BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	)))	**CASE NO. 2018-00294**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	)))	**CASE NO. 2018-00295**

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

JANUARY 2019

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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 ratemaking, accounting, finance, tax issues, and planning issues in proceedings before regulatory commissions and courts at the federal and state levels on hundreds of 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, Duke Energy Kentucky, Inc. ("Duke"), East Kentucky Power Company ("EKPC"), Big Rivers Electric Corporation ("BREC"), Atmos Energy Atmos Energy Corporation ("Atmos"), and Columbia Gas of Kentucky, Inc. ("Columbia Gas").[1]

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

Q. On whose behalf are you testifying?

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

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to summarize the KIUC revenue requirement recommendations and address specific issues that affect each Company's revenue requirement and claimed deficiency.

Q. Please summarize your testimony.

A. I recommend that the Commission increase KU's base rates by no more than $12.157 million, a reduction of $100.303 million from its requested increase of $112.460 million. When combined with the loss of the Tax Cuts and Jobs Act ("TCJA") surcredit of $58.355 million, the total increase for KU would be $70.512 million after the KIUC recommendations. I recommend that the Commission reduce LG&E's electric base rates by at least $10.092 million, a reduction of

$44.979 million from its requested increase of $34.887 million. When combined with the loss of the TCJA surcredit of $40.030 million, the total increase for LG&E would be $29.938 million.

The following table lists each KIUC adjustment and the effect on each Company's claimed revenue deficiency. The amounts for KU are shown on a Kentucky jurisdiction basis and the amounts for LG&E are electric only. The calculations are detailed in my workpapers for each Company, which have been filed with my testimony in the form of an Excel workbook in live format.

Kentucky Utilities Company and Louisville Gas & Electric Company
Summary of Revenue Requirement Adjustments-Jurisdictional Electric Operations
Recommended by KIUC
Case Nos. 2018-00294 and 2018-00295
For the Test Year Ended April 30, 2020
($ Millions)

	KU Amount	LG&E Amount
Increase Requested by Company - Base Rates	112.460	34.887
Expiration of TCJA Surcredit on May 1, 2019	58.355	40.030
Overall Increase Requested by Company	170.815	74.917
KIUC Adjustments:		
Capitalization Issues		
Reduce Capitalization to Reflect AFUDC Approach in Lieu of CWIP Approach	(12.693)	(7.727)
Reduce Capitalization to Reflect Reduction in Transmission Plant Additions	(2.921)	(0.048)
Reduce Capitalization to Reflect Reduction in Distribution Plant Additions	(2.024)	(2.486)
Reduce Capitalization to Reflect Reduction for Ash Pond Depreciation Not Recorded	(0.394)	(0.040)
Reduce Capitalization to Reflect No April 2019 LTD Outstanding for May 1, 2019 Issuance	(0.944)	(1.393)
	-	
Operating Income Issues	-	
Adjust Base Revenue to Remove Reductions in RTS Load	(1.483)	(1.795)
Adjust Base Revenue to Reflect Addition of Phoenix Paper Wickliffe LLC New Load	(7.659)	-
Remove Repair Expense to Brown 1 Stack after Unit is Retired	(0.299)	-
Reduce Brown 3 Employee and Contractor Labor Expenses	(2.098)	-
Normalize Generation Outage Expense Based on Inflation Adjusted 5 Year Actual	(6.734)	(1.775)
Reflect Reduction for Credit Card Rebates	(0.212)	(0.183)
Reduce 401K Matching Costs for Employees Who Also Participate in Defined Benefit Plan	(2.029)	(1.375)
Reduce Depreciation Expense to Reflect Reduction in Transmission Plant	(0.716)	(0.011)
Reduce Property Tax Expense to Reflect Reduction in Transmission Plant	(0.486)	(0.009)
Reduce Depreciation Expense to Reflect Reduction in Distribution Plant	(0.537)	(0.747)
Reduce Property Tax Expense to Reflect Reduction in Distribution Plant	(0.336)	(0.468)
Reduce Depreciation Expense to Correct Depreciation Rate for Brown 1 and 2 Ash Ponds	(2.779)	-
Reduce Depreciation Expense to Reflect 65 Year Service Lives on Coal Units	(26.933)	(12.007)
Reduce Depreciation Expense to Reflect Ash Pond Service Lives Based on Generating Units	(7.785)	(0.564)
Cost of Capital Issues		
Reduce Interest Rate for Projected May 1, 2019 LTD Issue from 4.90% to 4.25%	(1.334)	(1.709)
Reflect Return on Equity of 9.70%	(19.908)	(12.643)
Total KIUC Adjustments to Company Request	(100.303)	(44.979)
Change in Base Rates after KIUC Recommendations	12.157	(10.092)
Overall Increase After KIUC Recommendations	70.512	29.938

In the following sections of my testimony, I address each of the issues reflected in the preceding table in greater detail, except for the adjustment to increase RTS base revenues. That RTS base revenues issue is addressed by KIUC witness Mr. Stephen Baron. I also quantify the effects of my recommendation to maintain the 9.70% return on equity presently authorized and reject the Companies' request to increase it to 10.42%. The return on equity also has an effect on the

Companies' Environmental Cost Recovery ("ECR") riders, although I did not quantify the effect on the riders in the preceding table. These quantifications are detailed in my electronic workpapers, which I filed at the same time as my testimony was filed. The electronic workpapers consist of an Excel workbook in live format and with all formulas intact.

In conjunction with and in addition to the preceding table, I recommend numerous changes in the form and/or methodology for cost recovery sought by the Companies in their filings. First, I recommend that the Commission direct the Companies to capitalize their cost of construction financing as Allowance for Funds Used During Construction ("AFUDC") instead of prematurely recovering these costs during the construction period before the new construction provides service. Under this approach, construction work in progress ("CWIP") will be excluded from capitalization/rate base in the test year. Instead, for accounting and ratemaking purposes, the Companies will add the AFUDC to the CWIP during the construction period and then recover these additional capitalized costs from customers over the service lives of the assets. The use of AFUDC for Kentucky retail ratemaking and accounting purposes more appropriately recovers these costs from customers over the lives of the assets when they provide service. It also is consistent with generally accepted accounting principles ("GAAP"), which generally requires that construction financing costs be capitalized and then depreciated over the service lives of the assets. In addition, the AFUDC approach will ensure that the Companies recover all of their construction financing costs, no more and no less, and will ensure that the KU and LG&E construction financing costs are treated consistently with Kentucky Power Company, Duke (electric and gas), Columbia Gas, and KU (Virginia retail jurisdiction) for ratemaking purposes.

Second, I recommend that the Commission adopt a Purchased Power Adjustment ("PPA") rider to capture changes (savings and expenses) in "fixed" purchased power expense compared to the purchased power expenses that are reflected in the base revenue requirement in this proceeding and that are not otherwise reflected in the Fuel Adjustment Clause ("FAC") rider.

Third, I recommend that the Commission direct the Companies to defer all refunds and ongoing savings resulting from the Companies' pending FERC complaint as a regulatory liability. In that complaint, the Companies seek a reduction in merger mitigation de-pancaking charges. KIUC supports that complaint and filed a brief in the FERC proceeding in support of the Companies.

Fourth, I recommend that the Commission modify the sharing percentage for off-system sales margins from the present 75% customers/25% KU/LG&E to 90% customers/10% KU/LG&E. This change in sharing percentages will ensure that customers are provided a greater share of these margins as an offset to the cost of the generating facilities and other fixed costs that are included in base rates, while still providing the Companies a meaningful incentive to maximize the off-system sales and margins.

Fifth, I recommend that the Commission calculate the normalized generation outage expense using an inflation-adjusted average of historic actual expenses with no true-up mechanism and recommend that it reject the Companies' proposal to calculate this expense using forecast outage expense, subject to true-up of over or under recoveries. The use of historic actual expenses ensures that the normalized expense accurately reflects actual outage expenses and provides the Companies incentives to achieve efficiencies and minimize future outage expenses.

Q. Does the Companies' use of a forecast test year ending April 30, 2020 impact the Commission's review of their requests?

A. Yes. Unlike a historic test year based on actual results, a forecast test year is not anchored in actual results. All capitalization, operating revenues, operating expenses, and cost of capital components are projected based on tens of thousands of assumptions, including programs and approaches that may or not reflect the actual costs that will be incurred from May 1, 2019 through April 30, 2020. In fact, utilities, in conjunction with a forecast test year, have every incentive to understate their revenues and overstate their costs to maximize their revenue increases. The future actual base revenues are not trued-up to the forecast revenues and the utilities are not obligated to actually incur the forecast costs once the Commission sets their revenue requirements. In addition, the utilities have every incentive to propose new programs that increase capitalization, which is the basis for earnings and growth in earnings, an important consideration for their shareholders when growth in sales is relatively flat and doesn't contribute to increased revenues and earnings.

The Commission should carefully and critically review the Companies' requests, particularly when they seek approval for new programs, or include expansions of existing programs, along with significant increases in costs, such as increases in transmission and distribution capital expenditures, transmission maintenance expenses, and generation outage expenses, and when they seek significant increases in other costs, such as depreciation expense, among others.

II. CAPITALIZATION ISSUES

A. <u>Capitalization Should Be Reduced To Remove Construction Work In Progress; Construction Financing Costs Should Be Capitalized To CWIP In The Form Of AFUDC</u>

Q. Describe the Companies' requests for current recovery of construction financing costs.

A. The Companies seek current recovery of construction financing costs instead of capitalizing these costs in CWIP and then recovering the costs over the service lives of the assets. This CWIP approach provides the Company recovery of the construction financing costs before the project is completed and placed in service. The Commission historically has allowed the Companies to include these construction financing costs in the revenue requirement without removing the CWIP from capitalization or including AFUDC as an increase to operating income.

Q. Describe the AFUDC approach for capitalizing financing costs incurred during construction.

A. Under the AFUDC approach, the financing costs incurred during construction are capitalized and added to the cost of the plant. The financing costs are computed at the Company's embedded weighted cost of capital in accordance with the requirements of the Federal Energy Regulatory Commission ("FERC") methodology, unless the methodology is modified for retail ratemaking purposes. The FERC methodology requires that the Company's short-term debt first be assigned to the financing costs for construction and then requires the use of the weighted average cost of long-term debt, preferred equity, and common equity for the residual amount of financing costs.

Q. Will the Companies fully recover their construction financing costs under the AFUDC approach?

A. Yes. The AFUDC approach provides the Companies dollar for dollar recovery of their actual construction financing costs, no more and no less.

Q. Is the AFUDC approach consistent with generally accepted accounting principles?

A. Yes. GAAP generally requires that construction financing costs be capitalized into the cost of an asset because such costs are no different in concept than the cost of labor and materials used to construct an asset and because the cost has future economic value. Statement of Financial Accounting Standards No. 34, *Capitalization of Interest Cost,* states the following:

> 39. The Board concluded that interest cost is a part of the cost of acquiring an asset if a period of time is required in which to carry out the activities necessary to get it ready for its intended use. In reaching this conclusion, the Board considered that the point in time at which an asset is ready for its intended use is critical in determining its acquisition cost. Assets are expected to provide future economic benefits, and the notion of expected future economic benefits implies fitness for a particular purpose. Although assets may be capable of being applied to a variety of possible uses, the use

> intended by the enterprise in deciding to acquire an asset has an important bearing on the nature and value of the economic benefits that it will yield.
>
> 40. Some assets are ready for their intended use when purchased. Others are constructed or otherwise developed for a particular use by a series of activities whereby diverse resources are combined to form a new asset or a less valuable resource is transformed into a more valuable resource. Activities take time for their accomplishment. During the period of time required, the expenditures for the materials, labor, and other resources used in creating the asset must be financed. Financing has a cost. The cost may take the form of explicit interest on borrowed funds, or it may take the form of a return foregone on an alternative use of funds, but regardless of the form it takes, a financing cost is necessarily incurred. *On the premise that the historical cost of acquiring an asset should include all costs necessarily incurred to bring it to the condition and location necessary for its intended use, the Board concluded that, in principle, the cost incurred in financing expenditures for an asset during a required construction or development period is itself a part of the asset's historical acquisition cost.* (emphasis added).

Q. How does the CWIP approach differ from the GAAP requirement to capitalize carrying costs in the plant costs and then depreciate the plant costs over the useful service life of the asset?

A. The CWIP approach provides accelerated recovery to the utility of the construction financing cost subset of total construction costs during the construction period rather than over the service lives of the assets. The CWIP approach is unique to regulated utilities and is available to utilities only if they are allowed to prematurely recover construction financing costs during the construction period. On long lead time construction projects, the CWIP approach may allow a utility to recover 30% or 40% of the total construction costs during the construction period.

The AFUDC approach is consistent with the GAAP requirement to capitalize these construction financing costs and then depreciate the costs over the asset's service life. The recovery occurs over the service life. The revenue requirement is set to recover the depreciation expense plus a return on the declining capitalization/rate base as the asset is depreciated for book accounting and tax purposes. On long lead time construction projects, the AFUDC approach allocates the total cost over the service life of the assets to the customers who are served by the asset.

Q. Is there a penalty to customers under the CWIP approach?

A. Yes. Under the CWIP approach, the utility recovers and customers pay the construction financing costs on the related capitalization plus the income tax expense on the equity component of the return. This income tax expense then is remitted to the federal and state governments. In other words, this is an unnecessary expense during the construction period imposed on customers that provides no benefit to the utility. In fact, it causes an economic harm over the life of the assets on a net present value basis, all else equal.

Q. Describe how the Commission excludes CWIP from either capitalization or rate base for other utilities.

A. The Commission excludes CWIP from either capitalization or rate base for Kentucky Power Company, Duke Energy Kentucky, Inc. (electric and gas), and Columbia Gas of Kentucky, Inc. The Virginia Commission also excludes CWIP from rate base for KU. These utilities and KU in its Virginia jurisdiction capitalize their construction financing costs as AFUDC in the same manner that all other costs are capitalized and added to CWIP during the construction period. They do not recover their construction financing costs during construction. Instead, the construction financing costs are recovered after the CWIP is closed to plant-in-service. Thereafter, the utilities earn a return on the related capitalization and recover the cost through depreciation expense over the service lives of the assets.

Q. How does the Commission exclude CWIP in Kentucky Power Company rate cases?

A. It includes AFUDC in operating income, which effectively eliminates the return on the CWIP included in capitalization. This is referred to as the "AFUDC offset methodology.[2] Methodologically, it calculates AFUDC using the authorized rate of return, net of the income tax expense savings from the interest expense deduction, and includes the net of tax AFUDC in operating income. When the operating income deficiency or surplus is grossed up to the revenue requirement, the effect of the "AFUDC offset" is a reduction in the revenue requirement equivalent to the grossed-up return times the CWIP balance.

Q. How does the Commission exclude CWIP in the Duke rate cases?

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[2] Direct Testimony of Ranie K. Wohnhas at 22-23 in Case No. 2014-00396. I have attached the relevant pages from the Kentucky Power filing as my Exhibit___(LK-2).

A. In its most recent electric base rate case, Duke made a proforma adjustment to remove CWIP from its forecast capitalization.[3]

In its pending natural gas base rate case, Duke proposes a change from capitalization to rate base and simply excluded CWIP from its calculation of rate base.[4] In response to Staff discovery regarding the exclusion of CWIP from rate base, Duke responded:

> Similar to its most recently approved electric rate case, Case No. 2017-00321, Duke Energy Kentucky is not requesting to include recovery of CWIP in base rates because of past Commission precedent that effectively eliminates recovery of a return on CWIP. When CWIP is included in rate base, the Commission has, in past cases, included an AFUDC offset to operating income, which was calculated by multiplying the CWIP balance times the full weighted average cost of capital. The inclusion of the AFUDC offset effectively eliminates any revenue requirement in the test year related to CWIP.[5]

Q. How does the Commission exclude CWIP in the Columbia Gas rate cases?

A. In its most recent base rate case, Columbia Gas simply excluded CWIP from its calculation of rate base.[6]

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[3] I have attached the relevant pages from the Duke filing in Case No. 2017-00321 as my Exhibit___(LK-3).

[4] Direct Testimony of Cynthia S. Lee at 6 in Case No. 2018-00261. I have attached the relevant pages from the Duke filing as my Exhibit___(LK-4).

[5] Response to Staff 2-6 in Case No. 2018-00261. I have attached a copy of this response as my Exhibit___(LK-5).

[6] Schedule B-4 and the Direct Testimony of Columbia Gas witness Mr. S. Mark Katco at 7-8 in Case No. 2016-00162. I have attached the relevant pages from the Columbia Gas filing as my Exhibit___(LK-6).

Q. What is your recommendation?

A. I recommend that the Commission exclude CWIP from capitalization and direct the Companies to accrue AFUDC starting with the effective date when base rates are reset in this proceeding.

The AFUDC approach is beneficial to the Companies and their customers. It benefits the Companies because it allows them to capitalize and recover the entirety of their construction financing costs, no more and no less. It benefits customers because it avoids the premature recovery of these costs during the construction period before the assets provide service, minimizes base rate increases, and allows customers to pay for these costs over the service lives of the assets when they are used and useful.

The AFUDC approach also avoids the premature recovery of income tax expense from customers under the CWIP approach through the grossed-up rate of return. This unnecessary income tax expense is recovered from customers and then simply remitted to the federal and state governments during the construction period. It benefits neither the Companies nor their customers.

Q. What methodology should the Commission use to exclude CWIP from capitalization?

A. I recommend that the Commission use the Duke/Columbia Gas methodology for KU and LG&E whereby the 13-month average of CWIP is simply subtracted from 13-month average of capitalization, although the Kentucky Power methodology should yield the same result. The Duke/Columbia Gas methodology simply avoids the AFUDC offset calculation that is necessary if the Kentucky Power AFUDC offset methodology is used.

Q. What are the effects of your recommendation?

A. The effects are a reduction of $12.693 million in the KU revenue requirement and $7.727 million in the LG&E revenue requirement.

B. Transmission and Distribution Capital Expenditures and Plant Additions Are Excessive Compared to Recent Actual Expenditures and Additions

Q How do the forecast transmission and distribution capital expenditures in the test year compare to historic actual capital expenditures?

A. The Companies have significantly ratcheted up their forecast transmission and distribution capital expenditures compared to historic actual expenditures. For KU, the proposed increase in transmission capital expenditures is in addition to nearly doubling its transmission capital expenditures in the last base rate case proceeding. The Companies have no new generation under construction, so they now propose significant increases in transmission and distribution capital expenditures. The following table compares the proposed "non-mechanism" (base rate) generation, transmission, and distribution capital expenditures included in the test year compared to actual capital expenditures since 2014 for each Company.[7]

[7] Response to KIUC 1-26 for KU and response to KIUC 1-23 for LG&E. I have attached a copy of both responses as my Exhibit___(LK-7).

Actual and Forecast Capital Spending
Non-Mechanism Generation, Transmission, and Distribution
$ Millions

Kentucky Utilities Company (Total Company)

	2014	2015	2016	2017	Base Year	Test Year
Non-Mechanism Generation	129	82	69	93	113	172
Transmission	40	53	69	110	113	143
Distribution	78	95	94	108	127	147

Louisville Gas & Electric Company (Electric)

	2014	2015	2016	2017	Base Year	Test Year
Non-Mechanism Generation	86	74	67	124	118	90
Transmission	44	21	17	24	33	30
Distribution	68	82	80	91	114	141

KU proposes to increase its transmission capital expenditures by $33 million, or another 30% compared to 2017, which already reflected an increase of 59% compared to 2016. LG&E proposes to increase its transmission capital expenditures by $6 million, or another 25% compared to 2017, which already reflected an increase of 41% compared to 2016.

KU propose to increase its distribution capital expenditures by $39 million, or another 36% compared to 2017, which already reflected an increase of 15% compared to 2016. LG&E proposes to increase its distribution capital expenditures by $50 million, or another 55% compared to 2017, which already reflected an increase of 14% compared to 2016.

Q. Are transmission and distribution capital expenditures controllable costs?

A. Yes, except in the event of damage, such as an ice or other storm event, or untimely age-related and/or environmental deterioration. With these exceptions, capital expenditures are incurred as the result of a budget process in which capital projects are identified and then prioritized based on various factors, primarily need and capital constraints.[8]

Transmission and distribution capital expenditures include specific projects for new construction and upgrade/rebuild construction, such as building new lines and upgrading existing lines and equipment, as well as other projects for routine construction, such as replacing damaged or aging fixtures and connectors. KU included transmission capital expenditures in the test year consisting of $130.624 million in specific projects and only $12.031 million in routine projects.[9] LG&E's included transmission capital expenditures in the test year consisting of $25.349 million in specific projects and only $4.375 million in routine projects.[10]

KU included distribution capital expenditures in the test year consisting of $54.884 million in specific projects and $92.512 million in routine projects.[11] KU forecasts an increase of $23.352 million, or 34%, for distribution routine projects compared to actual expenditures in 2017.[12] LG&E included distribution capital expenditures in the test year consisting of $61.180 million in specific projects and $79.386 million in routine projects.[13] LG&E forecasts an increase of $21.452 million, or 37%, for distribution routine projects compared to actual expenditures

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[8] KU response to AG 1-38 and LG&E response to AG 1-38.
[9] KU response to KIUC 2-3.
[10] LG&E response to KIUC 2-3.
[11] KU response to KIUC 2-4.
[12] *Id.*
[13] LG&E response to KIUC 2-4.

in 2017.[14]

Q. Are capital expenditures and increases of the magnitude proposed by the Companies reasonable?

A. No. The Companies assume they will be allowed to recover the forecast capital expenditures in the test year revenue requirement and have every incentive to maximize the forecast costs. If the Commission reduces the test year revenue requirement to reflect lower forecast capital expenditures, then the Companies will respond and defer discretionary and lower priority projects into future years. In other words, the Companies' forecasts are self-fulfilling, whether more or less. For example, in the Companies' last base rate case filings, they included capital expenditures for an automated meter system ("AMS"). The settlement in those cases resulted in the withdrawal of the Companies' request for approval of the AMS and a reduction in the revenue requirement reflecting the removal of the AMS capital expenditures. Consistent with the denial of the forecast costs in the revenue requirements, the Companies did not make the forecast AMS capital expenditures.

This is an example of how assumptions can drive increases in the revenue requirement and why it is necessary to compare the forecast costs against historical actual costs to test the reasonableness of the assumptions. In addition, even if the Commission includes the costs in the test year, that does not require KU and LG&E to actually spend the forecast amounts. In fact, they have a behavioral incentive

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[14] *Id.*

not to spend the forecast amounts, but to spend something less.

Q. What is your recommendation?

A. I recommend that the Commission normalize the forecast transmission and distribution capital expenditures based on the average of the Companies' inflation-adjusted actual transmission capital expenditures for 2014 through 2017. Alternatively, I recommend that the Commission normalize the forecast transmission and distribution capital expenditures based on the Companies' actual 2017 capital expenditures. This recommendation would reflect a continuation in the test year of the significant increase in 2017 compared to 2016, but would reject the additional significant increases proposed in the test year compared to 2017.

Q. If the Commission adopts your recommendation, what is the likely effect on the Companies' transmission and distribution capital expenditures in the rate effective year?

A. The Companies will respond to the Commission's reductions in the forecast capital expenditures used to determine the base revenue requirement. They will review their forecasts and defer discretionary and lower priority projects into later years based on their budget prioritization process.

