included $6,441,434 in uncollectible expense in the forecasted test period. The stated uncollectible average from 2010-2014 of $4,249,960 and from 2011-2014 of $2,953,299 is incorrect. The correct average from 2010-2014 is $5,273,360 and from 2011-2014 is $4,970,874 as provided in AG 1-3(d).

The $6,441,434 Kentucky jurisdictional uncollectible expense in the forecasted test period represents .40% of total Kentucky jurisdictional revenues. This write-off percentage is lower than the actual percentage for the most recent calendar year and not unreasonable when compared to the five year average.

EXHIBIT ____ (LK-26)

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2014-00372

Response to Attorney General's Initial Request for Information
Dated January 8, 2015

Question No. 3

Responding Witness: Christopher M. Garrett

Q-3. Please provide the following amounts by class or rate schedule as available, for the years 2010-2014, and projected figures for the fully forecasted test period:

a. Late payment charges,

b. Customer deposits,

c. Customer advances, and,

d. Uncollectibles expense.

A-3. a. See attached.

b. See attached.

c. See attached.

d. See attached.

Louisville Gas and Electric Company
Case No. 2014-00372
Late Payment Charges by Revenue Class
For the Calendar Years 2010 through 2014, plus Fully Forecasted Test Period

Revenue Class	2010	2011	2012	2013	2014	Forecasted Test Period
Electric						
Residential	$ 4,917,351	$ 4,263,443	$ 4,075,622	$ 1,922,733	$ 2,021,155	$ 1,999,459
Commercial	1,342,637	1,182,647	1,126,090	429,615	391,788	428,320
Industrial	109,521	126,420	98,299	53,261	45,598	54,529
Public Authority	75,465	97,695	72,052	23,345	(21,616)	(8,012)
Street Lights	96	10	97	297	268	311
Total Electric Late Payment Charges	$ 6,445,070	$ 5,670,215	$ 5,372,160	$ 2,429,251	$ 2,437,193	$ 2,474,607
Gas						
Residential	$ 2,407,039	$ 2,123,472	$ 1,636,055	$ 845,131	$ 995,381	1,032,341
Commercial	626,593	575,935	404,917	164,917	177,980	194,854
Industrial	39,984	52,754	45,128	14,389	15,576	17,204
Public Authority	34,896	62,229	41,658	5,344	(20,879)	(11,510)
Transportation	691	1,139	2,776	2,911	517	1,879
Total Gas Late Payment Charges	$ 3,109,203	$ 2,815,529	$ 2,130,534	$ 1,032,692	$ 1,168,575	$ 1,234,768

Louisville Gas and Electric Company Case No. 2014-00372 Customer Deposits For the Calendar Years 2010 through 2014, plus Fully Forecasted Test Period	
As of	Balance
December 31, 2010	$ 23,187,608.55
December 31, 2011	22,311,041.85
December 31, 2012	23,464,189.08
December 31, 2013	24,075,548.94
December 31, 2014	24,498,183.30
Forecasted Test Period Ended June 30, 2016	24,000,006.56

LG&E does not maintain Customer Deposits by class or rate schedule.

Louisville Gas and Electric Company Case No. 2014-00372 Customer Advances For the Calendar Years 2010 through 2014, plus Fully Forecasted Test Period	
As of	Balance
December 31, 2010	$ 8,580,930.08
December 31, 2011	7,307,168.56
December 31, 2012	6,709,975.18
December 31, 2013	6,748,025.17
December 31, 2014	8,234,051.24
Forecasted Test Period Ended June 30, 2016	7,841,390.40

LG&E does not maintain Customer Advances by class or rate schedule.

Louisville Gas and Electric Company Case No. 2014-00372 Uncollectibles Expense by Revenue Class For the Calendar Years 2010 through 2014, plus Fully Forecasted Test Period						
Revenue Class	2010	2011	2012	2013	2014	Forecasted Test Period
Residential	$ 5,188,232	$ 3,628,632	$ 1,364,297	$ 1,565,965	$ 3,890,076	
Commercial	669,774	724,982	344,463	330,353	713,017	
Industrial	44,549	722	34,980	(6,353)	26,604	
Public Authority	1,704	803	5,393	31,205	90,575	
Street Lights	187	-	618	137	1	
Transportation	-	-	6	-	-	
Total Uncollectibles Expense	$ 5,904,446	$ 4,355,139	$ 1,749,757	$ 1,921,307	$ 4,720,273	$ 4,028,000

For the actuals, the accrual for bad debt is not recorded by revenue class; therefore, for the purposes of this response, the accrual has been allocated to each revenue class based on the actual write-offs.

For the forecasted test period, uncollectibles expense is not forecasted by revenue class.

EXHIBIT ____ (LK-27)

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2014-00372

Response to Attorney General's Supplemental Requests for Information Dated February 6, 2015

Question No. 3

Responding Witness: Christopher M. Garrett

Q-3. Reference AG 1-2 and AG1-3(d). Confirm that while LGE seeks $4,028,000 in uncollectible expense in the forecasted test period, the uncollectible average from 2010-2014 is $3,730,184 and from 2011-2014 is $3,186,619.

A-3. LG&E has included $4,028,000 in uncollectible expense in the forecasted test period, and the uncollectible average from 2010-2014 is $3,730,184 and from 2011-2014 is $3,186,619.

The $4,028,000 uncollectible expense in the forecasted test period represents .28% of total revenues. This write-off percentage is lower than the actual percentage for the most recent calendar year and not unreasonable when compared to the five year average.

EXHIBIT ____ (LK-28)

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to First Set of Data Requests of Kentucky Industrial Utility Customers, Inc. Dated January 8, 2015

Question No. 36

Responding Witness: Christopher M. Garrett

Q.1-36. 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.1-36. See attachment being provided in Excel format

Kentucky Utilities Company
2015 BP
Property & Other Taxes
Income Statement impact:
(round to 1,000's)

Budgeted Property Taxes	2014	2015	2016	Base Year Ending 02/28/15	Test Year Ending 06/30/16
Property Taxes (P&L)					
KU	24,196	26,817	28,200	24,633	27,509
KU Electric	23,049	25,142	26,248	23,398	25,695
KU ECR	1,147	1,675	1,952	1,235	1,814
KU Totals	24,196	26,817	28,200	24,633	27,509

Assumptions in MTP years (2015 BP):

The 2015 business plan years 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 authorites were increased 2% each year.

Kentucky Utilities Company
Property Tax Analysis
2015 BP

	1/1/2014	1/1/2015	1/1/2016
Summary			
AG:[Ending Gross Plant Balance]	6,970,964	7,798,487	8,968,009
AR:[Ending Accum Depreciation]	(2,666,166)	(2,811,345)	(3,011,974)
Net Plant	4,304,798	4,987,142	5,956,035
CWIP and RWIP	1,157,464	913,772	210,229
Total Plant	**5,462,262**	**5,900,914**	**6,166,264**
Exclude:			
Virginia and Tennessee Property	(75,925)	(78,045)	(74,633)
Virginia and Tennessee CWIP	(4,234)	(4,234)	(4,234)
Intangibles (ARO's, Org, Franch & Cons)	(156,366)	(165,721)	(165,711)
Vehicles	(940)	(2,233)	(2,972)
Add:			
Assessed Franchise Value	3,000	3,000	3,000
AS:[Fuel Inventory-151.0]	77,808	104,279	97,311
AU:[M&S Inventory-154.0]	36,405	35,193	34,989
AX:[Stores Expense-163.0]	10,214	10,521	10,521
Net Book Reportable for KY Property Tax	**5,352,224**	**5,803,674**	**6,064,537**
KY Reportable Original Costs			
Real Estate Original Costs	313,552	336,377	347,066
Manufacturing Machinery Original Costs	4,780,893	5,420,700	6,530,973
Other Tangible Property Original Costs	1,547,495	1,684,824	1,732,639
	6,641,939	**7,441,901**	**8,610,678**
Plant account 311 Split	326,215	329,263	331,929
Real Estate 55%	179,418	181,095	182,561
Manufacturing Machinery 45%	146,797	148,168	149,368
Reserve Summary			
Total Reserve	2,647,315	2,790,299	2,977,342
Less Exempt Plant accounts	(26,647)	(39,950)	(39,967)
Less Non-KY Reserves	(69,147)	(70,637)	(74,049)
Reserve to allocate	**2,551,522**	**2,679,712**	**2,863,326**
Reserve Allocation			
Real Estate Reserve	98,966	121,124	115,411
Manufacturing Machinery Reserve	1,805,306	1,951,909	2,171,757
Other Tangible Property Reserve	647,250	606,679	576,158
	2,551,522	**2,679,712**	**2,863,326**
Reportable NBV			
Real Estate Original NBV	214,586	215,253	231,655
Manufacturing Machinery NBV	2,975,587	3,468,791	4,359,216
Other Tangible Property NBV	900,245	1,078,145	1,156,481
	4,090,418	**4,762,189**	**5,747,352**
Allocated CWIP and RWIP			
Real Estate Original Costs	6,922	2,816	543
Manufacturing Machinery Original Costs	1,055,803	842,054	162,407
Other Tangible Property Original Costs	69,421	43,623	8,413
	1,132,146	**888,492**	**171,363**
Net Book Value Reported on Schedule J			
Real Estate Original Costs	221,508	218,068	232,198
Manufacturing Machinery Original Costs	4,031,390	4,310,845	4,521,623
Other Tangible Property Original Costs	1,019,285	1,170,482	1,213,405
Inventory	77,808	104,279	97,311
	5,349,991	**5,803,674**	**6,064,537**
	(2,233.36)	-	-
Average Tax Rates per Category (per $100)			
Real Estate Original Costs	1.0659	1.0851	1.1044
Manufacturing Machinery Original Costs	0.1500	0.1500	0.1500
Other Tangible Property Original Costs	1.4405	1.4608	1.4810
Inventory	0.0500	0.0500	0.0500
KY Property Tax Expense	**Year 2014**	**Year 2015**	**Year 2016**
Real Estate Original Costs	2,361	2,366	2,564
Manufacturing Machinery Original Costs	6,047	6,466	6,782
Other Tangible Property Original Costs	14,683	17,098	17,970
Inventory	39	52	49
Kentucky Property Tax	**23,130**	**25,983**	**27,366**
Virginia Property Tax	600	600	600
Paid and Assessed Locally	235	235	235
Accrual adjustments	232		
Total Property Tax Expense	**24,196**	**26,817**	**28,200**

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2014-00372

Response to First Set of Data Requests of Kentucky Industrial Utility Customers, Inc. Dated January 8, 2015

Question No. 36

Responding Witness: Christopher M. Garrett

Q.1-36. 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.1-36. See attachment being provided in Excel format.

Louisville Gas and Electric
2015 BP
Property & Other Taxes
Income Statement impact:
(round to 1,000's)

Budgeted Property Taxes	2014	2015	2016	Base Year Ending 02/28/15	Test Year Ending 06/30/1(
Property Taxes (P&L)					
LG&E	23,129	25,644	29,418	23,548	27,531
LG&E Electric	16,815	18,176	20,508	17,042	19,342
LG&E Gas	5,782	6,411	7,354	5,887	6,883
LG&E ECR	532	1,057	1,555	619	1,306
LG&E Totals	23,129	25,644	29,418	23,548	27,531

Assumptions in MTP years (2015 BP):

The 2015 business plan years 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 authorites were increased 2% each year.

Louisville Gas and Electric Company
Property Tax Analysis
2015 BP

	1/1/2014	1/1/2015	1/1/2016
Summary			
AG:[Ending Gross Plant Balance]	5,070,606	5,657,192	6,123,072
AR:[Ending Accum Depreciation]	(2,359,917)	(2,379,440)	(2,160,638)
Net Plant	2,710,689	3,277,752	3,962,434
CWIP and RWIP	676,665	657,760	439,763
Total Plant	**3,387,354**	**3,935,512**	**4,402,197**
Exclude:			
Indiana Property	(27,887)	(29,686)	(53,339)
Indiana CWIP	(7,203)	(26,653)	(1,734)
Fort Knox Estimate	(39,619)	(56,171)	(56,171)
Intangibles (ARO's, Org, Franch & Cons)	(61,322)	(59,060)	(59,060)
Nonrecoverable Natural Gas	(1,708)	(1,628)	(1,548)
Vehicles	(2,278)	(52,155)	(58,415)
Railcars estimate	(2,407)	(2,407)	(2,407)
Add:			
Assessed Franchise Value	3,000	3,000	3,000
Assessed Land Value	3,779	3,779	3,779
AW:[Gas Inventory-164.0]	47,547	52,855	51,299
AW:[Gas Inventory-164.0] Less Indiana	(5,603)	(5,603)	(5,603)
AS:[Fuel Inventory-151.0]	64,192	56,491	47,571
AU:[M&S Inventory-154.0]	35,817	34,989	25,783
AX:[Stores Expense-163.0]	6,187	6,278	6,278
Net Book Reportable for KY Property Tax	**3,399,850**	**3,859,542**	**4,301,631**
	29,318		
KY Reportable Original Costs (less Fort Knox and railcars)			
Real Estate Original Costs	1,027,011	1,013,319	1,063,634
Manufacturing Machinery Original Costs	2,715,793	3,087,660	3,428,390
Other Tangible Property Original Costs	1,156,021	1,283,977	1,327,668
	4,898,826	**5,384,955**	**5,819,691**
Reserve Summary			
Total Reserve	2,334,684	2,340,883	2,086,960
Less Exempt Plant accounts	(24,687)	(28,069)	(28,242)
Less Non-KY Reserves	(18,595)	(18,675)	(19,813)
Less Rail Cars	(2,060)	(2,060)	(2,060)
Less Fort Knox	(21,349)	(34,064)	(34,064)
Reserve to allocate	**2,267,993**	**2,258,014**	**2,002,781**
Reserve Allocation			
Real Estate Reserve	457,472	424,904	366,038
Manufacturing Machinery Reserve	1,275,321	1,294,714	1,179,842
Other Tangible Property Reserve	535,199	538,396	456,902
	2,267,993	**2,258,014**	**2,002,781**
Reportable NBV			
Real Estate Original NBV	569,539	588,415	697,596
Manufacturing Machinery NBV	1,440,471	1,792,945	2,248,548
Other Tangible Property NBV	620,822	745,581	870,766
	2,630,833	**3,126,941**	**3,816,910**
Allocated CWIP and RWIP			
Real Estate Original Costs	49,476	11,310	6,954
Manufacturing Machinery Original Costs	537,530	549,236	337,719
Other Tangible Property Original Costs	57,222	32,003	19,678
	644,229	**592,550**	**364,351**
Net Book Value Reported on Schedule J			
Real Estate Original Costs	622,795	603,504	708,330
Manufacturing Machinery Original Costs	1,978,001	2,342,182	2,586,267
Other Tangible Property Original Costs	723,048	821,851	925,506
Inventory - Gas Stored Underground (exclude Fort Knox)	30,205	35,513	33,957
Inventory - Fuel	64,192	56,491	47,571
	3,418,242	**3,859,542**	**4,301,631**
	18,392.53	-	-
Average Tax Rates per Category (per $100)			
Real Estate Original Costs	1.1896	1.2114	1.2332
Manufacturing Machinery Original Costs	0.1500	0.1500	0.1500
Other Tangible Property Original Costs	1.6780	1.7031	1.7281
Inventory - Gas Stored Underground (exclude Fort Knox)	1.0364	1.0565	1.0766
Inventory - Fuel	0.0500	0.0500	0.0500
KY Property Tax Expense	**Year 2014**	**Year 2015**	**Year 2016**
Real Estate Original Costs	7,409	7,311	8,735
Manufacturing Machinery Original Costs	2,967	3,513	3,879
Other Tangible Property Original Costs	12,133	13,997	15,994
Inventory - Gas Stored Underground (exclude Fort Knox)	313	375	366
Inventory - Fuel	32	28	24
Kentucky Property Tax	**22,854**	**25,224**	**28,998**
Indiana Property Tax	220	220	220
Paid and Assessed Locally	200	200	200
Accrual adjustments	(144)		
Total Property Tax Expense	**23,129**	**25,644**	**29,418**

EXHIBIT ____ (LK-29)

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Second Set of Data Requests of Kentucky Industrial Utility Customers, Inc. Dated February 6, 2015

Question No. 2-10

Responding Witness: Christopher M. Garrett

Q.2-10. Refer to the Company's response to KIUC 1-36 regarding property tax expense.

a. Please indicate if the Company allocates the property taxes assessed between expense and capital for accounting purposes, i.e., capitalizes the property tax expense related to CWIP. If the Company does not do so, then please explain why it does not.

b. Please indicate if the accumulated depreciation amounts used in the Company's calculation of property tax expense include the net negative salvage reflected in depreciation expense. If not, then please explain why net negative salvage was excluded for that purpose.

A.2-10. a. Per the Company's accounting policy, 656 - Capitalized Property Taxes, only property taxes on CWIP that relate to the original construction costs of coal-fired generating units are capitalized. All other property taxes on construction costs are expensed. There were no original construction costs of coal-fired generating units in the base year, therefore, no property taxes were capitalized.

b. Yes, the accumulated depreciation amounts include the net negative salvage reflected in depreciation expense.

EXHIBIT ____ (LK-30)

Kentucky Utilities Company
KIUC Adjustment to Remove Property Taxes on CWIP
For the Test Year Ended June 30, 2016
$ Millions

Source: Response to KIUC 1-36

CWIP Subject to Property Taxes Paid during 2015	892.726	
Net Plant (including CWIP) Subject to Property Taxes Paid During 2015	5,803.674	
CWIP as a Percentage of Reportable Net Book Value Subject to Property Taxes Paid During 2015	15.38%	
2015 Property Tax Expense - Total Company Excluding ECR	25.142	
2015 Property Tax Expense Based on CWIP	3.867	
Remove 2015 Property Tax Expense Based on CWIP in Test Year (6 Months)		(1.934)
CWIP Subject to Property Taxes Paid during 2016	175.597	
Net Plant (including CWIP) Subject to Property Taxes Paid During 2016	6,064.537	
CWIP as a Percentage of Reportable Net Book Value Subject to Property Taxes Paid During 2016	2.90%	
2016 Property Tax Expense - Total Company Excluding ECR	26.248	
2016 Property Tax Expense Based on CWIP	0.760	
Remove 2016 Property Tax Expense Based on CWIP in Test Year (6 Months)		(0.380)
Remove Test Year Property Tax Expense Based on CWIP-Total Co.		(2.314)
KY Jurisdiction Allocation % - Forecast Test Year Net Plant		88.870%
Remove Test Year Property Tax Expense Based on CWIP-KY Jur		(2.056)

EXHIBIT ____ (LK-31)

Louisville Gas and Electric Company
KIUC Adjustment to Remove Property Taxes on CWIP
For the Test Year Ended June 30, 2016
$ Millions

Source: Response to KIUC 1-36

CWIP Subject to Property Taxes Paid during 2015	619.203	
Net Plant (including CWIP) Subject to Property Taxes Paid During 2015	3,859.542	
CWIP as a Percentage of Reportable Net Book Value Subject to Property Taxes Paid During 2015	16.04%	
2015 Property Tax Expense - Electric and Excluding ECR	18.176	
2015 Property Tax Expense Based on CWIP	2.916	
Remove 2015 Property Tax Expense Based on CWIP in Test Year (6 Months)		(1.458)
CWIP Subject to Property Taxes Paid during 2016	366.085	
Net Plant (including CWIP) Subject to Property Taxes Paid During 2016	4,301.631	
CWIP as a Percentage of Reportable Net Book Value Subject to Property Taxes Paid During 2016	8.51%	
2016 Property Tax Expense - Electric and Excluding ECR	20.508	
2016 Property Tax Expense Based on CWIP	1.745	
Remove 2016 Property Tax Expense Based on CWIP in Test Year (6 Months)		(0.873)
Remove Test Year Property Tax Expense Based on CWIP		(2.331)

EXHIBIT ____ (LK-32)

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 8, 2015

Question No. 29

Responding Witness: Christopher M. Garrett

Q.1-29. Please provide a schedule of the amortization expense associated with each regulatory asset for each year 2010 through 2014, the base year, and the test year. Provide the balance of each regulatory asset at the beginning and end of each of those years as well as the amortization period that was used in each of those years. 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.1-29. See attached.