Q. What are the effects of your recommendation on KU's revenue requirement?

A. The effect is a reduction of $7.021 million in KU's Kentucky jurisdiction revenue requirement, consisting of a reduction of $4.946 million in the return on capitalization, including income taxes; \$1.253 million related to depreciation expense; and \$0.822 million related to property tax expense.

The effect is a reduction of \$3.768 million in LG&E's electric revenue requirement, consisting of a reduction of \$2.533 million in the return on capitalization, including income taxes; \$0.758 million related to depreciation expense; and \$0.477 million related to property tax expense.

C. KU and LG&E Historically Spend Less Than Their Budgeted And Forecast Capital Expenditures

Q. Do the Companies historically spend less than their capital expenditure budgets and forecasts?

A. Yes. In most years, the Companies spend less than their budgets and forecasts on capital costs recovered through base rates. The forecast test year in the Companies' last base rate case was the 12 months ending June 30, 2018. In 2017, KU actually spent \$331 million compared to its budget of \$353 million on base rate capital projects.[15] Similarly, in 2017, LG&E actually spent \$274 million compared to its budget of \$315 million.[16] This is typical for most utilities, in my experience, particularly when the utility's rates are set based on costs in a forecast test year rather than actual costs in a historic test year. The percentage of actual costs to budgeted or projected costs is referred to as a "slippage factor."

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[15] KU response to Staff 1-13(b). I have attached a copy of the relevant pages of this response as my Exhibit___(LK-8).

[16] LG&E response to Staff 1-13(b). I have attached a copy of the relevant pages of this response as my Exhibit___(LK-9).

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

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

> As part of the capital budgeting process, utilities will estimate the level of capital construction that will be undertaken during the year. Because of delays, weather conditions, or other events, the actual level of construction will often vary from the level budgeted. The difference between the actual and budgeted levels is reflected in the calculation of a "slippage factor," which serves as an indicator of the utility's accuracy in predicting the cost of its utility plant additions and when new plant will be placed into service. The Commission has routinely applied a slippage factor in the forward-looking test period rate cases for Kentucky-American Water Company. The Commission has usually utilized a slippage factor calculated by determining the annual slippage during the most recent 10-year period and then calculating the mathematic average of the annual slippage factors. The slippage factor is normally applied to the utility plant in service balance and the construction work in progress ("CWIP") balance to determine the slippage adjustment.[17] (footnote omitted).

Similarly, in its order in Case No. 2004-00103, the Commission applied a slippage factor adjustment to the capital expenditures in the forecast test year. It described the slippage factor "as an indicator of Kentucky-American's accuracy in predicting the cost of its utility plant additions."[18]

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

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

A. In this proceeding, KU calculated quantified a 95.373% weighted average slippage factor based on its actual experience compared to budget/forecast for the ten years 2008-2016.[19] LG&E calculated a 96.400% weighted average slippage factor based on its actual experience for the same ten years.[20]

Q. What is your recommendation?

A. If the Commission does not cap capital expenditures and plant additions based on recent inflation-adjusted and normalized actual experience, then I recommend that it apply the weighted average slippage factors calculated by the Companies to reduce their capitalization and revenue requirements. This is appropriate based on the Company's actual experience compared to budget/forecast and is consistent with Commission precedent.

Q. What are the effects of your recommendation?

A. If the weighted average slippage factor calculated by KU is applied to its forecast capital expenditures, it results in a reduction of $3.128 million in the Kentucky jurisdiction base revenue requirement.[21] If the weighted average slippage factor

[19] KU response to Staff 1-13(b).
[20] LG&E's response to Staff 1-13(b).
[21] In response to Staff 2-65, KU calculated a reduction in the jurisdictional revenue requirement of $2.686 million using a simple average slippage factor of 96.027%. I recalculated the reduction using the weighted average slippage factor.

calculated by LG&E is applied to its forecast capital expenditures, it results in a reduction of $1.650 million in the electric base revenue requirement.[22]

D. <u>Accumulated Depreciation Should Be Increased To Reflect Ash Pond Depreciation Inadvertently Not Recorded</u>

Q. Did the Companies inadvertently fail to record depreciation expense and the related increases in accumulated depreciation after the effective date of new base rates authorized in their last base rate proceedings?

A. Yes. The Companies inadvertently stopped recording depreciation expense for the ash ponds effective July 1, 2017, the effective date of the new base rates and new depreciation rates approved by the Commission in Case Nos. 2016-00370 and 2016-00371.[23]

The failure to record this depreciation expense since July 1, 2017 and through April 30, 2019 (until the beginning of the test year), has the effect of understating the accumulated depreciation expense and thus, overstating capitalization, and more specifically, overstating common equity due to the failure to record this depreciation expense for all months during the test year.

Q. What is your recommendation?

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[22] In response to Staff 2-75, LG&E calculated a reduction in the jurisdictional electric revenue requirement of $1.305 million using a simple average slippage factor of 97.153%. I recalculated the reduction using the weighted average slippage factor.

[23] KU response to KIUC 1-34 and LG&E response to KIUC 1-32. I have attached a copy of these responses as my Exhibit___(LK-10).

A. I recommend that the Commission reduce common equity capitalization by the error in accumulated depreciation. This is appropriate because earnings were overstated by this amount for the 22-month period. I recommend an increase in all components of capitalization for the related ADIT effects. This is appropriate because the ADIT represents income tax savings that displace the need for all forms of financing, not just debt and not just common equity.

Q. What are the effects of your recommendation?

A. The effect is a reduction in the KU revenue requirement of $0.394 million and a reduction in the LG&E revenue requirement of $0.040 million.

E. Capitalization Should Be Reduced to Correct Error In Companies' Calculations Of Thirteen Month Average Of Long-Term Debt

Q. Describe the error in the Companies' calculations of the thirteen-month average of long-term debt.

A. The Companies overstated the thirteen-month average of long-term debt and thus, the debt capitalization used for the return component of their revenue requirements. More specifically, the Companies failed to weight their forecast new debt issues in May 2019 for 12 months and instead included the new debt issues as if they were outstanding for the entire thirteen months used in the thirteen-month average. Consequently, the Companies included thirteen months, instead of twelve months, of interest on the new debt issues in their revenue requirements.

Q. Do the Companies agree that this was an error?

A. Yes.[24]

Q. Have you quantified the effects of this error?

A. Yes. The error overstated KU's revenue requirement by $0.944 million and overstated LG&E's revenue requirement by $1.393 million.

III. OPERATING INCOME ISSUES

A. KU's Revenues Are Understated Because They Do Not Include Revenues From The Start-Up of Phoenix Paper Wickliffe LLC In Early 2019

Q. Describe the start-up of Phoenix Paper Wickliffe LLC in early 2019.

A. There have been numerous press reports regarding the acquisition and planned start-up of a mill in Ballard County that was formerly owned and operated by Verso, before it was idled in late 2015 and then permanently closed in early 2016. The mill is located in KU's service territory. The mill was acquired in 2018 by Phoenix Paper Wickliffe LLC ("Phoenix"), which is upgrading the mill and converting it to produce kraft linerboard. The mill also will produce bleached hardwood and softwood pulp, as well as recycled pulp. Phoenix expects to start production in early 2019. The paper mill's annual peak demand was 50 MW and its annual load was 360 GWh prior to its shut down in 2015.[25]

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[24] KU response to KIUC 2-24 and LG&E response to KIUC 2-23. I have attached a copy of both responses as my Exhibit___(LK-11).

[25] According to KU's response to the Commission's June 22, 2017 Order in Case No. 2016-00370,

Q. Did KU include the Phoenix revenues in the test year?

A. No. It does not appear that these revenues are included in the test year. KIUC requested this specific information in discovery and KU declined to provide it in the following request and response.

> Q.2-25. For each month of the future test year, please provide the kwh sales, kVa billing demand and base revenue included for Phoenix Paper Wickliffe in Ballard County. Also, please identify the rate schedule for service to this customer.
>
> A.2-25. The Company does not share specific information about a Customer's account with third parties without the Customer's written authorization or unless legally required to do so. The response to KIUC 1-11 discusses large customer loads expected in the Future Test Year. Precisely when and at what level this customer might ultimately take service are unknown and uncertain.

Q. Should the Phoenix revenues be included in the test year?

A. Yes. The revenues are significant and will reduce the base revenue requirement for all other customers. If the revenues are not included in the test year, then the base revenue requirement for all other customers will be excessive and KU simply will retain the revenues until base rates are reset in its next base rate case proceeding.

Q. Have you quantified the Phoenix revenues?

A. Yes. The mill will provide $7.620 million in additional demand revenues that will reduce the base revenue requirement to all other customers, assuming that its peak demand is the same as it was prior to its shutdown in 2015. The mill will take service on the retail transmission service ("RTS") rate tariff, which has a three-tier demand rate as well as an energy rate. The revenue generated through the demand rate will provide a gross margin that will reduce the revenue deficiency for KU. I have assumed that the revenue generated through the energy rate equals the variable expenses incurred to serve this load and that the energy revenues will not provide a gross margin to reduce the revenue deficiency.[26]

B. <u>Off-System Sales Margins Are Volatile And OSS Sharing Should Be Modified To 90% Customers and 10% Companies</u>

Q. Describe the present OSS Adjustment Clause.

A. Prior to July 2015, the OSS margins were an offset to the base revenue requirement. Starting in July 2015, the OSS margins were removed from the base revenue requirement and the customer allocation of the OSS margins were included in OSS Adjustment Clause as the result of a settlement of the Companies base rate cases.

The OSS Adjustment Clause provides a sharing of off-system sales margins between the Companies and their customers. More specifically, the Companies retain 25% of the OSS margins and customers are allocated 75% of the OSS margins. The OSS margins allocated to customers are used to reduce the Fuel Adjustment Clause rates.

Q. What are the OSS margins forecast for the test year?

[26] Refer to my electronic workpapers filed contemporaneously with my testimony.

A. They are relatively small. The Companies forecast \$0.450 million for KU and \$1.337 million for LG&E,[27] although none of these margins are reflected in the base revenue requirement.

Q. How do these margins compare to prior years?

A. They are much less. In the base year, the KU OSS margins were \$4.144 million and the LG&E margins were \$14.529 million. In 2017, the KU OSS margins were \$0.839 million and the LG&E OSS margins were \$2.167 million. In 2016, the KU OSS margins were \$1.171 million and the LG&E margins were \$1.773 million.[28]

Q. Do you recommend a change to the OSS Adjustment Clause?

A. Yes. I recommend an increase in the allocation to customers from the present 75% to 90%. The 75% allocation was the result of a settlement in prior base rate proceedings and was not adjudicated. It would be reasonable to allocate 100% of the OSS margins to customers given that they pay 100% of the fixed costs of the assets used to generate the OSS margins, but a 10% allocation to the Companies arguably provides them an incentive to seek out OSS opportunities and to maximize the OSS margins.

Q. Does this recommendation have any effect on the base revenue requirement?

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[27] KU response to KIUC 1-77 and LG&E response to KIUC 1-66.
[28] *Id.*

A. No.

C. Fixed Purchased Power Expense Is Volatile And Changes Should Be Reflected In A Purchased Power Adjustment Rider

Q. Describe the forecast capacity-related purchased power expense included in the Companies' filings.

A. The only capacity-related purchased power expenses included in the Companies' base revenue requirements are demand charges from OVEC incurred pursuant to the OVEC Inter-Company Power Agreement ("ICPA"). KU included $11.352 million and LG&E included $27.272 million for OVEC demand purchased power expense.[29] These amounts represent increases compared to prior years. In the base year, KU incurred $8.372 million and LG&E incurred $21.504 million. In 2017, KU incurred $7.658 million and LG&E incurred $19.671 million. In 2016, KU incurred $6.725 million and LG&E incurred $17.278 million. In 2015, KU incurred $7.022 million and LG&E incurred $18.046 million.[30]

Q. What is the reason for the increase in the test year?

A. The Companies forecast that OVEC will increase its monthly demand charge in

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[29] KU response to Staff 2-45 and LG&E response to Staff 2-54. I have attached a copy of both responses as my Exhibit___(LK-12).

[30] KU response to KIUC 1-76 and LG&E response to KIUC 1-65. I have attached a copy of both responses as my Exhibit___(LK-13). I note that the amounts for LG&E are only for the OVEC demand purchased power expense to ensure comparability. The Bluegrass tolling agreement between LG&E and East Kentucky Power Cooperative, which began in May 2015, will terminate at the end of April 2019 and is not included in the test year expense.

November 2018 to include advance billing for recovery of certain debt repayments that are due in 2019 and 2020 (commencing approximately one year in advance of the repayment dates). KU's share of the advance billing is $5.2 million and LG&E's share is $11.7 million. Presumably, the demand purchased power expense will decline after the advance recovery is completed.

Q. **Is it appropriate to include a one-time increase in the OVEC demand purchased power expense in the test year revenue requirement?**

A. No. unless there is a means of reducing rates when the OVEC demand purchased power expense declines, such as a Purchased Power Adjustment ("PPA") rider. Otherwise, the increase should be deferred and amortized over three years to ensure that the Companies do not continue to recover expenses at a level greater than it incurs.

Q. **Are these "fixed" expenses sufficiently volatile to justify a PPA rider to refund or recover expenses that are less or more than the amount included in base rates?**

A. Yes. The recent history suggests that the OVEC purchased power expense will increase and then decline, while other expenses, such as the Bluegrass PPA, will be incurred for limited periods of time and then terminate.

Q. **What is your recommendation?**

A. I recommend that the Commission adopt a new PPA rider to recover or refund purchased power expense that is more or less than what is recovered in the base revenue requirement in this proceeding. This would include changes in other purchased power expense due to forced outages that are not recoverable through the fuel adjustment clause.

Q. Is there any effect of your recommendation on the revenue requirements in this proceeding?

A. No. However, if the Commission does not adopt a new PPA rider, then I recommend a reduction in the test year OVEC demand purchased power expense to reflect the base year expense plus one-third of the forecast increase in this expense in the test year. This would be coupled with a deferral of the remaining actual increase in the test year and continuing into each subsequent year until base rates are reset.

Q. How should the PPA rider expense be allocated?

A. I recommend that it be allocated in the same manner that fixed purchased power expense is allocated in base rates.

D. Refunds And Ongoing Savings From A Successful FERC Complaint To Eliminate Merger Mitigation De-pancaking Transmission Rates Should Be Deferred As A Regulatory Liability

Q. Describe the Companies' complaint before the FERC to eliminate merger mitigation de-pancaking ("MMD") transmission rate subsidies.

A. On August 3, 2018, the Companies filed a Joint Application at the FERC seeking to remove the MMD component of transmission Rate Schedule No. 402 ("RS 402").[31] That mechanism provides subsidized transmission service to RS 402 customers and allows them to avoid Midwest Independent System Operator, Inc. ("MISO") transmission charges when buying power sourced in MISO and KU/LG&E transmission charges when selling power into MISO. The MMD mechanism was initially adopted to address horizontal market power concerns stemming from the Companies' 1998 merger. However, the complaint asserts that market conditions have fundamentally changed since 1998, rendering the MMD mechanism no longer just and reasonable.

Q. Are these MMD expenses included in the Companies' revenue requirements?

A. Yes. These subsidies to the municipals and certain other customers are included in transmission expenses in the retail revenue requirement in these proceedings. The Companies state the following in their Application at the FERC:

> Exacerbating the cost-causation problems associated with MMD is the fact that the costs not borne by RS 402 Customers are shifted to LG&E/KU's other customers. A small portion of the MMD costs (reimbursing RS 402 Customers for MISO charges, plus lost LG&E/KU system charges) flow through the companies' Attachment O formula transmission rate. Approximately 80 percent of the MMD costs are borne by LG&E/KU's retail customers through rates approved by their state regulators.

Q. What is the MMD expense included in each Company's revenue requirement in these proceedings?

A. KU included $15.1 million and LG&E included $9.0 million in their revenue

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[31] *Joint Application Under FPA Section 203 and Section 205 of Louisville Gas and Electric Company and Kentucky Utilities Company*, FERC Docket Nos. EC98-2-00 and ER18-2162-000.

requirements.[32] These amounts reflect increases of $8 million for KU and $5 million for LG&E in the test year compared to the base year.[33]

Q. If the Companies are successful in their complaint, what will be the outcome?

A. There will be both a refund for the refund effective period that commenced with the filing of the complaint and an ongoing reduction in expense due to the elimination of the subsidies to the transmission customers.

Q. What is your recommendation?

A. I recommend that the Commission direct the Companies to defer all refunds and ongoing savings as a regulatory liability for disposition in a future base rate proceeding.

E. <u>Brown 1 And 2 One-Time Retirement Expenses Should Be Removed Or Deferred</u>

Q. Describe the Brown 1 and 2 retirement expenses that KU included in its revenue requirement.

A. KU included a one-time expense of $0.297 million to repair the Brown 1 stack. KU describes this one-time expense as follows:

> The $297k budgeted in the Test Year is to repair Brown Unit 1's stack to ensure its structural integrity. The structural integrity of the stack is required

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[32] Response to Lexington-Fayette Urban County Government 1-49. I have attached a copy of this response as my Exhibit___(LK-14).

[33] Direct Testimony of Kent Blake at 11.

> to facilitate employee safety and prevent damage to other assets / areas that will remain operational after the retirement of Brown Unit 1 and Brown Unit 2.

Q. Should this expense be included in the revenue requirement?

A. No. It is a non-recurring expense. If it is included in the revenue requirement, then KU will recover the expense again and again each year until its base rates are reset. If KU's base rates are reset in three years, then it would recover $0.891 million, or three times its actual expense. That is not reasonable.

Q. What is your recommendation?

A. I recommend that the Commission direct KU to defer the expense and seek recovery in a future proceeding.

F. Brown 1 And 2 Post-Retirement Employee Payroll And Contract Labor Expenses Should Be Removed From Test Year Expenses Or Deferred As Retirement Expenses, Not Reclassified As Brown 3 Expenses

Q. Did KU remove the Brown 1 and 2 pre-retirement payroll expense from the test year?

A. No. KU reflected only minimal reductions in the full-time equivalent employees ("FTE") and payroll expense in the test year compared to the base year to reflect the retirement of Brown 1 and 2 in February 2019. The following table provides a comparison of the Brown FTE employees for all three units and the related payroll expenses by unit prior to and after the Brown 1 and 2 retirements in February

2019.[34]

Kentucky Utilities Company					
Headcount and Payroll Related O&M Expense					
Brown Units 1, 2, and 3					
$					
	All Units Avg FTEs	Brown Unit 1 Labor Related O&M Expense	Brown Unit 2 Labor Related O&M Expense	Brown Unit 3 Labor Related O&M Expense	Total Brown Labor Related O&M Expense
2015	118	1,808,474	2,040,080	12,069,913	15,918,466
2016	123	1,666,553	2,337,517	11,847,604	15,851,675
2017	118	2,583,044	3,684,673	9,188,840	15,456,557
Base Year	109	2,272,177	3,434,620	8,771,004	14,477,801
Test Year	107	-	-	13,010,232	13,010,232

KU forecasts a reduction of only 2 FTE employees for the Brown Plant in total after Brown 1 and 2 are retired in February 2019. It reclassified and added the Brown 1 and 2 payroll expense for the remaining Brown 1 and 2 FTE employees to the Brown 3 payroll expense starting in March 2019, which it continued through the end of the test year.

Q. Did KU remove the Brown 1 and 2 pre-retirement contract labor expenses from the test year?

A. No. KU reflected a greater reduction in contract employees than in FTE employees, but nevertheless reflected an increase in total contract labor expense. The following

[34] Response to KIUC 1-72. I have attached a copy of this response as my Exhibit___(LK-15).

table provides a comparison of the Brown FTE contract employees and the related contract labor expenses incurred prior to and after the Brown 1 and 2 retirements in February 2019.[35]

Kentucky Utilities Company
Headcount and Contractor O&M Expense
Brown Units 1, 2, and 3
$

	All Units Avg FTEs	Brown Unit 1 Contractor O&M Expense	Brown Unit 2 Contractor O&M Expense	Brown Unit 3 Contractor O&M Expense	Total Brown Contractor O&M Expense
2015	-	318,302	392,772	1,290,742	2,001,816
2016	-	375,484	541,050	1,611,641	2,528,175
2017	51	254,963	386,228	976,929	1,618,120
Base Year	52	322,590	503,276	1,301,161	2,127,026
Test Year	41	-	-	2,499,131	2,499,131

KU forecasts a reduction of only 11 contract employees, but an increase in contract labor expense after February 2019. Similar to its approach with its own employees, KU reclassified and added the remaining contract employees and contract labor expenses to the Brown 3 contract labor expense starting in March 2019, which it continued through the end of the test year.

Q. **Are the forecast employee payroll and contract labor expenses reasonable for Brown 3?**

A. No. It is not reasonable to assume that it will take almost the same number of FTE employees and contract employees to operate and maintain Brown 3 as it did to

[35] Attachment to Filing Requirement 807 KAR 5:0001 Section 16(7)(c) page 22.

operate and maintain Brown 1, 2, and 3. KU reflected a net reduction of only 12 FTE employees and contract employees, from 161 in the base year to 149 in the test year.

If, in fact, there will be only a small reduction in total employees, it is quite likely that many of them will be engaged in Brown 1 and 2 post-retirement activities, as was the case when KU retired Green River and sought recovery of these expenses as ongoing operation and maintenance expenses in its rate case filing. If that is the case, then the expenses should be deferred and recovered over a reasonable amortization period, similar to the ratemaking treatment authorized for the Green River expenses.

Q. What is your recommendation?

A. I recommend that the Commission reduce the claimed Brown 3 employee payroll and contract labor expenses by 20% compared to the combined payroll and contract labor expenses in the base year. The base year is a reasonable starting point because all three units were operating in that year. In the base year, the Brown 1 and 2 payroll and contract labor expenses were approximately 40% of the total Brown plant payroll and contract labor expense. KU should be able to eliminate at least half of that payroll and contract labor expense.

Alternatively, if all or some of the expenses will be incurred for Brown 1 and 2 post-retirement activities, then I recommend that the Commission direct KU to defer the expenses and seek recovery in a subsequent base rate proceeding.

Q. What is the effect of your recommendation?

A. The effect is a reduction in the KU revenue requirement of $2.098 million. The reduction compared to the base year at 20% would be $3.321 million (total Company). The Company reflected a reduction of only $1.096 million (total Company). The incremental reduction in the test year expense would be $2.225 million (total Company) or $2.087 million (Kentucky jurisdictional).

G. Generation Outage Expense Should Be Normalized Based On Inflation-Adjusted Historic Actual Expenses, Not On A Combination of Historic Actual And Multi-Year Forecast Expenses

Q. Describe the Companies' proposal to normalize generation outage expense.

A. The Companies calculated normalized generation outage expense based on an average of four years of actual expense and four years of forecast expense, and propose to defer actual generation outage expenses that exceed or are less than the amount allowed in the base revenue requirement as either a regulatory asset or liability. The Companies also propose an amortization of any regulatory asset or liability balance over eight years on a rolling basis.

Q. Has the Commission ever adopted this calculation as the result of an adjudication?

A. No. The Companies' proposed calculation incorrectly relies on the perpetuation of one term of a settlement adopted in Case Nos. 2016-00370 and 2016-00371. The terms of that settlement were limited to those proceedings and are not precedential.

I do not agree with the calculation described in that settlement, except as a compromise among the parties to achieve an overall settlement of all issues for the purpose of those proceedings. The calculation in the settlement was solely the product of settlement negotiations; it was not proposed by the Companies in their filing or testimony or proposed by any other party.

In my Direct Testimony in the prior cases, I noted that the generation outage expense in the test year was abnormally high and recommended a normalized expense calculated as the simple average of the most recent five years of historic actual expenses.

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

A. The Companies' generation outage expense in the test year is unusually high compared to their recent actual expense. More specifically, KU's forecast generation outage expense is $44.889 million in the test year (before its proposed eight-year normalized average) compared to $23.504 million in the base year, $14.182 million in 2017, $16.039 million in 2016, $24.677 million in 2015, $22.891 million in 2014, and $8.921 million in 2013. These amounts are on a total Company basis and include outage expenses for units that have since been retired.[36] I would note that KU's forecast generation outage expense includes $21.7 million

[36] KU response to KIUC 1-61. I have attached a copy of this response as my Exhibit___(LK-16).

in March 2020 and April 2020, the last two months of the test year.[37]

LG&E forecast generation outage expense is $23.774 million in the test year (before its proposed eight-year normalized average) compared to $17.317 million in the base year, $15.528 million in 2017, $12.895 million in 2016, $9.429 million in 2015, $12.113 million in 2014, and $14.707 million in 2013.[38] I would note that KU's forecast generation outage expense includes $7.818 million in March 2020 and April 2020, the last two months of the test year.[39]

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

A. The difference is due primarily to the number and scope of the outages planned in the test year. In the test year, the Companies plan an increase in major outage activity compared to 2018 or in the years after the test year. In 2018, the Companies performed turbine overhauls at Ghent 3, Mill Creek 2, and Trimble 2 (HP rotor and IP rotors). In 2019, the Companies plan turbine overhauls at Brown 3, Ghent 2, Mill Creek 1, Mill Creek 3, and Trimble 2 (both LP rotors). In 2020, the Companies plan turbine overhauls at Trimble 2 (generator) and Ghent 4. In 2021, they plan a turbine overhaul at Ghent 1. In 2022, they plan a turbine overhaul at Mill Creek 4. Finally, in 2023, they plan no major turbine overhauls.[40]

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[37] KU response to KIUC 1-80. I have attached a copy of this response as my Exhibit___(LK-17).

[38] LG&E response to KIUC 1-53. I have attached a copy of this response as my Exhibit___(LK-18).

[39] LG&E response to KIUC 1-69. I have attached a copy of this response as my Exhibit___(LK-19).

[40] Attachment to Filing Requirement 807 KAR 5:001 Section 16(7)(c)(1) page 4 of 235. I have

Q. Is it reasonable to normalize generation outage expense?

A. Yes. There is significant variation from year to year depending on the number outages and the scope of the maintenance that is performed each year.

Q. Is the Company's proposal to normalize the expense using four years of actual and four years of forecast expense reasonable?

A. No. A single forecast test year presents significant challenges for the Commission and other parties in their reviews due to the fundamental uncertainty of the future and due to the inherent incentive for a utility to understate its forecast revenues and overstate its forecast costs (capitalization/rate base and expenses). Adding additional forecast years magnifies these problems and completely violates any rational concept of a single integrated test year. This is clearly demonstrated by the fact that the Companies' forecasts of outage expenses beyond the test year do not decline in magnitude compared to their planned outage schedules that indicate fewer outages in the later forecast years. This is further demonstrated by the Companies' history of modifying their outage schedules and the scope of their outages in their annual planning based on a variety of reasons.

Q. Is there a better methodology to normalize the outage expense?

A. Yes. An inflation-adjusted average of historic actual outage expense provides a better estimate of future outage expense because it properly captures the actual

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attached a copy of this page as my Exhibit___(LK-20).

expenses incurred over the major outage and overhaul cycle stated in future dollars that will be spent in future years when the cycle is repeated.

Q. Does the Companies' proposed true-up mechanism whereby they defer the difference between the allowed outage expense and actual outage expense and then amortize the regulatory asset or liability over eight years provide inappropriate behavioral incentives?

A. Yes. This methodology first incentivizes the Companies to forecast high on their forecast outage expenses in order to provide a high target spending threshold. It then allows the Companies to incur any amount of outage expense because they simply are able to defer it and then recover the deferred amount in future rate cases, as is the case in these proceedings. In fact, under their proposed methodology, KU forecasts a deferral of $20.411 million (total Company) and LG&E forecasts a deferral of $15.239 million as of April 30, 2020.[41]

Q. Is there a better ratemaking approach to incentivize the Companies to minimize the reasonable outage expense through prioritization of maintenance activities and adoption of best practices and efficiencies?

A. Yes. The Commission should deny the Companies' request for a true-up of their outage expenses and authorization for the related deferrals. Without guaranteed

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[41] Attachment to KU response to KIUC 1-56 page 7 of 7 and Attachment to LG&E response to KIUC 1-49 page 7 of 7.

recovery of excessive outage expenses, the Companies will be incentivized to minimize the reasonable outage expense, an appropriate regulatory objective.

Q. What is your recommendation?

A. I recommend that the Commission normalize the generation outage expense in the test year by using the inflation-adjusted most recent historical actual five-year average in lieu of the proposed average of historic and forecast expense.[42] In this manner, the Companies will recover less than their unusually high forecast outage expense in the test year, but more than their actual costs in the years after the test year when they forecast fewer outages. The idea is to normalize based on actual expenses, not to maximize based on continuing unusually high forecast outage expense beyond the test year.

Q. What are the effects of your recommendation?

A. The effects are a reduction in the KU revenue requirement of $6.734 million and in the LG&E revenue requirement of $1.775 million. I used a 2.0% annual inflation rate for this purpose, consistent with recent actual experience and forecasts for CPI.

<u>H. Credit Card Rebates Should Be Used to Reduce Customer Service Expense</u>

Q. Do the Companies use credit cards that provide rebates?

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[42] I also recommend removing the outage expense for generating units that have since been or will be retired from the historical actual outage expense.

A. Yes. The rebates are recorded in account 921 *Office Supplies and Expenses*. KU received $0.206 million (total Company) in rebates in 2016 and $0.211 million (total Company) in 2017.[43] LG&E received $0.237 million in rebates in 2016 (electric and gas) and $0.243 million in 2017 (electric and gas).[44]

Q. Did the Company reflect any credit card rebates in the test year expenses and revenue requirement?

A. No.[45]

Q. What is your recommendation?

A. I recommend that the Commission include the rebates as a reduction to the revenue requirement based on the actual 2017 rebates, the most recent information available when the Companies prepared their discovery responses on this issue.

I. Employee Retirement Benefits Expense Should Be Reduced To Reflect Commission Precedent

Q. Describe the disallowance of certain retirement benefits expense by the Commission in Case Nos. 2016-00370 and 2016-00371.

A. In those Orders, the Commission disallowed certain retirement plan expenses for those employees who participated in both a defined benefit pension plan and

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[43] KU response to AG 1-84. I have attached a copy of this response as my Exhibit___(LK-21).
[44] LG&E response to AG 1-84. I have attached a copy of this response as my Exhibit___(LK-22).
[45] KU response to AG 1-84 and LG&E response to AG 1-84.

received matching contributions pursuant a 401(k) retirement plan.

Q. Did the Companies quantify the disallowance of retirement benefits expense if the Commission applies the same methodology in these proceedings?[46]

A. Yes. However, they did not reflect these disallowances in their revenue requirements. KU quantified a disallowance of $2.019 million in expense and LG&E quantified a disallowance of $1.370 million in expense.[47] The revenue requirements associated with these disallowances amounted to $2.029 million and $1.375 million for KU and LG&E (electric), respectively.

J. <u>Depreciation Expense Should Be Reduced to Correct Calculation Error In Depreciation Expense for Brown 1 and 2 Ash Pond Costs</u>

Q. Did KU use an incorrect depreciation rate in its calculation of depreciation expense for the Brown 1 and 2 ash pond costs included in Account 312.1?

A. Yes. KU acknowledged this error and provided the correct monthly depreciation expense in response to KIUC discovery.[48]

More specifically, KU proposed depreciation rates of 0% and 7.82% for the Brown 1 and 2 ash pond costs included in Account 312.1, respectively.[49] The

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[46] I note that the Commission subsequently addressed this issue in Case No. 2017-00321 involving Duke (electric). It is not clear if, or if so, how, the decision in the Duke case may affect the issue or the quantification of the issue in this proceeding.

[47] KU response to KIUC 1-60 and LG&E response to KIUC 1-52. I have attached a copy of each response as my Exhibit___(LK-23).

[48] KU response to KIUC 1-35. I have attached a copy of this response as my Exhibit___(LK-24).

[49] Exhibit JJS-KU-1 at page VI-4.

weighted average depreciation rate for both units together is 2.32%. However, in its calculation of depreciation expense, KU incorrectly used a 24.68% depreciation rate.[50] This overstated depreciation expense by $2.954 million (total Company) or $2.765 million (Kentucky jurisdiction) in the test year. Correcting the error reduces the revenue requirement by $2.779 million for KU.

K. Depreciation Rates And Expense Should Be Reduced To Reflect 65-Year Planning Life For Coal-Fired Generating Units

Q. Describe the service life for coal-fired generating units used by the Companies for resource planning purposes.

A. The Companies assume a service life of 65 years for their coal-fired generating units for resource planning purposes. They clearly state this assumption in their 2019 Business Plan prepared by the Generation Planning & Analysis department.[51]

Q. Did the Companies reflect the 65-year service life planning assumption in their depreciation studies?

A. No. The Companies apparently directed Mr. Spanos to use shorter service lives based on a subjective review that they now describe as an "engineering analysis," which resulted in "the retirement date occurring at the lower end of the industry life

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[50] Refer to Att_KU-PSC_1-65_Depreciation_Exp_Wkpr provided in response to Staff 1-65 at cell row 66.

[51] Refer to Companies filings in Tab 16 of 807 KAR5:001 Section 16(7)(c). I have attached a copy of the relevant pages from KU's filing.

span range for coal units."[52] The so-called "engineering analysis" is simply a listing of factors that may affect the actual lives of generating units, but does not provide any specific analysis as to why the Companies' coal-fired generating units will not continue to operate for 65 years or longer.[53] The Companies will continue to operate their coal-fired units as long as they remain economic compared to alternative supply resources.

Q. Is there evidence that the Companies' coal-fired units may continue to operate beyond a 65-year service life?

A. Yes. The Companies are both owners of OVEC and purchase power from OVEC pursuant to the Inter-Company Power Agreement. OVEC owns the Clifty Creek and the Kyger Creek power plants. The Companies have both the right and obligation to purchase their respective ownership shares of the capacity and energy from both plants.

The Clifty Creek power plant consists of six units, the first five of which were placed in commercial operation in 1955 and the sixth of which was placed in commercial operation in 1956. The Kyger Creek power plant consists of five units, all of which were placed in commercial operation in 1955. All of the units have been in service now for 62-63 years.[54]

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[52] KU response to KIUC 1-33 and LG&E response to KIUC 1-30. I have attached a copy of both responses as my Exhibit___(LK-25).

[53] KU responses to US DOD 1-29(a) and US DOD 2-2. I have attached a copy of these responses as my Exhibit___(LK-26).

[54] SNL Services. I have attached a copy of the power plant profile data reflected in this database as my Exhibit___(LK-27).

In 2011, the Companies entered into an amended Inter-Company Power Agreement with OVEC and obtained approval of the amended agreement from the Commission in Case Nos. 2011-00099 and 2011-00100. The Commission stated the following in its Order in those proceedings:

> OVEC and its owners have entered into an amended ICPA, which extends the term an additional 14 years, through June 30, 2040. . . At the time of the previous extension of the ICPA, OVEC commissioned an independent engineering assessment of the remaining lives and production capabilities, environmental remediation, and decommissioning of its generating facilities. At OVEC's request, that assessment has been updated since the filing of LG&E's and KU's applications. The results of the updated assessment indicate that, largely due to the generating units having been nearly always operated in a base load mode, with limited thermal cycles of the equipment, the units are expected to be operational at or near their historic operating levels through the term of the ICPA extension, until mid 2040.

If the Clifty Creek and Kyger Creek power plants are operated through June 30, 2040, as forecast by the Companies, they will have actual service lives of 84-85 years, well in excess of even the 65-year service life used by the Companies for resource planning purposes.

Q. What is your recommendation?

A. I recommend that the Commission use 65-year lives to set the depreciation rates for the Companies' coal-fired units.

Q. What are the effects of your recommendation?

A. The effects are a reduction in KU's revenue requirement of $26.933 million and a reduction in LG&E's revenue requirement of $12.007 million.

L. Depreciation Rates And Expense Should Not Be Increased To Reflect Shorter Life for Ash Ponds

Q. Describe KU's proposal to increase the depreciation rates by shortening the depreciation lives for the Brown 1, 2, and 3 ash ponds, Ghent 1 ash pond, Ghent 4 ash pond, and the Trimble 2 ash pond and LG&E's proposal to shorten the depreciation lives for the Mill Creek 1 ash pond, Mill Creek 3 ash pond, Trimble 1 ash pond, and Trimble 2 ash pond.

A. The Companies propose to significantly increase the depreciation rates by shortening the depreciation lives for these ash ponds to using the forecast pond closure dates to determine the remaining lives. In their last depreciation studies, the Companies proposed depreciation lives for the ash ponds based on the probable retirement dates for the generating units, not the forecast pond closure dates.[55]

Q. What effect does the Companies' proposal have on the depreciation expense for these ash ponds?

A. The proposal increases KU's depreciation expense by $7.744 million and LG&E's depreciation expense by $0.562 million.

Q. Is there any requirement under GAAP that the Commission increase the depreciation rates to reflect the forecast closure dates?

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[55] KU response to US DOD 1-29(b) and LG&E response to US DOD 1-10(b) provide a comparison of the proposed probable retirement dates for the ash ponds compared to the approved probable retirement dates. I have attached a copy of these responses as my Exhibit___(LK-28).

A. No. This is a matter of regulatory policy, not a GAAP requirement.

Q. As a matter of regulatory policy, should the Commission shorten the depreciation lives to reflect the forecast closure dates?

A. No. I recommend that the Commission set depreciation rates to recover the remaining net book value over the remaining lives of the generating units, consistent with the Companies' prior depreciation studies. There is no compelling reason to increase the depreciation rates and accelerate the recovery of the remaining costs given the fundamental fact that the Companies will recover these costs as well as a return on those costs until they are fully recovered.

Q. What are the effects of your recommendation?

A. The effects are a reduction in KU's revenue requirement of $7.785 million and a reduction in LG&E's revenue requirement of $0.564 million.

IV. COST OF CAPITAL ISSUES

A. Reduce Cost of Long-Term Debt to Reflect Current 30 Year Treasury Yield for May 2019 Issuance

Q. Describe the Companies' proposed cost for the forecast May 2019 debt issuances reflected in their calculations of the weighted average cost of long-term debt.

A. The forecast KU capitalization includes a new 30-year debt issuance of $300 million in May 2019 at a coupon rate of 4.90%.[56] The forecast LG&E capitalization includes a new 30-year debt issuance of $500 million in May 2019 at a coupon rate of 4.90%.[57]

Q. How did the Companies forecast the proposed 4.90% interest rate?

A. The Companies added a credit spread of 1.25% to a forecast rate of 3.65% for the 30-year Treasury yield.[58]

Q. Is the forecast rate of 3.65% for the 30-year Treasury yield still reasonable?

A. No. 30-year Treasury yields have fallen since the Companies filed their cases. The 30-year Treasury yield now is 3.0%.[59]

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[56] KU filing Schedule J-3.

[57] LG&E filing Schedule J-3.

[58] KU response to KIUC 1-75 and LG&E response to KIUC 1-64. I have attached a copy of both responses as my Exhibit___(LK-29).

[59] Wall Street Journal January 10, 2019.

Q. What is your recommendation for the forecast coupon rate on the Companies new debt issuances?

A. I recommend that the Commission use a coupon rate of 4.25% for the new debt issues to reflect the present 30-year Treasury yield of 3.0% plus the Company's proposed credit spread of 1.25%.

Q. What are the effects of your recommendation?

A. The effects are a reduction in KU's revenue requirement of $1.334 million and a reduction in LG&E's revenue requirement of $1.709 million, using the capitalization for each Company after KIUC's recommended adjustments.

B. Reduce Return on Equity

Q. Have you performed an independent study of the required return on equity?

A. No. KIUC has not retained an expert to perform an independent study of the required return on equity.

Q. Have you reviewed the testimony of Companies' witness Mr. Adrien McKenzie?

A. Yes. Mr. McKenzie recommends a return on equity of 10.42%. Mr. McKenzie utilized various methodologies to develop his recommendation, including the discounted cash flow ("DCF"), capital asset pricing model ("CAPM"), risk premium, and expected earnings. In addition, he added flotation costs to the results derived from these methodologies.

Q. What methodology has the Commission's historically relied on for the return on equity?

A. The Commission historically has relied on the DCF methodology and has not relied on the results of the CAPM, risk premium, or other methodologies. More recently, the Commission has cited and given consideration to the returns on equity allowed by other regulatory commission as a guide to the required rate of return. Further, the Commission historically has rejected utility requests to add flotation costs to increase the required rate of return.[60]

Q. What is the range of Mr. McKenzie's DCF results without flotation costs?

A. The range of Mr. McKenzie's DCF results without flotation costs is 9.4% to 10.5%, with an average of 8.9% and a midpoint of 9.9%.[61]

Q. How do Mr. McKenzie's DCF results compare to other recently authorized returns on equity?

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[60] See Order, Case No. 2017-00321, *In Re Electronic Application of Duke Energy Kentucky, Inc. For: 1) An Adjustment of The Electric Rates; 2) Approval of An Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; And 5) All Other Required Approvals and Relief* (Ky. PSC Apr. 13, 2018) at 39.

[61] McKenzie Exhibit No. 5 page 3 of 3.

A. The average actual authorized electric returns on equity in general rate cases decided in 2017 was 9.68% and decided from January 2018 through September 2018 was 9.59%.[62]

Q. What is your recommendation?

A. I recommend that the Commission simply continue the present authorized 9.7% return on equity. This return is consistent with Mr. McKenzie's DCF results without flotation costs and is consistent with recently authorized returns for other electric utilities in 2017 and 2018.

Q. What are the effects of your recommendation?

A. The effects are a reduction in KU's revenue requirement of $19.908 million and a reduction in LG&E's revenue requirement of $12.643 million, using the capitalization for each Company after KIUC's recommended adjustments.

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

A. Yes. For KU, each 1.0% return on equity equals $27.649 million in revenue requirements. For LG&E, each 1.0% return on equity equals $17.560 million in

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[62] KU response to Staff 2-39 and LG&E response to Staff 2-47. I have attached a copy of KU's response as my Exhibit___(LK-30).

revenue requirements. These quantifications reflect the capitalization for each Company after KIUC's recommended adjustments.

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
16th day of January 2019.

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
JULY 31, 2019
CHEROKEE COUNTY, GEORGIA

BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	)))	**CASE NO. 2018-00294**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	)))	**CASE NO. 2018-00295**

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

JANUARY 2019

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 December 2018**

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.

Expert Testimony Appearances
of
Lane Kollen
As of December 2018

Date	Case	Jurisdict.	Party	Utility	Subject
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric Corp.	Financial workout plan.
5/88	M-87017-1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
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.

**Expert Testimony Appearances
of
Lane Kollen
As of December 2018**

Date	Case	Jurisdict.	Party	Utility	Subject
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
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.

**Expert Testimony Appearances
of
Lane Kollen
As of December 2018**

Date	Case	Jurisdict.	Party	Utility	Subject
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Recovery of CAAA costs, least cost financing.
9/91	91-231-E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	PUC Docket 10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
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	8469	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.

Expert Testimony Appearances
of
Lane Kollen
As of December 2018

Date	Case	Jurisdict.	Party	Utility	Subject
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base.
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
3/93	93-01-EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission	Gulf States Utilities /Entergy Corp.	Merger.
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.
11/94	U-19904 Initial Post-Merger Earnings Review (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.
6/95	3905-U Rebuttal	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
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.

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

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

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10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735 Rebuttal	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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
7/99	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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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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Date	Case	Jurisdict.	Party	Utility	Subject
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.

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

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

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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 Healthcare 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.
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 (Subdocket B)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.

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03/06	NOPR Reg 104385-OR	IRS	Alliance for Valley Health Care and Houston Council for Health Education	AEP Texas Central Company and CenterPoint Energy Houston Electric	Proposed Regulations affecting flow- through to ratepayers of excess deferred income taxes and investment tax credits on generation plant that is sold or deregulated.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	2002-2004 Audit of Fuel Adjustment Clause Filings. Affiliate transactions.
07/06	R-00061366, Et. al.	PA	Met-Ed Ind. Users Group Pennsylvania Ind. Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of NUG-related stranded costs, government mandated program costs, storm damage costs.
07/06	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
08/06	U-21453, U-20925, U-22092 (Subdocket J)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
11/06	05CVH03-3375 Franklin County Court Affidavit	OH	Various Taxing Authorities (Non-Utility Proceeding)	State of Ohio Department of Revenue	Accounting for nuclear fuel assemblies as manufactured equipment and capitalized plant.
12/06	U-23327 Subdocket A Reply Testimony	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
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.

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05/07	ER07-682-000 Supplemental Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and account 924 effects on MSS-3 equalization remedy payments and receipts.
06/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC, Entergy Gulf States, Inc.	Show cause for violating LPSC Order on fuel hedging costs.
07/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Revenue requirements, post-test year adjustments, TIER, surcharge revenues and costs, financial need.
07/07	ER07-956-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Storm damage costs related to Hurricanes Katrina and Rita and effects of MSS-3 equalization payments and receipts.
10/07	05-UR-103 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	05-UR-103 Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	25060-U Direct	GA	Georgia Public Service Commission Public Interest Adversary Staff	Georgia Power Company	Affiliate costs, incentive compensation, consolidated income taxes, §199 deduction.
11/07	06-0033-E-CN Direct	WV	West Virginia Energy Users Group	Appalachian Power Company	IGCC surcharge during construction period and post-in-service date.
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.

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

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

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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 Answer	CO	CF&I Steel, Rocky Mountain Steel Mills LP, Climax Molybdenum Company	Public Service Company of Colorado	Forecasted test year, historic test year, proforma adjustments for major plant additions, tax depreciation.
09/09	6680-UR-117 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Power and Light Company	Revenue requirements, CWIP in rate base, deferral mitigation, payroll, capacity shutdowns, regulatory assets, rate of return.
10/09	09A-415E Answer	CO	Cripple Creek & Victor Gold Mining Company, et al.	Black Hills/CO Electric Utility Company	Cost prudence, cost sharing mechanism.
10/09	EL09-50 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
10/09	2009-00329	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Trimble County 2 depreciation rates.
12/09	PUE-2009-00030	VA	Old Dominion Committee for Fair Utility Rates	Appalachian Power Company	Return on equity incentive.

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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.
04/10	2009-00548, 2009-00549	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.

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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.
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.

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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.
10/11	11-4571-EL-UNC 11-4572-EL-UNC	OH	Ohio Energy Group	Columbus Southern Power Company, Ohio Power Company	Significantly excessive earnings.

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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.