Kentucky Utilities Company - 2010

Regulatory Assets with specific amortization periods

Account	Description	Amortization Period	Order No. / Docket No.	Beginning Balance	Annual Activity	Amortization	Ending Balance
182320/182345	WINTER STORM 2009 - ELECTRIC	Aug-10 to Jul-20	2009-00548 2009-00174 2008-00251 PUE 2009-00029	57,236,758	(476,973)	(1,907,892)	54,851,894
182321/182341	MISO EXIT FEE	Mar-09 to Dec-14	EC06-4 ER06-20	8,758,240	(2,492,896)	(1,144,488)	5,120,856
182322/182335	RATE CASE EXPENSES - ELECTRIC	Jan-13 to Dec-15	2012-00221	997,877	1,734,767	(460,559)	2,272,086
182324/182337	EKPC FERC TRANSMISSION COST - KY PORTION	Mar-09 to Feb-14	ER06-1458	1,394,571	-	(334,697)	1,059,874
182332/182348	CMRG FUNDING [CARBON MGT RESEARCH GROUP]	Aug-10 to Jul-20	2009-00548	216,500	(11,620)	(42,683)	162,197
182333/182349	KCCS FUNDING [KY CONSORTIUM FOR CARBON STORAGE]	Aug-10 to Jul-14	2009-00548	921,961	-	(96,038)	825,923
182334/182347	WIND STORM 2008	Aug-10 to Jul-20	2009-00548 2008-00457	2,195,516	(18,296)	(73,184)	2,104,037
182339	MOUNTAIN STORM - ELECTRIC	Nov-11 to Oct-16	PUE 2010-00141	-	-	-	-
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	Jan-13 to Dec-15	2012-00222	-	-	-	-
Regulatory Assets with specific amortization periods Total				71,721,423	(1,265,017)	(4,059,540)	66,396,866

Other Regulatory Assets

Account	Description	Amortization Period	Order No. / Docket No.	Beginning Balance	Annual Activity	Amortization	Ending Balance
182305/182315	SFAS 158 - PENSION AND POSTRETIREMENT			104,664,344	12,610,024		117,274,368
182328-182331	SFAS 109 - INCOME TAXES			12,478,514	1,116,822		13,595,336
182309/182368	VA FUEL COMPONENT			-	4,795,000		4,795,000
182311	FERC JURISDICTIONAL PENSION EXPENSES			3,823,143	967,794		4,790,937
182317-18/182325	ASSET RETIREMENT OBLIGATION			29,970,260	(28,419,411)		1,550,849
182307	ENVIRONMENTAL COST RECOVERY			28,377,088	(28,377,088)		-
182306	KY FUEL ADJUSTMENT CLAUSE			675,000	(675,000)		-
Other Regulatory Assets Total				179,988,349	(37,981,859)	-	142,006,490
KU Regulatory Assets Total				251,709,772	(39,246,876)	(4,059,540)	208,403,356

Kentucky Utilities Company - 2011

Regulatory Assets with specific amortization periods

Account	Description	Amortization Period	Order No. / Docket No.	Beginning Balance	Annual Activity	Amortization	Ending Balance
			2009-00548				
182320/182345	WINTER STORM 2009 - ELECTRIC	Aug-10 to Jul-20	2009-00174	54,851,894	-	(5,723,676)	49,128,218
			2008-00251				
			PUE 2009-00029				
			EC06-4				
182321/182341	MISO EXIT FEE	Mar-09 to Dec-14	ER06-20	5,120,856	(63,426)	(1,413,481)	3,643,950
182322/182335	RATE CASE EXPENSES - ELECTRIC	Jan-13 to Dec-15	2012-00221	2,272,086	-	(1,132,082)	1,140,004
182324/182337	EKPC FERC TRANSMISSION COST - KY PORTION	Mar-09 to Feb-14	ER06-1458	1,059,874	-	(334,697)	725,177
182332/182348	CMRG FUNDING [CARBON MGT RESEARCH GROUP]	Aug-10 to Jul-20	2009-00548	162,197	102,440	(102,440)	162,197
182333/182349	KCCS FUNDING [KY CONSORTIUM FOR CARBON STORAGE]	Aug-10 to Jul-14	2009-00548	825,923	-	(230,490)	595,433
			2009-00548				
182334/182347	WIND STORM 2008	Aug-10 to Jul-20	2008-00457	2,104,037	-	(219,552)	1,884,485
182339	MOUNTAIN STORM - ELECTRIC	Nov-11 to Oct-16	PUE 2010-00141	-	6,041,670	(201,389)	5,840,281
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	Jan-13 to Dec-15	2012-00222	-	140,906	-	140,906
Regulatory Assets with specific amortization periods Total				66,396,866	6,221,590	(9,357,806)	63,260,650

Other Regulatory Assets

Account	Description	Amortization Period	Order No. / Docket No.	Beginning Balance	Annual Activity	Amortization	Ending Balance
182305/182315	ASC 715 - PENSION AND POSTRETIREMENT			117,274,368	(4,010,222)		113,264,146
182328-182331	ASC 740 - INCOME TAXES			13,595,336	61,617,019		75,212,355
182317-18/182325	ASSET RETIREMENT OBLIGATION			1,550,849	5,870,443		7,421,292
182311	FERC JURISDICTIONAL PENSION EXPENSES			4,790,937	1,084,916		5,875,853
182309/182368	VA FUEL COMPONENT			4,795,000	(1,001,000)		3,794,000
Other Regulatory Assets Total				142,006,490	63,561,156	-	205,567,646
KU Regulatory Assets Total				208,403,356	69,782,746	(9,357,806)	268,828,296

Kentucky Utilities Company - 2012

Regulatory Assets with specific amortization periods

Account	Description	Amortization Period	Order No. / Docket No.	Beginning Balance	Annual Activity	Amortization	Ending Balance
			2009-00548				
182320/182345	WINTER STORM 2009 - ELECTRIC	Aug-10 to Jul-20	2009-00174	49,128,218	-	(5,723,676)	43,404,542
			2008-00251				
			PUE 2009-00029				
			EC06-4				
182321/182341	MISO EXIT FEE	Mar-09 to Dec-14	ER06-20	3,643,950	-	(1,345,267)	2,298,683
182322/182335	RATE CASE EXPENSES - ELECTRIC	Jan-13 to Dec-15	2012-00221	1,140,004	1,654,125	(748,283)	2,045,847
182324/182337	EKPC FERC TRANSMISSION COST - KY PORTION	Mar-09 to Feb-14	ER06-1458	725,177	-	(334,697)	390,480
182332/182348	CMRG FUNDING [CARBON MGT RESEARCH GROUP]	Aug-10 to Jul-20	2009-00548	162,197	102,440	(102,440)	162,197
182333/182349	KCCS FUNDING [KY CONSORTIUM FOR CARBON STORAGE]	Aug-10 to Jul-14	2009-00548	595,433	-	(230,490)	364,943
			2009-00548				
182334/182347	WIND STORM 2008	Aug-10 to Jul-20	2008-00457	1,884,485	-	(219,552)	1,664,933
182339	MOUNTAIN STORM - ELECTRIC	Nov-11 to Oct-16	PUE 2010-00141	5,840,281	-	(1,208,334)	4,631,947
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	Jan-13 to Dec-15	2012-00222	140,906	1,615	-	142,521
Regulatory Assets with specific amortization periods Total				63,260,650	1,758,179	(9,912,738)	55,106,092

Other Regulatory Assets

Account	Description	Amortization Period	Order No. / Docket No.	Beginning Balance	Annual Activity	Amortization	Ending Balance
182305/182315	ASC 715 - PENSION AND POSTRETIREMENT			113,264,146	22,778,591		136,042,737
182328-182331	ASC 740 - INCOME TAXES			75,212,355	(2,381,974)		72,830,381
182317-18/182325	ASSET RETIREMENT OBLIGATION			7,421,292	3,808,109		11,229,401
182311	FERC JURISDICTIONAL PENSION EXPENSES			5,875,853	790,908		6,666,761
182309/182368	VA FUEL COMPONENT			3,794,000	(151,000)		3,643,000
182363	DSM COST RECOVERY			-	401,912		401,912
Other Regulatory Assets Total				205,567,646	25,246,546	-	230,814,192
KU Regulatory Assets Total				268,828,296	27,004,725	(9,912,738)	285,920,284

Kentucky Utilities Company - 2013

Regulatory Assets with specific amortization periods

Account	Description	Amortization Period	Order No. / Docket No.	Beginning Balance	Annual Activity	Amortization	Ending Balance
182320/182345	WINTER STORM 2009 - ELECTRIC	Aug-10 to Jul-20	2009-00548 2009-00174 2008-00251 PUE 2009-00029 EC06-4	43,404,542	-	(5,723,676)	37,680,866
182321/182341	MISO EXIT FEE	Mar-09 to Dec-14	ER06-20	2,298,683	(382,728)	(127,069)	1,788,886
182322/182335	RATE CASE EXPENSES - ELECTRIC	Jan-13 to Dec-15	2012-00221	2,045,847	116	(943,097)	1,102,866
182324/182337	EKPC FERC TRANSMISSION COST - KY PORTION	Mar-09 to Feb-14	ER06-1458	390,480	-	(334,697)	55,783
182332/182348	CMRG FUNDING [CARBON MGT RESEARCH GROUP]	Aug-10 to Jul-20	2009-00548	162,197	122,000	(102,440)	181,757
182333/182349	KCCS FUNDING [KY CONSORTIUM FOR CARBON STORAGE]	Aug-10 to Jul-14	2009-00548	364,943	-	(230,490)	134,453
182334/182347	WIND STORM 2008	Aug-10 to Jul-20	2009-00548 2008-00457	1,664,933	-	(219,552)	1,445,382
182339	MOUNTAIN STORM - ELECTRIC	Nov-11 to Oct-16	PUE 2010-00141	4,631,947	-	(1,208,334)	3,423,613
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	Jan-13 to Dec-15	2012-00222	142,521	-	(47,507)	95,014
Regulatory Assets with specific amortization periods Total				55,106,092	(260,612)	(8,936,861)	45,908,619

Other Regulatory Assets

Account	Description	Amortization Period	Order No. / Docket No.	Beginning Balance	Annual Activity	Amortization	Ending Balance
182305/182315	ASC 715 - PENSION AND POSTRETIREMENT			136,042,737	(48,189,079)		87,853,658
182328-182331	ASC 740 - INCOME TAXES			72,830,381	(1,554,062)		71,276,319
182317-18/182325	ASSET RETIREMENT OBLIGATION			11,229,401	11,328,676		22,558,077
182311	FERC JURISDICTIONAL PENSION EXPENSES			6,666,760	(6,666,760)		-
182309/182368	VA FUEL COMPONENT			3,643,000	(3,643,000)		-
182363	DSM COST RECOVERY - UNDER-RECOVERY			401,912	4,944,597		5,346,509
182307	ENVIRONMENTAL COST RECOVERY			-	4,635,326		4,635,326
Other Regulatory Assets Total				230,814,191	(39,144,302)	-	191,669,889
KU Regulatory Assets Total				285,920,283	(39,404,914)	(8,936,861)	237,578,508

Kentucky Utilities Company - 2014

Regulatory Assets with specific amortization periods

Account	Description	Amortization Period	Order No. / Docket No.	Beginning Balance	Annual Activity	Amortization	Ending Balance
182320/182345	WINTER STORM 2009 - ELECTRIC	Aug-10 to Jul-20	2009-00548 2009-00174 2008-00251 PUE 2009-00029 EC06-4	37,680,866	-	(5,723,676)	31,957,190
182321/182341	MISO EXIT FEE	Mar-09 to Dec-14	ER06-20	1,788,886	(1,679,029)	(109,857)	0
182322/182335	RATE CASE EXPENSES - ELECTRIC	Jan-13 to Dec-15	2012-00221	1,102,866	1,357,905	(551,375)	1,909,396
182324/182337	EKPC FERC TRANSMISSION COST - KY PORTION	Mar-09 to Feb-14	ER06-1458	55,783	-	(55,783)	-
182332/182348	CMRG FUNDING [CARBON MGT RESEARCH GROUP]	Aug-10 to Jul-20	2009-00548	181,757	122,000	(141,560)	162,197
182333/182349	KCCS FUNDING [KY CONSORTIUM FOR CARBON STORAGE]	Aug-10 to Jul-14	2009-00548	134,453	-	(134,453)	-
182334/182347	WIND STORM 2008	Aug-10 to Jul-20	2009-00548 2008-00457	1,445,382	-	(219,552)	1,225,830
182339	MOUNTAIN STORM - ELECTRIC	Nov-11 to Oct-16	PUE 2010-00141	3,423,613	-	(1,208,334)	2,215,279
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	Jan-13 to Dec-15	2012-00222	95,014	-	(47,507)	47,507
182367	REG ASSET - MUNI MISO EXIT FEE			-	1,208,048	-	1,208,048
Regulatory Assets with specific amortization periods Total				45,908,619	1,008,924	(8,192,096)	38,725,447

Other Regulatory Assets

Account	Description	Amortization Period	Order No. / Docket No.	Beginning Balance	Annual Activity	Amortization	Ending Balance
182305/182315	ASC 715 - PENSION AND POSTRETIREMENT			87,853,658	(6,983,399)		80,870,259
182328-182331	ASC 740 - INCOME TAXES			71,276,319	(811,290)		70,465,029
182317-18/182325	ASSET RETIREMENT OBLIGATION			22,558,077	28,197,621		50,755,698
182363	DSM COST RECOVERY - UNDER-RECOVERY			5,346,509	(5,346,509)		-
182307	ENVIRONMENTAL COST RECOVERY			4,635,326	(3,832,326)		803,000
182306	FUEL ADJUSTMENT CLAUSE			-	2,464,000		2,464,000
182364	LONG TERM INTEREST RATE SWAP FORWARD STARTING			-	33,287,299		33,287,299
Other Regulatory Assets Total				191,669,889	46,975,396	-	238,645,285
KU Regulatory Assets Total				237,578,508	47,984,319	(8,192,096)	277,370,732

Kentucky Utilities Company (Base Period Actual/Forecast 3/14 - 2/15)

Regulatory Assets with specific amortization periods

Account	Description	Amortization Period	Order No. / Docket No.	Beginning Balance	Annual Activity	Amortization	Ending Balance
			2009-00548				
182320/182345	WINTER STORM 2009 - ELECTRIC	Aug-10 to Jul-20	2009-00174	36,727,000	-	(5,723,000)	31,004,000
			2008-00251				
			PUE 2009-00029				
			EC06-4				
182321/182341	MISO EXIT FEE	Mar-09 to Dec-14	ER06-20	1,732,000	(1,641,000)	(91,000)	-
182322/182335	RATE CASE EXPENSES - ELECTRIC	Jan-13 to Dec-15	2012-00221	1,017,000	1,313,000	(551,000)	1,779,000
182332/182348	CMRG FUNDING [CARBON MGT RESEARCH GROUP]	Aug-10 to Jul-20	2009-00548	165,000	185,000	(102,000)	248,000
182333/182349	KCCS FUNDING [KY CONSORTIUM FOR CARBON STORAGE]	Aug-10 to Jul-14	2009-00548	96,000	-	(96,000)	-
			2009-00548				
182334/182347	WIND STORM 2008	Aug-10 to Jul-20	2008-00457	1,409,000	-	(220,000)	1,189,000
182339	MOUNTAIN STORM - ELECTRIC	Nov-11 to Oct-16	PUE 2010-00141	3,222,000	-	(1,208,000)	2,014,000
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	Jan-13 to Dec-15	2012-00222	87,000	-	(48,000)	39,000
182367	REG ASSET - MUNI MISO EXIT FEE			-	1,361,000	(234,000)	1,127,000
Regulatory Assets with specific amortization periods Total				44,455,000	1,218,000	(8,273,000)	37,400,000
Other Regulatory Assets				100,415,772	19,652,228	-	120,068,000
KU Regulatory Assets Total				144,870,772	20,870,228	(8,273,000)	157,468,000

Kentucky Utilities Company (Test Period Forecast 7/15 - 6/16)

Regulatory Assets with specific amortization periods

Account	Description	Amortization Period	Order No. / Docket No.	Beginning Balance	Annual Activity	Amortization	Ending Balance
182320/182345	WINTER STORM 2009 - ELECTRIC	Aug-10 to Jul-20	2009-00548 2009-00174	29,095,000	-	(5,723,000)	23,372,000
182322/182335	RATE CASE EXPENSES - ELECTRIC	Jan-13 to Dec-15	2012-00221	2,433,000	1,179,000	(960,000)	2,652,000
182332/182348	CMRG FUNDING [CARBON MGT RESEARCH GROUP]	Aug-10 to Jul-20	2009-00548	213,000	102,000	(102,000)	213,000
182333/182349	KCCS FUNDING [KY CONSORTIUM FOR CARBON STORAGE]	Aug-10 to Jul-14	2009-00548	-	-	-	-
182334/182347	WIND STORM 2008	Aug-10 to Jul-20	2009-00548 2008-00457	1,116,000	-	(220,000)	896,000
182339	MOUNTAIN STORM - ELECTRIC	Nov-11 to Oct-16	PUE 2010-00141	1,611,000	-	(1,208,000)	403,000
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	Jan-13 to Dec-15	2012-00222	208,000	-	(83,000)	125,000
182367	REG ASSET - MUNI MISO EXIT FEE			966,000	-	(484,000)	482,000
Regulatory Assets with specific amortization periods Total				35,642,000	1,281,000	(8,780,000)	28,143,000
Other Regulatory Assets				119,066,000	22,058,000	-	141,124,000
KU Regulatory Assets Total				154,708,000	23,339,000	(8,780,000)	169,267,000

EXHIBIT ____ (LK-33)

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2014-00372

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 8, 2015

Question No. 29

Responding Witness: Christopher M. Garrett

Q.1-29. Please provide a schedule of the amortization expense associated with each regulatory asset for each year 2010 through 2014, the base year, and the test year. Provide the balance of each regulatory asset at the beginning and end of each of those years as well as the amortization period that was used in each of those years. 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.1-29. See attached.

Louisville Gas and Electric Company - 2010

Regulatory Assets with specific amortization periods

Account	Description	Amortization Period	Order No. / Docket No.	Beginning Balance	Annual Activity	Amortization	Ending Balance
182320/182345	WINTER STORM 2009 - ELECTRIC	Aug-10 to Jul-20	2009-00549 2009-00175	43,670,702	-	(1,819,613)	41,851,089
182342/182346	WINTER STORM 2009 - GAS	Aug-10 to Jul-20	2009-00549 2009-00175	167,689	16,769	(23,756)	160,702
182321/182341	MISO EXIT FEE	Mar-09 to Dec-13	2008-00251 EC06-4 ER06-20	4,308,025	(1,692,544)	(1,106,015)	1,509,467
182322/182335	RATE CASE EXPENSES - ELECTRIC	Jan-13 to Dec-15	2012-00222	536,806	722,898	(247,757)	1,011,948
182323/182336	RATE CASE EXPENSES - GAS	Jan-13 to Dec-15	2012-00222	179,818	413,700	(82,993)	510,525
182324/182337	EKPC FERC TRANSMISSION COST - KY PORTION	Mar-09 to Feb-14	ER06-1458	706,552	-	(169,572)	536,979
182332/182348	CMRG FUNDING [CARBON MGT RESEARCH GROUP]	Aug-10 to Jul-20	2009-00549	183,500	11,620	(40,650)	154,470
182333/182349	KCCS FUNDING [KY CONSORTIUM FOR CARBON STORAGE]	Aug-10 to Jul-14	2009-00549	878,041	-	(91,463)	786,578
182334/182347	WIND STORM REGULATORY ASSET	Aug-10 to Jul-20	2009-00549 2008-00456	23,540,333	-	(980,847)	22,559,486
182343/182344	SWAP TERMINATION	Aug-10 to Apr-35	2009-00549	-	9,303,396	(107,698)	9,195,698
Regulatory Assets with specific amortization periods Total				74,171,466	8,775,839	(4,670,363)	78,276,942

Other Regulatory Assets

Account	Description	Amortization Period	Order No. / Docket No.	Beginning Balance	Annual Activity	Amortization	Ending Balance
182305/182315	ASC 715 - PENSION AND POSTRETIREMENT			204,123,304	9,057,366	-	213,180,670
182352	LONG TERM INTEREST RATE SWAP			-	34,281,361	-	34,281,361
182317-18/182325	ASSET RETIREMENT OBLIGATION - ELECTRIC			21,443,936	(14,856,145)	-	6,587,791
182326	ASSET RETIREMENT OBLIGATION - GAS			8,129,187	(7,879,141)	-	250,046
182327	ASSET RETIREMENT OBLIGATION - COMMON			26,290	(25,015)	-	1,275
182307	ENVIRONMENTAL COST RECOVERY			7,213,893	(2,493,584)	-	4,720,309
182306	FUEL ADJUSTMENT CLAUSE			66,000	3,125,000	-	3,191,000
182340	PERFORMANCE-BASED RATES			2,714,433	(279,480)	-	2,434,953
182308	GAS SUPPLY CLAUSE			55,271	1,056,746	-	1,112,017
182319	MILL CREEK ASH POND RECOVERED THROUGH ECR	May-06 to Apr-10		685,885	(685,885)	-	-
Other Regulatory Assets Total				244,458,199	21,301,223	-	265,759,422
LG&E Regulatory Assets Total				318,629,665	30,077,062	(4,670,363)	344,036,364

Louisville Gas and Electric Company - 2011

Regulatory Assets with specific amortization periods

Account	Description	Amortization Period	Order No. / Docket No.	Beginning Balance	Annual Activity	Amortization	Ending Balance
182320/182345	WINTER STORM 2009 - ELECTRIC	Aug-10 to Jul-20	2009-00549 2009-00175	41,851,089	-	(4,367,070)	37,484,019
182342/182346	WINTER STORM 2009 - GAS	Aug-10 to Jul-20	2009-00549 2009-00175	160,702	-	(16,769)	143,933
182321/182341	MISO EXIT FEE	Mar-09 to Dec-13	2008-00251 EC06-4 ER06-20	1,509,467	-	(749,834)	759,633
182322/182335	RATE CASE EXPENSES - ELECTRIC	Jan-13 to Dec-15	2012-00222	1,011,948	-	(527,588)	484,359
182323/182336	RATE CASE EXPENSES - GAS	Jan-13 to Dec-15	2012-00222	510,525	-	(243,135)	267,390
182324/182337	EKPC FERC TRANSMISSION COST - KY PORTION	Mar-09 to Feb-14	ER06-1458	536,979	-	(169,572)	367,407
182332/182348	CMRG FUNDING [CARBON MGT RESEARCH GROUP]	Aug-10 to Jul-20	2009-00549	154,470	97,560	(97,560)	154,470
182333/182349	KCCS FUNDING [KY CONSORTIUM FOR CARBON STORAGE]	Aug-10 to Jul-14	2009-00549	786,578	-	(219,510)	567,068
182334/182347	WIND STORM REGULATORY ASSET	Aug-10 to Jul-20	2009-00549 2008-00456	22,559,486	-	(2,354,033)	20,205,452
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	Jan-13 to Dec-15	2012-00222	-	90,545	-	90,545
182360	GENERAL MANAGEMENT AUDIT - GAS	Jan-13 to Dec-15	2012-00222	-	29,486	-	29,486
182361	2011 SUMMER STORM - ELECTRIC	Jan-13 to Dec-17	2012-00222	-	8,052,125	-	8,052,125
182343/182344	SWAP TERMINATION	Aug-10 to Apr-35	2009-00549	9,195,698	-	(258,476)	8,937,222
Regulatory Assets with specific amortization periods Total				78,276,942	8,269,716	(9,003,548)	77,543,109

Other Regulatory Assets

Account	Description	Amortization Period	Order No. / Docket No.	Beginning Balance	Annual Activity	Amortization	Ending Balance
182305/182315	ASC 715 - PENSION AND POSTRETIREMENT			213,180,670	12,124,492	-	225,305,162
182352	LONG TERM INTEREST RATE SWAP			34,281,361	25,285,103	-	59,566,464
182328-182331	ASC 740 - INCOME TAXES			-	14,730,134	-	14,730,134
182317-18/182325	ASSET RETIREMENT OBLIGATION - ELECTRIC			6,587,791	2,835,742	-	9,423,533
182326	ASSET RETIREMENT OBLIGATION - GAS			250,046	983,874	-	1,233,920
182327	ASSET RETIREMENT OBLIGATION - COMMON			1,275	7,832	-	9,107
182307	ENVIRONMENTAL COST RECOVERY			4,720,309	(4,720,309)	-	-
182306	FUEL ADJUSTMENT CLAUSE			3,191,000	407,000	-	3,598,000
182340	PERFORMANCE-BASED RATES			2,434,953	1,583,139	-	4,018,092
182308	GAS SUPPLY CLAUSE			1,112,017	571,363	-	1,683,380
Other Regulatory Assets Total				265,759,422	53,808,370	-	319,567,792
LG&E Regulatory Assets Total				344,036,364	62,078,086	(9,003,548)	397,110,901

Louisville Gas and Electric Company - 2012

Regulatory Assets with specific amortization periods

Account	Description	Amortization Period	Order No. / Docket No.	Beginning Balance	Annual Activity	Amortization	Ending Balance
182320/182345	WINTER STORM 2009 - ELECTRIC	Aug-10 to Jul-20	2009-00549 2009-00175	37,484,019	-	(4,367,070)	33,116,949
182342/182346	WINTER STORM 2009 - GAS	Aug-10 to Jul-20	2009-00549 2009-00175	143,933	-	(16,769)	127,165
182321/182341	MISO EXIT FEE	Mar-09 to Dec-13	2008-00251 EC06-4 ER06-20	759,633	-	(749,834)	9,798
182322/182335	RATE CASE EXPENSES - ELECTRIC	Jan-13 to Dec-15	2012-00222	484,359	894,414	(321,124)	1,057,649
182323/182336	RATE CASE EXPENSES - GAS	Jan-13 to Dec-15	2012-00222	267,390	284,806	(173,974)	378,222
182324/182337	EKPC FERC TRANSMISSION COST - KY PORTION	Mar-09 to Feb-14	ER06-1458	367,407	-	(169,572)	197,834
182332/182348	CMRG FUNDING [CARBON MGT RESEARCH GROUP]	Aug-10 to Jul-20	2009-00549	154,470	97,560	(97,560)	154,470
182333/182349	KCCS FUNDING [KY CONSORTIUM FOR CARBON STORAGE]	Aug-10 to Jul-14	2009-00549	567,068	-	(219,510)	347,558
182334/182347	WIND STORM REGULATORY ASSET	Aug-10 to Jul-20	2009-00549 2008-00456	20,205,452	-	(2,354,033)	17,851,419
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	Jan-13 to Dec-15	2012-00222	90,545	1,038	-	91,583
182360	GENERAL MANAGEMENT AUDIT - GAS	Jan-13 to Dec-15	2012-00222	29,486	338	-	29,824
182361	2011 SUMMER STORM - ELECTRIC	Jan-13 to Dec-17	2012-00222	8,052,125	-	-	8,052,125
182343/182344	SWAP TERMINATION	Aug-10 to Apr-35	2009-00549	8,937,222	-	(258,476)	8,678,746
Regulatory Assets with specific amortization periods Total				77,543,109	1,278,155	(8,727,924)	70,093,341

Other Regulatory Assets

Account	Description	Amortization Period	Order No. / Docket No.	Beginning Balance	Annual Activity	Amortization	Ending Balance
182305/182315	ASC 715 - PENSION AND POSTRETIREMENT			225,305,162	6,400,487	-	231,705,649
182352	LONG TERM INTEREST RATE SWAP			59,566,464	(960,980)	-	58,605,484
182328-182331	ASC 740 - INCOME TAXES			14,730,134	(407,551)	-	14,322,583
182317-18/182325	ASSET RETIREMENT OBLIGATION - ELECTRIC			9,423,533	3,586,834	-	13,010,367
182326	ASSET RETIREMENT OBLIGATION - GAS			1,233,920	764,111	-	1,998,031
182327	ASSET RETIREMENT OBLIGATION - COMMON			9,107	8,120	-	17,227
182307	ENVIRONMENTAL COST RECOVERY			-	631,535	-	631,535
182306	FUEL ADJUSTMENT CLAUSE			3,598,000	2,470,000	-	6,068,000
182340	PERFORMANCE-BASED RATES			4,018,092	1,621,793	-	5,639,885
182308	GAS SUPPLY CLAUSE			1,683,380	3,755,859	-	5,439,239
182363	DSM COST RECOVERY - UNDER-RECOVERY			-	930,885	-	930,885
Other Regulatory Assets Total				319,567,792	18,801,093	-	338,368,885
LG&E Regulatory Assets Total				397,110,901	20,079,248	(8,727,924)	408,462,226

Louisville Gas and Electric Company - 2013

Regulatory Assets with specific amortization periods

Account	Description	Amortization Period	Order No. / Docket No.	Beginning Balance	Annual Activity	Amortization	Ending Balance
182320/182345	WINTER STORM 2009 - ELECTRIC	Aug-10 to Jul-20	2009-00549 2009-00175	33,116,949	-	(4,367,070)	28,749,879
182342/182346	WINTER STORM 2009 - GAS	Aug-10 to Jul-20	2009-00549 2009-00175	127,165	-	(16,769)	110,396
182321/182341	MISO EXIT FEE	Mar-09 to Dec-13	2008-00251 EC06-4 ER06-20	9,798	(9,798)	-	-
182322/182335	RATE CASE EXPENSES - ELECTRIC	Jan-13 to Dec-15	2012-00222	1,057,649	74	(461,373)	596,350
182323/182336	RATE CASE EXPENSES - GAS	Jan-13 to Dec-15	2012-00222	378,222	24	(188,351)	189,895
182324/182337	EKPC FERC TRANSMISSION COST - KY PORTION	Mar-09 to Feb-14	ER06-1458	197,834	0	(169,572)	28,262
182332/182348	CMRG FUNDING [CARBON MGT RESEARCH GROUP]	Aug-10 to Jul-20	2009-00549	154,470	78,000	(97,560)	134,910
182333/182349	KCCS FUNDING [KY CONSORTIUM FOR CARBON STORAGE]	Aug-10 to Jul-14	2009-00549	347,558	-	(219,510)	128,048
182334/182347	WIND STORM REGULATORY ASSET	Aug-10 to Jul-20	2009-00549 2008-00456	17,851,419	-	(2,354,033)	15,497,386
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	Jan-13 to Dec-15	2012-00222	91,583	-	(30,528)	61,055
182360	GENERAL MANAGEMENT AUDIT - GAS	Jan-13 to Dec-15	2012-00222	29,824	-	(9,941)	19,883
182361	2011 SUMMER STORM - ELECTRIC	Jan-13 to Dec-17	2012-00222	8,052,125	-	(1,610,425)	6,441,700
182343/182344	SWAP TERMINATION	Aug-10 to Apr-35	2009-00549	8,678,746	-	(388,659)	8,290,087
Regulatory Assets with specific amortization periods Total				70,093,341	68,301	(9,913,792)	60,247,849

Other Regulatory Assets

Account	Description	Amortization Period	Order No. / Docket No.	Beginning Balance	Annual Activity	Amortization	Ending Balance
182305/182315	ASC 715 - PENSION AND POSTRETIREMENT			231,705,649	(67,617,768)	-	164,087,881
182352	LONG TERM INTEREST RATE SWAP			58,605,484	(22,692,563)	-	35,912,921
182328-182331	ASC 740 - INCOME TAXES			14,322,583	(265,233)	-	14,057,350
182317-18/182325	ASSET RETIREMENT OBLIGATION - ELECTRIC			13,010,367	5,019,980	-	18,030,347
182326	ASSET RETIREMENT OBLIGATION - GAS			1,998,031	906,896	-	2,904,927
182327	ASSET RETIREMENT OBLIGATION - COMMON			17,227	7,771	-	24,998
182307	ENVIRONMENTAL COST RECOVERY			631,535	1,529,176	-	2,160,711
182306	FUEL ADJUSTMENT CLAUSE			6,068,000	(4,376,000)	-	1,692,000
182340	PERFORMANCE-BASED RATES			5,639,885	(3,065,854)	-	2,574,031
182308	GAS SUPPLY CLAUSE			5,439,239	1,920,406	-	7,359,645
182363	DSM COST RECOVERY - UNDER-RECOVERY			930,885	2,673,248	-	3,604,133
Other Regulatory Assets Total				338,368,885	(85,959,941)	-	252,408,944
LG&E Regulatory Assets Total				408,462,226	(85,891,640)	(9,913,792)	312,656,793

Louisville Gas and Electric Company - 2014

Regulatory Assets with specific amortization periods

Account	Description	Amortization Period	Order No. / Docket No.	Beginning Balance	Annual Activity	Amortization	Ending Balance
182320/182345	WINTER STORM 2009 - ELECTRIC	Aug-10 to Jul-20	2009-00549 2009-00175	28,749,879	-	(4,367,070)	24,382,809
182342/182346	WINTER STORM 2009 - GAS	Aug-10 to Jul-20	2009-00549 2009-00175	110,396	-	(16,769)	93,627
182322/182335	RATE CASE EXPENSES - ELECTRIC	Jan-13 to Dec-15	2012-00222	596,350	753,344	(298,138)	1,051,556
182323/182336	RATE CASE EXPENSES - GAS	Jan-13 to Dec-15	2012-00222	189,895	188,336	(94,935)	283,295
182324/182337	EKPC FERC TRANSMISSION COST - KY PORTION	Mar-09 to Feb-14	ER06-1458	28,262	-	(28,262)	-
182332/182348	CMRG FUNDING [CARBON MGT RESEARCH GROUP]	Aug-10 to Jul-20	2009-00549	134,910	78,000	(58,440)	154,470
182333/182349	KCCS FUNDING [KY CONSORTIUM FOR CARBON STORAGE]	Aug-10 to Jul-14	2009-00549	128,048	-	(128,048)	-
182334/182347	WIND STORM REGULATORY ASSET	Aug-10 to Jul-20	2009-00549 2008-00456	15,497,386	-	(2,354,033)	13,143,352
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	Jan-13 to Dec-15	2012-00222	61,055	-	(30,528)	30,527
182360	GENERAL MANAGEMENT AUDIT - GAS	Jan-13 to Dec-15	2012-00222	19,883	-	(9,941)	9,941
182361	2011 SUMMER STORM - ELECTRIC	Jan-13 to Dec-17	2012-00222	6,441,700	-	(1,610,425)	4,831,275
182343/182344	SWAP TERMINATION	Aug-10 to Apr-35	2009-00549	8,290,087	-	(388,659)	7,901,428
Regulatory Assets with specific amortization periods Total				60,247,849	1,019,680	(9,385,248)	51,882,281

Other Regulatory Assets

Account	Description	Amortization Period	Order No. / Docket No.	Beginning Balance	Annual Activity	Amortization	Ending Balance
182305/182315	ASC 715 - PENSION AND POSTRETIREMENT			164,087,881	4,990,002	-	169,077,883
182352	LONG TERM INTEREST RATE SWAP			35,912,921	12,075,907	-	47,988,828
182328-182331	ASC 740 - INCOME TAXES			14,057,350	(265,233)	-	13,792,117
182317-18/182325	ASSET RETIREMENT OBLIGATION - ELECTRIC			18,030,347	6,827,514	-	24,857,861
182326	ASSET RETIREMENT OBLIGATION - GAS			2,904,927	483,947	-	3,388,874
182327	ASSET RETIREMENT OBLIGATION - COMMON			24,998	(24,998)	-	-
182307	ENVIRONMENTAL COST RECOVERY			2,160,711	1,679,289	-	3,840,000
182306	FUEL ADJUSTMENT CLAUSE			1,692,000	(130,000)	-	1,562,000
182340	PERFORMANCE-BASED RATES			2,574,031	(862,813)	-	1,711,218
182308	GAS SUPPLY CLAUSE			7,359,645	6,435,332	-	13,794,977
182363	DSM COST RECOVERY - UNDER-RECOVERY			3,604,133	(3,604,133)	-	-
182364	LONG TERM INTEREST RATE SWAP FORWARD STARTING			-	33,263,681	-	33,263,681
Other Regulatory Assets Total				252,408,944	60,868,495	-	313,277,439
LG&E Regulatory Assets Total				312,656,793	61,888,175	(9,385,248)	365,159,719

Louisville Gas and Electric Company (Base Period Actual/Forecast 3/14 - 2/15)

Regulatory Assets with specific amortization periods

Account	Description	Amortization Period	Order No. / Docket No.	Beginning Balance	Annual Activity	Amortization	Ending Balance
182320/182345	WINTER STORM 2009 - ELECTRIC	Aug-10 to Jul-20	2009-00549 2009-00175	28,022,000	-	(4,366,000)	23,656,000
182342/182346	WINTER STORM 2009 - GAS	Aug-10 to Jul-20	2009-00549 2009-00175	108,000	-	(17,000)	91,000
182322/182335	RATE CASE EXPENSES - ELECTRIC	Jan-13 to Dec-15	2012-00222	551,000	669,000	(298,000)	922,000
182323/182336	RATE CASE EXPENSES - GAS	Jan-13 to Dec-15	2012-00222	175,000	212,000	(95,000)	292,000
182332/182348	CMRG FUNDING [CARBON MGT RESEARCH GROUP]	Aug-10 to Jul-20	2009-00549	119,000	215,000	(98,000)	236,000
182333/182349	KCCS FUNDING [KY CONSORTIUM FOR CARBON STORAGE]	Aug-10 to Jul-14	2009-00549	91,000	-	(91,000)	-
182334/182347	WIND STORM REGULATORY ASSET	Aug-10 to Jul-20	2009-00549 2008-00456	15,105,000	-	(2,354,000)	12,751,000
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	Jan-13 to Dec-15	2012-00222	56,000	-	(31,000)	25,000
182360	GENERAL MANAGEMENT AUDIT - GAS	Jan-13 to Dec-15	2012-00222	18,000	-	(10,000)	8,000
182361	2011 SUMMER STORM - ELECTRIC	Jan-13 to Dec-17	2012-00222	6,173,000	-	(1,610,000)	4,563,000
182343/182344	SWAP TERMINATION	Aug-10 to Apr-35	2009-00549	8,225,000	-	(389,000)	7,836,000
Regulatory Assets with specific amortization periods Total				58,643,000	1,096,000	(9,359,000)	50,380,000
Other Regulatory Assets				260,610,000	(4,368,000)	-	256,242,000
LG&E Regulatory Assets Total				319,253,000	(3,272,000)	(9,359,000)	306,622,000

Louisville Gas and Electric Company (Test Period Forecast 7/15 - 6/16)

Regulatory Assets with specific amortization periods

Account	Description	Amortization Period	Order No. / Docket No.	Beginning Balance	Annual Activity	Amortization	Ending Balance
182320/182345	WINTER STORM 2009 - ELECTRIC	Aug-10 to Jul-20	2009-00549 2009-00175	22,200,000	-	(4,366,000)	17,834,000
182342/182346	WINTER STORM 2009 - GAS	Aug-10 to Jul-20	2009-00549 2009-00175	85,000	-	(17,000)	68,000
182322/182335	RATE CASE EXPENSES - ELECTRIC	Jan-13 to Dec-15	2012-00222	1,287,000	701,000	(485,000)	1,503,000
182323/182336	RATE CASE EXPENSES - GAS	Jan-13 to Dec-15	2012-00222	409,000	223,000	(154,000)	478,000
182332/182348	CMRG FUNDING [CARBON MGT RESEARCH GROUP]	Aug-10 to Jul-20	2009-00549	203,000	98,000	(98,000)	203,000
182333/182349	KCCS FUNDING [KY CONSORTIUM FOR CARBON STORAGE]	Aug-10 to Jul-14	2009-00549	-	-	-	-
182334/182347	WIND STORM REGULATORY ASSET	Aug-10 to Jul-20	2009-00549 2008-00456	11,966,000	-	(2,354,000)	9,612,000
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC	Jan-13 to Dec-15	2012-00222	131,000	-	(50,000)	81,000
182360	GENERAL MANAGEMENT AUDIT - GAS	Jan-13 to Dec-15	2012-00222	43,000	-	(16,000)	27,000
182361	2011 SUMMER STORM - ELECTRIC	Jan-13 to Dec-17	2012-00222	4,026,000	-	(1,610,000)	2,416,000
182343/182344	SWAP TERMINATION	Aug-10 to Apr-35	2009-00549	7,707,000	-	(389,000)	7,318,000
Regulatory Assets with specific amortization periods Total				48,057,000	1,022,000	(9,539,000)	39,540,000
Other Regulatory Assets				250,103,000	(16,230,000)	-	233,873,000
LG&E Regulatory Assets Total				298,160,000	(15,208,000)	(9,539,000)	273,413,000

EXHIBIT ____ (LK-34)

Kentucky Utilities Company
KIUC Adjustment to Extend Amortization Expense on Deferred Costs
For the Test Year Ended June 30, 2016
$ Millions

Source: Response to KIUC 1-29

Mountain Storm Regulatory Asset Balance at 7/1/2015	1.611	
Amortization over 5 Years	5	
Annual Amortization of Mountain Storm Regulatory Asset	0.322	
As Filed Annual Amortization of Mountain Storm Regulatory Asset	1.208	
KIUC Reduction to Reflect 5-Year Amortization of Mountain Storm Reg Asset		(0.886)
Muni MISO Exit Fee Regulatory Asset Balance at 7/1/2015	0.966	
Amortization over 5 Years	5	
Annual Amortization of Muni MISO Exit Fee Regulatory Asset	0.193	
As Filed Annual Amortization of Muni MISO Exit Fee Regulatory Asset	0.484	
KIUC Reduction to Reflect 5-Year Amortization of Muni MISO Exit Fee Reg Asset		(0.291)
KIUC Adjustment to Extend Amortization Expense on Deferred Costs		(1.177)

EXHIBIT ____ (LK-35)

Louisville Gas and Electric Company
KIUC Adjustment to Extend Amortization Expense on Deferred Costs
For the Test Year Ended June 30, 2016
$ Millions

Source: Response to KIUC 1-29

2011 Summer Storm Regulatory Asset Balance at 7/1/2015	4.026
Amortization over 5 Years	5
Annual Amortization of 2011 Summer Storm Regulatory Asset	0.805
As Filed Annual Amortization of 2011 Summer Storm Regulatory Asset	1.610
KIUC Adjustment to Extend Amortization Expense on Deferred Costs	(0.805)

EXHIBIT ____ (LK-36)

EXHIBIT JJS-1

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO ELECTRIC PLANT AS OF APRIL 30, 2015

KENTUCKY UTILITIES COMPANY
CANE RUN 7

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF APRIL 30, 2015

	ACCOUNT (1)	SURVIVOR CURVE (2)		NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
	ELECTRIC PLANT									
	OTHER PRODUCTION									
341	STRUCTURES AND IMPROVEMENTS	60-S1.5	*	0	66,577,670.00	0	66,577,870	1,742,676	2.62	38.2
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	55-R3	*	(5)	31,069,673.00	0	32,623,157	849,119	2.73	38.4
343	PRIME MOVERS	55-R2.5	*	(5)	102,086,067.00	0	107,190,370	2,844,755	2.79	37.7
344	GENERATORS	50-R1.5	*	(10)	199,733,610.00	0	219,706,971	6,215,190	3.11	35.4
345	ACCESSORY ELECTRIC EQUIPMENT	50-S0.5	*	(5)	35,508,197.00	0	37,283,607	1,055,296	2.97	35.3
346	MISCELLANEOUS POWER PLANT EQUIPMENT	45-R2	*	0	8,877,049.00	0	8,877,049	250,693	2.82	35.4
	TOTAL OTHER PRODUCTION PLANT				443,852,466.00	0	472,259,024	12,957,929	2.92	

* Life Span Procedure was used. Curve Shown is Interim Survivor Curve.