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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.

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07/13	2013-00221	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Hawesville Smelter market access.
10/13	2013-00199	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.
12/13	2013-00413	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Sebree Smelter market access.
01/14	ER10-1350 Direct and Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 lease accounting and treatment in annual bandwidth filings.
02/14	U-32981	LA	Louisiana Public Service Commission	Entergy Louisiana, LLC	Montauk renewable energy PPA.
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.

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As of December 2018**

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

**Expert Testimony Appearances
of
Lane Kollen
As of December 2018**

Date	Case	Jurisdict.	Party	Utility	Subject
07/15	EL10-65 Direct and Answering Consolidated Bandwidth Dockets	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback ADIT, Bandwidth Formula.
09/15	14-1693-EL-RDR	OH	Public Utilities Commission of Ohio	Ohio Energy Group	PPA rider for charges or credits for physical hedges against market.
12/15	45188	TX	Cities Served by Oncor Electric Delivery Company	Oncor Electric Delivery Company	Hunt family acquisition of Oncor; transaction structure; income tax savings from real estate investment trust (REIT) structure; conditions.
12/15 01/16	6680-CE-176 Direct, Surrebuttal, Supplemental Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Need for capacity and economics of proposed Riverside Energy Center Expansion project; ratemaking conditions.
03/16 03/16 04/16 05/16 06/16	EL01-88 Remand Direct Answering Cross-Answering Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Bandwidth Formula: Capital structure, fuel inventory, Waterford 3 sale/leaseback, Vidalia purchased power, ADIT, Blythesville, Spindletop, River Bend AFUDC, property insurance reserve, nuclear depreciation expense.
03/16	15-1673-E-T	WV	West Virginia Energy Users Group	Appalachian Power Company	Terms and conditions of utility service for commercial and industrial customers, including security deposits.
04/16	39971 Panel Direct	GA	Georgia Public Service Commission Staff	Southern Company, AGL Resources, Georgia Power Company, Atlanta Gas Light Company	Southern Company acquisition of AGL Resources, risks, opportunities, quantification of savings, ratemaking implications, conditions, settlement.
04/16	2015-00343	KY	Office of the Attorney General	Atmos Energy Corporation	Revenue requirements, including NOL ADIT, affiliate transactions.
04/16	2016-00070	KY	Office of the Attorney General	Atmos Energy Corporation	R & D Rider.
05/16	2016-00026 2016-00027	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Need for environmental projects, calculation of environmental surcharge rider.
05/16	16-G-0058 16-G-0059	NY	New York City	Keyspan Gas East Corp., Brooklyn Union Gas Company	Depreciation, including excess reserves, leak prone pipe.
06/16	160088-EI	FL	South Florida Hospital and Healthcare Association	Florida Power and Light Company	Fuel Adjustment Clause Incentive Mechanism re: economy sales and purchases, asset optimization.

Expert Testimony Appearances
of
Lane Kollen
As of December 2018

Date	Case	Jurisdict.	Party	Utility	Subject
07/16	160021-EI	FL	South Florida Hospital and Healthcare Association	Florida Power and Light Company	Revenue requirements, including capital recovery, depreciation, ADIT.
07/16	16-057-01	UT	Office of Consumer Services	Dominion Resources, Inc. / Questar Corporation	Merger, risks, harms, benefits, accounting.
08/16	15-1022-EL-UNC 16-1105-EL-UNC	OH	Ohio Energy Group	AEP Ohio Power Company	SEET earnings, effects of other pending proceedings.
9/16	2016-00162	KY	Office of the Attorney General	Columbia Gas Kentucky	Revenue requirements, O&M expense, depreciation, affiliate transactions.
09/16	E-22 Sub 519, 532, 533	NC	Nucor Steel	Dominion North Carolina Power Company	Revenue requirements, deferrals and amortizations.
09/16	15-1256-G-390P (Reopened) 16-0922-G-390P	WV	West Virginia Energy Users Group	Mountaineer Gas Company	Infrastructure rider, including NOL ADIT and other income tax normalization and calculation issues.
10/16	10-2929-EL-UNC 11-346-EL-SSO 11-348-EL-SSO 11-349-EL-SSO 11-350-EL-SSO 14-1186-EL-RDR	OH	Ohio Energy Group	AEP Ohio Power Company	State compensation mechanism, capacity cost, Retail Stability Rider deferrals, refunds, SEET.
11/16	16-0395-EL-SSO Direct	OH	Ohio Energy Group	Dayton Power & Light Company	Credit support and other riders; financial stability of Utility, holding company.
12/16	Formal Case 1139	DC	Healthcare Council of the National Capital Area	Potomac Electric Power Company	Post test year adjust, merger costs, NOL ADIT, incentive compensation, rent.
01/17	46238	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Company	Next Era acquisition of Oncor; goodwill, transaction costs, transition costs, cost deferrals, ratemaking issues.
02/17	16-0395-EL-SSO Direct (Stipulation)	OH	Ohio Energy Group	Dayton Power & Light Company	Non-unanimous stipulation re: credit support and other riders; financial stability of utility, holding company.
02/17	45414	TX	Cities of Midland, McAllen, and Colorado City	Sharyland Utilities, LP, Sharyland Distribution & Transmission Services, LLC	Income taxes, depreciation, deferred costs, affiliate expenses.
03/17	2016-00370 2016-00371	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas and Electric Company	AMS, capital expenditures, maintenance expense, amortization expense, depreciation rates and expense.
06/17	29849 (Panel with Philip Hayet)	GA	Georgia Public Service Commission Staff	Georgia Power Company	Vogtle 3 and 4 economics.

Expert Testimony Appearances
of
Lane Kollen
As of December 2018

Date	Case	Jurisdict.	Party	Utility	Subject
08/17	17-0296-E-PC	WV	Public Service Commission of West Virginia Charleston	Monongahela Power Company, The Potomac Edison Power Company	ADIT, OPEB.
10/17	2017-00179	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Weather normalization, Rockport lease, O&M, incentive compensation, depreciation, income taxes.
10/17	2017-00287	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Fuel cost allocation to native load customers.
12/17	2017-00321	KY	Attorney General	Duke Energy Kentucky	Revenues, depreciation, income taxes, O&M, regulatory assets, environmental surcharge rider, FERC transmission cost reconciliation rider.
12/17	29849 (Panel with Philip Hayet, Tom Newsome)	GA	Georgia Public Service Commission Staff	Georgia Power Company	Vogtle 3 and 4 economics, tax abandonment loss.
01/18	2017-00349	KY	Kentucky Attorney General	Atmos Energy Kentucky	O&M expense, depreciation, regulatory assets and amortization, Annual Review Mechanism, Pipeline Replacement Program and Rider, affiliate expenses.
06/18	18-0047	OH	Ohio Energy Group	Ohio Electric Utilities	Tax Cuts and Jobs Act. Reduction in income tax expense; amortization of excess ADIT.
07/18	T-34695	LA	LPSC Staff	Crimson Gulf, LLC	Revenues, depreciation, income taxes, O&M, ADIT.
08/18	48325	TX	Cities Served by Oncor	Oncor Electric Delivery Company	Tax Cuts and Jobs Act; amortization of excess ADIT.
08/18	48401	TX	Cities Served by TNMP	Texas-New Mexico Power Company	Revenues, payroll, income taxes, amortization of excess ADIT, capital structure.
08/18	2018-00146	KY	KIUC	Big Rivers Electric Corporation	Station Two contracts termination, regulatory asset, regulatory liability for savings
09/18 10/18	20170235-EI 20170236-EU Direct Supplemental Direct	FL	Office of Public Counsel	Florida Power & Light Company	FP&L acquisition of City of Vero Beach municipal electric utility systems.
09/18 10/18	2017-370-E Direct 2017-207, 305, 370-E Surrebuttal Supplemental Surrebuttal	SC	Office of Regulatory Staff	South Carolina Electric & Gas Company and Dominion Energy, Inc.	Recovery of Summer 2 and 3 new nuclear development costs, related regulatory liabilities, securitization, NOL carryforward and ADIT, TCJA savings, merger conditions and savings.

EXHIBIT ____ (LK-2)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For: (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2014 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; And (4) An Order Granting All Other Required Approvals And Relief	)))))))	**Case No. 2014-00396**

DIRECT TESTIMONY OF

RANIE K. WOHNHAS

ON BEHALF OF KENTUCKY POWER COMPANY

Amortization of Intangible Plant
(Section V, Exhibit 2, Adjustment W38)

Q. WHY IS INTANGIBLE PLANT AMORTIZATION ANNUALIZED?

A. The Company annualized the September 30, 2014 monthly intangible plant amortization expense and compared the result with the level of intangible plant amortization expense included in the test year. The annualized value better represents the on-going level of expense for intangible plant amortization expense. The effect of this adjustment is to increase Kentucky Power's depreciation expense and decrease the deferred taxes, as explained by Witness Bartsch, by $209,475 and $73,316 respectively.

Interest Synchronization Adjustment
(Section V, Exhibit 2, Adjustment W48)

Q. WHY IS AN INTEREST SYNCHRONIZATION ADJUSTMENT NECESSARY?

A. The purpose of this adjustment is synchronize the capital costs and capital structure included by the Company in this filing with the Federal and State Income Taxes included in the test period cost of service and the interest expense tax deduction that will result. The adjustment resulted in an increase to state income tax of $311,143 and an increase to federal income tax of $1,790,035 for a total increase to expenses of $2,101,178.

AFUDC Offset Adjustment
(Section V, Exhibit 2, Adjustment W52)

Q. PLEASE EXPLAIN THE AFUDC OFFSET ADJUSTMENT.

A. The September 30, 2014 balance of Construction Work In Progress ("CWIP") was used in the determination of Rate Base. The adjustment eliminates all CWIP related to Big Sandy in compliance with the Stipulation and Settlement Agreement. All AFUDC related to Big Sandy is also eliminated. Consistent with prior Commission practice for the Company, an Allowance for Funds Used During Construction (AFUDC) "offset" adjustment is being made to record AFUDC above the line. The non-Big Sandy CWIP balance was $76,287,594 on September 30, 2014, of which $2,007,095 is not subject to AFUDC. The remaining balance of $74,280,499 is subject to AFUDC. Using the requested overall return of 7.71%, the annualized AFUDC is $5,664,029. The AFUDC booked during the test year was $5,521,834 requiring an adjustment to increase the AFUDC offset by $250,424. The Deferred Federal Income Taxes (DFIT) associated with the borrowed funds portion of the $5,664,029 is $748,162. The booked DFIT on the borrowed funds portion was $658,123. This increases DFIT by $90,039.

VIII. TARIFF REVISIONS

System Sales Clause (Tariff S.S.C.)

Q. IS THE COMPANY PROPOSING ANY MODIFICATIONS TO THE TREATMENT OF SYSTEM SALES OR TARIFF S.S.C. IN THIS PROCEEDING?

A. Yes. First, as has been the practice in past cases, the Company proposes to update the system sales margin amount included as a credit in base rates. This updated system sales margin amount is reflected in Tariff S.S.C., the System Sales Clause. Company Witness Vaughan describes the derivation of the proposed updated system sales margin base rate credit amount in his testimony. The Company is

EXHIBIT ____ (LK-3)

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2017-00321
OVERALL FINANCIAL SUMMARY
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2017
FOR THE TWELVE MONTHS ENDED MARCH 31, 2019

DATA: "X" BASE PERIOD "X" FORECASTED PERIOD
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED
WORK PAPER REFERENCE NO(S).: SEE BELOW

SCHEDULE A
PAGE 1 OF 1
WITNESS RESPONSIBLE:
S. E. LAWLER

LINE NO.	DESCRIPTION	SUPPORTING SCHEDULE REFERENCE	JURISDICTIONAL REVENUE REQUIREMENTS BASE PERIOD	FORECASTED PERIOD
1	Capitalization Allocated to Electric Operations	WPA-1a, 1c	565,195,503	705,051,140
2	Operating Income	C-2	36,387,908	20,091,071
3	Earned Rate of Return (Line 2 / Line 1)		6.438%	2.850%
4	Rate of Return	J-1	7.208%	7.083%
5	Required Operating Income (Line 1 x Line 4)		40,739,292	49,938,772
6	Operating Income Deficiency (Line 5 - Line 2)		4,351,384	29,847,701
7	Gross Revenue Conversion Factor	H	1.6298147	1.6298147
8	Revenue Deficiency (Line 6 x Line 7)		7,091,950	48,646,222
9	Revenue Increase Requested	C-1	N/A	48,646,213
10	Adjusted Operating Revenues	C-1	N/A	308,857,946
11	Revenue Requirements (Line 9 + Line 10)		N/A	357,504,159

DUKE ENERGY KENTUCKY, INC.
ELECTRIC DEPARTMENT
CASE NO. 2017-00321
DATA: BASE PERIOD "X" FORECASTED PERIOD
CALCULATION OF JURISDICTIONAL CAPITALIZATION

WPA-1c
WITNESS RESPOI
S. E. LAWLER

Line No.	Description		Capitalization Total	Capitalization Electric
1	Total Forecasted Period Capitalization	(1)	1,069,192,372	
2				
3	Less: Gas Non-jurisdictional Rate Base	(2)	5,927,796	
4	Electric Non-jurisdictional Rate Base	(2)	792,644	
5	Non-jurisdictional Rate Base	(2)	(50,651,286)	
6				
7				
8	Jurisdictional Capitalization		1,113,123,218	
9				
10	Electric Jurisdictional Rate Base Allocation %	(2)	72.045%	801,949,623
11				
12	Plus: Jurisdictional Electric ITC	(3)		4,354,475
13	Less: CWIP	(4)		(85,525,336)
14	Plant in Service included in ESM	(5)		(15,727,622)
15				
16	Total Allocated Capitalization			705,051,140

To Sch. A

Notes:
(1) Schedule J-1, page 2.
(2) WPA-1d.
(3) Schedule B-6, page 2.
(4) Schedule B-4. The Company is not requesting to include recovery of CWIP in base rates.
(5) The Company will recover this plant in service through the Environmental Surcharge Mechanism

EXHIBIT ____ (LK-4)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Natural Gas Rates; 2) Approval of a Decoupling Mechanism; 3) Approval of New Tariffs; and 4) All Other Required Approvals, Waivers, and Relief.	)))))))	Case No. 2018-00261

DIRECT TESTIMONY OF

CYNTHIA S. LEE

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

August 31, 2018

each major property grouping. It also shows the proposed depreciation and amortization accrual rate, calculated annual depreciation and amortization expense, percentage of net salvage value, average service life and curve form, as applicable for each account. The calculated annual depreciation and amortization was determined by multiplying the 13-month average adjusted jurisdictional plant investment for the forecast period by the proposed depreciation and amortization accrual rates.

With this filing, the Company proposes depreciation and amortization accrual rates prepared in 2018 and sponsored by Mr. Spanos of Gannett Fleming, Inc., who prepared the depreciation study. The account numbers referred to in the depreciation study were those in effect in 2018 for Duke Energy Kentucky. The Company requests that the Commission approve these new depreciation and amortization accrual rates included in this filing and that the depreciation and amortization accrual rates be effective April 1, 2019, corresponding with the effective date of the natural gas rates established in this case.

Q. PLEASE DESCRIBE SCHEDULE B-4.

A. Schedule B-4 is a list of construction work in progress (CWIP) by major property grouping. Duke Energy Kentucky is not requesting to include its investment in CWIP in rate base.

EXHIBIT ____ (LK-5)

Duke Energy Kentucky
Case No. 2018-00261
Staff Second Set Data Requests
Date Received: October 10, 2018

STAFF-DR-02-006

REQUEST:

Refer to the Application, Volume 12.1, Section B, Schedule B-1.

a. Explain the reason(s) that Duke Kentucky is not requesting to include recovery of construction work in progress (CWIP) in base rates per footnote (2) on Schedule B-1.

b. Explain how Duke Kentucky obtains recovery on CWIP. Provide any authority for the Company's method of recovery on CWIP.

c. Provide the thirteen-month average of CWIP for the base period and forecasted test period and the amount of recovery Duke Kentucky is expected to receive on the CWIP investment for each period.

RESPONSE:

a. Similar to its most recently approved electric rate case, Case No. 2017-00321, Duke Energy Kentucky is not requesting to include recovery of CWIP in base rates because of past Commission precedent that effectively eliminates recovery of a return on CWIP. When CWIP is included in rate base, the Commission has, in past cases, included an AFUDC offset to operating income, which was calculated by multiplying the CWIP balance times the full weighted average cost of capital. The inclusion of the AFUDC offset effectively eliminates any revenue requirement in the test year related to CWIP.

b. See response to item a. The Company does not recover any return on CWIP in base rates.

c. Please see STAFF-DR-01-017(d) Attachment for a revised Schedule B-4 which provides CWIP as of November 30, 2018, for the base period and the thirteen-month average as of March 31, 2020, for the forecasted period.

PERSON RESPONSIBLE: Sarah E. Lawler

EXHIBIT ____ (LK-6)

Columbia Exhibit No. ______.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:	)	
	)	
APPLICATION OF COLUMBIA GAS OF KENTUCKY, INC. FOR AN ADJUSTMENT OF RATES	)	Case No. 2016-00162
	)	
	)	

PREPARED DIRECT TESTIMONY OF
S. MARK KATKO
ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

Brooke E. Wancheck,
Assistant General Counsel
Stephen B. Seiple, Assistant General Counsel
Joseph M. Clark, Senior Counsel
290 W. Nationwide Blvd.
Columbus, Ohio 43216-0117
Telephone: (614) 460-5558
E-mail: bleslie@nisource.com
sseiple@nisource.com
josephclark@nisource.com

Richard S. Taylor
225 Capital Avenue
Frankfort, Kentucky 40601
Telephone: (502) 223-8967
Fax: (502) 226-6383
Email: attysmitty@aol.com

Lindsey W. Ingram III
Stoll Keenon Ogden PLLC
300 West Vine Street, Suite 2100
Lexington, Kentucky 40507-1801
Telephone: (859) 231-3982
Fax: (859): 246-3672
Email: l.ingram@skofirm.com

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 27, 2016

A: Since Columbia is filing a forecast test period rate case, a thirteen month average calculation was used to comply with Filing Requirement 6-c.

Q: **Please describe in detail the individual supporting schedules for Schedule B.**

A: Schedule B-2 shows Columbia's plant-in-service investment by major property grouping for the base period and the forecasted test period. Schedules B-2.1 through B-2.7 provide detail of the major property groupings by gas plant account and show the plant additions and retirements for each account during the base period and forecasted test period.

Schedule B-3 shows the accumulated depreciation and amortization balances by gas plant account for the base period and the forecasted test period.

Workpaper WPB-2.1 provides the monthly balances of plant-in-service by gas plant account for the base period and forecasted test period. Workpaper WPB-3.1 provides the monthly balances of accumulated depreciation and amortization by gas plant account for the base period and forecasted test period.

Schedule B-4 shows the amount of construction work-in-progress ("CWIP") as of February 29, 2016. Columbia has identified $731,955 of the total CWIP balance that was in-service as of February 29, 2016, but not yet classified to Account 106 or Account 101 as of that date. Therefore, this amount is included for recovery in rate base.

Q: How was the forecasted test period plant-in-service developed?

A: Calculations showing the development of the forecasted monthly plant-in-service balances are found in WPB-2.2. Actual per books plant-in-service as of February 29, 2016 in Accounts 101, 106, and the in-service portion of Account 107 is the starting point for the forecast. Budgeted plant additions were then added by month and budgeted retirements were deducted by month through the forecasted test period. Monthly budgeted capital additions were based on Columbia's capital budget discussed in the testimony of Columbia witness Belle and further adjusted for updated assumptions regarding the capital initiatives discussed previously in my testimony. Projected plant retirements were based on a three year average level of actual retirements recorded in 2013 through 2015. Projected plant additions and retirements were then increased by 5.3 percent to reflect Columbia's ten year history of exceeding its original capital expenditure forecasts. Columbia witness Belle describes Columbia's ten year budget experience.

COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2016 - 00162
ACCOUNT 107 CONSTRUCTION WORK IN PROGRESS IN SERVICE
AS OF FEBRUARY 29, 2016

Data:__X__Base Period__X__Forecasted Period
Type of Filing:___X____Original________Updated
Workpaper Reference No(s). WPB-4

SCHEDULE B-4
SHEET 1 OF 1
WITNESS: S. M. KATKO

LINE NO. (A)	GPA (B)	DESCRIPTION (C)	TOTAL CWIP AMOUNT (D)	ACCUMULATED COSTS CONSTRUCTION AMOUNT (E)	CWIP AMOUNT IN SERVICE (F=D-E)	JURISDICTIONAL (G)	TOTAL COST (H=F*G)
			$	$	$	%	$
1	303.00	MISC INTANGIBLE PLANT	21,987	21,987	0	100.00	0
2	303.30	MISC INTANGIBLE PLANT	707,153	707,153	0		0
3		SUBTOTAL	729,140	729,140	0		0
4	374.40	LAND RIGHTS - OTHER DIST	71,154	71,154	0		0
5	375.40	REGULATING STRUCTURES	90,409	90,409	0		0
6	375.70	OTHER STRUCTURES	42,869	42,869	0		0
7	375.71	OTHER STRUCTURES-LEASED	26,357	26,357	0		0
8	376.00	MAINS	5,256,891	4,524,168	732,723		732,723
9	378.20	M&R EQUIP-GENERAL-REG	279,184	279,952	(768)		(768)
10	380.00	SERVICES	93,161	93,161	0		0
11	381.00	METERS	(21,903)	(21,903)	0		0
12	382.00	METER INSTALLATIONS	(14,872)	(14,872)	0		0
13	383.00	HOUSE REGULATORS	8,213	8,213	0		0
14	385.00	IND M&R EQUIPMENT	116,522	116,522	0		0
15	387.45	OTHER EQ-TELEMETERING	357,362	357,362	0		0
16		SUBTOTAL	6,305,349	5,573,394	731,955		731,955
17	391.10	OFF FUR & EQ UNSPECIF	21,458	21,458	0		0
18	391.12	OFF FUR & EQ INFORM. SYS.	63,206	63,206	0		0
19	394.30	TOOLS & OTHER	7,365	7,365	0		0
20		SUBTOTAL	92,029	92,029	0		0
21	TOTAL		7,126,518	6,394,563	731,955		731,955

EXHIBIT ____ (LK-7)

KENTUCKY UTILITIES COMPANY

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated November 13, 2018

Case No. 2018-00294

Question No. 26

Responding Witness: Daniel K. Arbough

Q.1-26. Refer to the tables depicted on page 6 of Mr. Blake's Direct Testimony. Please provide the same information for the calendar years ended 2014, 2015, 2016, 2017, 2018 actual to date, 2018 projected, 2019 projected, and the first four projected months of 2020.

A.1-26.