KENTUCKY UTILITIES COMPANY
CANE RUN 7

ACCOUNT 341 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF APRIL 30, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 60-S1.5						
PROBABLE RETIREMENT YEAR.. 6-2055						
NET SALVAGE PERCENT.. 0						
2015	66,577,870.00			66,577,870	38.20	1,742,876
	66,577,870.00			66,577,870		1,742,876

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.2 2.62

KENTUCKY UTILITIES COMPANY
CANE RUN 7

ACCOUNT 342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF APRIL 30, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 55-R3						
PROBABLE RETIREMENT YEAR.. 6-2055						
NET SALVAGE PERCENT.. -5						
2015	31,069,673.00			32,623,157	38.42	849,119
	31,069,673.00			32,623,157		849,119

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.4 2.73

KENTUCKY UTILITIES COMPANY
CANE RUN 7

ACCOUNT 343 PRIME MOVERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF APRIL 30, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 55-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2055						
NET SALVAGE PERCENT.. -5						
2015	102,086,067.00			107,190,370	37.68	2,844,755
	102,086,067.00			107,190,370		2,844,755

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.7 2.79

KENTUCKY UTILITIES COMPANY
CANE RUN 7

ACCOUNT 344 GENERATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF APRIL 30, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 50-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2055						
NET SALVAGE PERCENT.. -10						
2015	199,733,610.00			219,706,971	35.35	6,215,190
	199,733,610.00			219,706,971		6,215,190

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 35.4 3.11

KENTUCKY UTILITIES COMPANY
CANE RUN 7

ACCOUNT 345 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF APRIL 30, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 50-S0.5						
PROBABLE RETIREMENT YEAR.. 6-2055						
NET SALVAGE PERCENT.. -5						
2015	35,508,197.00			37,283,607	35.33	1,055,296
	35,508,197.00			37,283,607		1,055,296

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 35.3 2.97

KENTUCKY UTILITIES COMPANY
CANE RUN 7

ACCOUNT 346 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF APRIL 30, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 45-R2						
PROBABLE RETIREMENT YEAR.. 6-2055						
NET SALVAGE PERCENT.. 0						
2015	8,877,049.00			8,877,049	35.41	250,693
	8,877,049.00			8,877,049		250,693

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 35.4 2.82

EXHIBIT ____ (LK-37)

EXHIBIT JJS-1

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO ELECTRIC PLANT AS OF APRIL 30, 2015

LOUISVILLE GAS AND ELECTRIC COMPANY
CANE RUN 7

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF APRIL 30, 2015

	ACCOUNT (1)	SURVIVOR CURVE (2)		NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
	ELECTRIC PLANT									
	OTHER PRODUCTION									
341	STRUCTURES AND IMPROVEMENTS	60-S1.5	*	0	18,912,029.00	0	16,912,029	495,079	2.62	38.2
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	55-R3	*	(5)	8,825,614.00	0	9,266,895	241,200	2.73	38.4
343	PRIME MOVERS	55-R2.5	*	(5)	28,998,445.00	0	30,448,367	808,078	2.79	37.7
344	GENERATORS	50-R1.5	*	(10)	56,736,088.00	0	62,409,697	1,765,479	3.11	35.4
345	ACCESSORY ELECTRIC EQUIPMENT	50-S0.5	*	(5)	10,086,416.00	0	10,590,737	299,766	2.97	35.3
346	MISCELLANEOUS POWER PLANT EQUIPMENT	45-R2	*	0	2,521,604.00	0	2,521,604	71,212	2.82	35.4
	TOTAL OTHER PRODUCTION PLANT				126,080,196.00	0	134,149,329	3,680,814	2.92	

* Life Span Procedure was used. Curve Shown is Interim Survivor Curve.

LOUISVILLE GAS AND ELECTRIC COMPANY
CANE RUN 7

ACCOUNT 341 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF APRIL 30, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 60-S1.5						
PROBABLE RETIREMENT YEAR.. 6-2055						
NET SALVAGE PERCENT.. 0						
2015	18,912,029.00			18,912,029	38.20	495,079
	18,912,029.00			18,912,029		495,079

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.2 2.62

LOUISVILLE GAS AND ELECTRIC COMPANY
CANE RUN 7

ACCOUNT 342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF APRIL 30, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 55-R3						
PROBABLE RETIREMENT YEAR.. 6-2055						
NET SALVAGE PERCENT.. -5						
2015	8,825,614.00			9,266,895	38.42	241,200
	8,825,614.00			9,266,895		241,200

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.4   2.73

LOUISVILLE GAS AND ELECTRIC COMPANY
CANE RUN 7

ACCOUNT 343 PRIME MOVERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF APRIL 30, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 55-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2055						
NET SALVAGE PERCENT.. -5						
2015	28,998,445.00			30,448,367	37.68	808,078
	28,998,445.00			30,448,367		808,078

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.7 2.79

LOUISVILLE GAS AND ELECTRIC COMPANY
CANE RUN 7

ACCOUNT 344 GENERATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF APRIL 30, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 50-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2055						
NET SALVAGE PERCENT.. -10						
2015	56,736,088.00			62,409,697	35.35	1,765,479
	56,736,088.00			62,409,697		1,765,479

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 35.4 3.11

LOUISVILLE GAS AND ELECTRIC COMPANY
CANE RUN 7

ACCOUNT 345 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF APRIL 30, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 50-S0.5						
PROBABLE RETIREMENT YEAR.. 6-2055						
NET SALVAGE PERCENT.. -5						
2015	10,086,416.00			10,590,737	35.33	299,766
	10,086,416.00			10,590,737		299,766

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 35.3 2.97

LOUISVILLE GAS AND ELECTRIC COMPANY
CANE RUN 7

ACCOUNT 346 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF APRIL 30, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 45-R2						
PROBABLE RETIREMENT YEAR.. 6-2055						
NET SALVAGE PERCENT.. 0						
2015	2,521,604.00			2,521,604	35.41	71,212
	2,521,604.00			2,521,604		71,212

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 35.4 2.82

EXHIBIT ____ (LK-38)

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 6, 2015

Question No. 2-12

Responding Witness: John J. Spanos

Q.2-12. Refer to the Company's response to PSC 2-40, which shows the net negative salvage rate applicable to the entirety of the depreciable plant balance.

a. Please confirm that the entirety of the depreciable plant balance consists of both interim retirements and terminal retirements.

b. Please provide the calculations of the net negative salvage rate separated into net negative interim salvage and net negative terminal salvage and the weighting that was used to develop a single net negative salvage rate.

c. Provide this same information for all Cane Run 7 plant accounts.

A.2-12.

a. The attachment to PSC 2-40 represents the weighted net salvage percentage, which includes a component of interim and terminal net salvage associated with the projected assets to be retired based on interim and terminal retirements.

b. The attached document sets forth the calculations of the net negative net salvage percentages for both interim and terminal net salvage with the developed weighting.

c. The calculations for Cane Run Unit 7 were not conducted in the exact same fashion because it was determined not to include a terminal net salvage component in the proposed rates since no plans have been established for how the facility would be dismantled.

KENTUCKY UTILITIES COMPANY

CALCULATION OF WEIGHTED NET SALVAGE PERCENT FOR GENERATION PLANT AS OF DECEMBER 31, 2011

	Account	Terminal Retirements: Retirements ($)	Terminal Retirements: Net Salvage (%)	Terminal Retirements: Net Salvage ($)	Interim Retirements: Retirements ($)	Interim Retirements: Net Salvage (%)	Interim Retirements: Net Salvage ($)	Total Net Salvage ($)	Total Retirements	Estimated Net Salvage (%)
	(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)=(4)+(7)	(9)=(2)+(5)	(10)=(8)/(9)
	STEAM PRODUCTION PLANT									
	BROWN GENERATING STATION									
311	STRUCTURES AND IMPROVEMENTS	68,849,852	(2)	(1,273,722)	3,042,333	(25)	760,583	2,034,305	71,892,185	(4)
312	BOILER PLANT EQUIPMENT	509,778,912	(2)	(9,430,910)	43,833,934	(30)	13,150,180	22,581,090	553,612,846	(4)
314	TURBOGENERATOR UNITS	34,988,354	(2)	(647,285)	14,117,591	(15)	2,117,639	2,764,923	49,105,945	(4)
315	ACCESSORY ELECTRIC EQUIPMENT	41,743,969	(2)	(772,263)	2,382,005	(20)	476,401	1,248,664	44,125,974	(4)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	4,844,375	(2)	(89,621)	765,310	0	-	89,621	5,609,684	(4)
	TOTAL BROWN GENERATING STATION	*660,205,462*		*(12,213,601)*	*64,141,173*		*15,504,803*	*28,718,604*	*724,346,634*	*(4)*
	GHENT GENERATING STATION									
311	STRUCTURES AND IMPROVEMENTS	120,501,240	(2)	(2,229,273)	11,852,267	(25)	2,963,067	5,192,340	132,353,507	(5)
312	BOILER PLANT EQUIPMENT	1,321,271,054	(2)	(24,443,515)	171,355,455	(30)	51,406,637	75,850,151	1,492,626,510	(5)
314	TURBOGENERATOR UNITS	111,677,673	(2)	(2,066,037)	55,059,770	(15)	8,258,966	10,325,002	166,737,443	(5)
315	ACCESSORY ELECTRIC EQUIPMENT	94,779,021	(2)	(1,753,412)	13,632,245	(20)	2,726,449	4,479,861	108,411,266	(5)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	12,430,337	(2)	(229,961)	2,456,361	0	-	229,961	14,886,698	(5)
	TOTAL GHENT GENERATING STATION	*1,660,659,326*		*(30,722,198)*	*254,356,098*		*65,355,118*	*96,077,315*	*1,915,015,424*	*(5)*
	GREEN RIVER GENERATING STATION									
311	STRUCTURES AND IMPROVEMENTS	10,698,728	(2)	(197,926)	159,527	(25)	39,882	237,808	10,858,255	(2)
312	BOILER PLANT EQUIPMENT	36,914,230	(2)	(682,913)	746,752	(30)	224,026	906,939	37,660,983	(2)
314	TURBOGENERATOR UNITS	14,317,850	(2)	(264,880)	634,829	(15)	95,224	360,105	14,952,679	(2)
315	ACCESSORY ELECTRIC EQUIPMENT	3,785,377	(2)	(70,029)	115,314	(20)	23,063	93,092	3,900,691	(2)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	2,606,735	(2)	(48,225)	38,304	0	-	48,225	2,645,039	(2)
	TOTAL GREEN RIVER GENERATING STATION	*58,322,920*		*(1,263,974)*	*1,694,727*		*382,195*	*1,646,169*	*70,017,647*	*(2)*
	PINEVILLE GENERATING STATION									
311	STRUCTURES AND IMPROVEMENTS	16,195	(2)	(300)	9	(25)	2	302	16,204	(2)
312	BOILER PLANT EQUIPMENT	232,704	(2)	(4,305)	3,766	(30)	1,130	5,435	236,470	(2)
314	TURBOGENERATOR UNITS	-	(2)	0	-	(15)	-	-	-	(2)
315	ACCESSORY ELECTRIC EQUIPMENT	-	(2)	0	-	(20)	-	-	-	(2)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	-	(2)	0	-	0	-	-	-	(2)
	TOTAL PINEVILLE GENERATING STATION	*248,900*		*(4,605)*	*3,775*		*1,132*	*5,737*	*252,675*	*(2)*
	SYSTEM LAB									
311	STRUCTURES AND IMPROVEMENTS	744,220	0	0	80,748	(25)	20,187	20,187	824,969	(1)
312	BOILER PLANT EQUIPMENT	-	0	0	-	(30)	-	-	-	(1)
314	TURBOGENERATOR UNITS	-	0	0	-	(15)	-	-	-	(1)
315	ACCESSORY ELECTRIC EQUIPMENT	-	0	0	-	(20)	-	-	-	(1)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	2,394,972	0	0	368,077	0	-	-	2,763,049	(1)
	TOTAL SYSTEM LAB	*3,139,193*		-	*448,825*		*20,187*	*20,187*	*3,588,017*	*(1)*
	STEAM PRODUCTION PLANT (CONT.)									
	TYRONE GENERATING STATION									
311	STRUCTURES AND IMPROVEMENTS	6,066,662	(2)	(112,233)	125,545	(25)	31,386	143,619	6,192,207	(3)
312	BOILER PLANT EQUIPMENT	14,040,352	(2)	(259,747)	374,833	(30)	112,450	372,197	14,415,186	(3)
314	TURBOGENERATOR UNITS	4,588,909	(2)	(84,895)	284,811	(15)	42,722	127,616	4,873,719	(3)
315	ACCESSORY ELECTRIC EQUIPMENT	2,110,076	(2)	(39,036)	70,827	(20)	14,165	53,202	2,180,903	(3)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	592,490	(2)	(10,961)	10,992	0	-	10,961	603,482	(3)
	TOTAL TYRONE GENERATING STATION	*27,398,488*		*(506,872)*	*867,009*		*200,723*	*707,595*	*28,265,497*	*(3)*
	TRIMBLE COUNTY									
311	STRUCTURES AND IMPROVEMENTS	86,202,297	(2)	(1,594,742)	25,610,591	(25)	6,402,648	7,997,390	111,812,888	(11)
312	BOILER PLANT EQUIPMENT	352,937,892	(2)	(6,529,351)	222,956,396	(30)	66,886,919	73,416,270	575,894,288	(11)
314	TURBOGENERATOR UNITS	31,029,751	(2)	(574,050)	52,964,982	(15)	7,944,747	8,518,798	83,994,733	(11)
315	ACCESSORY ELECTRIC EQUIPMENT	26,315,352	(2)	(486,834)	16,700,474	(20)	3,340,095	3,826,929	43,015,826	(11)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	2,298,460	(2)	(42,522)	1,203,987	0	-	42,522	3,502,447	(11)
	TOTAL TRIMBLE COUNTY	*498,783,752*		*(9,227,499)*	*319,436,430*		*84,574,409*	*93,801,908*	*818,220,182*	*(11)*
	TOTAL STEAM PRODUCTION PLANT	2,918,758,040		(53,938,949)	640,948,036		167,038,567	220,977,515	3,559,706,076	

Attachment to Response to KU KIUC-2 Question No. 12(b)
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KENTUCKY UTILITIES COMPANY

CALCULATION OF WEIGHTED NET SALVAGE PERCENT FOR GENERATION PLANT AS OF DECEMBER 31, 2011

	Account	Terminal Retirements			Interim Retirements			Total		Estimated
		Retirements ($)	Net Salvage (%)	Net Salvage ($)	Retirements ($)	Net Salvage (%)	Net Salvage ($)	Total Net Salvage ($)	Total Retirements	Net Salvage (%)
	(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)=(4)+(7)	(9)=(2)+(5)	(10)=(8)/(9)
	HYDRAULIC PRODUCTION PLANT									
	DIX DAM									
331	STRUCTURES AND IMPROVEMENTS	460,238	(2)	(8,514)	156,289	(5)	7,814	16,329	616,527	(3)
332	RESERVOIRS, DAMS AND WATERWAYS	19,039,829	(2)	(352,237)	2,564,141	(10)	256,414	608,651	21,603,970	(3)
333	WATER WHEELS, TURBINES AND GENERATORS	4,076,011	(2)	(75,406)	354,613	(20)	70,923	146,329	4,430,624	(3)
334	ACCESSORY ELECTRIC EQUIPMENT	355,642	(2)	(6,579)	222,692	0	-	6,579	578,333	(3)
335	MISCELLANEOUS POWER PLANT EQUIPMENT	77,245	(2)	(1,429)	219,779	(5)	10,989	12,418	297,024	(3)
336	ROADS, RAILROADS AND BRIDGES	124,770	(2)	(2,308)	51,589	0	-	2,308	176,360	(3)
	TOTAL DIX DAM	24,133,734		(446,474)	3,569,103		346,140	792,614	27,702,837	(3)
	TOTAL HYDRAULIC PRODUCTION PLANT	24,133,734		(446,474)	3,569,103		346,140	792,614	27,702,837	
	OTHER PRODUCTION PLANT									
	BROWN CTS									
341	STRUCTURES AND IMPROVEMENTS	9,195,757	(2)	(170,122)	2,731,546	0	-	170,122	11,927,303	(2)
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	10,211,547	(2)	(188,914)	2,322,415	(5)	116,121	305,034	12,533,962	(2)
343	PRIME MOVERS	136,839,902	(2)	(2,531,538)	49,000,992	(5)	2,450,050	4,981,588	185,840,895	(2)
344	GENERATORS	29,442,983	(2)	(544,695)	1,388,038	(5)	69,402	614,097	30,831,020	(2)
345	ACCESSORY ELECTRIC EQUIPMENT	15,263,350	(2)	(282,372)	2,458,791	(5)	122,940	405,312	17,722,142	(2)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	2,938,221	(2)	(54,357)	1,201,669	0	-	54,357	4,139,890	(2)
	TOTAL BROWN CTS	203,891,761		(3,771,998)	59,103,452		2,758,512	6,530,509	262,995,213	(2)
	HAEFLING CTS									
341	STRUCTURES AND IMPROVEMENTS	412,940	(2)	(7,639)	21,913	0	-	7,639	434,853	(2)
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	479,905	(2)	(8,878)	38,800	(5)	1,940	10,818	518,705	(2)
344	GENERATORS	3,223,465	(2)	(59,634)	799,537	(5)	39,977	99,611	4,023,002	(2)
345	ACCESSORY ELECTRIC EQUIPMENT	1,211,240	(2)	(22,408)	240,717	(5)	12,036	34,444	1,451,957	(2)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	13,500	(2)	(250)	22,305	0	-	250	35,805	(2)
	TOTAL HAEFLING CTS	5,341,050		(98,809)	1,123,272		53,953	152,762	6,464,323	(2)
	PADDY'S RUN CTS									
341	STRUCTURES AND IMPROVEMENTS	1,563,219	(2)	(28,920)	347,109	0	-	28,920	1,910,328	(2)
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	1,730,245	(2)	(32,010)	264,856	(5)	13,243	45,252	1,995,101	(2)
343	PRIME MOVERS	12,869,763	(2)	(238,091)	4,933,601	(5)	246,680	484,771	17,803,364	(2)
344	GENERATORS	5,045,282	(2)	(93,338)	140,354	(5)	7,018	100,355	5,185,636	(2)
345	ACCESSORY ELECTRIC EQUIPMENT	2,184,168	(2)	(40,407)	272,152	(5)	13,608	54,015	2,456,320	(2)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	784,628	(2)	(14,516)	304,922	0	-	14,516	1,089,550	(2)
	TOTAL PADDY'S RUN CTS	24,177,306		(447,280)	6,262,993		280,548	727,828	30,440,299	(2)
	TRIMBLE COUNTY CTS									
341	STRUCTURES AND IMPROVEMENTS	17,661,338	(2)	(326,735)	4,084,591	0	-	326,735	21,745,929	(3)
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	6,528,160	(2)	(120,771)	1,171,888	(5)	58,594	179,365	7,700,048	(3)
343	PRIME MOVERS	109,263,693	(2)	(2,021,378)	45,915,081	(5)	2,295,754	4,317,132	155,178,774	(3)
344	GENERATORS	18,798,072	(2)	(347,764)	523,030	(5)	26,152	373,916	19,321,102	(3)
345	ACCESSORY ELECTRIC EQUIPMENT	20,149,294	(2)	(372,762)	2,587,693	(5)	129,385	502,147	22,736,987	(3)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	75,076	(2)	(1,389)	22,620	0	-	1,389	97,696	(3)
	TOTAL TRIMBLE COUNTY CTS	172,475,634		(3,190,799)	54,304,902		2,509,885	5,700,684	226,780,536	(3)
	TOTAL OTHER PRODUCTION PLANT	405,885,751		(7,508,886)	120,794,620		5,602,897	13,111,784	526,680,370	
	GRAND TOTAL	3,348,777,525		(61,894,309)	765,311,759		172,987,604	234,881,913	4,114,089,284	

Attachment to Response to KU KIUC-2 Question No. 12(b)
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LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2014-00372

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 6, 2015

Question No. 2-12

Responding Witness: John J. Spanos

Q.2-12. Refer to the Company's response to PSC 2-40, which shows the net negative salvage rate applicable to the entirety of the depreciable plant balance.

a. Please confirm that the entirety of the depreciable plant balance consists of both interim retirements and terminal retirements.

b. Please provide the calculations of the net negative salvage rate separated into net negative interim salvage and net negative terminal salvage and the weighting that was used to develop a single net negative salvage rate.

c. Provide this same information for all Cane Run 7 plant accounts.

A.2-12. It is assumed that reference to Company's response to PSC 2-51 for LG&E was intended.

a. The attachment to PSC 2-51 represents the weighted net salvage percentage, which includes a component of interim and terminal net salvage associated with the projected assets to be retired based on interim and terminal retirements.

b. The attached document sets forth the calculations of the net negative net salvage percentages for both interim and terminal net salvage with the developed weighting.

c. The calculations for Cane Run Unit 7 were not conducted in the exact same fashion because it was determined not to include a terminal net salvage component in the proposed rates since no plans have been established for how the facility would be dismantled.

LOUISVILLE GAS AND ELECTRIC COMPANY

CALCULATION OF WEIGHTED NET SALVAGE PERCENT FOR GENERATION PLANT AS OF DECEMBER 31, 2011

	Account	Terminal Retirements: Retirements ($)	Terminal Retirements: Net Salvage (%)	Terminal Retirements: Net Salvage ($)	Interim Retirements: Retirements ($)	Interim Retirements: Net Salvage (%)	Interim Retirements: Net Salvage ($)	Total Net Salvage ($)	Total Retirements	Estimated Net Salvage (%)
	(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)=(4)+(7)	(9)=(2)+(5)	(10)=(8)/(9)
	STEAM PRODUCTION PLANT									
	CANE RUN GENERATING STATION									
311	STRUCTURES AND IMPROVEMENTS	51,602,971	(2)	(954,655)	558,080	(20)	111,616	1,066,271	52,161,051	(2)
312	BOILER PLANT EQUIPMENT	199,372,082	(2)	(3,888,384)	5,402,162	(25)	1,600,541	5,288,924	205,774,244	(2)
314	TURBOGENERATOR UNITS	33,056,350	(2)	(611,542)	1,629,396	(15)	244,409	855,952	34,685,746	(2)
315	ACCESSORY ELECTRIC EQUIPMENT	35,972,609	(2)	(685,493)	1,278,211	(10)	127,821	793,314	37,250,819	(2)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	3,187,494	(2)	(58,969)	63,334	0	-	58,969	3,250,828	(2)
	TOTAL CANE RUN GENERATING STATION	*323,191,505*		*(5,979,043)*	*9,931,183*		*2,084,387*	*8,063,430*	*333,122,688*	*(2)*
	MILL CREEK GENERATING STATION									
311	STRUCTURES AND IMPROVEMENTS	113,850,940	(2)	(2,106,427)	15,122,788	(20)	3,024,558	5,130,985	128,983,727	(8)
312	BOILER PLANT EQUIPMENT	510,025,681	(2)	(9,435,475)	249,227,761	(25)	82,306,940	71,742,415	759,253,422	(8)
314	TURBOGENERATOR UNITS	60,055,758	(2)	(1,111,032)	45,970,072	(15)	6,895,511	8,006,542	106,025,820	(8)
315	ACCESSORY ELECTRIC EQUIPMENT	44,720,898	(2)	(827,337)	35,906,938	(10)	3,590,694	4,418,230.41	80,629,836	(8)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	5,104,648	(2)	(94,436)	3,531,925	0	-	94,436	8,630,573	(8)
	TOTAL MILL CREEK GENERATING STATION	*733,767,906*		*(13,574,706)*	*349,761,483*		*75,817,902*	*89,392,609*	*1,083,529,388*	*(8)*
	TRIMBLE COUNTY GENERATING STATION									
311	STRUCTURES AND IMPROVEMENTS	120,950,736	(2)	(2,237,589)	20,641,275	(20)	4,128,255	6,365,844	141,592,011	(11)
312	BOILER PLANT EQUIPMENT	195,964,406	(2)	(3,625,342)	220,882,987	(25)	55,220,747	58,846,088	416,847,394	(11)
314	TURBOGENERATOR UNITS	38,451,719	(2)	(711,542)	38,986,646	(15)	5,847,997	6,559,539	77,448,365	(11)
315	ACCESSORY ELECTRIC EQUIPMENT	26,385,902	(2)	(488,139)	33,812,288	(10)	3,381,229	3,869,368	60,198,191	(11)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	1,302,739	(2)	(24,101)	3,155,044	0	-	24,101	4,457,783	(11)
	TOTAL TRIMBLE COUNTY GENERATING STATION	*383,065,504*		*(7,086,712)*	*317,478,240*		*68,578,228*	*75,664,939*	*700,543,744*	*(11)*
	TOTAL STEAM PRODUCTION PLANT	1,440,024,914		(26,640,461)	677,170,906		146,480,517	173,120,978	2,117,195,820	(8)
	HYDRAULIC PRODUCTION PLANT									
	OHIO FALLS									
331	STRUCTURES AND IMPROVEMENTS	3,328,502	(2)	(61,577)	1,634,873	(20)	326,075	388,552	4,963,376	(3)
332	RESERVOIRS, DAMS AND WATERWAYS	11,521,557	(2)	(213,149)	168,694	(10)	16,869	230,018	11,690,252	(3)
333	WATER WHEELS, TURBINES AND GENERATORS	19,222,953	(2)	(355,625)	722,261	(20)	144,452	500,077	19,945,214	(3)
334	ACCESSORY ELECTRIC EQUIPMENT	5,118,196	(2)	(94,687)	391,640	(20)	78,328	173,015	5,509,836	(3)
335	MISCELLANEOUS POWER PLANT EQUIPMENT	283,259	(2)	(5,240)	26,989	(15)	4,048	9,289	310,247	(3)
336	ROADS, RAILROADS AND BRIDGES	10,714	(2)	(198)	19,216	(5)	961	1,159	29,931	(3)
	TOTAL OHIO FALLS	*39,485,181*		*(730,476)*	*2,963,674*		*571,633*	*1,302,109*	*42,448,855*	*(3)*
	TOTAL HYDRAULIC PRODUCTION PLANT	39,485,181		(730,476)	2,963,674		571,633	1,302,100	42,448,855	
	OTHER PRODUCTION PLANT									
	BROWN CTS									
341	STRUCTURES AND IMPROVEMENTS	1,044,742	(2)	(19,328)	64,131	(10)	6,413	25,741	1,108,873	(3)
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	1,236,676	(2)	(22,879)	154,654	(10)	15,465	38,344	1,391,330	(3)
343	PRIME MOVERS	35,802,233	(2)	(662,341)	18,267,027	(5)	913,351	1,575,693	54,069,260	(3)
344	GENERATORS	7,973,866	(2)	(147,513)	114,767	(10)	11,477	158,990	8,088,434	(3)
345	ACCESSORY ELECTRIC EQUIPMENT	4,040,820	(2)	(74,755)	470,993	0	-	74,755	4,511,812	(3)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	2,328,882	(2)	(43,084)	111,857	0	-	43,084	2,440,720	(3)
	TOTAL BROWN CTS	*52,426,998*		*(969,899)*	*19,183,439*		*946,707*	*1,916,606*	*71,610,437*	*(3)*
	CANE RUN CT									
341	STRUCTURES AND IMPROVEMENTS	206,999	(2)	(3,829)	4,519	(10)	452	4,281	211,518	(2)
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	309,146	(2)	(5,719)	9,896	(10)	990	6,709	319,042	(2)
344	GENERATORS	2,779,505	(2)	(51,421)	130,616	(10)	13,062	64,483	2,910,124	(2)
345	ACCESSORY ELECTRIC EQUIPMENT	86,422	(2)	(1,599)	30,206	0	-	1,599	116,627	(2)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	-	(2)	0	-	0	-	-	-	(2)
	TOTAL CANE RUN CT	*3,382,072*		*(62,568)*	*175,239*		*14,503*	*77,072*	*3,557,311*	*(2)*

Attachment to Response to LGE KIUC-2 Question No. 12(b)
Page 1 of 2
Spanos

LOUISVILLE GAS AND ELECTRIC COMPANY

CALCULATION OF WEIGHTED NET SALVAGE PERCENT FOR GENERATION PLANT AS OF DECEMBER 31, 2011

Account	Terminal Retirements: Retirements ($)	Terminal Retirements: Net Salvage (%)	Terminal Retirements: Net Salvage ($)	Interim Retirements: Retirements ($)	Interim Retirements: Net Salvage (%)	Interim Retirements: Net Salvage ($)	Total Net Salvage ($)	Total Retirements	Estimated Net Salvage (%)
(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)=(4)+(7)	(9)=(2)+(5)	(10)=(8)/(9)
PADDY'S RUN GENERATORS									
341 STRUCTURES AND IMPROVEMENTS	2,085,881	(2)	(38,589)	136,931	(10)	13,693	52,282	2,222,811	(3)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	1,961,670	(2)	(36,661)	304,573	(10)	30,457	67,118	2,266,243	(3)
343 PRIME MOVERS	12,324,033	(2)	(227,995)	7,822,158	(5)	391,108	619,103	20,146,191	(3)
344 GENERATORS	9,871,969	(2)	(182,631)	502,594	(10)	50,259	232,891	10,374,563	(3)
345 ACCESSORY ELECTRIC EQUIPMENT	3,410,054	(2)	(63,066)	349,690	0	-	63,066	3,759,743	(3)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	1,231,728	(2)	(22,787)	58,801	0	-	22,787	1,290,529	(3)
TOTAL PADDY'S RUN GENERATORS	30,905,334		(571,749)	9,174,746		485,518	1,057,266	40,080,080	(3)
TRIMBLE COUNTY CTS									
341 STRUCTURES AND IMPROVEMENTS	8,733,433	(2)	(161,569)	2,719,563	(10)	271,956	433,525	11,452,996	(3)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	2,727,814	(2)	(50,465)	850,961	(10)	85,096	135,561	3,578,775	(3)
343 PRIME MOVERS	42,005,110	(2)	(777,095)	41,251,779	(5)	2,062,589	2,839,683	83,256,889	(3)
344 GENERATORS	8,115,286	(2)	(150,133)	1,855,900	(10)	185,596	335,729	9,971,246	(3)
345 ACCESSORY ELECTRIC EQUIPMENT	6,977,260	(2)	(129,079)	5,282,778	0	-	129,079	12,260,038	(3)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	29,199	(2)	(540)	26,379	0	-	540	55,577	(3)
TOTAL TRIMBLE COUNTY CTS	68,588,102		(1,266,880)	51,987,419		2,605,237	3,874,117	120,575,521	(3)
ZORN AND RIVER ROAD CTS									
341 STRUCTURES AND IMPROVEMENTS	7,050	(2)	(130)	1,191	(10)	119	250	8,241	(3)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	20,251	(2)	(375)	3,183	(10)	316	693	23,434	(3)
343 PRIME MOVERS	-	(2)	0	-	(5)	-	-	-	(3)
344 GENERATORS	1,639,904	(2)	(30,338)	187,677	(10)	18,768	49,106	1,827,581	(3)
345 ACCESSORY ELECTRIC EQUIPMENT	30,561	(2)	(565)	13,722	0	-	565	44,283	(3)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	9,487	(2)	(176)	1	0	-	176	9,488	(3)
TOTAL ZORN AND RIVER ROAD CTS	1,707,254		(31,584)	205,773		19,203	50,789	1,913,027	(3)
TOTAL OTHER PRODUCTION PLANT	157,009,760		(2,904,681)	80,726,817		4,071,170	6,975,851	237,736,377	
GRAND TOTAL	1,636,519,855		(30,275,617)	760,861,197		151,123,320	181,398,938	2,397,381,052	

EXHIBIT ____ (LK-39)

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 6, 2015

Question No. 2-13

Responding Witness: John J. Spanos

Q.2-13. Refer to the Company's response to PSC 2-41, which states that there is no terminal salvage included in the Cane Run 7 depreciation rates.

a. Please separate the Cane Run 7 depreciable plant balance into interim retirements and terminal retirements.

b. Please confirm that the proposed Cane Run 7 net negative salvage rate was applied to the entirety of the depreciable plant balance, including the portion expected to survive to terminal retirement.

A.2-13.

a. The attached document sets forth the projected assets as of April 30, 2015 which will be retired on an interim and terminal basis.

b. For purposes of establishing the projected depreciation rates in this case, the net salvage percentages were applied to the entire depreciable plant balance as of April 30, 2015.

KENTUCKY UTILITIES COMPANY
CANE RUN 7

PROJECTED INTERIM AND TERMINAL RETIREMENTS BASED ON
APRIL 30, 2015

	ACCOUNT	SURVIVOR CURVE	RETIREMENT DATE	ORIGINAL COST	INTERIM RETIREMENTS	TERMINAL RETIREMENTS
	(1)	(2)	(3)	(4)	(5)	(6)
341	STRUCTURES AND IMPROVEMENTS	60-S1.5	6-2055	67,731,300.00	(12,108,915.70)	(55,622,384.30)
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	55-R3	6-2055	31,607,940.00	(4,955,060.20)	(26,652,879.80)
343	PRIME MOVERS	55-R2.5	6-2055	103,854,660.00	(19,607,326.16)	(84,247,333.84)
344	GENERATORS	50-R1.5	6-2055	203,193,900.00	(60,611,508.93)	(142,582,391.07)
345	ACCESSORY ELECTRIC EQUIPMENT	50-S0.5	6-2055	36,123,360.00	(12,098,829.55)	(24,024,530.45)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	45-R2	6-2055	9,030,840.00	(3,093,422.56)	(5,937,417.44)
	TOTAL OTHER PRODUCTION PLANT			451,542,000.00	(112,475,063.10)	(339,066,936.90)

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2014-00372

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 6, 2015

Question No. 2-13

Responding Witness: John J. Spanos

Q.2-13. Refer to the Company's response to PSC 2-41, which states that there is no terminal salvage included in the Cane Run 7 depreciation rates.

a. Please separate the Cane Run 7 depreciable plant balance into interim retirements and terminal retirements.

b. Please confirm that the proposed Cane Run 7 net negative salvage rate was applied to the entirety of the depreciable plant balance, including the portion expected to survive to terminal retirement.

A.2-13. It is assumed that reference to Company response to PSC-2-52 for LG&E was intended.

a. The attached document sets forth the projected assets as of April 30, 2015 which will be retired on an interim and terminal basis.

b. For purposes of establishing the projected depreciation rates in this case, the net salvage percentages were applied to the entire depreciable plant balance as of April 30, 2015.

LOUISVILLE GAS AND ELECTRIC COMPANY
CANE RUN 7

PROJECTED INTERIM AND TERMINAL RETIREMENTS BASED ON
APRIL 30, 2015

	ACCOUNT (1)	SURVIVOR CURVE (2)	RETIREMENT DATE (3)	ORIGINAL COST (4)	INTERIM RETIREMENTS (5)	TERMINAL RETIREMENTS (6)
341	STRUCTURES AND IMPROVEMENTS	60-S1.5	6-2055	19,103,700.00	(3,415,335.19)	(15,688,364.81)
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	55-R3	6-2055	8,915,060.00	(1,397,581.11)	(7,517,478.89)
343	PRIME MOVERS	55-R2.5	6-2055	29,292,340.00	(5,530,271.48)	(23,762,068.52)
344	GENERATORS	50-R1.5	6-2055	57,311,100.00	(17,095,553.84)	(40,215,546.16)
345	ACCESSORY ELECTRIC EQUIPMENT	50-S0.5	6-2055	10,188,640.00	(3,412,490.40)	(6,776,149.60)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	45-R2	6-2055	2,547,160.00	(872,503.82)	(1,674,656.18)
	TOTAL OTHER PRODUCTION PLANT			127,358,000.00	(31,723,735.84)	(95,634,264.16)

Attachment to Response to LGE KIUC-2 Question No. 13
Page 1 of 1
Spanos

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2014-00372

Response to Second Set of Data Requests of Kentucky Industrial Utility Customers, Inc. Dated February 6, 2015

Question No. 2-13

Responding Witness: John J. Spanos

Q.2-13. Refer to the Company's response to PSC 2-41, which states that there is no terminal salvage included in the Cane Run 7 depreciation rates.

a. Please separate the Cane Run 7 depreciable plant balance into interim retirements and terminal retirements.

b. Please confirm that the proposed Cane Run 7 net negative salvage rate was applied to the entirety of the depreciable plant balance, including the portion expected to survive to terminal retirement.

A.2-13. It is assumed that reference to Company response to PSC-2-52 for LG&E was intended.

a. The attached document sets forth the projected assets as of April 30, 2015 which will be retired on an interim and terminal basis.

b. For purposes of establishing the projected depreciation rates in this case, the net salvage percentages were applied to the entire depreciable plant balance as of April 30, 2015.

LOUISVILLE GAS AND ELECTRIC COMPANY
CANE RUN 7

PROJECTED INTERIM AND TERMINAL RETIREMENTS BASED ON
APRIL 30, 2015

	ACCOUNT (1)	SURVIVOR CURVE (2)	RETIREMENT DATE (3)	ORIGINAL COST (4)	INTERIM RETIREMENTS (5)	TERMINAL RETIREMENTS (6)
341	STRUCTURES AND IMPROVEMENTS	60-S1.5	6-2055	19,103,700.00	(3,415,335.19)	(15,688,364.81)
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	55-R3	6-2055	8,915,060.00	(1,397,581.11)	(7,517,478.89)
343	PRIME MOVERS	55-R2.5	6-2055	29,292,340.00	(5,530,271.48)	(23,762,068.52)
344	GENERATORS	50-R1.5	6-2055	57,311,100.00	(17,095,553.84)	(40,215,546.16)
345	ACCESSORY ELECTRIC EQUIPMENT	50-S0.5	6-2055	10,188,640.00	(3,412,490.40)	(6,776,149.60)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	45-R2	6-2055	2,547,160.00	(872,503.82)	(1,674,656.18)
	TOTAL OTHER PRODUCTION PLANT			127,358,000.00	(31,723,735.84)	(95,634,264.16)

EXHIBIT ____ (LK-40)

Kentucky Utilities Company
KIUC Adjustment to Reduce Depreciation Expense for Cane Run 7
To Remove Net terminal Salvage Embedded into Net Salvage Rates
For the Test Year Ended June 30, 2016
$ Millions

Depreciaton Expense Total Company - As Filed	12.939
Depreciaton Expense Total Company - KIUC Recommended	12.363
Reduction in Total Company Depreciation Expense	(0.576)
KY Jurisdiction Allocation % - Forecast Test Year for Depreciation	88.761%
KIUC Recommended Reduction in Cane Run 7 Depreciation Expense	(0.511)

Kentucky Utilities Company
KIUC Adjustment to Reduce Depreciation Expense for Cane Run 7
To Remove Net Terminal Salvage Embedded into Net Salvage Rates
For the Test Year Ended June 30, 2016
$ Millions

AS ADJUSTED BY KIUC

ACCT. (I)	TITLE (II)	NET SALVAGE PERCENT	ORIGINAL COST (III)	BOOK RESERVE	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT (X)	ANNUAL ACCRUAL PERCENT (XI)	COMPOSITE REMAIN LIFE (IX)
	Other Production Plant							
	Cane Run 7							
341	Structures & Improvements	-	66,577,870	-	66,577,870	1,742,876	2.62%	38.2
342	Fuel Holders and Accessories	(1)	31,069,673	-	31,313,207	815,024	2.62%	38.4
343	Prime Movers	(1)	102,086,067	-	103,049,738	2,734,866	2.68%	37.7
344	Generators	(3)	199,733,610	-	205,691,543	5,818,714	2.91%	35.4
345	Accessory Electrical Equipment	(2)	35,508,197	-	36,102,837	1,021,875	2.88%	35.3
346	Misc. Power Plant Equip.	-	8,877,049	-	8,877,049	250,693	2.82%	35.4
	Total		443,852,466	-	451,612,243	12,384,048	2.79%	36.5

Source: DEPRC_EXP_WKPR (AG 1-59)

As Filed Plant Balances By Month during Test Year		KIUC Recommended Depreciation Expense during Test Year
Jul-15	440,312,137	1,023,726
Aug-15	441,347,394	1,026,133
Sep-15	442,382,650	1,028,540
Oct-15	443,059,106	1,030,112
Nov-15	443,376,762	1,030,851
Dec-15	443,694,029	1,031,589
Jan-16	443,852,467	1,031,957
Feb-16	443,852,467	1,031,957
Mar-16	443,852,467	1,031,957
Apr-16	443,852,467	1,031,957
May-16	443,852,467	1,031,957
Jun-16	443,852,467	1,031,957
		12,362,692

Response to KIUC 2-13

		Interim Retirements	Terminal Retirements	Total Retirments
341	Structures & Improvements	-18%	-82%	-100%
342	Fuel Holders and Accessories	-16%	-84%	-100%
343	Prime Movers	-19%	-81%	-100%
344	Generators	-30%	-70%	-100%
345	Accessory Electrical Equipment	-33%	-67%	-100%
346	Misc. Power Plant Equip.	-34%	-66%	-100%

Kentucky Utilities Company
KIUC Adjustment to Reduce Depreciation Expense for Cane Run 7
To Remove Net Terminal Salvage Embedded into Net Salvage Rates
For the Test Year Ended June 30, 2016
$ Millions

AS FILED

ACCT. (I)	TITLE (II)	NET SALVAGE PERCENT	ORIGINAL COST (III)	BOOK RESERVE	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT (X)	ANNUAL ACCRUAL PERCENT (XI)	COMPOSITE REMAIN LIFE (IX)
	Other Production Plant							
	Cane Run 7							
341	Structures & Improvements	-	66,577,870	-	66,577,870	1,742,876	2.62%	38.2
342	Fuel Holders and Accessories	(5)	31,069,673	-	32,623,157	849,119	2.73%	38.4
343	Prime Movers	(5)	102,086,067	-	107,190,370	2,844,755	2.79%	37.7
344	Generators	(10)	199,733,610	-	219,706,971	6,215,190	3.11%	35.4
345	Accessory Electrical Equipment	(5)	35,508,197	-	37,283,607	1,055,296	2.97%	35.3
346	Misc. Power Plant Equip.	-	8,877,049	-	8,877,049	250,693	2.82%	35.4
	Total		443,852,466	-	472,259,024	12,957,929	2.92%	36.4

Source: DEPRC_EXP_WKPR (AG 1-59)

	As Filed Plant Balances By Month during Test Year	As Filed Depreciation Expense during Test Year
Jul-15	440,312,137	1,071,426
Aug-15	441,347,394	1,073,945
Sep-15	442,382,650	1,076,464
Oct-15	443,059,106	1,078,110
Nov-15	443,376,762	1,078,883
Dec-15	443,694,029	1,079,655
Jan-16	443,852,467	1,080,041
Feb-16	443,852,467	1,080,041
Mar-16	443,852,467	1,080,041
Apr-16	443,852,467	1,080,041
May-16	443,852,467	1,080,041
Jun-16	443,852,467	1,080,041
		12,938,731 Matches WP D-2.1a

Response to KIUC 2-13

		Interim Retirements	Terminal Retirements	Total Retirments
341	Structures & Improvements	-18%	-82%	-100%
342	Fuel Holders and Accessories	-16%	-84%	-100%
343	Prime Movers	-19%	-81%	-100%
344	Generators	-30%	-70%	-100%
345	Accessory Electrical Equipment	-33%	-67%	-100%
346	Misc. Power Plant Equip.	-34%	-66%	-100%

EXHIBIT ____ (LK-41)

Louisville Gas and Electric Company
KIUC Adjustment to Reduce Depreciation Expense for Cane Run 7
To Remove Net Terminal Salvage Embedded into Net Salvage Rates
For the Test Year Ended June 30, 2016
$ Millions

Depreciaton Expense Total Company - As Filed	3.675
Depreciaton Expense Total Company - KIUC Recommended	3.512
Reduction in Total Company Depreciation Expense	(0.164)
KY Jurisdiction Allocation % - Forecast Test Year for Depreciation	100.000%
KIUC Recommended Reduction in Cane Run 7 Depreciation Expense	(0.164)

Louisville Gas and Electric Company
KIUC Adjustment to Reduce Depreciation Expense for Cane Run 7
To Remove Net Terminal Salvage Embedded into Net Salvage Rates
For the Test Year Ended June 30, 2016
$ Millions

AS ADJUSTED BY KIUC

ACCT. (I)	TITLE (II)	NET SALVAGE PERCENT	ORIGINAL COST (III)	BOOK RESERVE	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT (X)	ANNUAL ACCRUAL PERCENT (XI)	COMPOSITE REMAIN LIFE (IX)
	Other Production Plant							
	Cane Run 7							
341	Structures & Improvements	-	18,912,029	-	18,912,029	495,079	2.62%	38.2
342	Fuel Holders and Accessories	(1)	8,825,614	-	8,894,792	231,515	2.62%	38.4
343	Prime Movers	(1)	28,998,445	-	29,272,184	776,863	2.68%	37.7
344	Generators	(3)	56,736,088	-	58,428,491	1,652,857	2.91%	35.4
345	Accessory Electrical Equipment	(2)	10,086,416	-	10,255,329	290,273	2.88%	35.3
346	Misc. Power Plant Equip.	-	2,521,604	-	2,521,604	71,212	2.82%	35.4
	Total		126,080,196	-	128,284,429	3,517,799	2.79%	36.5