KU- Total Capital

$ millions	2014	2015	2016	2017	2018 Actuals to Date	2018 Projected	2019 Projected	2020 Projected (Jan-Apr)
Generation	$456	$290	$148	$231	$234	$334	$289	$84
Electric Transmission	40	53	69	110	95	113	132	56
Electric Distribution	78	95	94	108	102	127	145	44
Gas Operations								
Customer Service	8	10	7	15	14	20	16	3
Other	19	20	31	23	17	26	28	11
Total	$601	$469	$349	$487	$462	$620	$610	$198

KU- Non Mech

$ millions	2014	2015	2016	2017	2018 Actuals to Date	2018 Projected	2019 Projected	2020 Projected (Jan-Apr)
Generation	$129	$82	$69	$93	$69	$113	$161	$65
Electric Transmission	40	53	69	110	95	113	132	56
Electric Distribution	78	95	94	108	102	127	145	44
Gas Operations								
Customer Service	6	7	5	14	14	20	15	3
Other	19	20	31	23	17	26	28	11
Total	$272	$258	$269	$348	$297	$400	$482	$179

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated November 13, 2018

Case No. 2018-00295

Question No. 23

Responding Witness: Daniel K. Arbough

Q.1-23. Refer to the tables depicted on page 6 of Mr. Blake's Direct Testimony. Please provide the same information for the calendar years ended 2014, 2015, 2016, 2017, 2018 actual to date, 2018 projected, 2019 projected, and the first four projected months of 2020.

A.1-23.

LGE- Total Capital

$ millions	2014	2015	2016	2017	2018 Actuals to Date	2018 Projected	2019 Projected	2020 Projected (Jan-Apr)
Generation	$495	$411	$195	$280	$240	$274	$178	$27
Electric Transmission	44	21	17	24	27	33	37	12
Electric Distribution	68	82	80	91	89	114	140	41
Gas Operations	78	88	87	78	61	83	147	29
Customer Service	9	10	9	17	15	20	20	4
Other	17	18	25	19	15	24	28	11
Total	$710	$629	$414	$508	$447	$548	$549	$124

LGE- Non Mech

$ millions	2014	2015	2016	2017	2018 Actuals to Date	2018 Projected	2019 Projected	2020 Projected (Jan-Apr)
Generation	$86	$74	$67	$124	$98	$118	$107	$19
Electric Transmission	44	21	17	24	27	33	37	12
Electric Distribution	68	82	80	91	89	114	140	41
Gas Operations	25	32	29	32	37	50	71	22
Customer Service	7	7	7	16	16	20	20	4
Other	17	18	25	19	15	24	28	11
Total	$247	$234	$226	$306	$282	$358	$402	$109

EXHIBIT ____ (LK-8)

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's First Request for Information Dated September 19, 2018

Case No. 2018-00294

Question No. 13

Responding Witness: Kent W. Blake / Lonnie E. Bellar

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

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

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

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

A-13.

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

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

c. No. KU did not recognize a Slippage Factor for capital additions in either the base period or the forecasted test period. The requested calculations of the slippage factors (96.027% for KU and 97.153% for LG&E) on capital projects that are recovered in base rates demonstrate the reasonableness of KU and LG&E's accuracy in projecting capital additions. In addition, through August 2018, non-mechanism capital spend is trending over budget by 3%. Given the

Kentucky Utilities Company
Case No. 2018-00294
Calculation of Capital Construction Project Slippage Factor -Non-Mechanism Construction Projects

Schedule 13b(1)

Source: Schedule 13a - Construction Projects

Years	Base Rate Capital Actual Cost	Base Rate Capital Budget Cost	Variance in Dollars	Variance as a percent	Slippage Factor
2017	331,452,600	353,148,308	(21,695,708)	-6.144%	93.856%
2016	257,316,496	247,479,708	9,836,788	3.975%	103.975%
2015	240,247,704	254,705,926	(14,458,222)	-5.676%	94.324%
2014	258,672,601	285,655,724	(26,983,123)	-9.446%	90.554%
2013	467,930,147	442,723,204	25,206,943	5.694%	105.694%
2012	250,621,314	298,013,293	(47,391,979)	-15.903%	84.097%
2011	203,042,999	215,256,373	(12,213,373)	-5.674%	94.326%
2010	209,036,428	183,198,611	25,837,818	14.104%	114.104%
2009	247,393,650	254,530,196	(7,136,546)	-2.804%	97.196%
2008	299,810,659	364,973,077	(65,162,418)	-17.854%	82.146%
Totals	**2,765,524,598**	**2,899,684,420**	**(134,159,822)**	**-4.627%**	**95.373%**

10 Year Average Slippage Factor (Mathematic Average of the Yearly Slippage Factors / 10 Years)	**96.027%**

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

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

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

Schedule 13b (2)

Kentucky Utilities Company
Case No. 2018-00294
Calculation of Capital Construction Project Slippage Factor - Mechanisms Construction Projects Only

Source: Schedule 13a - Construction Projects

	A	B	C=A+B	D	E	F=D+E	G=C-F	H=G/F	I=C/F
Years	Actual ECR	Actual DSM	Mechanism Capital Actual Total	Budget ECR	Budget DSM	Mechanism Capital Budget Total	Variance in Dollars	Variance as a percent	Slippage Factor
2017	113,633,138	902,940	114,536,077	155,701,578	1,931,766	157,633,344	(43,097,267)	-27.340%	72.660%
2016	65,003,671	1,716,079	66,719,750	133,378,623	2,332,374	135,710,997	(68,991,246)	-50.837%	49.163%
2015	202,607,589	3,226,169	205,833,758	221,828,814	1,546,665	223,375,478	(17,541,720)	-7.853%	92.147%
2014	325,250,119	1,235,843	326,485,962	311,941,339	2,102,322	314,043,661	12,442,301	3.962%	103.962%
2013	357,471,329	1,808,343	359,279,672	331,193,876	1,307,386	332,501,262	26,778,410	8.054%	108.054%
2012	249,935,786	304,046	250,239,832	319,312,275	1,604,339	320,916,614	(70,676,782)	-22.023%	77.977%
2011	122,599,687	-	122,599,687	222,559,895	1,853,002	224,412,896	(101,813,209)	-45.369%	54.631%
2010	136,407,834	-	136,407,834	232,331,970	-	232,331,970	(95,924,136)	-41.288%	58.712%
2009	227,067,458	-	227,067,458	260,647,784	-	260,647,784	(33,580,326)	-12.883%	87.117%
2008	381,490,690	-	381,490,690	441,357,545	-	441,357,545	(59,866,855)	-13.564%	86.436%
Totals	2,181,467,302	9,193,420	2,190,660,722	2,630,253,699	12,677,852	2,642,931,551	(452,270,829)	-17.112%	82.888%

10 Year Average Slippage Factor (Mathematic Average of the Yearly Slippage Factors / 10 Years)	79.086%

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

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

Explanation for significant variances from budget:

2017 – Under budget due to Brown Landfill phase II being delayed and also due to delays in the Trimble Co landfill and CCRT construction.

2016 – Lower costs on the Trimble landfill due to delays in the permitting process. In addition, there was a shift in spend related to CCR Pond Closures from 2016 to future years.

2015 – Lower costs on the Trimble landfill due to delays in the permitting process.

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

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

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

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

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

EXHIBIT ____ (LK-9)

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Commission Staff's First Request for Information
Dated September 19, 2018**

Case No. 2018-00295

Question No. 13

Responding Witness: Kent W. Blake / Lonnie E. Bellar

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

a. For each project started during the last 10 calendar years, provide the information requested in the format contained in Schedule 13a for electric and gas operations separately. For each project, include the amount of any cost variance and delay encountered, and explain in detail the reasons for such variances and delays.

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

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

A-13.

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

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

c. No. LG&E did not recognize a Slippage Factor for capital additions in either the base period or the forecasted test period. The requested calculations of the slippage factors (96.027% for KU and 97.153% for LG&E) on capital projects that are recovered in base rates demonstrate the reasonableness of KU and

Schedule 13b(1)

Louisville Gas and Electric Company
Case No. 2018-00295
Calculation of Capital Construction Project Slippage Factor -Non-Mechanism Construction Projects

Source: Schedule 13a - Construction Projects

Year	Base Rate Capital Actual Cost	Base Rate Capital Budget Cost	Variance in Dollars	Variance as a percent	Slippage Factor
2017	273,814,739	314,514,052	(40,699,313)	-12.940%	87.060%
2016	201,820,465	205,916,322	(4,095,857)	-1.989%	98.011%
2015	213,433,085	213,558,521	(125,436)	-0.059%	99.941%
2014	233,542,915	246,109,548	(12,566,633)	-5.106%	94.894%
2013	301,411,194	297,836,538	3,574,656	1.200%	101.200%
2012	198,826,795	214,793,287	(15,966,492)	-7.433%	92.567%
2011	197,524,642	226,223,175	(28,698,533)	-12.686%	87.314%
2010	203,125,349	170,001,291	33,124,058	19.485%	119.485%
2009	167,411,673	179,893.509	(12,481,836)	-6.938%	93.062%
2008	212,232,535	216,569,290	(4,336,754)	-2.002%	97.998%
Totals	**2,203,143,393**	**2,285,415,533**	**(82,272,140)**	**-3.600%**	**96.400%**

10 Year Average Slippage Factor (Mathematic Average of the Yearly Slippage Factors / 10 Years)	**97.153%**

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

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

Louisville Gas and Electric Company
Case No. 2018-00295
Calculation of Capital Construction Project Slippage Factor -Mechanism Construction Projects Only

Schedule 13b (2)

Source: Schedule 13a - Construction Projects

	A	B	C	D = A+B+C	E	F	G	H=E+F+G	I=D-H	J=I/H	K=D/H
Year	Actual ECR	Actual DSM	Actual GLT	Mechanism Capital Actual Total	ECR	DSM	GLT	Mechanism Capital Budget Total	Variance in Dollars	Variance as a percent	Slippage Factor
2017	152,550,358	901,116	43,068,468	196,519,941	137,392,654	1,931,766	49,518,353	188,842,773	7,677,168	4.065%	104.065%
2016	118,080,979	2,032,812	56,811,210	176,925,001	213,541,391	2,332,374	57,452,364	273,326,130	(96,401,129)	-35.270%	64.730%
2015	332,975,913	2,956,595	54,787,547	390,720,056	328,957,067	1,546,665	52,747,681	383,251,413	7,468,643	1.949%	101.949%
2014	404,522,580	1,407,752	51,358,901	457,289,233	286,241,263	2,102,330	54,601,467	342,945,060	114,344,172	33.342%	133.342%
2013	247,148,691	1,530,891	44,368,114	293,047,695	323,761,867	1,307,381	48,259,066	373,328,314	(80,280,619)	-21.504%	78.496%
2012	80,423,350	248,316	15,858,155	96,529,822	231,552,739	1,603,839	14,753,636	247,910,213	(151,380,392)	-61.063%	38.937%
2011	9,605,232	-	-	9,605,232	77,034,797	1,900,012	-	78,934,809	(69,329,578)	-87.831%	12.169%
2010	7,859,154	-	-	7,859,154	17,203,191	-	-	17,203,191	(9,344,037)	-54.316%	45.684%
2009	17,420,492	-	-	17,420,492	11,793,861	-	-	11,793,861	5,626,631	47.708%	147.708%
2008	25,900,841	-	-	25,900,841	26,519,109	-	-	26,519,109	(618,268)	-2.331%	97.669%
Totals	1,396,487,590	9,077,481	266,252,395	1,671,817,466	1,653,997,940	12,724,366	277,332,567	1,944,054,874	(272,237,408)	-14.004%	85.996%

10 Year Average Slippage Factor (Mathematic Average of the Yearly Slippage Factors / 10 Years)	82.475%

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

Explanation for significant variances from budget:

2017 – Over budget due to Mill Creek Gypsum Dewatering and Process Water Systems construction.

2016 – Lower costs on the Trimble landfill due to delays in the permitting process. In addition, there was a shift in spend related to CCR Pond Closures from 2016 to future years.

2015 – The Mill Creek Environmental Air project was above budget due to change orders and higher actual costs against the target pricing contract in place with the primary contractor Zachry, partially offset by lower costs on the Trimble landfill due to delays in

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

2013 – Continued permitting delays on the Trimble County landfill and less work completed on the Mill Creek Environmental Air Project than had been expected in the budget.

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

2011 – Later start to the Mill Creek environmental air projects under the 2011 ECR plan than had been expected in the budget, and permitting delays on the Trimble County landfill.
With regards to DSM, lower costs were the result of the approval of Case No. 2011-00134 being later than originally expected.

2010 – Delay in the Trimble County barge Loading (Holcim) project, and the Mill Creek SAM mitigation cancelled.

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

Case No. 2018-00295
Attachment to Response to PSC-1 Question No. 13(b)
Page 2 of 2
Bellar/Blake

EXHIBIT ____ (LK-10)

KENTUCKY UTILITIES COMPANY

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated November 13, 2018

Case No. 2018-00294

Question No. 34

Responding Witness: John J. Spanos / Christopher M. Garrett

Q.1-34. Refer to the composite remaining lives associated with the Ash Ponds, the costs for which are included in account 312.10, for the various units contained on page VI-4 of Exhibit JJS-KU-1 (Depreciation Study attached to Mr. Spanos' Direct Testimony).

a. Please describe in detail the Company's proposal in regards to the remaining service lives depicted for each unit, the basis for each, and the proposal to start depreciating the assets again.

b. Please indicate when the Company stopped recording depreciation expense for the Ash Ponds in prior years and the reasons why. Provide citations as applicable.

A.1-34.

a. In Exhibit JJS-KU-1, the remaining net plant is set forth to be recovered over a remaining life of 3 to 6 years. Each ash pond has a set period of time before being closed which corresponds to the remaining life. The ash ponds should not have stopped being depreciated in 2017.

b. The Company stopped recording depreciation expense for the ash ponds effective July 1, 2017. The ash pond rates were inadvertently listed as a zero rate as part of the settlement agreement in Case No. 2016-00370. The ash pond assets were moved to separate depreciation groups in the previous depreciation study resulting in the omission. The separate depreciation groups were the result of the decision reached in Case No. 2016-00026 whereby the closure costs would be amortized for ratemaking purposes rather than recovered through depreciation rates. As a result, the proposed study corrects this omission.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated November 13, 2018

Case No. 2018-00295

Question No. 32

Responding Witness: John J. Spanos / Christopher M. Garrett

Q.1-32. Refer to the composite remaining lives associated with the Ash Ponds, the costs for which are included in account 312.10, for the various units contained on page VI-5 of Exhibit JJS-LG&E-1 (Depreciation Study attached to Mr. Spanos' Direct Testimony).

a. Please describe in detail the Company's proposal in regards to the remaining service lives depicted for each unit, the basis for each, and the proposal to start depreciating the assets again.

b. Please indicate when the Company stopped recording depreciation expense for the Ash Ponds in prior years and the reasons why. Provide citations as applicable.

A.1-32.

a. In Exhibit JJS-LGE-1, the remaining net plant is set forth to be recovered over a remaining life of 1.5 to 6 years. Each ash pond has a set period of time before being closed which corresponds to the remaining life. The ash ponds should not have stopped being depreciated in 2017.

b. The Company stopped recording depreciation expense for the ash ponds effective July 1, 2017. The ash pond rates were inadvertently listed as a zero rate as part of the settlement agreement in Case No. 2016-00370. The ash pond assets were moved to separate depreciation groups in the previous depreciation study resulting in the omission. The separate depreciation groups were the result of the decision reached in Case No. 2016-00026 whereby the closure costs would be amortized for ratemaking purposes rather than recovered through depreciation rates. As a result, the proposed study corrects this omission.

EXHIBIT ____ (LK-11)

KENTUCKY UTILITIES COMPANY

Response to Supplemental Set of Data Requests of Kentucky Industrial Utility Customers, Inc. Dated December 13, 2018

Case No. 2018-00294

Question No. 24

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

Q.2-24. Refer to the response to Kroger/Walmart 1-6(c).

a. In part i of this response, the Company forecast a debt issuance on May 1, 2019 that it claims causes capitalization to be greater than rate base. Provide a more detailed explanation of this difference and provide the Company's calculation of the difference. Address whether the forecast debt issuance results in a short-term investment for some period of time until the funds are invested in rate base. If so, describe this investment in detail and quantify the daily average each month and the month end balance for each month in the test year.

b. In part ii of this response, the Company provided a schedule to provide "additional information regarding the difference between capitalization and rate base." Provide a more detailed description of the schedule and how it provides a reconciliation between the capitalization and rate base amounts.

c. Refer to line Provide the Company's calculation of the 13 month average and the monthly short-term investments used for the 13 month average reflected on this schedule.

A.2-24.

a. The calculation of capitalization includes all long-term debt outstanding at the end of the Forecasted Period (April 2020). Rate base utilizes a monthly average and as a result there is a difference between rate base and capitalization for debt issued during the Forecasted Period. The Company plans to issue $300 million of debt on May 1, 2019. Therefore, the full amount of this issuance is included in capitalization while only 12/13 of the impact is included in rate base. Therefore, the reconciling item represents 1/13 of the $300 million debt issuance ($300 million/13 = $23 million). The forecasted debt issuance does not result in a short-term investment. It will be used to pay off short-term debt.

The Company believes that both rate base and capitalization should reflect this long-term debt issuance for the full year as the Company will incur a full year of interest expense in the forecasted test period. However, in making its adjustment to capitalization (Schedule J-2, Page 3 of 3, Tab 63 of the Filing Requirements), the Company failed to show an offsetting reduction in the short-term debt balance. The impact of this error on the revenue requirement is approximately $1.0 million.

b. The schedule referenced in the question provides the account detail information as to what is included in the reconciling items included in the attachment to filing requirement 807 KAR 5:001 Section 16(6)(f). The totals of each column agree to the reconciling items included in the attachment to 807 KAR 5:001 Filing Requirement Section 16(6)(f). For example, the total of the "Other Property and Investments" column agrees to the total of the "Other Property and Investments" line on the reconciliation.

c. The Company assumes the question refers to detail related to the Cash and Temporary Investments line from attachment to 807 KAR 5:001 Filing Requirement Section 16(6)(f). See attachment being provided in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Supplemental Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated December 13, 2018**

Case No. 2018-00295

Question No. 23

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

Q.2-23. Refer to the response to Kroger/Walmart 1-6(c).

a. In part i of this response, the Company forecast a debt issuance on May 1, 2019 that it claims causes capitalization to be greater than rate base. Provide a more detailed explanation of this difference and provide the Company's calculation of the difference. Address whether the forecast debt issuance results in a short-term investment for some period of time until the funds are invested in rate base. If so, describe this investment in detail and quantify the daily average each month and the month end balance for each month in the test year.

b. In part ii of this response, the Company provided a schedule to provide "additional information regarding the difference between capitalization and rate base." Provide a more detailed description of the schedule and how it provides a reconciliation between the capitalization and rate base amounts.

c. Refer to line Provide the Company's calculation of the 13-month average and the monthly short-term investments used for the 13-month average reflected on this schedule.

A.2-23.

a. The calculation of capitalization includes all long-term debt outstanding at the end of the Forecasted Period (April 2020). Rate base utilizes a monthly average and as a result there is a difference between rate base and capitalization for debt issued and retired during the Forecasted Period. The Company plans to issue $500 million of debt on May 1, 2019 and retire $200 million of debt in May 2019. Therefore, the full amount of this issuance and retirement is included in capitalization while only 12/13 of the impact is included in rate base. Therefore, the reconciling item represents 1/13 of the $300 million net debt activity ($300 million/13 = $23 million). The forecasted debt issuance does not result in a short-term investment. It will be used to pay off short-term debt.

The Company believes that both rate base and capitalization should reflect this long-term debt issuance for the full year as the Company will incur a full year of interest expense in the forecasted test period. However, in making its adjustment to capitalization (Schedule J-2, Page 3 of 3, Tab 63 of the Filing Requirements), the Company failed to show an offsetting reduction in the short-term debt balance. The impact of this error on the revenue requirement is approximately $0.9 million for electric operations and $0.2 million for gas operations.

b. The schedule referenced in the question provides the account detail information as to what is included in the reconciling items included in the attachment to filing requirement 807 KAR 5:001 Section 16(6)(f). The totals of each column agree to the reconciling items included in the attachment to 807 KAR 5:001 Filing Requirement Section 16(6)(f). For example, the total of the "Other Property and Investments" column agrees to the total of the "Other Property and Investments" line on the reconciliation.

c. The Company assumes the question refers to detail related to the Cash and Temporary Investments line from attachment to 807 KAR 5:001 Filing Requirement Section 16(6)(f). See attachment being provided in Excel format.

EXHIBIT ____ (LK-12)

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated November 13, 2018

Case No. 2018-00294

Question No. 45

Responding Witness: Daniel K. Arbough / Lonnie E. Bellar

Q-45. Refer to Schedule D-1, page 4 of 8.

a. Refer to line 61. Provide intercompany purchased power and OVEC costs for the base period and the forecast period.

b. Refer to line 73. Explain the term "depancaking costs."

A-45.

a.

	Base Period	Forecast Period
	$	$
Intercompany purchased power	28,744,377	35,346,555
OVEC - Energy Charges	5,097,931	5,521,730
OVEC - Demand Charges	8,371,744	11,352,373
Market Purchases	116,679	1,505,518
Purchased Power SCH D-1	42,330,731	53,726,176

b. "Depancaking costs" are expenses resulting from the application of the Merger Mitigation Depancaking ("MMD") mechanism in LG&E and KU's FERC-filed Rate Schedule 402. Under MMD, transmission charges for the combined transmission system of LG&E and KU for exports to MISO are waived for certain municipalities, reducing transmission revenues paid by those municipal customers. For imports of electricity from a source in MISO for delivery to load interconnected to the LG&E and KU transmission system, certain municipalities are billed for LG&E and KU transmission charges, but LG&E and KU are obligated to credit to those municipal customers the MISO transmission charges associated with the delivery of the electricity to the MISO-LG&E/KU border. This typically results in a net payment to those municipal customers because the MISO transmission charges exceed the LG&E and KU transmission charges.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information Dated November 13, 2018

Case No. 2018-00295

Question No. 54

Responding Witness: Daniel K. Arbough / Lonnie E. Bellar

Q-54. Refer to Schedule D-1 Electric, page 4 of 9.

a. Refer to line 61. Provide intercompany purchased power and OVEC costs for the base period and the forecast period.

b. Refer to line 73. Explain the term "depancaking expense."

A-54.

a.

	Base Period	Forecast Period
	$	$
Intercompany purchased power	5,579,300	7,337,483
OVEC - Energy Charges	13,296,040	13,534,023
OVEC - Demand Charges	21,503,975	27,272,357
Bluegrass Generation Co., LLC [1)] - Energy Charges	1,299,981	-
Bluegrass Generation Co., LLC [1)] - Demand Charges	10,482,608	-
Market Purchases	10,988	919,112
Purchased Power SCH D-1	52,172,892	49,062,975

[1)] a.k.a East Kentucky Power Cooperative, Inc., tolling agreement ends April 30, 2019

b. "Depancaking costs" are expenses resulting from the application of the Merger Mitigation Depancaking ("MMD") mechanism in LG&E and KU's FERC-filed Rate Schedule 402. Under MMD, transmission charges for the combined transmission system of LG&E and KU for exports to MISO are waived for certain municipalities, reducing transmission revenues paid by those municipal customers. For imports of electricity from a source in MISO for delivery to load interconnected to the LG&E and KU transmission system, certain municipalities are billed for LG&E and KU transmission charges but LG&E and KU are obligated to credit to those municipal customers the MISO transmission charges associated with the delivery of the electricity to the MISO-LG&E/KU border. This typically results in a net payment to those municipal customers because the MISO transmission charges exceed the LG&E and KU transmission charges.