Source: DEPRC_EXP_WKPR (AG 1-59)

	As Filed Plant Balances By Month during Test Year	KIUC Recommended Depreciation Expense during Test Year
Jul-15	125,081,647	290,815
Aug-15	125,373,642	291,494
Sep-15	125,665,638	292,173
Oct-15	125,856,433	292,616
Nov-15	125,946,029	292,825
Dec-15	126,035,511	293,033
Jan-16	126,080,195	293,136
Feb-16	126,080,195	293,136
Mar-16	126,080,195	293,136
Apr-16	126,080,195	293,136
May-16	126,080,195	293,136
Jun-16	126,080,195	293,136
		3,511,773

Response to KIUC 2-13

		Interim Retirements	Terminal Retirements	Total Retirments
341	Structures & Improvements	-18%	-82%	-100%
342	Fuel Holders and Accessories	-16%	-84%	-100%
343	Prime Movers	-19%	-81%	-100%
344	Generators	-30%	-70%	-100%
345	Accessory Electrical Equipment	-33%	-67%	-100%
346	Misc. Power Plant Equip.	-34%	-66%	-100%

Louisville Gas and Electric Company
KIUC Adjustment to Reduce Depreciation Expense for Cane Run 7
To Remove Net Terminal Salvage Embedded into Net Salvage Rates
For the Test Year Ended June 30, 2016
$ Millions

AS FILED

ACCT. (I)	TITLE (II)	NET SALVAGE PERCENT	ORIGINAL COST (III)	BOOK RESERVE	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT (X)	ANNUAL ACCRUAL PERCENT (XI)	COMPOSITE REMAIN LIFE (IX)
	Other Production Plant							
	Cane Run 7							
341	Structures & Improvements	-	18,912,029	-	18,912,029	495,079	2.62%	38.2
342	Fuel Holders and Accessories	(5)	8,825,614	-	9,266,895	241,200	2.73%	38.4
343	Prime Movers	(5)	28,998,445	-	30,448,367	808,078	2.79%	37.7
344	Generators	(10)	56,736,088	-	62,409,697	1,765,479	3.11%	35.4
345	Accessory Electrical Equipment	(5)	10,086,416	-	10,590,737	299,766	2.97%	35.3
346	Misc. Power Plant Equip.	-	2,521,604	-	2,521,604	71,212	2.82%	35.4
	Total		126,080,196	-	134,149,329	3,680,814	2.92%	36.4

Source: DEPRC_EXP_WKPR (AG 1-59)

As Filed Plant Balances By Month during Test Year		As Filed Depreciation Expense during Test Year
Jul-15	125,081,647	304,365
Aug-15	125,373,642	305,076
Sep-15	125,665,638	305,786
Oct-15	125,856,433	306,251
Nov-15	125,946,029	306,469
Dec-15	126,035,511	306,686
Jan-16	126,080,195	306,795
Feb-16	126,080,195	306,795
Mar-16	126,080,195	306,795
Apr-16	126,080,195	306,795
May-16	126,080,195	306,795
Jun-16	126,080,195	306,795
		3,675,404 Matches WP D-2.1a

Response to KIUC 2-13

		Interim Retirements	Terminal Retirements	Total Retirments
341	Structures & Improvements	-18%	-82%	-100%
342	Fuel Holders and Accessories	-16%	-84%	-100%
343	Prime Movers	-19%	-81%	-100%
344	Generators	-30%	-70%	-100%
345	Accessory Electrical Equipment	-33%	-67%	-100%
346	Misc. Power Plant Equip.	-34%	-66%	-100%

EXHIBIT ____ (LK-42)

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Commission Staff's Second Request for Information
Dated January 8, 2015

Question No. 75

Responding Witness: Kent W. Blake

Q-75. Refer to the response to Item 13 of Staff's First Request and page 1 of the attachment to part b. of the response.

a. Part c. of the response indicates, with the result for capital projects that are recovered in base rates being a slippage factor of 97.803 percent, that KU believes there is no need to apply a slippage factor. Provide the percentage at which KU believes there would be a need to apply a slippage factor.

b. Using the slippage factor of 97.803 percent shown on page 1 of the attachment to part b. of the response, provide the resulting net investment rate base, capitalization, COSS, and revised revenue requirement for KU for the base period and forecasted period. Include all work papers, spreadsheets, etc. which show the derivation of each item for each period in Excel spreadsheet format with the formulas intact and unprotected and with all columns and rows accessible.

A-75. a. As stated in response to Commission Staff's First Request for Information Item No. 13(c), given the demonstrated reasonable accuracy of the Company's predicting the cost of its utility plant additions and when new plant will be placed in service, KU does not believe there is a need to apply a Slippage Factor. Without waiver of its position, the Slippage Factor of 97.803 percent is the least unreasonable Slippage Factor when compared with the other Slippage Factor calculations shown in the response to Staff First Request for Information Item No. 13.

b. See the attachments being provided in Excel format. The impact on the KU revenue requirement for the forecasted test year is a reduction of $899,576.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371 - RESPONSE TO PSC 2-75 (SLIPPAGE FACTOR 97.803%)

OVERALL FINANCIAL SUMMARY

BASE YEAR FOR THE 12 MONTHS ENDED FEBRUARY 28, 2015

FORECAST PERIOD FOR THE 12 MONTHS ENDED JUNE 30, 2016

DATA: __X__BASE PERIOD__X__FORECASTED PERIOD
TYPE OF FILING: __X__ ORIGINAL _____ UPDATED _____ REVISED
WORKPAPER REFERENCE NO(S).:

SCHEDULE A

WITNESS: K. W. BLAKE

LINE NO.	DESCRIPTION	SUPPORTING SCHEDULE REFERENCE	BASE PERIOD JURISDICTIONAL REVENUE REQUIREMENT	FORECASTED PERIOD JURISDICTIONAL REVENUE REQUIREMENT
			$	$
1	CAPITALIZATION ALLOCATED TO KENTUCKY JURISDICTION	J	3,485,732,288	3,562,036,768
2	ADJUSTED OPERATING INCOME	C-1	199,088,737	167,173,560
3	EARNED RATE OF RETURN (2 / 1)		5.71%	4.69%
4	REQUIRED RATE OF RETURN	J	7.23%	7.38%
5	REQUIRED OPERATING INCOME (1 x 4)	C-1	251,937,561	263,003,244
6	OPERATING INCOME DEFICIENCY (5 - 2)	C-1	52,848,824	95,829,683
7	GROSS REVENUE CONVERSION FACTOR	H	1.591828	1.591828
8	REVENUE DEFICIENCY (6 x 7)		84,126,238	152,544,374
9	REVENUE INCREASE REQUESTED	C-1		152,544,374
10	ADJUSTED OPERATING REVENUES	C-1		1,413,402,191
11	REVENUE REQUIREMENTS (9 + 10)			1,565,946,565

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371 - RESPONSE TO PSC 2-75 (SLIPPAGE FACTOR 97.803%)

COST OF CAPITAL SUMMARY

THIRTEEN MONTH AVERAGE

FROM JULY 1, 2015 TO JUNE 30, 2016

DATA:____BASE PERIOD__X__FORECASTED PERIOD

DATE OF CAPITAL STRUCTURE: 13 MO AVG FOR FORECASTED PERIOD

TYPE OF FILING: __X__ ORIGINAL _____ UPDATED _____ REVISED

WORKPAPER REFERENCE NO(S).:

SCHEDULE J-1.1/J-1.2

PAGE 1 OF 3

WITNESS: K. W. BLAKE

LINE NO.	CLASS OF CAPITAL	WORKPAPER REFERENCE	13 MONTH AVERAGE AMOUNT	ADJUSTMENT AMOUNT	ADJUSTED CAPITAL	JURISDICTIONAL RATE BASE PERCENTAGE	JURISDICTIONAL CAPITAL	JURISDICTIONAL ADJUSTMENTS	JURISDICTIONAL ADJUSTED CAPITAL	PERCENT OF TOTAL	COST RATE	13 MONTH AVERAGE WEIGHTED COST
	(A)	(B)	(C)	(D)	(E=C+D)	(F)	(G=ExF)	(H)	(I=G+H)	(J)	(K)	(L=JxK)
			$	$	$		$	$	$		%	%
1	SHORT-TERM DEBT	J-2	153,968,041	(36,379)	153,931,662	88.88%	136,814,461	(30,762,647)	106,051,814	2.98%	0.90%	0.03%
2	LONG-TERM DEBT	J-3	2,275,223,678	(537,579)	2,274,686,099	88.88%	2,021,741,005	(454,587,217)	1,567,153,788	44.00%	4.07%	1.79%
3	COMMON EQUITY		2,741,554,426	38,665	2,741,593,091	88.88%	2,436,727,940	(547,896,773)	1,888,831,166	53.03%	10.50%	5.57%
4	TOTAL CAPITAL		5,170,746,145	(535,293)	5,170,210,852		4,595,283,405	(1,033,246,637)	3,562,036,768	100.00%		7.38%

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371 - RESPONSE TO PSC 2-75 (SLIPPAGE FACTOR 97.803%)

COST OF CAPITAL SUMMARY - ADJUSTMENT AMOUNT

THIRTEEN MONTH AVERAGE

FROM JULY 1, 2015 TO JUNE 30, 2016

DATA:____BASE PERIOD__X__FORECASTED PERIOD

DATE OF CAPITAL STRUCTURE: 13 MO AVG FOR FORECASTED PERIOD

TYPE OF FILING: __X__ ORIGINAL _____ UPDATED _____ REVISED

WORKPAPER REFERENCE NO(S).:

SCHEDULE J-1.1/J-1.2

WITNESS: K. W. BLAKE

LINE NO.	CLASS OF CAPITAL	WORKPAPER REFERENCE	13 MONTH AVERAGE AMOUNT	PERCENT OF TOTAL	OTHER COMPREHENSIVE INCOME - EEI	EEI DEFERRED TAXES	INVESTMENT IN OVEC	NET NONUTILITY PROPERTY	ADJUSTMENT AMOUNT
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I=E+F+G+H)
			$		$	$	$	$	$
1	SHORT-TERM DEBT	J-2	153,968,041	2.98%	-	-	(7,444)	(28,935)	(36,379)
2	LONG-TERM DEBT	J-3	2,275,223,678	44.00%	-	-	(110,005)	(427,575)	(537,579)
3	COMMON EQUITY		2,741,554,426	53.02%	1,190,493	(504,066)	(132,551)	(515,211)	38,665
4	TOTAL CAPITAL		5,170,746,145	100.00%	1,190,493	(504,066)	(250,000)	(971,720)	(535,293)

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371 - RESPONSE TO PSC 2-75 (SLIPPAGE FACTOR 97.803%)

COST OF CAPITAL SUMMARY - JURISDICTIONAL ADJUSTMENTS

THIRTEEN MONTH AVERAGE

FROM JULY 1, 2015 TO JUNE 30, 2016

DATA:____BASE PERIOD__X__FORECASTED PERIOD

DATE OF CAPITAL STRUCTURE: 13 MO AVG FOR FORECASTED PERIOD

TYPE OF FILING: __X__ ORIGINAL _____ UPDATED _____ REVISED

WORKPAPER REFERENCE NO(S).:

SCHEDULE J-1.1/J-1.2

WITNESS: K. W. BLAKE

LINE NO.	CLASS OF CAPITAL	WORKPAPER REFERENCE	JURISDICTIONAL CAPITAL	PERCENT OF TOTAL	ECR RATE BASE	DSM RATE BASE	PROFORMA ADJUSTMENT RATE BASE	JURISDICTIONAL ADJUSTMENTS
	(A)	(B)	(C=PAGE 1 COL G)	(D)	(E)	(F)	(G)	(H=E+F+G)
			$		$	$	$	$
1	SHORT-TERM DEBT		136,814,461	2.98%	(30,647,421)	(114,232)	(995)	(30,762,647)
2	LONG-TERM DEBT		2,021,741,005	44.00%	(452,884,489)	(1,688,031)	(14,697)	(454,587,217)
3	COMMON EQUITY		2,436,727,940	53.03%	(545,844,540)	(2,034,519)	(17,714)	(547,896,773)
4	TOTAL CAPITAL		4,595,283,405	100.00%	(1,029,376,450)	(3,836,782)	(33,405)	(1,033,246,637)

EXHIBIT ____ (LK-43)

KIUC Adjustments to KU Capitalization and Cost of Capital
Case No. 2014-00371
Test Year Ending June 30, 2016

I. KU Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Per Filing

	13 Month Average Balance	KU Proforma Adjustments	KU Adjusted Total Co. Capitalization	KU Kentucky Jurisdictional Factor	KU Jurisdictional Capitalization	Capital Ratio	Jurisdictional Adjustments	Adjusted KU Jurisdictional Capitalization	Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement
Short Term Debt	157,804,449	(37,228)	157,767,221	88.88%	140,223,506	3.05%	(31,484,483)	108,739,023	3.05%	0.91%	0.03%	0.03%	994,650
Long Term Debt	2,275,223,678	(536,756)	2,274,686,922	88.88%	2,021,741,736	43.93%	(453,943,096)	1,567,798,640	43.93%	4.07%	1.79%	1.80%	64,139,853
Common Equity	2,745,650,329	38,691	2,745,689,020	88.88%	2,440,368,401	53.02%	(547,937,636)	1,892,430,765	53.02%	10.50%	5.57%	8.86%	316,304,579
Total Capital	5,178,678,456	(535,293)	5,178,143,163		4,602,333,643	100.00%	(1,033,365,215)	3,568,968,428	100.00%		7.38%	10.69%	381,439,082

II. KU Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Reducing Capitalization for CWIP Slippage - See Company's Quantification of Adjusted Capitalization in Staff 2-75

	Adjusted KU Jurisdictional Capitalization	KIUC Proforma Adjustment 1	KU Kentucky Jurisdictional Factor	KIUC Jurisdictional Proforma Adjustment 1	KIUC Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	108,739,023			(2,687,209)	106,051,814	2.98%	2.98%	0.91%	0.03%	0.03%	970,069	(24,580)
Long Term Debt	1,567,798,640			(644,852)	1,567,153,788	44.00%	44.00%	4.07%	1.79%	1.80%	64,113,472	(26,381)
Common Equity	1,892,430,765			(3,599,599)	1,888,831,166	53.03%	53.03%	10.50%	5.57%	8.86%	315,702,935	(601,644)
Total Capital	3,568,968,428			(6,931,660)	3,562,036,768	100.00%	100.00%		7.39%	10.69%	380,786,476	(652,606)

III. KU Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Reducing Capitalization to Reflect 50% Bonus Depreciation - See Company's Quantification in AG 1-27

	Adjusted KU Jurisdictional Capitalization	KIUC Proforma Adjustment 1	KU Kentucky Jurisdictional Factor	KIUC Jurisdictional Proforma Adjustment 1	KIUC Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	106,051,814			(842,082)	105,209,732	2.98%	2.98%	0.91%	0.03%	0.03%	962,367	(7,703)
Long Term Debt	1,567,153,788			(12,443,646)	1,554,710,142	44.00%	44.00%	4.07%	1.79%	1.80%	63,604,393	(509,079)
Common Equity	1,888,831,166			(14,997,856)	1,873,833,310	53.03%	53.03%	10.50%	5.57%	8.86%	313,196,164	(2,506,771)
Total Capital	3,562,036,768			(28,283,584)	3,533,753,184	100.00%	100.00%		7.39%	10.69%	377,762,923	(3,023,553)

KIUC Adjustments to KU Capitalization and Cost of Capital
Case No. 2014-00371
Test Year Ending June 30, 2016

IV. KU Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Cost of Short Term Debt

	KIUC Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	105,209,732	2.98%	0.30%	0.01%	0.01%	317,264	(645,103)
Long Term Debt	1,554,710,142	44.00%	4.07%	1.79%	1.80%	63,604,393	-
Common Equity	1,873,833,310	53.03%	10.50%	5.57%	8.86%	313,196,164	-
Total Capital	3,533,753,184	100.00%		7.37%	10.67%	377,117,821	(645,103)

V. KU Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Cost of Long Term Debt

	KIUC Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	105,209,732	2.98%	0.30%	0.01%	0.01%	317,264	-
Long Term Debt	1,554,710,142	44.00%	3.99%	1.76%	1.76%	62,354,183	(1,250,209)
Common Equity	1,873,833,310	53.03%	10.50%	5.57%	8.86%	313,196,164	-
Total Capital	3,533,753,184	100.00%		7.33%	10.64%	375,867,611	(1,250,209)

VI. KU Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Return on Common Equity to 8.6%.

	KIUC Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	105,209,732	2.98%	0.30%	0.01%	0.01%	317,264	-
Long Term Debt	1,554,710,142	44.00%	3.99%	1.76%	1.76%	62,354,183	-
Common Equity	1,873,833,310	53.03%	8.60%	4.56%	7.26%	256,522,573	(56,673,592)
Total Capital	3,533,753,184	100.00%		6.32%	9.03%	319,194,020	(56,673,592)
					Each 1% ROE		(29,828,206)

EXHIBIT ____ (LK-44)

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2014-00372

Response to Commission Staff's Second Request for Information
Dated January 8, 2015

Question No. 89

Responding Witness: Kent W. Blake

Q-89. Refer to the response to Item 13 of Staff's First Request and page 1 of the attachment to part b. of the response.

a. Part c. of the response indicates, with the result for capital projects that are recovered in base rates being a slippage factor of 97.728 percent, that LG&E believes there is no need to apply a slippage factor. Provide the percentage at which LG&E believes there would be a need to apply a slippage factor.

b. Using the slippage factor of 97.728 percent shown on page 1 of the attachment to part b. of the response, provide the resulting net investment rate base, capitalization, COSS, and revised revenue requirement for both LG&E's electric and gas operations for the base period and forecasted period. Include all work papers, spreadsheets, etc., which show the derivation of each item for each period in Excel spreadsheet format with the formulas intact and unprotected and with all columns and rows accessible.

A-89. a. As stated in response to Commission Staff's First Request for Information Item No. 13(c), given the demonstrated reasonable accuracy of the Company's predicting the cost of its utility plant additions and when new plant will be placed in service, LG&E does not believe there is a need to apply a Slippage Factor. Without waiver of its position, the Slippage Factor of 97.728 percent is the least unreasonable Slippage Factor when compared with the other Slippage Factor calculations shown in the response to Staff First Request for Information Item No. 13.

b. See the attachments being provided in Excel format. The impact on the LG&E Electric revenue requirement for the forecasted test year is a reduction of \$738,268. The impact on the LG&E Gas revenue requirement for the forecasted test year is a reduction of \$ \$152,310.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2014-00372 - ELECTRIC OPERATIONS - RESPONSE TO PSC 2-89 (SLIPPAGE FACTOR 97.728%)

OVERALL FINANCIAL SUMMARY

BASE YEAR FOR THE 12 MONTHS ENDED FEBRUARY 28, 2015

FORECAST PERIOD FOR THE 12 MONTHS ENDED JUNE 30, 2016

DATA:__X__BASE PERIOD__X__FORECASTED PERIOD — SCHEDULE A

TYPE OF FILING: __X__ ORIGINAL _____ UPDATED _____ REVISED — PAGE 1 OF 1

WORKPAPER REFERENCE NO(S).: — WITNESS: K. W. BLAKE

LINE NO.	DESCRIPTION	SUPPORTING SCHEDULE REFERENCE	BASE PERIOD JURISDICTIONAL REVENUE REQUIREMENT	FORECASTED PERIOD JURISDICTIONAL REVENUE REQUIREMENT
			$	$
1	CAPITALIZATION ALLOCATED TO ELECTRIC OPERATIONS	J	2,037,688,629	2,140,161,141
2	ADJUSTED OPERATING INCOME	C-1	134,371,933	139,147,308
3	EARNED RATE OF RETURN (2 / 1)		6.59%	6.50%
4	REQUIRED RATE OF RETURN	J	7.31%	7.36%
5	REQUIRED OPERATING INCOME (1 x 4)	C-1	149,047,468	157,516,167
6	OPERATING INCOME DEFICIENCY (5 - 2)	C-1	14,675,535	18,368,859
7	GROSS REVENUE CONVERSION FACTOR	H	1.608581	1.608581
8	REVENUE DEFICIENCY (6 x 7)		23,606,782	29,547,790
9	REVENUE INCREASE REQUESTED	C-1		29,547,790
10	ADJUSTED OPERATING REVENUES	C-1		1,044,651,189
11	REVENUE REQUIREMENTS (9 + 10)			1,074,198,979

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2014-00372 - RESPONSE TO PSC 2-89 (SLIPPAGE FACTOR 97.7268%)

COST OF CAPITAL SUMMARY

THIRTEEN MONTH AVERAGE

FROM JULY 1, 2015 TO JUNE 30, 2016

DATA:____BASE PERIOD__X__FORECASTED PERIOD

DATE OF CAPITAL STRUCTURE: 13 MO AVG FOR FORECASTED PERIOD

TYPE OF FILING: __X__ ORIGINAL _____ UPDATED _____ REVISED

WORKPAPER REFERENCE NO(S).:

SCHEDULE J-1.1/J-1.2

WITNESS: K. W. BLAKE

LINE NO.	CLASS OF CAPITAL	WORKPAPER REFERENCE	13 MONTH AVERAGE AMOUNT	JURISDICTIONAL RATE BASE PERCENTAGE	JURISDICTIONAL CAPITAL	ADJUSTMENT AMOUNT	JURISDICTIONAL ADJUSTED CAPITAL	PERCENT OF TOTAL	COST RATE	13 MONTH AVERAGE WEIGHTED COST
	(A)	(B)	(C)	(D)	(E=CxD)	(F)	(G=E+F)	(H)	(I)	(J=HxI)
			$	%	$	$	$		%	%
	ELECTRIC:									
1	SHORT-TERM DEBT	J-2	165,087,328	82.61%	136,378,642	(40,922,032)	95,456,610	4.46%	0.89%	0.04%
2	LONG-TERM DEBT	J-3	1,583,768,878	82.61%	1,308,351,470	(392,586,406)	915,765,064	42.79%	4.16%	1.78%
3	COMMON EQUITY		1,952,443,115	82.61%	1,612,913,257	(483,973,790)	1,128,939,467	52.75%	10.50%	5.54%
4	TOTAL CAPITAL		3,701,299,321		3,057,643,369	(917,482,229)	2,140,161,141	100.00%		7.36%