EXHIBIT ____ (LK-13)

KENTUCKY UTILITIES COMPANY

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated November 13, 2018

Case No. 2018-00294

Question No. 76

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

Q.1-76. Provide a schedule showing total Company and jurisdictional purchased power expense by month from January 2015 through the end of the test year, including the months between the end of the base year and beginning of the test year separated into the amounts included in the (a) base revenue requirement and in the (b) fuel adjustment clause. Disaggregate the expense included in the base revenue requirement by supplier in the same manner that the Company reports purchased power expense in the Form 1 on pages 326-327. Highlight and explain each actual and forecasted change in resource and/or capacity for a given resource throughout this 64-month period for the expense included in the base revenue requirement.

A.1-76. See attached.

In January 2017, OVEC began including in its demand charge $2.5 million per month for the billing of an advance/general reserve for debt service, KU's share of which was $62,500 per month. The forecast also reflects the expectation for OVEC to begin in November 2018 to include in its demand charge monthly amounts in advance for repayments of certain of its debt currently scheduled to be due in 2019 and 2020 (commencing approximately one year in advance), totaling approximately $208 million, KU's share of which is $5.2 million.

KENTUCKY UTILITIES COMPANY
PURCHASED POWER EXPENSE
ACTUAL PERIOD FOR THE 12 MONTHS ENDED DECEMBER 31, 2015

Description	Actual Jan-15	Actual Feb-15	Actual Mar-15	Actual Apr-15	Actual May-15	Actual Jun-15	Actual Jul-15	Actual Aug-15	Actual Sep-15	Actual Oct-15	Actual Nov-15	Actual Dec-15	TOTAL
EXTERNAL PURCHASED POWER													
BENHAM POWER BOARD	-	-	-	-	-	-	-	90	29	56	158	85	418
BLUEGRASS GENERATION COMPANY, LLC	-	-	-	4,478	-	-	-	-	-	-	-	797	5,274
CITY OF PARIS	(733)	-	60	-	-	100	(20)	-	-	-	-	-	(593)
EAST KENTUCKY POWER COOPERATIVE, INC.	-	-	1,715	-	-	-	186	-	-	-	-	-	1,901
FAYETTE COUNTY BOARD OF EDUCATION	78	120	158	238	363	479	489	277	260	393	297	89	3,241
ILLINOIS MUNICIPAL ELECTRIC AGENCY	312	(735)	1,188	706	(215)	(425)	1,591	91	138	524	(377)	1,035	3,831
INDIANA MUNICIPAL POWER AGENCY	(569)	1,838	(905)	1,342	2,966	(985)	481	1,471	211	29	220	153	6,251
KENTUCKY MUNICIPAL POWER AGENCY	9,337	4,446	10,171	12,481	3,363	4,781	7,261	4,222	2,214	96	473	636	59,481
KENTUCKY NATIONAL GUARD	-	-	-	-	664	-	233	-	30.00	-	-	227.00	1,154
OHIO VALLEY ELECTRIC CORPORATION	705,470	476,054	743,148	605,938	477,283	522,314	538,141	653,384	666,206	513,667	435,104	378,803	6,715,511
OWENSBORO MUNICIPAL UTILITIES	1,997	677	445	2,772	2,436	2,575	1,862	4,926	3,602	3,688	1,997	957	27,933
PJM INTERCONNECTION LLC	-	-	-	20,589	-	-	-	22,432	-	715	19,411	-	63,147
ROCKCASTLE HOSPITAL ANNEX	106	105	153	210	239	326	285	273	323	172	115	117	2,424
TENNESSEE VALLEY AUTHORITY	-	-	33,600	43,200	19,931	3,443	-	11,059	2,302	75,810	43,155	7,267	239,768
INTERNAL PURCHASED POWER													
LOUISVILLE GAS AND ELECTRIC COMPANY	7,522,472	8,454,270	5,835,857	5,248,187	2,078,385	1,019,675	567,060	685,260	814,321	1,680,640	2,153,416	800,401	36,859,944
CAPACITY													
OHIO VALLEY ELECTRIC CORPORATION DEMAND	650,148	486,319	644,447	832,790	572,575	590,948	648,205	632,691	624,538	788,676	602,836	939,148	8,013,322
*JURISDICTIONALIZED**													
OHIO VALLEY ELECTRIC CORPORATION DEMAND	569,686	426,132	564,690	729,724	501,713	517,812	567,983	554,390	547,246	691,070	528,229	822,919	7,021,593

*Jurisdictional energy amount not readily available. Recoverable through the Fuel Adjustment Clause
Purchased Power expense included in the base revenue requirement for the 2014 and 2016 rate case was $8,058,767 total company and $7,051,986 jurisdictional and $8,349,413 total company and $7,312,226 jurisdictional, respectively.

KENTUCKY UTILITIES COMPANY
PURCHASED POWER EXPENSE
ACTUAL PERIOD FOR THE 12 MONTHS ENDED DECEMBER 31, 2016

Description	Actual Jan-16	Actual Feb-16	Actual Mar-16	Actual Apr-16	Actual May-16	Actual Jun-16	Actual Jul-16	Actual Aug-16	Actual Sep-16	Actual Oct-16	Actual Nov-16	Actual Dec-16	TOTAL
EXTERNAL PURCHASED POWER													
BENHAM POWER BOARD	82	109	124	-	-	-	-	16	133	-	231	(432)	262
BLUEGRASS GENERATION COMPANY, LLC	3,561	(3,561)	-	-	-	-	-	-	-	-	-	-	-
CARLISLE ARMORY	1	-	-	-	-	-	-	-	-	-	-	29	30
DEPARTMENT OF MILITARY AFFAIRS	-	-	-	-	-	20	449	754	551	751	1,115	288	3,928
EAST KENTUCKY POWER COOPERATIVE, INC.	-	3,668	-	1,536	1,213	-	10,547	(341)	22	-	896	314	17,855
FAYETTE COUNTY BOARD OF EDUCATION	86	158	188	303	433	347	645	420	388	395	204	220	3,786
HOOSIER ENERGY RURAL ELECTRIC COOPERATIVE	-	-	-	-	-	-	-	-	-	-	-	(1,375)	(1,375)
ILLINOIS MUNICIPAL ELECTRIC AGENCY	272	39	105	-	754	-	240	359	222	226	516	220	2,951
INDIANA MUNICIPAL POWER AGENCY	72	368	129	20	759	-	395	95	162	110	18	-	2,128
KENTUCKY MUNICIPAL POWER AGENCY	931	3,685	356	2,523	1,940	2,039	8,321	4,402	3,184	1,079	2,871	(33,741)	(2,411)
KENTUCKY NATIONAL GUARD	-	26	89	356	542	351	132	87	-	56	141	139	1,919
MEMORIAL METHODIST CHURCH	-	-	-	-	10	-	-	-	-	-	-	-	10
OHIO VALLEY ELECTRIC CORPORATION	692,779	628,126	475,705	408,639	604,589	726,725	764,823	649,166	672,814	367,037	498,360	672,794	7,161,557
OWENSBORO MUNICIPAL UTILITIES	1,185	3,249	10,741	10,857	5,839	3,393	9,219	5,555	7,760	5,724	8,481	(53,296)	18,708
PJM INTERCONNECTION LLC	-	7,616	8,351	452	10,402	-	14,915	-	11,245	-	-	-	52,979
ROCKCASTLE HOSPITAL ANNEX	102	121	160	255	209	350	270	238	229	157	154	67	2,311
TENNESSEE VALLEY AUTHORITY	-	5,500	1,500	-	18,050	12,443	33,668	24,096	39,157	(91)	17,000	-	151,323
INTERNAL PURCHASED POWER													
LOUISVILLE GAS AND ELECTRIC COMPANY	4,439,385	3,731,909	2,962,309	3,215,263	571,937	1,411,676	1,315,526	344,350	1,010,914	495,328	1,004,893	3,582,792	24,086,283
CAPACITY													
OHIO VALLEY ELECTRIC CORPORATION DEMAND	434,781	545,803	576,860	835,117	773,427	412,283	603,186	616,425	537,498	749,250	697,633	890,103	7,672,366
*JURISDICTIONALIZED**													
OHIO VALLEY ELECTRIC CORPORATION DEMAND	381,098	478,413	505,635	732,005	677,932	361,378	528,711	540,315	471,133	656,740	611,496	780,202	6,725,059

*Jurisdictional energy amount not readily available. Recoverable through the Fuel Adjustment Clause

Purchased Power expense included in the base revenue requirement for the 2014 and 2016 rate case was $8,058,767 total company and $7,051,986 jurisdictional and $8,349,413 total company and $7,312,226 jurisdictional, respectively.

KENTUCKY UTILITIES COMPANY
PURCHASED POWER EXPENSE
ACTUAL PERIOD FOR THE 12 MONTHS ENDED DECEMBER 31, 2017

Description	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	TOTAL
EXTERNAL PURCHASED POWER													
BENHAM POWER BOARD	-	154	29	-	(29)	-	-	-	-	-	-	-	154
CARLISLE ARMORY	29	44	110	175	179	248	212	182	205	169	78	73	1,704
DEPARTMENT OF MILITARY AFFAIRS	181	246	551	-	855	-	1,304	604	564	574	403	383	5,666
DOUGLAS LANGLEY	-	-	-	-	-	-	-	281	314	111	8	19	733
EAST KENTUCKY POWER COOPERATIVE, INC.	-	1,308	22,256	8,330	40,178	20,417	7,607	33,284	1	743	77,322	1	211,448
FAYETTE COUNTY BOARD OF EDUCATION	101	50	175	241	370	138	298	356	333	366	186	179	2,792
ILLINOIS MUNICIPAL ELECTRIC AGENCY	17	61	-	1,016	1,147	1,367	945	1,588	1,861	1,524	1,341	1,357	12,222
INDIANA MUNICIPAL POWER AGENCY	36	86	-	1,553	1,920	1,819	1,326	2,045	2,349	1,842	1,877	1,571	16,424
KENTUCKY MUNICIPAL ENERGY AGENCY	-	-	-	-	-	148	290	-	-	107	166	607	1,317
KENTUCKY MUNICIPAL POWER AGENCY	1,670	566	6,664	2,006	2,055	3,321	3,657	3,082	1,903	1,430	550	982	27,886
KENTUCKY NATIONAL GUARD	-	-	508	-	1,129	-	255	284	-	415	114	-	2,704
OHIO VALLEY ELECTRIC CORPORATION	771,833	505,332	564,791	469,245	267,247	474,278	520,635	469,157	309,982	466,695	644,353	592,035	6,055,585
OWENSBORO MUNICIPAL UTILITIES	5,135	10,390	7,817	9,076	2,608	6,800	6,827	6,090	2,430	9,176	6,827	11,795	84,972
PJM INTERCONNECTION LLC	-	-	-	1,306	-	-	-	-	-	-	8,279	-	9,585
ROCKCASTLE HOSPITAL ANNEX	54	99	166	184	210	252	209	176	156	149	74	70	1,799
TENNESSEE VALLEY AUTHORITY	-	55,520	(1,240)	-	23,551	526	12,322	0	-	652	-	-	91,331
INTERNAL PURCHASED POWER													
LOUISVILLE GAS AND ELECTRIC COMPANY	6,055,890	5,844,415	5,360,141	940,116	1,741,620	1,187,394	505,068	586,203	558,129	2,217,524	353,901	5,094,349	30,444,750
CAPACITY													
OHIO VALLEY ELECTRIC CORPORATION DEMAND	523,376	629,185	897,865	423,727	1,094,390	588,764	690,717	652,743	843,057	830,989	776,340	783,418	8,734,570
*JURISDICTIONALIZED**													
OHIO VALLEY ELECTRIC CORPORATION DEMAND	458,865	551,631	787,194	371,499	959,495	516,193	605,579	572,286	739,142	728,561	680,649	686,854	7,657,947

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Purchased Power expense included in the base revenue requirement for the 2014 and 2016 rate case was $8,058,767 total company and $7,051,986 jurisdictional and $8,349,413 total company and $7,312,226 jurisdictional, respectively.

KENTUCKY UTILITIES COMPANY
PURCHASED POWER EXPENSE
BASE PERIOD FOR THE 12 MONTHS ENDED DECEMBER 31, 2018

Description	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Forecast Jul-18	Forecast Aug-18	Forecast Sep-18	Forecast Oct-18	Forecast Nov-18	Forecast Dec-18	TOTAL
EXTERNAL PURCHASED POWER*													
CARLISLE ARMORY	53	37	122	127	229	244	-	-	-	-	-	-	811
DEPARTMENT OF MILITARY AFFAIRS	-	377	367	493	718	1,154	-	-	-	-	-	-	3,109
DOUGLAS LANGLEY	60	59	179	252	349	311	-	-	-	-	-	-	1,210
EAST KENTUCKY POWER COOPERATIVE, INC.	5,254	0	4,733	5,649	15,769	26,067	-	-	-	-	-	-	57,473
FAYETTE COUNTY BOARD OF EDUCATION	115	79	98	167	365	417	-	-	-	-	-	-	1,241
ILLINOIS MUNICIPAL ELECTRIC AGENCY	230	954	-	-	3,904	2,294	-	-	-	-	-	-	7,382
INDIANA MUNICIPAL POWER AGENCY	410	1,336	-	-	4,246	3,230	-	-	-	-	-	-	9,222
KENTUCKY MUNICIPAL ENERGY AGENCY	(330)	-	484	301	261	207	-	-	-	-	-	-	924
KENTUCKY MUNICIPAL POWER AGENCY	1,709	646	3,360	1,238	3,161	6,148	-	-	-	-	-	-	16,262
KENTUCKY NATIONAL GUARD	-	28	57	28	408	555	-	-	-	-	-	-	1,077
LYNCH WATER WORKS	-	-	-	-	-	178							178
MEMORIAL METHODIST CHURCH	-	-	-	10	-	-	-	-	-	-	-	-	10
OHIO VALLEY ELECTRIC CORPORATION	624,967	418,225	616,833	486,644	369,264	517,820	460,945	460,847	355,609	386,492	557,513	536,206	5,791,364
OWENSBORO MUNICIPAL UTILITIES	5,096	5,732	7,025	24,929	9,426	12,847	-	-	-	-	-	-	65,055
ROCKCASTLE HOSPITAL ANNEX	61	58	103	152	170	189	-	-	-	-	-	-	732
PJM (MKT)	-	-	-	-	-	-	-	280	-	13,687	7,538	-	21,505
INTERNAL PURCHASED POWER													
LOUISVILLE GAS AND ELECTRIC COMPANY	5,770,365	2,436,558	4,180,940	1,621,400	1,101,558	1,155,580	1,138,394	1,444,373	2,746,020	2,123,796	3,067,201	6,385,412	33,171,595
CAPACITY													
OHIO VALLEY ELECTRIC CORPORATION DEMAND	537,085	646,422	678,860	942,911	913,478	727,452	765,415	769,582	769,582	769,582	987,681	1,040,723	9,548,770
*JURISDICTIONALIZED***													
EXTERNAL PURCHASED POWER	561,278	376,341	557,525	457,728	359,386	503,213	405,753	405,914	313,030	352,264	497,394	472,003	5,261,828
INTERNAL PURCHASED POWER	5,079,446	2,144,815	3,680,332	1,427,261	969,662	1,017,216	1,002,087	1,271,430	2,417,223	1,869,501	2,699,947	5,620,849	29,199,768
OHIO VALLEY ELECTRIC CORPORATION DEMAND	470,882	566,741	595,180	826,683	800,879	637,782	671,066	674,719	674,719	674,719	865,934	912,438	8,371,744

*Energy is not forecast at the counterparty level
**Jurisdictional energy amount not readily available. Recoverable through the Fuel Adjustment Clause
Purchased Power expense included in the base revenue requirement for the 2014 and 2016 rate case was $8,058,767 total company and $7,051,986 jurisdictional and $8,349,413 total company and $7,312,226 jurisdictional, respectively.

KENTUCKY UTILITIES COMPANY
PURCHASED POWER EXPENSE
FORECAST PERIOD FOR THE 4 MONTHS ENDED APRIL 30, 2019

Description	Forecast Jan-19	Forecast Feb-19	Forecast Mar-19	Forecast Apr-19	TOTAL
EXTERNAL PURCHASED POWER*					
PJM (MKT)	20,311	-	-	8,682	28,993
OHIO VALLEY ELECTRIC CORPORATION	598,020	482,890	628,270	545,843	2,255,023
PURCHASED POWER FOR OFF-SYSTEM SALES	-	-	19	-	19
INTERNAL PURCHASED POWER					
LOUISVILLE GAS AND ELECTRIC COMPANY	6,576,889	4,986,588	4,316,191	2,689,715	18,569,382
CAPACITY					
OHIO VALLEY ELECTRIC CORPORATION DEMAND	1,021,668	1,021,668	1,021,668	1,021,668	4,086,671
JURISDICTIONALIZED*					
OHIO VALLEY ELECTRIC CORPORATION DEMAND	895,732	895,732	895,732	895,732	3,582,929

*Energy is not forecast at the counterparty level
**Jurisdictional energy amount not readily available. Recoverable through the Fuel Adjustment Clause
Purchased Power expense included in the base revenue requirement for the 2014 and 2016 rate case was $8,058,767 total company and $7,051,986 jurisdictional and $8,349,413 total company and $7,312,226 jurisdictional, respectively.

KENTUCKY UTILITIES COMPANY
PURCHASED POWER EXPENSE
TEST PERIOD FOR THE 12 MONTHS ENDED APRIL 30, 2020

Description	Forecast May-19	Forecast Jun-19	Forecast Jul-19	Forecast Aug-19	Forecast Sep-19	Forecast Oct-19	Forecast Nov-19	Forecast Dec-19	Forecast Jan-20	Forecast Feb-20	Forecast Mar-20	Forecast Apr-20	TOTAL
EXTERNAL PURCHASED POWER*													
PJM (MKT)	40,090	-	221,158	421,251	-	19,716	612,273	12,168	30,444	8,492	226,546	7,047	1,599,183
OHIO VALLEY ELECTRIC CORPORATION	304,956	406,558	460,048	490,001	372,840	413,941	613,950	573,492	588,388	429,595	763,525	450,588	5,867,881
PURCHASED POWER FOR OFF-SYSTEM SALES	-	-	-	-	-	9	-	-	-	-	-	-	9
INTERNAL PURCHASED POWER													
LOUISVILLE GAS AND ELECTRIC COMPANY	2,294,937	1,396,530	1,089,504	976,283	1,566,163	1,854,851	4,256,344	5,445,832	5,689,660	3,938,076	8,039,373	1,913,287	38,458,840
CAPACITY													
OHIO VALLEY ELECTRIC CORPORATION DEMAND	1,021,668	1,021,668	1,021,668	1,183,183	1,183,183	1,183,183	965,084	912,042	904,651	904,651	904,651	904,651	12,110,283
JURISDICTIONALIZED*													
INTERNAL PURCHASED POWER	324,691	382,575	641,021	857,496	350,845	408,084	1,153,887	551,111	582,326	412,244	931,665	430,639	7,026,584
OHIO VALLEY ELECTRIC CORPORATION DEMAND	2,159,557	1,314,148	1,025,233	918,691	1,473,774	1,745,431	4,005,259	5,124,578	5,354,023	3,705,766	7,565,124	1,798,539	36,190,121
OHIO VALLEY ELECTRIC CORPORATION DEMAND	957,728	957,728	957,728	1,109,135	1,109,135	1,109,135	904,685	854,963	848,034	848,034	848,034	848,034	11,352,373

*Energy is not forecast at the counterparty level
Jurisdictional energy amount not readily available. Recoverable through the Fuel Adjustment Clause.
Purchased Power expense included in the base revenue requirement for the 2014 and 2016 rate case was $8,058,767 total company and $7,051,986 jurisdictional and $8,349,413 total company and $7,312,226 jurisdictional, respectively.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to First Set of Data Requests of Kentucky Industrial Utility Customers, Inc. Dated November 13, 2018

Case No. 2018-00295

Question No. 65

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

Q.1-65. Provide a schedule showing purchased power expense by month from January 2015 through the end of the test year, including the months between the end of the base year and beginning of the test year separated into the amounts included in the (a) base revenue requirement and in the (b) fuel adjustment clause. Disaggregate the expense included in the base revenue requirement by supplier in the same manner that the Company reports purchased power expense in the Form 1 on pages 326-327. Highlight and explain each actual and forecasted change in resource and/or capacity for a given resource throughout this 64-month period for the expense included in the base revenue requirement.

A.1-65. See attached.

In January 2017, OVEC began including in its demand charge $2.5 million per month for the billing of an advance/general reserve for debt service, LG&E's share of which was $140,750 per month. The forecast also reflects the expectation for OVEC to begin in November 2018 to include in its demand charge monthly amounts in advance for repayments of certain of its debt currently scheduled to be due in 2019 and 2020 (commencing approximately one year in advance), totaling approximately $208 million, LG&E's share of which is $11.7 million. LG&E's purchased power demand charges also reflect the cost of the Bluegrass tolling agreement with East Kentucky Power Cooperative, which began in May 2015 and will terminate at the end of April 2019.