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2014-00372 - RESPONSE TO PSC 2-89 (SLIPPAGE FACTOR 97.7268%)

COST OF CAPITAL SUMMARY

THIRTEEN MONTH AVERAGE

FROM JULY 1, 2015 TO JUNE 30, 2016

DATA:____BASE PERIOD__X__FORECASTED PERIOD

DATE OF CAPITAL STRUCTURE: 13 MO AVG FOR FORECASTED PERIOD

TYPE OF FILING: __X__ ORIGINAL _____ UPDATED _____ REVISED

WORKPAPER REFERENCE NO(S).:

SCHEDULE J-1.1/J-1.2

WITNESS: K. W. BLAKE

LINE NO.	CLASS OF CAPITAL	WORKPAPER REFERENCE	13 MONTH AVERAGE AMOUNT	JURISDICTIONAL RATE BASE PERCENTAGE	JURISDICTIONAL CAPITAL	ADJUSTMENT AMOUNT	JURISDICTIONAL ADJUSTED CAPITAL	PERCENT OF TOTAL	COST RATE	13 MONTH AVERAGE WEIGHTED COST
	(A)	(B)	(C)	(D)	(E=CxD)	(F)	(G=E+F)	(H)	(I)	(J=HxI)
			$	%	$	$	$		%	%
	GAS:									
1	SHORT-TERM DEBT	J-2	165,087,328	17.39%	28,708,686	(5,394,881)	23,313,806	4.46%	0.89%	0.04%
2	LONG-TERM DEBT	J-3	1,583,768,878	17.39%	275,417,408	(51,755,906)	223,661,502	42.79%	4.16%	1.78%
3	COMMON EQUITY		1,952,443,115	17.39%	339,529,858	(63,803,793)	275,726,065	52.75%	10.50%	5.54%
4	TOTAL CAPITAL		3,701,299,321		643,655,952	(120,954,579)	522,701,373	100.00%		7.36%

KIUC Adjustments to LG&E (Electric) Capitalization and Cost of Capital
Case No. 2014-00372
Test Year Ending June 30, 2016

I. LG&E (Electric) Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Per Filing

	13 Month Average Balance	Capital Ratio	LG&E Kentucky Electric Factor	LG&E Electric Capitalization	LG&E Adjustments to Capitalization	Adjusted LG&E Electric Capitalization	Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement
Short Term Debt	168,476,606	4.54%	82.61%	139,178,524	(41,678,967)	97,499,557	4.54%	0.90%	0.04%	0.04%	882,040
Long Term Debt	1,583,768,878	42.71%	82.61%	1,308,351,470	(391,804,249)	916,547,221	42.71%	4.16%	1.78%	1.79%	38,325,819
Common Equity	1,956,064,974	52.75%	82.61%	1,615,905,275	(483,905,561)	1,131,999,714	52.75%	10.50%	5.54%	8.91%	191,195,844
Total Capital	3,708,310,458	100.00%		3,063,435,269	(917,388,777)	2,146,046,492	100.00%		7.36%	10.74%	230,403,703

II. LG&E (Electric) Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Reducing Capitalization for CWIP Slippage - See Company's Quantification of Adjusted Capitalization in Staff 2-89

	Adjusted LG&E Electric Capitalization	KIUC Proforma Adjustment	LG&E Kentucky Electric Factor	KIUC Electric Proforma Adjustment 1		KIUC Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	97,499,557			(2,042,947)		95,456,610	4.46%	0.90%	0.04%	0.04%	863,559	(18,482)
Long Term Debt	916,547,221			(782,157)		915,765,064	42.79%	4.16%	1.78%	1.79%	38,293,113	(32,706)
Common Equity	1,131,999,714			(3,060,247)		1,128,939,467	52.75%	10.50%	5.54%	8.91%	190,678,965	(516,879)
Total Capital	2,146,046,492			(5,885,351)		2,140,161,141	100.00%		7.36%	10.74%	229,835,636	(568,067)

III. LG&E (Electric) Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Reducing Capitalization to Reflect 50% Bonus Depreciation for 2014

	Adjusted LG&E Electric Capitalization	KIUC Proforma Adjustment	LG&E Kentucky Electric Factor	KIUC Electric Proforma Adjustment 1		KIUC Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	95,456,610			(1,998,465)		93,458,145	4.46%	0.90%	0.04%	0.04%	845,479	(18,079)
Long Term Debt	915,765,064			(19,172,318)		896,592,746	42.79%	4.16%	1.78%	1.79%	37,491,414	(801,699)
Common Equity	1,128,939,467			(23,635,304)		1,105,304,163	52.75%	10.50%	5.54%	8.91%	186,686,939	(3,992,026)
Total Capital	2,140,161,141			(44,806,087)		2,095,355,054	100.00%		7.36%	10.74%	225,023,833	(4,811,804)

KIUC Adjustments to LG&E (Electric) Capitalization and Cost of Capital
Case No. 2014-00372
Test Year Ending June 30, 2016

IV. LG&E (Electric) Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Reducing Capitalization to Remove Costs for Paddy's Run Demolition

	Adjusted LG&E Electric Capitalization	KIUC Proforma Adjustment	LG&E Kentucky Electric Factor	KIUC Electric Proforma Adjustment 1	KIUC Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	93,458,145	(512,929)	100.00%	(512,929)	92,945,216	4.46%	0.90%	0.04%	0.04%	840,839	(4,640)
Long Term Debt	896,592,746	(4,920,797)	100.00%	(4,920,797)	891,671,950	42.79%	4.16%	1.78%	1.79%	37,285,649	(205,765)
Common Equity	1,105,304,163	(6,066,274)	100.00%	(6,066,274)	1,099,237,889	52.75%	10.50%	5.54%	8.91%	185,662,340	(1,024,600)
Total Capital	2,095,355,054	(11,500,000)		(11,500,000)	2,083,855,054	100.00%		7.36%	10.74%	223,788,828	(1,235,005)

V. LG&E (Electric) Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Reducing Cost of Short Term Debt

	Adjusted LG&E Electric Capitalization	KIUC Proforma Adjustment	LG&E Kentucky Electric Factor	KIUC Electric Proforma Adjustment 1	KIUC Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	92,945,216				92,945,216	4.46%	0.30%	0.01%	0.01%	280,280	(560,559)
Long Term Debt	891,671,950				891,671,950	42.79%	4.16%	1.78%	1.79%	37,285,649	-
Common Equity	1,099,237,889				1,099,237,889	52.75%	10.50%	5.54%	8.91%	185,662,340	-
Total Capital	2,083,855,054				2,083,855,054	100.00%		7.33%	10.71%	223,228,268	(560,559)

VI. LG&E (Electric) Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Reducing Cost of Long Term Debt

	Adjusted LG&E Electric Capitalization	KIUC Proforma Adjustment	LG&E Kentucky Electric Factor	KIUC Electric Proforma Adjustment 1	KIUC Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	92,945,216				92,945,216	4.46%	0.30%	0.01%	0.01%	280,280	-
Long Term Debt	891,671,950				891,671,950	42.79%	4.04%	1.73%	1.74%	36,210,101	(1,075,548)
Common Equity	1,099,237,889				1,099,237,889	52.75%	10.50%	5.54%	8.91%	185,662,340	-
Total Capital	2,083,855,054				2,083,855,054	100.00%		7.28%	10.66%	222,152,721	(1,075,548)

KIUC Adjustments to LG&E (Electric) Capitalization and Cost of Capital
Case No. 2014-00372
Test Year Ending June 30, 2016

VII. LG&E (Electric) Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Return on Common Equity to 8.6%.

	KIUC Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	92,945,216	4.46%	0.30%	0.01%	0.01%	280,280	-
Long Term Debt	891,671,950	42.79%	4.04%	1.73%	1.74%	36,210,101	-
Common Equity	1,099,237,889	52.75%	8.60%	4.54%	7.30%	152,066,297	(33,596,042)
Total Capital	2,083,855,054	100.00%		6.28%	9.05%	188,556,678	(33,596,042)
					Each 1% ROE		(17,682,128)

EXHIBIT ____ (LK-46)

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Attorney General's Initial Requests for Information
Dated January 8, 2015

Question No. 27

Responding Witness: Kent W. Blake / Christopher M. Garrett

Q-27. At the end of 2014, the United States Congress passed a "tax extender" bill. Public Law No. 113-295 extended certain expiring tax provisions through the end of 2014, retroactively beginning January 1, 2014.

a. Please explain the impact of Public Law No. 113-295 on KUs revenue, depreciation schedules, and other phases of the KU application.

b. Will this law allow the company to decrease depreciation expense?

A-27.

a. See attachment being provided in Excel Format for the detailed analysis of the estimated impacts of the Tax Increase Prevention Act of 2014. An Appendix has been included in the attachment to provide an overview of the various tabs in the workbook.

The Tax Increase Prevention Act of 2014 provided for the extension of 50% bonus tax depreciation in 2014 for qualified property while also providing for 50% bonus tax depreciation in 2015 for long-production-period property. As KU's rate case had been prepared and filed prior to the passing of this law, the effects of this extension were not considered in the filing.

The Company has calculated the revenue requirement impact of this extension assuming KU were to take bonus depreciation in 2014 and 2015. This calculation is included in the attached file as "TAB 2 –Elect Bonus".

This calculation shows that the revenue requirement would actually increase were KU to take the bonus tax depreciation deduction in both years. This result is driven by the negative impact of losing the ability to take the Internal Revenue Code §199 manufacturing deduction, which more than offsets the positive impact of the lower rate base and capitalization resulting from the increase in the accumulated deferred income tax liability.

KU would be unable to take the Internal Revenue Code §199 tax deduction given its taxable loss in both 2014 and 2015. The loss of the §199 manufacturing deduction results in an increase in KU's tax provision thereby increasing its Net Operating Income Deficiency and Gross-Revenue Conversion Factor. While KU would be able to utilize the majority of the 2014 tax loss as a result of its ability to carryback the loss to 2013, the additional loss in 2015 would have to be carried forward (See Tab: "Taxable Income"). As a result, KU would need to record a deferred tax asset for the 2015 NOL carryforward resulting in an offsetting increase in rate base and capitalization.

The Company then ran a separate calculation assuming that KU elected bonus depreciation in 2014 but declined to do so in 2015 (opt-out). This calculation is shown in "TAB3 – Opt out in 2015". This scenario proves beneficial to customers by lowering the revenue requirement for the following reasons:

- The benefits from the lower rate base and capitalization resulting from the 2014 bonus tax depreciation continue to be realized
- The benefit of the §199 manufacturing deduction in 2015 is preserved, and
- The need to record a deferred tax asset for the 2015 Net Operating Loss is eliminated.

The two calculations above were prepared for the forecast test period without considering incremental revenue awarded in this rate case. In order to determine whether incremental revenue would impact this decision to take bonus depreciation in 2014 but opt out in 2015, the Company re-ran the two calculations assuming the revenue increase requested in the Company's filing is granted as filed. These calculations are included in the attached file as "TAB4 – Elect Bonus with Rev" and "TAB5 – Opt Out 2015 with Rev". These additional scenarios demonstrate that even with the projected rate increases, KU would still incur a taxable loss in 2014 and 2015 when taking the bonus tax depreciation deduction. As such, the analysis continues to support the prior conclusion that the lowest revenue requirement for customers would be achieved if KU elected to take the bonus depreciation deduction in 2014 but elected to opt out in 2015. Also, "TAB1- Summary" shows that customers receive a $3 million detriment of increased revenue requirement if KU elects to take the bonus depreciation deduction in both 2014 and 2015 as compared to a $4 million benefit of reduced revenue requirement if KU elects to take the bonus depreciation deduction in 2014 but elects to opt out in 2015.

b. The law will not allow the Company to decrease its book depreciation expense which is the means by which the Company recovers its capital investments. The law applies to bonus tax depreciation which is a timing difference between book income and taxable income. It allows for an increase to the amount of tax depreciation deductible on the income tax return with no effect on book depreciation. The impact on the Company's revenue requirement is that its deferred tax liability is increased which lowers rate base and capitalization in the near term and thus lowers the current revenue requirement in this proceeding. See the response above for a discussion of the overall impact on the revenue requirement.

Kentucky Utilities Company
Bonus Depreciation Analysis
Summary
$ millions
Return to Appendix

	Forecasted Test Period - Base Rates			
	Excluding Rate Case Revenues		With Rate Case Revenues	
LINKS	TAB 2	TAB 3	TAB 4	TAB 5
Variances by Component	With Bonus	Opt out of Bonus*	With Bonus	Opt out of Bonus*
Lower Capitalization	(4)	(3)	(6)	(3)
Loss of Sec. 199 deduction - Adjusted NOI	2	(1)	5	(1)
Impact of Loss of Sec. 199 on Gross-Up Factor	5	0	5	0
Increase/(Decrease) to Filed Revenue Requirement	**3**	**(4)**	**4**	**(4)**

	Forecasted Test Period - ECR			
	Excluding Rate Case Revenues		With Rate Case Revenues	
	TAB 2	TAB 3	TAB 4	TAB 5
Variances by Component	With Bonus	Opt out of Bonus*	With Bonus	Opt out of Bonus*
Lower Capitalization	(6)	(2)	(6)	(2)
Loss of Sec. 199 deduction - Adjusted NOI	0	0	0	0
Impact of Loss of Sec. 199 on Gross-Up Factor	5	0	5	0
Increase/(Decrease) to Filed Revenue Requirement	**(1)**	**(2)**	**(1)**	**(2)**

	Forecasted Test Period - Total			
	Excluding Rate Case Revenues		With Rate Case Revenues	
	TAB 2	TAB 3	TAB 4	TAB 5
Variances by Component	With Bonus	Opt out of Bonus*	With Bonus	Opt out of Bonus*
Lower Capitalization	(10)	(5)	(12)	(5)
Loss of Sec. 199 deduction - Adjusted NOI	2	(1)	5	(1)
Impact of Loss of Sec. 199 on Gross-Up Factor	10	0	10	0
Increase/(Decrease) to Filed Revenue Requirement	**2**	**(6)**	**3**	**(6)**

** Opt out of Bonus for 2015 Tax Year.*

Kentucky Utilities Company
$ millions
Return to Appendix

	Cumulative Total (Base)		Cumulative Total (ECR)		Total			Base			ECR		
	Feb-15 Base Test Period	13 ME 6/30/16 FC Test Period	Feb-15 Base Test Period	13 ME 6/30/16 FC Test Period	2014	2015	2016	2014	2015	2016	2014	2015	2016
Bonus Depreciation	(106)	(105)	(20)	(89)	(195)			(106)	-	-	(89)		
Depreciation Impact	6	16	1	15	11	21	20	6	11	10	5	10	10
Net Effect	(100)	(89)	(19)	(74)	(184)	21	20	(100)	11	10	(84)	10	10
Tax Rate (35%)	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
Accumulated Deferred Income Taxes (Rate Base)	(35)	(31)	(7)	(26)	(64)	7	7	(35)	4	4	(29)	4	4
NOL Carryforward	-	-	-	-	-	-	-	-	-	-	-	-	-
Tax Rate (35%)	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
Accumulated Deferred Income Taxes (Rate Base)	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Accumulated Deferred Income Tax effect for Bonus	(35)	(31)	(7)	(26)	(64)	7	7	(35)	4	4	(29)	4	4
Other Capitalization effects	(3)	(1)	0	2	-	-	-	-	-	-	-	-	-
Net Reduction to Capitalization/Rate Base	(38)	(32)	(7)	(24)	(64)	7	7	(35)	4	4	(29)	4	4
Jurisdictional Factor	88.76%	88.88%											
Jurisdictionalized Reduction to Capitalization/Rate Base	(34)	(28.283584)											
Rate of Return (as filed)	7.23%	7.38%	10.27%	10.29%									
NOI found Reasonable	(2)	(2)	(1)	(2)		538							
Loss of Sec. 199 Manufacturing Deduction (lower adjusted NOI)	0	(0.350)				0							
Operating Income Deficiency associated with Bonus	(2)	(2)				188							
Operating Income Deficiency as filed	53	96				350							
Adjusted Operating Income Deficiency	51	94											
Gross Revenue Conversion Factor (revised to remove Sec. 199 c	1.64112	1.59183											
Total Adjusted Revenue Requirement	31	59											
As filed Revenue Requirement	84	153											
Variance	(53)	(94)											
Change in Gross-Up Factor	(1)	(1)											
Variances by Component													
Lower Capitalization	(4)	(3)	(1)	(2)									
Loss of Sec. 199 deduction - Adjusted NOI	0	(0.557)	-	-									
Impact of Loss of Sec. 199 on Gross-Up Factor	(1)	(0)	-	-									
	(5)	(4)	(1)	(2)									
Gross-Up Impact													
NOI Deficiency As Filed	53	96											
As Filed Gross Revenue Conversion Factor	1.59183	1.59183											
Revenue Deficiency	33	60											
NOI Deficiency As Filed	53	96											
Revised Gross Revenue Conversion Factor	1.64112	1.64112											
Revenue Deficiency	32	58											
	1	2											

EXHIBIT ____ (LK-47)

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2014-00372

Response to Attorney General's Initial Request for Information
Dated January 8, 2015

Question No. 26

Responding Witness: Kent W. Blake / Christopher M. Garrett

Q-26. At the end of 2014, the United States Congress passed a "tax extender" bill. Public Law No. 113-295 extended certain expiring tax provisions through the end of 2014, retroactively beginning January 1, 2014.

a. Please explain the impact of Public Law No. 113-295 on LG&Es revenue, depreciation schedules, and other phases of the LG&E application.

b. Will this law allow the company to decrease depreciation expense?

A-26.

a. See attachment being provided in Excel format for the detailed analysis of the impacts of the Tax Increase Prevention Act of 2014. An Appendix has been included in the attachment to provide an overview of the various tabs in the workbook.

The Tax Increase Prevention Act of 2014 provided for the extension of 50% bonus tax depreciation in 2014 for qualified property while also providing 50% bonus tax depreciation in 2015 for long-production-period property. As LG&E's rate case had been prepared and filed prior to the passing of the law, the effects of this extension were not considered in the filing.

The Company has calculated the revenue requirement impact of this extension assuming LG&E were to take bonus depreciation in 2014 and 2015. This calculation is included in the attached file as "TAB 2 _ Elect Bonus".

This calculation shows that customers would benefit from LG&E electing to take the bonus tax depreciation deduction in 2014 and 2015.

LG&E would be able to fully utilize its projected 2014 and 2015 tax losses as a result of its ability to carryback the losses to 2013. The ability to utilize its tax losses would provide LG&E customers the full benefit of the lower rate base and capitalization associated with the recording of the deferred income tax liability for the bonus tax depreciation deduction. The level of benefits to customers is mitigated somewhat by LG&E incurring a tax loss in 2014 and

2015 thereby losing its ability to take an Internal Revenue Code §199 manufacturing deduction. The loss of the §199 deduction results in an increase in LG&E's tax provision thereby increasing its Net Operating Income Deficiency and Gross-Revenue Conversion Factor.

The Company then ran a separate calculation assuming that LG&E elected bonus depreciation in 2014 but declined to do so in 2015 (opt-out). This calculation is shown in "TAB3- Opt out in 2015". This scenario also proves beneficial to customers, but to a slightly lesser extent than the first, as the benefits from the ability to take the §199 deduction in 2015 is overtaken by the benefits of the lower rate base and capitalization resulting from the 2015 bonus tax depreciation.

The two calculations above were prepared for the forecasted test period without considering incremental revenue awarded in this rate case. In order to determine whether incremental revenue would impact this decision to take bonus depreciation in 2014 but opt out in 2015, the Company re-ran the two calculations assuming the revenue increase requested in the Company's filing is granted as filed. These calculations are included in the attachment file as "TAB4 – Elect Bonus with Rev" and "TAB5- Opt Out 2015 with Rev". These additional scenarios demonstrate that even with the projected rate increases, LG&E will still incur a taxable loss in 2014 and 2015 when taking the bonus tax depreciation deduction such that the benefit of the deduction will be offset by an incremental impact of the loss of the §199 manufacturing deduction. Also, "TAB1- Summary" shows that customers receive a $6 million ($4 million electric and $2 million gas) benefit of reduced revenue requirement if LG&E elects to take the bonus depreciation deduction in both 2014 and 2015 as compared to a $5 million ($3 million electric and $2 million gas) benefit of reduced revenue requirement if LG&E elects to take the bonus depreciation deduction in 2014 but elects to opt out in 2015. It should also be noted that there is an incremental benefit to customers of $1 million through the ECR rate mechanism in the forecasted rate period as a result of the bonus depreciation deduction in both years, but a $2 million dollar benefit if bonus depreciation is not elected in 2015.

b. The law will not allow the Company to decrease its book depreciation expense which is the means by which the Company recovers its capital investments. The law applies to bonus tax depreciation which is a timing difference between book income and taxable income. It allows for an increase to the amount of tax depreciation deductible on the income tax return. There is no effect on book depreciation. The impact on the Company's revenue requirement is that its deferred tax liability is increased which lowers rate base and capitalization in the near term and thus lowers the current revenue requirement in this proceeding. See the response above for a discussion of the overall impact on the revenue requirement.