LOUISVILLE GAS AND ELECTRIC COMPANY
PURCHASED POWER EXPENSE
ACTUAL PERIOD FOR THE 12 MONTHS ENDED DECEMBER 31, 2015

Description	Actual Jan-15	Actual Feb-15	Actual Mar-15	Actual Apr-15	Actual May-15	Actual Jun-15	Actual Jul-15	Actual Aug-15	Actual Sep-15	Actual Oct-15	Actual Nov-15	Actual Dec-15	TOTAL
EXTERNAL PURCHASED POWER													
BENHAM POWER BOARD	-	-	-	-	-	-	-	-	-	-	-	444	444
BLUEGRASS GENERATION COMPANY, LLC	-	-	-	318	-	-	-	-	-	-	-	1,077	1,395
CITY OF PARIS	(17)	-	-	-	-	200	(40)	-	-	-	-	-	143
EAST KENTUCKY POWER COOPERATIVE, INC.	-	-	245	-	-	-	603	-	-	-	339	(339)	848
ILLINOIS MUNICIPAL ELECTRIC AGENCY	1,674	(333)	1,077	114	599	(438)	1,371	161	270	886	1,212	153	6,746
INDIANA MUNICIPAL POWER AGENCY	244	4,274	(3,353)	3,262	3,389	223	504	271	186	39	624	118	9,780
KENTUCKY MUNICIPAL POWER AGENCY	6,951	20,095	10,962	1,132	3,862	8,644	12,677	6,429	4,647	753	1,016	1,188	78,357
OHIO VALLEY ELECTRIC CORPORATION	1,586,895	1,065,072	1,671,338	1,359,973	1,065,453	1,167,442	1,209,637	1,465,871	1,497,232	1,148,422	975,645	858,274	15,071,254
OWENSBORO MUNICIPAL UTILITIES	1,961	4,411	2,088	478	2,262	4,297	2,764	9,252	8,630	2,963	4,290	1,669	45,065
PJM INTERCONNECTION LLC	-	-	-	73	-	-	317	3,936	-	436	19,433	-	24,195
TENNESSEE VALLEY AUTHORITY	-	-	33,612	31,750	25,169	4,395	-	1,941	394	44,802	76,244	8,305	226,612
INTERNAL PURCHASED POWER													
KENTUCKY UTILITIES COMPANY	571,114	1,818,546	631,773	86,186	1,392,488	2,794,546	3,574,108	2,855,915	2,464,593	665,079	789,014	2,005,484	19,648,847
CAPACITY													
OHIO VALLEY ELECTRIC CORPORATION DEMAN	1,464,155	1,095,206	1,451,316	1,875,471	1,289,457	1,330,834	1,459,778	1,424,842	1,406,481	1,776,124	1,357,605	2,114,993	18,046,262
EAST KENTUCKY POWER COOPERATIVE, INC. C	-	-	-	-	809,282	853,411	929,503	844,053	791,446	887,931	828,052	800,250	6,743,929

Purchased Power expense included in the base revenue requirement for the 2014 and 2016 rate case was $28,265,656 and $29,245,261, respectively. Energy amounts are not readily available. Recoverable through the Fuel Adjustment Clause.
*Energy is not forecast at the counterparty level

LOUISVILLE GAS AND ELECTRIC COMPANY
PURCHASED POWER EXPENSE
ACTUAL PERIOD FOR THE 12 MONTHS ENDED DECEMBER 31, 2016

Description	Actual Jan-16	Actual Feb-16	Actual Mar-16	Actual Apr-16	Actual May-16	Actual Jun-16	Actual Jul-16	Actual Aug-16	Actual Sep-16	Actual Oct-16	Actual Nov-16	Actual Dec-16	TOTAL
EXTERNAL PURCHASED POWER													
BENHAM POWER BOARD	97	6	15	-	-	-	-	48	85	-	161	(416)	(4)
BLUEGRASS GENERATION COMPANY, LLC	3,550	(3,550)	-	-	-	-	-	-	-	-	-	-	-
EAST KENTUCKY POWER COOPERATIVE, INC.	-	3,556	-	1,254	1,487	-	7,020	1,238	18	-	816	(56,695)	(41,308)
HOOSIER ENERGY RURAL ELECTRIC COOPERA	-	-	-	-	-	-	-	-	-	-	-	(854)	(854)
ILLINOIS MUNICIPAL ELECTRIC AGENCY	160	95	140	-	889	-	286	451	292	279	479	231	3,303
INDIANA MUNICIPAL POWER AGENCY	54	312	134	20	755	-	438	109	163	128	-	-	2,114
KENTUCKY MUNICIPAL POWER AGENCY	1,281	591	86	1,326	2,343	3,940	5,379	4,934	2,931	634	2,559	(26,423)	(421)
OHIO VALLEY ELECTRIC CORPORATION	1,553,732	1,409,441	1,065,181	917,234	1,353,240	1,631,842	1,717,014	1,457,415	1,511,840	827,267	1,118,333	1,509,732	16,072,269
OWENSBORO MUNICIPAL UTILITIES	1,783	430	3,304	4,738	7,374	6,557	4,577	9,433	7,224	4,659	6,478	(38,407)	18,151
PJM INTERCONNECTION LLC	-	7,616	8,351	10,810	10,402	-	14,915	-	5,891	-	-	-	57,784
TENNESSEE VALLEY AUTHORITY	-	5,480	1,500	-	18,050	26,120	24,051	5,354	2,764	(6)	17,000	-	100,313
INTERNAL PURCHASED POWER													
KENTUCKY UTILITIES COMPANY	204,733	51,735	1,336,848	841,621	1,488,180	1,297,880	1,178,547	1,538,560	1,439,518	2,787,187	857,257	589,502	13,411,566
CAPACITY													
OHIO VALLEY ELECTRIC CORPORATION DEMAN	979,140	1,229,167	1,299,107	1,880,711	1,741,782	928,474	1,358,394	1,388,210	1,210,463	1,687,336	1,571,091	2,004,541	17,278,417
EAST KENTUCKY POWER COOPERATIVE, INC. D	449,870	1,043,213	803,550	812,891	860,630	254,033	102,267	833,971	840,470	850,986	822,245	803,550	8,477,675

Purchased Power expense included in the base revenue requirement for the 2014 and 2016 rate case was $28,265,656 and $29,245,261, respectively. Energy amounts are not readily available. Recoverable through the Fuel Adjustment Clause.
*Energy is not forecast at the counterparty level

LOUISVILLE GAS AND ELECTRIC COMPANY
PURCHASED POWER EXPENSE
ACTUAL PERIOD FOR THE 12 MONTHS ENDED DECEMBER 31, 2017

Description	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	TOTAL
EXTERNAL PURCHASED POWER													
BENHAM POWER BOARD	-	52	-	-	29	-	-	-	-	-	-	-	81
EAST KENTUCKY POWER COOPERATIVE, INC.	-	616	22,600	8,215	37,618	13,325	4,297	20,830	1	245	59,004	1	166,753
ILLINOIS MUNICIPAL ELECTRIC AGENCY	33	95	-	772	683	1,078	904	1,289	1,429	975	990	641	8,891
INDIANA MUNICIPAL POWER AGENCY	36	45	-	1,068	1,292	1,497	1,301	1,682	1,821	1,179	1,386	731	12,039
KENTUCKY MUNICIPAL ENERGY AGENCY	-	-	-	-	-	102	338	-	-	68	114	338	960
KENTUCKY MUNICIPAL POWER AGENCY	702	182	7,659	1,428	1,937	2,438	3,484	2,535	1,421	975	661	377	23,799
OHIO VALLEY ELECTRIC CORPORATION	1,734,562	1,130,898	1,264,624	1,056,941	595,450	1,061,820	1,165,311	1,051,063	688,643	1,049,144	1,456,468	1,327,471	13,582,392
OWENSBORO MUNICIPAL UTILITIES	2,777	4,088	6,230	7,772	6,412	5,696	5,836	4,924	1,759	6,623	5,698	5,387	63,203
PJM INTERCONNECTION LLC	-	-	-	71	-	-	-	-	-	-	8,298	-	8,369
TENNESSEE VALLEY AUTHORITY	-	27,442	(454)	-	15,989	(523)	19,280	0	-	363	-	-	62,107
INTERNAL PURCHASED POWER													
KENTUCKY UTILITIES COMPANY	883,260	60,938	745,193	1,068,804	541,642	945,190	1,009,546	586,757	1,250,867	414,640	1,930,388	324,415	9,761,641
CAPACITY													
OHIO VALLEY ELECTRIC CORPORATION DEMAN	1,178,680	1,416,944	2,022,021	954,248	2,464,602	1,325,895	1,555,536	1,469,998	1,898,592	1,871,414	1,748,344	1,764,283	19,670,536
EAST KENTUCKY POWER COOPERATIVE, INC. D	825,636	826,408	825,827	828,606	806,850	835,939	870,083	806,531	835,271	825,840	844,635	816,051	9,947,676

Purchased Power expense included in the base revenue requirement for the 2014 and 2016 rate case was $28,265,656 and $29,245,261, respectively. Energy amounts are not readily available. Recoverable through the Fuel Adjustment Clause.
*Energy is not forecast at the counterparty level

LOUISVILLE GAS AND ELECTRIC COMPANY
PURCHASED POWER EXPENSE
BASE PERIOD FOR THE 12 MONTHS ENDED DECEMBER 31, 2018

Description	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Forecast Jul-18	Forecast Aug-18	Forecast Sep-18	Forecast Oct-18	Forecast Nov-18	Forecast Dec-18	TOTAL
EXTERNAL PURCHASED POWER*													
EAST KENTUCKY POWER COOPERATIVE, INC.	15,319	(0)	475	8,311	14,849	17,849	308,016	308,016	298,080	308,016	5,550	15,500	1,299,981
ILLINOIS MUNICIPAL ELECTRIC AGENCY	922	583	-	-	5,685	1,724	-	-	-	-	-	-	8,925
INDIANA MUNICIPAL POWER AGENCY	1,396	816	-	-	6,215	2,408	-	-	-	-	-	-	10,836
KENTUCKY MUNICIPAL ENERGY AGENCY	280	0	85	216	509	143	-	-	-	-	-	-	1,233
KENTUCKY MUNICIPAL POWER AGENCY	5,094	457	472	841	6,169	4,611	-	-	-	-	-	-	17,643
OHIO VALLEY ELECTRIC CORPORATION	1,402,867	931,809	1,387,591	1,094,793	826,434	1,161,229	1,087,792	1,105,083	844,107	882,852	1,283,475	1,288,007	13,296,040
OWENSBORO MUNICIPAL UTILITIES	14,997	3,742	583	16,807	19,222	9,446	-	-	-	-	-	-	64,797
PURCHASED POWER FOR OFF-SYSTEM SALES	-	-	-	-	893	221	-	-	-	-	-	-	1,115
PJM (MKT)	-	-	-	-	-	-	-	6,599	-	-	-	-	6,599
INTERNAL PURCHASED POWER													
KENTUCKY UTILITIES COMPANY	4,429,493	617,191	299,252	581,679	803,217	433,524	1,247,419	1,079,622	579,405	740,100	858,150	954,072	12,623,125
CAPACITY													
OHIO VALLEY ELECTRIC CORPORATION DEMAN	1,209,534	1,455,762	1,528,814	2,123,466	2,057,183	1,638,244	1,723,715	1,733,098	1,733,098	1,733,098	2,224,257	2,343,707	21,503,975
EAST KENTUCKY POWER COOPERATIVE, INC. D	857,713	822,183	856,945	846,629	861,189	865,759	933,764	915,066	895,243	857,309	913,158	857,850	10,482,808

Purchased Power expense included in the base revenue requirement for the 2014 and 2016 rate case was $28,265,656 and $29,245,261, respectively. Energy amounts are not readily available. Recoverable through the Fuel Adjustment Clause.
*Energy is not forecast at the counterparty level

LOUISVILLE GAS AND ELECTRIC COMPANY
PURCHASED POWER EXPENSE
FORECAST PERIOD FOR THE 4 MONTHS ENDED APRIL 30, 2019

Description	Forecast Jan-19	Forecast Feb-19	Forecast Mar-19	Forecast Apr-19	TOTAL
EXTERNAL PURCHASED POWER*					
PJM (MKT)	-	-	13,095	-	13,095
OHIO VALLEY ELECTRIC CORPORATION	1,405,191	1,094,660	1,470,225	1,247,670	5,217,745
EAST KENTUCKY POWER COOPERATIVE, INC.	15,500	14,000	5,735	-	35,235
PURCHASED POWER FOR OFF-SYSTEM SALES	-	-	979	-	979
INTERNAL PURCHASED POWER					
KENTUCKY UTILITIES COMPANY	278,685	245,876	246,804	517,340	1,288,705
CAPACITY					
OHIO VALLEY ELECTRIC CORPORATION DEMAN	2,300,796	2,300,796	2,300,796	2,300,796	9,203,183
EAST KENTUCKY POWER COOPERATIVE, INC. D	919,125	882,407	948,926	833,281	3,583,740

Purchased Power expense included in the base revenue requirement for the 2014 and 2016 rate case was $28,265,656 and $29,245,261, respectively. Energy amounts are not readily available. Recoverable through the Fuel Adjustment Clause.
*Energy is not forecast at the counterparty level

LOUISVILLE GAS AND ELECTRIC COMPANY
PURCHASED POWER EXPENSE
TEST PERIOD FOR THE 12 MONTHS ENDED APRIL 30, 2020

Description	Forecast May-19	Forecast Jun-19	Forecast Jul-19	Forecast Aug-19	Forecast Sep-19	Forecast Oct-19	Forecast Nov-19	Forecast Dec-19	Forecast Jan-20	Forecast Feb-20	Forecast Mar-20	Forecast Apr-20	TOTAL
EXTERNAL PURCHASED POWER*													
PJM (MKT)	-	3,354	177,748	712,341	19,194	210	6,267	-	-	-	-	-	919,112
OHIO VALLEY ELECTRIC CORPORATION	685,674	937,091	1,080,960	1,144,285	858,158	944,375	1,388,541	1,347,291	1,364,960	1,027,431	1,724,205	1,031,054	13,534,023
PURCHASED POWER FOR OFF-SYSTEM SALES	-	-	-	-	-	22	-	-	-	-	-	-	22
INTERNAL PURCHASED POWER													
KENTUCKY UTILITIES COMPANY	1,016,349	1,010,190	1,191,689	1,573,807	1,308,121	499,995	169,649	395,796	213,885	157,248	56,942	508,622	8,102,292
CAPACITY													
OHIO VALLEY ELECTRIC CORPORATION DEMAN	2,300,796	2,300,796	2,300,796	2,664,528	2,664,528	2,664,528	2,173,369	2,053,919	2,037,274	2,037,274	2,037,274	2,037,274	27,272,357

Purchased Power expense included in the base revenue requirement for the 2014 and 2016 rate case was $28,265,658 and $29,245,261, respectively. Energy amounts are not readily available. Recoverable through the Fuel Adjustment Clause.
*Energy is not forecast at the counterparty level

EXHIBIT ____ (LK-14)

KENTUCKY UTILITIES COMPANY

Response to Lexington-Fayette Urban County Government's Request for Information Dated November 13, 2018

Case No. 2018-00294

Question No. 49

Responding Witness: Lonnie E. Bellar / Robert M. Conroy

Q-49. Please refer to Mr. Blake's testimony at his answer to the question beginning on line 19 of page 10.

a. Explain what costs will be added for KU under its Merger Mitigation Depancaking transmission rate mechanism.

b. On line 23 of page 10, Mr. Blake indicates that there will be added costs for only KU, but on lines 1-2 on page 11, he mentions added revenue requested by both KU and LG&E as a result of the MMD mechanism. Reconcile and explain this discrepancy.

c. Confirm that, if KU and LG&E receive FERC approval to eliminate the MMD charges, the Companies should not recover additional revenue for these costs that the Companies will not have.

d. Identify the total amount of costs related to the MMD mechanism that KU and LG&E has included to recover from customers in this case.

e. Identify the FERC Docket Number for the matter that has been established to review KU and LG&E's request to eliminate the MMD mechamism.

f. State the approximate date on which KU and LG&E anticipate FERC will render a decision on the above-referenced matter.

A-49.

a. See the response to KPSC 2-45(b).

b. The omission of LG&E on line 23 of page 10 was inadvertent; the MMD mechanism arises out of a joint LG&E and KU rate schedule under the FERC Open Access Transmission Tariff. The projections set forth in lines 1-2 of page 11, indicating costs for both LG&E and KU, are correct.

c. See the response to AG 1-9(e).

d. The costs related to the MMD mechanism included for recovery in this case are $15.1 million from KU customers and $9.0 million from LG&E customers.

e. FERC Docket Nos. EC98-2-001 and ER18-2162-000.

f. Under Section 203 of the Federal Power Act, FERC is required to issue an order within 180 days of a Section 203 filing (in this case January 30, 2019), but FERC is also permitted to issue a tolling order seeking an additional 180 days of time to consider the filing. In its order FERC could accept or reject LG&E and KU's request to eliminate the MMD mechanism, or FERC could order the parties to be sent to hearing and settlement procedures, which could delay a final disposition of the matter for an unspecified amount of time.

EXHIBIT ____ (LK-15)

KENTUCKY UTILITIES COMPANY

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated November 13, 2018

Case No. 2018-00294

Question No. 72

Responding Witness: Lonnie E. Bellar / Daniel K. Arbough

Q.1-72. Please provide in an Excel spreadsheet the FTE staffing levels and related payroll (direct and burdens) by month from January 2015 through April 2020 at each generating unit/plant that the Company has retired or plans to retire during that period of just over five years.

A.1-72. See attachment provided in Excel format.

Brown Steam Unit 1

Month/Year	Brown Steam Total Headcount (1)	Direct	Burdens	Grand Total
201501	119	$78,909	$19,603	$98,512
201502	119	$86,762	$22,135	$108,897
201503	119	$155,543	$46,792	$202,335
201504	117	$120,675	$32,966	$153,641
201505	115	$100,093	$23,823	$123,915
201506	116	$75,487	$20,334	$95,821
201507	115	$83,342	$20,000	$103,342
201508	116	$88,663	$23,123	$111,786
201509	121	$67,875	$17,659	$85,534
201510	122	$64,540	$27,432	$91,971
201511	119	$60,783	$25,174	$85,957
201512	120	$58,512	$26,393	$84,904
201601	122	$75,585	$19,378	$94,963
201602	123	$77,915	$19,606	$97,522
201603	125	$131,549	$37,356	$168,905
201604	124	$111,319	$26,615	$137,933
201605	124	$71,206	$18,723	$89,928
201606	125	$79,908	$21,759	$101,667
201607	124	$78,461	$19,941	$98,402
201608	121	$86,687	$22,868	$109,555
201609	121	$81,066	$21,424	$102,489
201610	122	$74,207	$23,723	$97,929
201611	122	$72,015	$21,936	$93,951
201612	122	$59,522	$30,377	$89,899
201701	122	$134,015	$36,339	$170,354
201702	122	$126,726	$34,007	$160,733
201703	120	$186,860	$49,182	$236,042
201704	120	$105,898	$27,308	$133,206
201705	118	$121,302	$34,607	$155,909
201706	118	$130,000	$33,798	$163,799
201707	117	$111,804	$30,177	$141,981
201708	114	$131,973	$35,426	$167,399
201709	115	$122,266	$34,521	$156,787
201710	115	$116,184	$33,073	$149,257
201711	116	$113,265	$32,234	$145,499
201712	116	$95,634	$40,454	$136,088

Brown Steam Unit 1

Month/Year	Brown Steam Total Headcount (1)	Direct	Burdens	Grand Total
201801	114	$141,699	$35,323	$177,022
201802	113	$106,826	$27,485	$134,311
201803	109	$137,754	$32,796	$170,550
201804	108	$123,715	$30,030	$153,745
201805	108	$110,967	$27,836	$138,803
201806	108	$116,417	$28,759	$145,176
201807	107	$107,864	$27,486	$135,350
201808	107	$129,336	$32,696	$162,032
201809	107	$104,445	$26,367	$130,812
201810	107	$128,065	$32,300	$160,365
201811	107	$111,419	$28,106	$139,525
201812	107	$93,721	$23,627	$117,348
201901	106	$105,183	$27,000	$132,183
201902	106	$87,688	$22,734	$110,422
201903	106	$0	$0	$0
201904	106	$0	$0	$0
201905	106	$0	$0	$0
201906	106	$0	$0	$0
201907	106	$0	$0	$0
201908	106	$0	$0	$0
201909	106	$0	$0	$0
201910	106	$0	$0	$0
201911	106	$0	$0	$0
201912	106	$0	$0	$0
202001	106	$0	$0	$0
202002	106	$0	$0	$0
202003	106	$0	$0	$0
202004	106	$0	$0	$0
Grand Total		**$5,141,645**	**$1,412,811**	**$6,554,456**

(1) - Headcount is for all Brown Steam Units; as Company does not allocate headcount between units. Brown 3 is not retiring. Remaining employees will offset existing FTE contractors.

Brown Steam Unit 2

Month/Year	Brown Steam Total Headcount (1)	Direct	Burdens	Grand Total
201501	119	$89,452	$22,433	$111,885
201502	119	$109,013	$25,443	$134,456
201503	119	$85,308	$20,908	$106,216
201504	117	$99,320	$25,093	$124,413
201505	115	$85,704	$22,750	$108,453
201506	116	$94,021	$26,728	$120,749
201507	115	$83,478	$23,211	$106,690
201508	116	$99,720	$27,470	$127,190
201509	121	$92,144	$26,261	$118,405
201510	122	$178,333	$76,563	$254,896
201511	119	$78,010	$33,899	$111,909
201512	120	$87,683	$40,318	$128,001
201601	122	$120,252	$28,529	$148,782
201602	123	$112,037	$28,797	$140,834
201603	125	$163,354	$41,276	$204,630
201604	124	$134,165	$30,606	$164,770
201605	124	$109,465	$28,394	$137,859
201606	125	$102,081	$26,836	$128,917
201607	124	$94,031	$24,025	$118,057
201608	121	$121,151	$31,263	$152,414
201609	121	$121,873	$32,359	$154,232
201610	122	$104,642	$33,421	$138,063
201611	122	$94,970	$30,023	$124,993
201612	122	$88,317	$44,774	$133,091
201701	122	$192,220	$51,240	$243,461
201702	122	$189,999	$51,434	$241,433
201703	120	$233,227	$63,049	$296,277
201704	120	$226,346	$59,909	$286,255
201705	118	$186,179	$49,454	$235,633
201706	118	$171,787	$44,892	$216,679
201707	117	$154,160	$41,478	$195,638
201708	114	$184,444	$49,496	$233,940
201709	115	$156,583	$44,311	$200,893
201710	115	$165,921	$46,573	$212,494
201711	116	$155,790	$44,256	$200,045
201712	116	$139,159	$58,943	$198,102

Brown Steam Unit 2

Month/Year	Brown Steam Total Headcount (1)	Direct	Burdens	Grand Total
201801	114	$181,984	$46,228	$228,213
201802	113	$158,733	$41,115	$199,848
201803	109	$181,037	$45,842	$226,879
201804	108	$195,560	$47,335	$242,895
201805	108	$181,502	$48,171	$229,672
201806	108	$167,753	$41,914	$209,667
201807	107	$172,582	$43,978	$216,560
201808	107	$206,937	$52,314	$259,251
201809	107	$167,112	$42,187	$209,299
201810	107	$204,904	$51,679	$256,584
201811	107	$178,270	$44,969	$223,239
201812	107	$149,953	$37,804	$187,757
201901	106	$168,292	$43,200	$211,493
201902	106	$140,301	$36,375	$176,676
201903	106	$0	$0	$0
201904	106	$0	$0	$0
201905	106	$0	$0	$0
201906	106	$0	$0	$0
201907	106	$0	$0	$0
201908	106	$0	$0	$0
201909	106	$0	$0	$0
201910	106	$0	$0	$0
201911	106	$0	$0	$0
201912	106	$0	$0	$0
202001	106	$0	$0	$0
202002	106	$0	$0	$0
202003	106	$0	$0	$0
202004	106	$0	$0	$0
Grand Total		**$7,159,259**	**$1,979,527**	**$9,138,787**

(1) - Headcount is for all Brown Steam Units; as Company does not allocate headcount between units. Brown 3 is not retiring. Remaining employees will offset existing FTE contractors.