Louisville Gas and Electric Company
Bonus Depreciation Analysis
Summary
$ millions
Return to Appendix

	Forecasted Test Period - Electric Base Rates				Forecasted Test Period - Gas Base Rates			
	Excluding Rate Case Revenues		Including Rate Case Revenues		Excluding Rate Case Revenues		Including Rate Case Revenues	
LINKS	TAB 2	TAB 3	TAB 4	TAB 5	TAB 2	TAB 3	TAB 4	TAB 5
Variances by Component	With Bonus	Opt out of Bonus*	With Bonus	Opt out of Bonus*	With Bonus	Opt out of Bonus*	With Bonus	Opt out of Bonus*
Lower Capitalization	(7)	(3)	(7)	(3)	(2)	(2)	(2)	(2)
Loss of Sec. 199 deduction - Adjusted NOI	2	0	2	0	0	0	0	0
Impact of Loss of Sec. 199 on Gross-Up Factor	1	0	1	0	0	0	0	0
Increase/(Decrease) to Filed Revenue Requirement	**(4)**	**(3)**	**(4)**	**(3)**	**(2)**	**(2)**	**(2)**	**(2)**

	Forecasted Test Period - ECR			
	Excluding Rate Case Revenues		Including Rate Case Revenues	
	TAB 2	TAB 3	TAB 4	TAB 5
Variances by Component	With Bonus	Opt out of Bonus*	With Bonus	Opt out of Bonus*
Lower Capitalization	(6)	(2)	(6)	(2)
Loss of Sec. 199 deduction - Adjusted NOI	0	0	0	0
Impact of Loss of Sec. 199 on Gross-Up Factor	5	0	5	0
Increase/(Decrease) to Filed Revenue Requirement	**(1)**	**(2)**	**(1)**	**(2)**

	Forecasted Test Period - Electric Total			
LINKS	Excluding Rate Case Revenues		Including Rate Case Revenues	
	TAB 2	TAB 3	TAB 4	TAB 5
Variances by Component	With Bonus	Opt out of Bonus*	With Bonus	Opt out of Bonus*
Lower Capitalization	(13)	(5)	(13)	(5)
Loss of Sec. 199 deduction - Adjusted NOI	2	0	2	0
Impact of Loss of Sec. 199 on Gross-Up Factor	6	0	6	0
Increase/(Decrease) to Filed Revenue Requirement	**(5)**	**(5)**	**(5)**	**(5)**

* *Opt out of Bonus for 2015 Tax Year.*

Louisville Gas and Electric
$ millions
Return to Appendix

	Cumulative Total (Electric)		Cumulative Total (Gas)		Cumulative Total (ECR)	
	Feb-15	13 ME 6/30/16	Feb-15	13 ME 6/30/16	Feb-15	13 ME 6/30/16
	Base Test Period	FC Test Period	Base Test Period	FC Test Period	Base Test Period	FC Test Period
Bonus Depreciation	(98)	(190)	(57)	(58)	(18)	(205)
Depreciation Impact	5	19	3	9	1	23
Net Effect	(93)	(171)	(54)	(49)	(17)	(182)
Tax Rate (35%)	35%	35%	35%	35%	35%	35%
Accumulated Deferred Income Taxes (Rate Base)	(33)	(60)	(19)	(17)	(6)	(64)
NOL Carryforward	-	-	-	-	-	-
Tax Rate (35%)	35%	35%	35%	35%	35%	35%
Accumulated Deferred Income Taxes (Rate Base)	-	-	-	-	-	-
Net Accumulated Deferred Income Tax effect for Bonus	(33)	(60)	(19)	(17)	(6)	(64)
Other Capitalization effects	0	6	0	2	-	5
Net Reduction to Capitalization	(32)	(54.238091)	(19)	(16)	(6)	(59)
Rate of Return (as filed)	7.23%	7.38%	7.23%	7.38%	10.20%	10.20%
NOI found Reasonable	(2)	(4)	(1)	(1)	(1)	(6)
Loss of Sec. 199 Manufacturing Deduction (lower adjusted NOI)	2	1.606				
Operating Income Deficiency associated with Bonus	(1)	(2.396)	(1)	(1)		
Operating Income Deficiency as filed	15	19	5	9		
Adjusted Operating Income Deficiency	14	17	4	8		
Gross Revenue Conversion Factor (revised to remove Sec. 199 d	1.64241	1.64241	1.64317	1.64317		
Total Adjusted Revenue Requirement	24	27	6	13		
As filed Revenue Requirement	24	30	8	14		
Variance	(0)	(3)	(2)	(2)		
Change in Gross-Up Factor	(1)	(1)	(1)	(1)		
Variances by Component						
Lower Capitalization	(4)	(6.574)	(2)	(2)	(1)	(6)
Loss of Sec. 199 deduction - Adjusted NOI	3	2.238	-	-	-	-
Impact of Loss of Sec. 199 on Gross-Up Factor	1	1	-	-	2	5
	(0)	(3)	(2)	(2)	1	(1)
Gross-Up Impact						
NOI Deficiency As Filed	15	19	5	9		
As Filed Gross Revenue Conversion Factor	1.59185	1.59185	1.64317	1.64317		
Revenue Deficiency	24	30	8	14		
NOI Deficiency As Filed	15	19	5	9		
Revised Gross Revenue Conversion Factor	1.64241	1.64241	1.64317	1.64317		
Revenue Deficiency	25	31	8	14		
	(1)	(1)	-	-		

	Total			Base Total			Base Electric			Base Gas			ECR		
	2014	2015	2016	2014	2015	2016	2014	2015	2016	2014	2015	2016	2014	2015	2016
Bonus Depreciation	(224)	(276)		(155)	(112)	-	(98)	(111)		(57)	(1)		(69)	(164)	
Depreciation Impact	12	40	55	8	20	24	5	14	18	3	6	5	4	20	31
Net Effect	(212)	(236)	55	(147)	(92)	24	(93)	(97)	18	(54)	5	5	(65)	(144)	31
Tax Rate (35%)	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
Accumulated Deferred Income Taxes (Rate Base)	(74)	(83)	19	(51)	(32)	8	(33)	(34)	6	(19)	2	2	(23)	(50)	11
NOL Carryforward	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tax Rate (35%)	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
Accumulated Deferred Income Taxes (Rate Base)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Accumulated Deferred Income Tax effect for Bonus	(74)	(83)	19	(51)	(32)	8	(33)	(34)	6	(19)	2	2	(23)	(50)	11
Other Capitalization effects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Reduction to Capitalization	(74)	(83)	19	(51)	(32)	8	(33)	(34)	6	(19)	2	2	(23)	(50)	11

EXHIBIT ____ (LK-48)

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2014-00372

Response to First Set of Data Requests of Kentucky Industrial Utility Customers, Inc. Dated January 8, 2015

Question No. 6

Responding Witness: Christopher M. Garrett / Russel A. Hudson

Q.1-6. Refer to pages 27-28 of Mr. Thompson's Direct Testimony wherein he describes the "capital investments" both Companies are expected to incur over the next several years, including the demolition of the retired units at Paddy's Creek and the costs to retire the coal units at Cane Run.

a. Please provide the projected amounts for each of these projects by unit, by month, and in total through June 30, 2016. Also, please indicate which line item includes these amounts on the table on page 28 of Mr. Thompson's Direct Testimony.

b. Please describe the Company's accounting for the costs that will be incurred to retire the coal units, e.g. will they be expensed?

c. Please describe the costs included by the Company in the revenue requirement to retire the coal units, to recover the remaining net book value at the date of retirement, if any, and to demolish the units.

d. Please provide a copy of all studies performed by or on behalf of the Company that address: i) the legal requirements to demolish the units; ii) any alternatives to demolition that were considered; and iii) why the Company chose to demolish the units rather than retire them in place for an extended period.

e. Please provide a copy of demolition/dismantling studies and/or cost estimates. If no such studies exist, then please state.

A.1-6. a. See attached. The costs will all be incurred by LG&E. In reference to the table on page 28 of the Mr. Thompson direct testimony, these costs are in the "Other Generation Projects" line for Paddy's Run Coal and the "Investment in Existing Generation" line for Cane Run Coal.

b. The Company's accounting for the costs that will be incurred to retire the coal units will be in accordance with the guidelines prescribed in the Code of Federal Regulations 18 CFR, Chapter 1, Subchapter C, Part 101, Electric Plant Instruction 10, Additions and Retirements of Electric Plant. The Company will charge the accumulated provision for depreciation reserve for the majority of the costs to physically retire the units, e.g. cost of removal and salvage. A smaller portion of the costs may be expensed.

c. See the response to part b) above regarding the costs to physically retire and demolish the coal units. The costs charged to the accumulated reserve for depreciation are reflected in the Company's capitalization. To the extent the retired unit has a remaining net book value, LG&E plans to recover the value through future depreciation expense in accordance with the next depreciation study as normal retirement treatment is appropriate.

d. There have been no such studies prepared.
   i) There is no legal requirement to demolish the units.
   ii) For Paddy's Run Coal, the only alternative is to leave the station in its current state, which continues to deteriorate over time.
   iii) The Paddy's Run Coal Station has already been retired for an extended period of time. Once Cane Run Coal is retired, it will be retired in place, with the only retirement expenditures in the 2015 Business Plan to preserve it in a "dry" state that will not rapidly deteriorate. There is no retirement capital for demolition in the 2015 Business Plan specific to the Cane Run Coal facility. A decision for dismantlement of the Cane Run Coal units has not been determined at this time.

e. See attached. The cost estimate for the complete demolition of Paddy's Run Coal is $17.4 million, consistent with the 2015 Business Plan. There has not been an estimate done to date on the Cane Run Coal facility.

Capital Expenditures for Paddy's Run Coal Retirement and Cane Run Coal Retirement

2012 (actuals)

Project	January	February	March	April	May	June	July	August	September	October	November	December	Total
132874 Paddy's Run	$0	$0	$1,650	$7,924	$5,119	$6,620	$8,106	$13,471	$211,811	$255,060	$379,224	$207,168	$1,096,153

2013 (actuals)

Project	January	February	March	April	May	June	July	August	September	October	November	December	Total
132874 Paddy's Run	$196,191	$20,078	$60,080	($7,223)	$15,370	($7,084)	($2,131)	$0	$0	($129)	$0	$0	$275,153

2014 (actuals through August, forecast September through December)

Project	January	February	March	April	May	June	July	August	September	October	November	December	Total
132874 Paddy's Run	$1,685	$3,074	$7,822	$4,245	$3,514	$18,054	$56,329	$53,876	$29,457	$34,004	$25,612	$12,328	$250,000

2015 (forecast)

Project	January	February	March	April	May	June	July	August	September	October	November	December	Total
132874 Paddy's Run	$0	$0	$0	$500,000	$750,000	$750,000	$1,500,000	$1,500,000	$1,500,000	$0	$0	$0	$6,500,000
137600 Cane Run					$0	$0	$0	$0	$250,000	$750,000	$3,800,000	$0	$4,800,000

2016 (forecast)

Project	January	February	March	April	May	June	July	August	September	October	November	December	Total
132874 Paddy's Run	$750,000	$750,000	$750,000	$750,000	$1,000,000	$1,000,000							$5,000,000

Attachment to Response to LGE KIUC Question No. 6(a)
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Garrett/Hudson

LG&E KU
PPL companies

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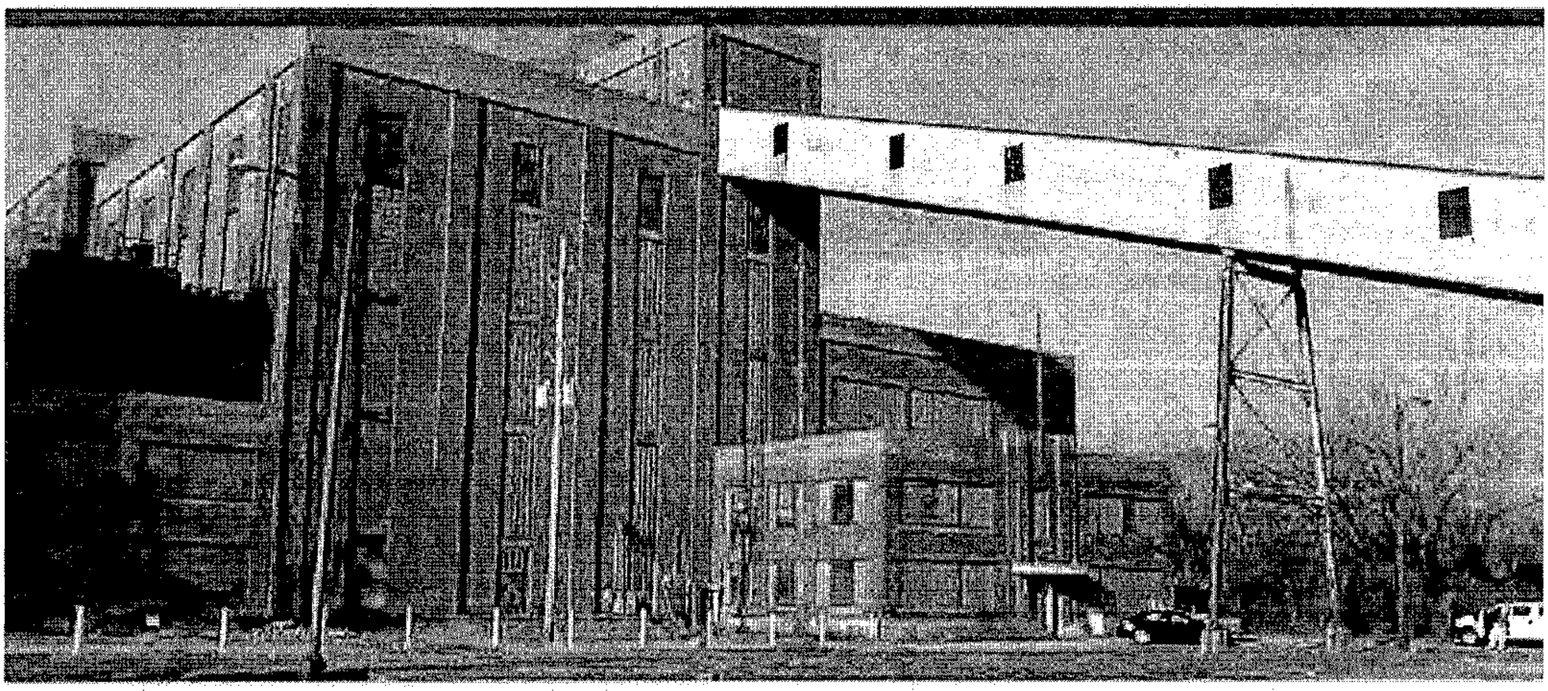
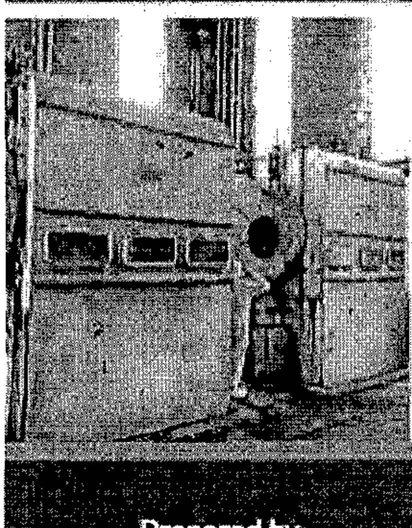
Paddy's Run Station
Conceptual Phase Study
Demolition with Clean Fill Option





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APPENDIX 1 - PRELIMINARY CONCEPTS REPORT

APPENDIX 2 - FIGURES

- Figure 1 Site Location Map
- Figure 2 Site Layout Maps and Plot Plans
- Figure 3 Cross Section of Main Powerhouse
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- Demolition cost estimate
- Hazardous building material abatement cost estimate
- Implementation phase planning

APPENDIX 5 - OPTION 3 STAKEHOLDERS AND PERMITS

EXHIBIT ____ (LK-49)

Borrowing Benchmarks

Money Rates

February 26, 2015

Key annual interest rates paid to borrow or lend money in U.S. and international markets. Rates below are a guide to general levels but don't always represent actual transactions.

Inflation

	Jan. Index level	CHG FROM (%) Dec. '14	Jan. '14
U.S. consumer price index			
All items	**233.707**	–0.47	–0.1
Core	**239.248**	0.20	1.6

International rates

	Latest	Week ago	—52-WEEK— High	Low
Prime rates				
U.S.	**3.25**	3.25	3.25	3.25
Canada	**2.85**	2.85	3.00	2.85
Euro zone	**0.05**	0.05	0.25	0.05
Japan	**1.475**	1.475	1.475	1.475
Switzerland	**0.50**	0.50	0.51	0.50
Britain	**0.50**	0.50	0.50	0.50
Australia	**2.25**	2.25	2.50	2.25
Overnight repurchase				
U.S.	**0.12**	0.13	0.29	0.00

U.S. government rates

	Latest	Week ago	—52-WEEK— High	Low
Discount				
	0.75	0.75	0.75	0.75
Federal funds				
Effective rate	**0.1400**	0.1400	0.1800	0.0800
High	**0.3125**	0.3125	0.5160	0.2500
Low	**0.0700**	0.0400	0.0800	0.0100
Bid	**0.0600**	0.0600	0.1200	0.0000
Offer	**0.0900**	0.0800	0.2800	0.0400
Treasury bill auction				
4 weeks	**0.015**	0.010	0.060	0.000
13 weeks	**0.020**	0.015	0.055	0.010
26 weeks	**0.065**	0.065	0.155	0.040

Secondary market

	Latest	Week ago	—52-WEEK— High	Low
Freddie Mac				
30-year mortgage yields				
30 days	**n.a.**	n.a.	n.a.	n.a.
60 days	**n.a.**	n.a.	n.a.	n.a.
Fannie Mae				
30-year mortgage yields				
30 days	**3.326**	3.386	4.069	3.024
60 days	**3.357**	3.415	4.135	3.080
Bankers acceptance				
30 days	**0.15**	0.15	0.15	0.15
60 days	**0.19**	0.19	0.19	0.19
90 days	**0.23**	0.23	0.23	0.23
120 days	**0.25**	0.25	0.25	0.25
150 days	**0.28**	0.28	0.28	0.28
180 days	**0.38**	0.38	0.38	0.38

Other short-term rates

	Latest	Week ago	—52-WEEK— high	low
Call money				
	2.00	2.00	2.00	2.00
Commercial paper				
30 to 239 days	**n.q.**	...	...	...
240 to 255 days	**0.33**	...	...	...
256 to 256 days	**n.q.**	...	...	...
257 to 264 days	**0.33**	...	...	...
265 to 270 days	**0.36**	...	...	...
Commercial paper (AA financial)				
90 days	**0.15**	0.14	0.19	0.09
Euro commercial paper				
30 day	**n.q.**	n.q.	0.20	0.20
Two month	**n.q.**	n.q.	0.22	0.03
Three month	**0.01**	n.q.	0.24	0.01
Four month	**0.02**	n.q.	0.28	0.02
Five month	**0.03**	n.q.	0.30	0.03
Six month	**0.04**	n.q.	0.33	0.04
London interbank offered rate, or Libor				
One month	**0.17190**	0.17350	0.17350	0.14775
Three month	**0.26160**	0.26060	0.26260	0.22285
Six month	**0.37835**	0.38530	0.38570	0.31940
One year	**0.66935**	0.68410	0.68410	0.53350
Euro Libor				
One month	**-0.006**	-0.006	0.249	-0.021
Three month	**0.021**	0.026	0.321	0.021
Six month	**0.085**	0.091	0.417	0.085
One year	**0.209**	0.223	0.579	0.209
Euro interbank offered rate (Euribor)				
One month	**-0.004**	0.001	0.269	-0.005
Three month	**0.040**	0.048	0.347	0.040
Six month	**0.114**	0.125	0.444	0.114
One year	**0.238**	0.252	0.621	0.238
Hibor				
One month	**0.237**	0.238	0.253	0.204
Three month	**0.385**	0.388	0.393	0.360
Six month	**0.539**	0.539	0.551	0.534
One year	**0.839**	0.840	0.871	0.837

	Latest	Value Traded	—52-WEEK— High	Low
DTCC GCF Repo Index				
Treasury	**0.101**	105.394	0.249	0.018
MBS	**0.105**	73.450	0.429	0.058

	Settle	Change	Open Interest	Implied Rate
DTCC GCF Repo Index Futures				
Treasury Feb	**99.865**	-0.005	6161	0.135
Treasury Mar	**99.850**	-0.005	6001	0.150
Treasury Apr	**99.845**	-0.005	2019	0.155

	LATEST Offer	Bid	Week ago	52-WEEK high	low
Eurodollars (mid rates)					
One month	**0.10**	0.20	0.15	0.15	0.15
Two month	**0.12**	0.25	0.19	0.19	0.19
Three month	**0.15**	0.30	0.23	0.23	0.23
Four month	**0.20**	0.30	0.25	0.25	0.25
Five month	**0.20**	0.35	0.28	0.28	0.28
Six month	**0.25**	0.50	0.38	0.38	0.38

Weekly survey

	Latest	Week ago	Year ago
Freddie Mac			
30-year fixed	**3.80**	3.76	4.37
15-year fixed	**3.07**	3.05	3.39
Five-year ARM	**2.99**	2.97	3.05
One-year ARM	**2.44**	2.45	2.52

Notes on data:

U.S. prime rate is effective December 16, 2008.
Discount rate is effective February 19, 2010.
U.S. prime rate is the base rate on corporate loans posted by at least 70% of the 10 largest U.S. banks;
Other prime rates aren't directly comparable; lending practices vary widely by location;
Discount rate is the charge on loans to depository institutions by the New York Federal Reserve Banks;
Federal-funds rate is on reserves traded among commercial banks for overnight use in amounts of $1 million or more;
Call money rate is the charge on loans to brokers on stock-exchange collateral;
Commercial Paper (AA financial) is from the Federal Reserve and is presented with a one-day lag.
Libor is the Intercontinental Exchange Benchmark Administration Ltd average of interbank offered rates for dollar deposits in the London market;
DTCC GCF Repo Index is Depository Trust & Clearing Corp.'s weighted average for overnight trades in applicable CUSIPs. Value traded is in billions of U.S. dollars.
Futures on the DTCC GCF Repo Index are traded on NYSE Liffe US.

Sources: Federal Reserve; Bureau of Labor Statistics; DTCC; SIX Financial Information; General Electric Capital Corp.; Tullett Prebon Information, Ltd.