Brown Steam Unit 3

Month/Year	Brown Steam Total Headcount (1)	Direct	Burdens	Grand Total
201501	119	$574,876	$141,089	$715,965
201502	119	$559,380	$132,840	$692,219
201503	119	$533,571	$129,599	$663,170
201504	117	$615,230	$147,961	$763,191
201505	115	$519,220	$123,799	$643,019
201506	116	$542,164	$134,747	$676,911
201507	115	$532,160	$128,910	$661,070
201508	116	$555,133	$132,252	$687,386
201509	121	$548,134	$134,450	$682,584
201510	122	$689,309	$285,588	$974,897
201511	119	$653,282	$273,736	$927,019
201512	120	$511,188	$222,582	$733,770
201601	122	$633,934	$150,534	$784,468
201602	123	$524,663	$133,380	$658,043
201603	125	$623,364	$153,765	$777,129
201604	124	$632,849	$145,070	$777,920
201605	124	$560,536	$138,767	$699,303
201606	125	$551,000	$138,735	$689,736
201607	124	$559,088	$137,216	$696,305
201608	121	$647,628	$158,509	$806,136
201609	121	$552,811	$138,324	$691,135
201610	122	$588,383	$177,636	$766,018
201611	122	$610,003	$183,172	$793,175
201612	122	$500,494	$240,422	$740,917
201701	122	$483,019	$127,744	$610,763
201702	122	$415,778	$111,711	$527,489
201703	120	$447,139	$119,773	$566,912
201704	120	$511,910	$130,961	$642,871
201705	118	$501,256	$135,163	$636,420
201706	118	$432,094	$113,122	$545,216
201707	117	$388,047	$104,407	$492,454
201708	114	$480,914	$127,842	$608,756
201709	115	$412,107	$116,876	$528,983
201710	115	$430,729	$125,596	$556,325
201711	116	$439,934	$125,998	$565,931
201712	116	$468,580	$191,931	$660,510

Brown Steam Unit 3

Month/Year	**Brown Steam Total Headcount (1)**	**Direct**	**Burdens**	**Grand Total**
201801	114	$520,330	$136,711	$657,041
201802	113	$419,849	$109,402	$529,251
201803	109	$465,959	$116,382	$582,341
201804	108	$519,134	$128,392	$647,526
201805	108	$478,016	$126,368	$604,384
201806	108	$406,519	$103,252	$509,771
201807	107	$438,646	$111,778	$550,424
201808	107	$525,966	$132,964	$658,930
201809	107	$424,742	$107,226	$531,968
201810	107	$520,798	$131,352	$652,150
201811	107	$453,103	$114,297	$567,400
201812	107	$381,131	$96,084	$477,215
201901	106	$427,299	$110,245	$537,544
201902	106	$356,262	$92,788	$449,050
201903	106	$679,729	$170,619	$850,348
201904	106	$771,619	$179,386	$951,005
201905	106	$719,833	$181,193	$901,026
201906	106	$561,256	$144,549	$705,805
201907	106	$666,251	$173,326	$839,577
201908	106	$711,346	$185,088	$896,434
201909	106	$650,450	$167,089	$817,539
201910	106	$712,942	$186,775	$899,717
201911	106	$639,205	$158,266	$797,471
201912	106	$697,513	$163,814	$861,327
202001	106	$696,414	$179,220	$875,634
202002	106	$576,095	$149,994	$726,089
202003	106	$705,613	$177,898	$883,511
202004	106	$765,722	$178,179	$943,901
Grand Total		**$35,121,648**	**$9,426,844**	**$44,548,493**

(1) - Headcount is for all Brown Steam Units; as Company does not allocate headcount between units. Brown 3 is not retiring. Remaining employees will offset existing FTE contractors.

Green River Steam

Month/Year	Headcount	Direct	Burdens	Grand Total
201501	41	$291,449	$66,339	$357,788
201502	39	$358,487	$79,676	$438,163
201503	37	$283,322	$63,147	$346,469
201504	37	$284,743	$59,481	$344,225
201505	37	$300,384	$62,368	$362,753
201506	37	$264,060	$57,382	$321,442
201507	37	$262,803	$56,738	$319,542
201508	37	$275,453	$59,612	$335,064
201509	37	$2,770,138	$561,594	$3,331,732
201510	27	$830,930	$236,675	$1,067,605
201511	4	-$100,251	$18,188	-$82,063
201512	4	$256,958	$8,449	$265,407
201601	4	$30,565	$7,793	$38,357
201602	4	$30,737	$7,426	$38,162
201603	3	$71,880	$10,361	$82,241
201604	3	$26,555	$6,667	$33,222
201605	3	$26,494	$6,610	$33,104
201606	3	$26,072	$6,573	$32,644
201607	3	$27,946	$14,148	$42,094
201608	3	$35,797	$19,137	$54,934
201609	3	$22,136	$14,208	$36,344
201610	3	$26,290	$17,008	$43,299
201611	3	$22,108	$15,022	$37,129
201612	3	$31,073	$23,140	$54,213
201701	1	$5,747	$2,766	$8,512
201702	1	$10,014	$2,855	$12,868
201703	1	$13,092	$3,732	$16,824
201704	0	$0	$0	$0
201705	0	$0	$0	$0
201706	0	$0	$0	$0
201707	0	$0	$0	$0
201708	0	$0	$0	$0
201709	0	$0	$0	$0
201710	0	$0	$0	$0
201711	0	$0	$0	$0
201712	0	$0	$0	$0
201801	0	$0	$0	$0

Green River Steam

Month/Year	Headcount	Direct	Burdens	Grand Total
201802	0	$0	$0	$0
201803	0	$0	$0	$0
201804	0	$0	$0	$0
201805	0	$0	$0	$0
201806	0	$0	$0	$0
201807	0	$0	$0	$0
201808	0	$0	$0	$0
201809	0	$0	$0	$0
201810	0	$0	$0	$0
201811	0	$0	$0	$0
201812	0	$0	$0	$0
201901	0	$0	$0	$0
201902	0	$0	$0	$0
201903	0	$0	$0	$0
201904	0	$0	$0	$0
201905	0	$0	$0	$0
201906	0	$0	$0	$0
201907	0	$0	$0	$0
201908	0	$0	$0	$0
201909	0	$0	$0	$0
201910	0	$0	$0	$0
201911	0	$0	$0	$0
201912	0	$0	$0	$0
202001	0	$0	$0	$0
202002	0	$0	$0	$0
202003	0	$0	$0	$0
202004	0	$0	$0	$0
Grand Total		**$6,484,983**	**$1,487,093**	**$7,972,076**

EXHIBIT ____ (LK-16)

KENTUCKY UTILITIES COMPANY

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated November 13, 2018

Case No. 2018-00294

Question No. 61

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

Q.1-61. Refer to page 36, line 19, through page 37, line 17, of Mr. Garrett's Direct Testimony wherein he describes changes to the deferred costs and amortization of generation plant outage expenses. Please provide a schedule showing the total company 2013, 2014, 2015, 2016, 2017, 2018 to date, base year and test year maintenance expenses recorded or budgeted if not yet incurred for generation plant maintenance and outage expenses by plant/unit and by FERC O&M expense account.

A.1-61. See attached.

KU Jurisdictional Generator Outage - Not normalized Unit	FERC	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual YTD October	Base Year	Test Year
0321 - TRIMBLE COUNTY 2 - GENERATION	510	$ -	$ 170,631	$ -	$ 246,762	$ -	$ -	$ -	$ 156,257
	511	-	-	2,693	-	-	50,193	50,193	-
	512	1,989	1,992,060	494,326	1,121,821	1,512,181	3,125,979	2,937,822	770,951
	513	1,436	168,959	139,686	838,407	167,838	1,904,619	1,643,247	2,537,951
5591 - KU GENERATION - COMMON	510	57,941	(62,537)	-	442	-	-	-	-
	513	-	-	-	-	-	-	-	-
5613 - GREEN RIVER UNIT 3 (1)	500	13,472	-	-	-	-	-	-	-
	510	44,178	-	-	-	-	-	-	-
	511	3,813	34,979	2,722	-	-	-	-	-
	512	186,803	698,782	249,813	-	-	-	-	-
	513	12,570	84,493	7,211	-	-	-	-	-
	514	-	-	-	-	-	-	-	-
5614 - GREEN RIVER UNIT 4(1)	500	80,138	-	-	-	-	-	-	-
	511	24,640	42,034	-	-	-	-	-	-
	512	834,933	652,914	686,268	-	-	-	-	-
	513	92,316	81,101	36,934	-	-	-	-	-
	514	15,692	3,436	489	-	-	-	-	-
5621 - E W BROWN UNIT 1(2)	510	54,019	-	234,710	-	-	17,581	24,966	-
	511	-	-	28,185	2,551	-	1,459	1,459	-
	512	314,065	342,658	770,115	424,173	170,514	165,342	163,293	-
	513	39,697	27,379	2,814,425	746,401	66,619	56,373	56,373	-
	514						395	395	-
5622 - E W BROWN UNIT 2(2)	510	95,776	155,756	(170,598)	(7,422)	-	86,647	79,263	-
	511	-	5,310	-	-	35	-	-	-
	512	688,190	519,286	177,554	524,039	319,321	146,367	144,734	-
	513	379,582	440,069	69,033	13,200	170,328	51,853	49,205	-
	514						1,050	1,444	-
5623 - E W BROWN UNIT 3	510	140,322	-	-	224,361	-	-	-	-
	511	-	-	1,930	-	799	-	-	-
	512	352,651	1,072,508	1,002,174	645,014	793,360	1,222,541	1,222,614	3,498,859
	513	59,679	90,586	566,909	77,949	169,502	114,587	106,175	5,338,184
	514	1,044	-	5,676	842	443	3,546	255	-
5624 - E W BROWN UNITS 1 & 2(3)	512	12,840	523	2,156	1,128	567	-	-	-
	513	8,839	-	-	2,497	-	-	-	-
	514	832	-	-	-	756	-	-	-
5625 - E W BROWN UNITS 2 & 3(2)	512	-	8,793	-	25,188	-	-	-	-
5630 - E W BROWN STEAM UNITS 1,2,3 SCRUBBER(2)	512	759	153,162	-	285,730	0	-	-	-
5651 - GHENT UNIT 1	510	-	-	701,055	-	-	351,731	354,066	-
	511	41,916	15,149	288,139	82,540	27,536	91,437	91,770	-
	512	1,967,332	2,150,500	3,921,111	1,365,142	1,722,885	2,829,518	2,760,866	3,080,760
	513	317,370	181,478	4,228,284	515,167	657,717	443,029	385,064	813,136
	514	715	79	53	321	227	-	-	-
5652 - GHENT UNIT 2	510	15,067	-	270,844	21,862	-	-	-	1,248,844
	511	9,231	24,888	38,347	44,419	117,136	-	-	-
	512	532,846	1,276,945	3,374,848	1,661,414	1,560,425	97,018	1,106,437	7,126,213
	513	99,002	358,005	748,493	596,452	582,492	34,505	678,317	1,982,962
	514	-	-	-	-	-	-	-	-

KU Jurisdictional Generator Outage - Not normalized Unit	FERC	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual YTD October	Base Year	Test Year
5653 - GHENT UNIT 3	510	-	283,560	-	-	984	441,348	946,718	-
	511	5,100	5,342	330	38,566	75,058	227,406	-	-
	512	864,538	3,587,624	2,220,256	2,282,186	1,560,943	2,571,243	2,319,563	2,007,930
	513	136,085	292,935	1,030,676	638,626	375,552	1,615,350	3,966,563	774,032
	514	-	144	180	-	-	567	-	-
5654 - GHENT UNIT 4	510	-	707,460	128,295	-	(984)	251,063	247,458	-
	511	409	52,774	8,577	112,854	16,550	83,750	69,684	-
	512	889,084	3,420,107	(97,614)	1,932,458	1,435,331	2,110,098	2,139,601	5,952,650
	513	89,934	3,519,889	119,526	350,705	423,903	543,382	530,093	1,538,959
	514	-	5,325	-	-	3,338	-	-	-
5655 - GHENT UNITS 1 & 2	511	-	-	1,985	-	-	-	-	-
	512	20,421	8,827	988	-	-	-	-	-
	513	-	598	1,687	20,994	-	-	-	-
5656 - GHENT UNITS 3 & 4	511	129	-	49	5,884	-	-	-	-
	512	1,716	5,592	-	-	-	-	-	-
	513	-	618	769	311	702	-	-	-
0172 - CANE RUN CC GT 2016	549	-	-	51,497	22	158,408	20,119	55	-
	551	-	-	-	-	-	-	-	456,615
	552	-	-	5,043	65,558	116,957	87,597	21,014	-
	553	-	-	133,338	680,409	1,332,856	524,255	(99,433)	3,096,143
	554	-	-	56,148	212,949	247,998	276,674	861,367	4,197,360
0432 - PADDYS RUN GT 13	553	33,788	76,980	44,366	59,562	106,504	138,890	61,976	105,033
	554	315	-	-	-	-	-	-	-
0470 - TRIMBLE COUNTY #5 COMBUSTION TURBINE	553	-	-	-	-	1,537	9,959	9,959	13,985
0471 - TRIMBLE COUNTY #6 COMBUSTION TURBINE	553	-	-	-	-	-	44,136	110,482	20,635
0474 - TRIMBLE COUNTY #7 COMBUSTION TURBINE	553	-	-	1,093	-	29,220	79,193	50,993	12,410
0475 - TRIMBLE COUNTY #8 COMBUSTION TURBINE	553	-	-	-	-	26,928	15,912	21,737	17,130
0476 - TRIMBLE COUNTY #9 COMBUSTION TURBINE	553	-	-	-	-	-	35,851	10,745	13,590
0477 - TRIMBLE COUNTY #10 COMBUSTION TURBINE	553	-	-	-	-	-	33,406	22,192	12,410
5635 - E W BROWN COMBUSTION TURBINE UNIT 5	553	-	-	-	-	188,025	-	-	-
	554	-	-	12,158	-	-	13,673	13,673	-
5636 - E W BROWN COMBUSTION TURBINE UNIT 6	551	-	-	-	-	-	-	-	-
	552	-	-	-	-	-	-	-	-
	553	23,019	63,267	18,187	6,492	(3,094)	-	14,919	14,664
	554	-	-	-	-	-	-	-	-
5637 - E W BROWN COMBUSTION TURBINE UNIT 7	553	(34,813)	130,959	(62,547)	29,506	-	-	-	29,645
5638 - E W BROWN COMBUSTION TURBINE UNIT 8	553	-	-	-	-	-	-	-	61,819
	554	-	-	-	-	-	541	541	-
5639 - E W BROWN COMBUSTION TURBINE UNIT 9	553	244,891	(14,057)	-	-	-	-	-	-
	554	-	30,555	-	-	-	-	-	-
5640 - E W BROWN COMBUSTION TURBINE UNIT 10	553	-	23,135	274,447	-	-	-	-	-
	554	-	-	33,825	-	-	-	-	-
5641 - E W BROWN COMBUSTION TURBINE UNIT 11	553	-	-	-	-	-	148,099	316,710	-
5645 - E W BROWN CT UNIT 9 GAS PIPELINE	554	-	-	-	141,017	44,490	-	-	-
5693 - HAEFLING UNIT 1	553	6,033	65	-	-	-	-	4,713	5,136
5694 - HAEFLING UNIT 2	553	6,033	65	-	-	-	-	4,713	5,136
5695 - CLOSED 03/14 - HAEFLING UNIT 3[3]	553	133,418	-	-	-	-	-	-	-
Total		$ 8,921,794	$ 22,891,690	$ 24,676,845	$ 16,038,500	$ 14,181,887	$ 20,068,282	$ 23,503,993	$ 44,889,398

(1) Green River units 3 and 4 were retired in 2015.
(2) E.W. Brown units 1 and 2 are expected to be retired in 2019.
(3) Haefling unit 3 was retired in 2013.

Case No. 2018-00294
Attachment to Response to KIUC-1 Question No. 61
Page 2 of 2
Arbough

EXHIBIT ____ (LK-17)

KENTUCKY UTILITIES COMPANY

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated November 13, 2018

Case No. 2018-00294

Question No. 80

Responding Witness: Daniel K. Arbough

Q.1-80. Provide a schedule showing generation outage costs by generating unit and in the aggregate for each month January 2017 through the end of the test year. In addition, provide the beginning balance of the generation outage regulatory asset, expense accruals (credits) to the generation outage regulatory asset, and charges to regulatory asset (debits) for each month January 2017 through the end of the test year.

A.1-80. See attached.

Unit	Jan-17 Actuals	Feb-17 Actuals	Mar-17 Actuals	Apr-17 Actuals	May-17 Actuals	Jun-17 Actuals
0172 - CANE RUN CC GT 2016	$ 5,357	$ (105,739)	$ 24	$ -	$ -	$ 169
0321 - TRIMBLE COUNTY 2 - GENERATION	94,491	80,054	1,493,340	112,611	25,038	(12,587)
0432 - PADDYS RUN GT 13	-	-	-	-	-	-
0470 - TRIMBLE COUNTY #5 COMBUSTION TURBINE	-	-	-	-	-	-
0471 - TRIMBLE COUNTY #6 COMBUSTION TURBINE	-	-	-	-	-	-
0474 - TRIMBLE COUNTY #7 COMBUSTION TURBINE	-	-	-	-	-	-
0475 - TRIMBLE COUNTY #8 COMBUSTION TURBINE	-	-	-	-	-	-
0476 - TRIMBLE COUNTY #9 COMBUSTION TURBINE	-	-	-	-	-	-
0477 - TRIMBLE COUNTY #10 COMBUSTION TURBINE	-	-	-	-	-	-
5621 - E W BROWN UNIT 1	22,070	18,891	192,256	10,058	(7,483)	(3,773)
5622 - E W BROWN UNIT 2	(16,168)	33,397	246,393	178,888	(11)	(6,143)
5623 - E W BROWN UNIT 3	11,226	30,451	16,981	546,487	189,906	(20,428)
5624 - E W BROWN UNITS 1 & 2	-	1,325	(2)	-	-	-
5635 - E W BROWN COMBUSTION TURBINE UNIT 5	-	-	-	-	-	-
5636 - E W BROWN COMBUSTION TURBINE UNIT 6	(3,094)	-	-	-	-	-
5637 - E W BROWN COMBUSTION TURBINE UNIT 7	-	-	-	-	-	-
5638 - E W BROWN COMBUSTION TURBINE UNIT 8	-	-	-	-	-	-
5641 - E W BROWN COMBUSTION TURBINE UNIT 11	-	-	-	-	-	-
5645 - E W BROWN CT UNIT 9 GAS PIPELINE	32	13,328	-	1,754	-	11,303
5651 - GHENT UNIT 1	54,647	111,253	1,797,911	363,702	58,083	14,936
5652 - GHENT UNIT 2	(2,158)	-	(4,793)	-	-	(6,586)
5653 - GHENT UNIT 3	6,810	1,717	-	-	89	369
5654 - GHENT UNIT 4	7,042	35,104	38,187	1,618,317	181,056	2,385
5656 - GHENT UNITS 3 & 4	-	-	-	1,223	(521)	-
5693 - HAEFLING UNIT 1	-	-	-	-	-	-
5694 - HAEFLING UNIT 2	-	-	-	-	-	-
Total Outage Expense	$ 180,255	$ 219,780	$ 3,780,297	$ 2,833,038	$ 446,155	$ (20,355)

Normalized Outage Cost (based on eight-year average)	N/A	N/A	N/A	N/A	N/A	N/A
Regulatory Asset Charges - Debits						
Regulatory Asset Amortization - Credits	N/A	N/A	N/A	N/A	N/A	N/A
Regulatory Asset (Liability) Balance	N/A	N/A	N/A	N/A	N/A	N/A

Unit	Jul-17 Actuals	Aug-17 Actuals	Sep-17 Actuals	Oct-17 Actuals	Nov-17 Actuals	Dec-17 Actuals
0172 - CANE RUN CC GT 2016	$ 21,069	$ 32,949	$ 51,213	$ 1,657,644	$ 151,808	$ 41,724
0321 - TRIMBLE COUNTY 2 - GENERATION	(45,144)	(95,325)	16,675	(1,069)	1,084	10,851
0432 - PADDYS RUN GT 13	-	-	-	-	71,106	35,398
0470 - TRIMBLE COUNTY #5 COMBUSTION TURBINE	-	1,114	-	-	-	424
0471 - TRIMBLE COUNTY #6 COMBUSTION TURBINE		-	-	-	-	-
0474 - TRIMBLE COUNTY #7 COMBUSTION TURBINE	-	-	9,491	19,285	444	-
0475 - TRIMBLE COUNTY #8 COMBUSTION TURBINE	-	1,188	15,442	10,298	-	-
0476 - TRIMBLE COUNTY #9 COMBUSTION TURBINE		-	-	-	-	-
0477 - TRIMBLE COUNTY #10 COMBUSTION TURBINE		-	-	-	-	-
5621 - E W BROWN UNIT 1	-	-	5,115		-	-
5622 - E W BROWN UNIT 2	(1.967)	238	186	1,465	-	53,408
5623 - E W BROWN UNIT 3	(22,881)	4,480	240	9,332	107,440	90,870
5624 - E W BROWN UNITS 1 & 2	-	-			-	-
5635 - E W BROWN COMBUSTION TURBINE UNIT 5	-	-	12,777	112,729	76,592	(14,072)
5636 - E W BROWN COMBUSTION TURBINE UNIT 6	-	-	-	-	-	-
5637 - E W BROWN COMBUSTION TURBINE UNIT 7	-	-	-	-	-	-
5638 - E W BROWN COMBUSTION TURBINE UNIT 8	-	-	-	-	-	-
5641 - E W BROWN COMBUSTION TURBINE UNIT 11	-	-	-	-	-	-
5645 - E W BROWN CT UNIT 9 GAS PIPELINE	20,722	(2,649)	-	-	-	-
5651 - GHENT UNIT 1	3,314	(884)	758	4,645	-	-
5652 - GHENT UNIT 2	1,030	11,208	108,107	785,800	1,252,463	114,981
5653 - GHENT UNIT 3	37,475	11,540	98,295	1,149,068	706,906	268
5654 - GHENT UNIT 4	(4,827)	584		(86)	379	-
5656 - GHENT UNITS 3 & 4	-	-	-	-	-	-
5693 - HAEFLING UNIT 1	-	-	-	-	-	-
5694 - HAEFLING UNIT 2	-	-	-	-	-	-
Total Outage Expense	$ 8,790	$ (35,558)	$ 318,300	$ 3,749,111	$ 2,368,222	$ 333,851
Normalized Outage Cost (based on eight-year average)	55,660	37,324	665,186	4,196,615	2,688,408	319,661
Regulatory Asset Charges - Debits	(46,870)	(72,882)	(346,886)	(447,504)	(320,186)	14,191
Regulatory Asset Amortization - Credits	N/A	N/A	N/A	N/A	N/A	N/A
Regulatory Asset (Liability) Balance	$ (46,870)	$ (119,752)	$ (466,639)	$ (914,143)	$ (1,234,329)	$ (1,220,138)

Unit	Jan-18 Actuals	Feb-18 Actuals	Mar-18 Actuals	Apr-18 Actuals	May-18 Actuals	Jun-18 Forecast
0172 - CANE RUN CC GT 2016	$ 37,314	$ (147,708)	$ 832	$ -	$ 33,493	$ -
0321 - TRIMBLE COUNTY 2 - GENERATION	211,678	214,424	2,495,229	1,402,456	307,475	-
0432 - PADDYS RUN GT 13	18,099	-		-	-	-
0470 - TRIMBLE COUNTY #5 COMBUSTION TURBINE	-	-	8,783	1,176	1	-
0471 - TRIMBLE COUNTY #6 COMBUSTION TURBINE	-	-	9,853	3,804	2,048	37,168
0474 - TRIMBLE COUNTY #7 COMBUSTION TURBINE	-	16,364	-	-		-
0475 - TRIMBLE COUNTY #8 COMBUSTION TURBINE	-	366	-	-	3,216	-
0476 - TRIMBLE COUNTY #9 COMBUSTION TURBINE	-	-	-	310	10,434	-
0477 - TRIMBLE COUNTY #10 COMBUSTION TURBINE	-	-	-		22,192	-
5621 - E W BROWN UNIT 1	728	14,838	13,438	211,093	1,841	4,547
5622 - E W BROWN UNIT 2		3,069	5,600	219,323	43,221	3,433
5623 - E W BROWN UNIT 3	5,498	106,833	26,414	804,733	268,798	36,311
5624 - E W BROWN UNITS 1 & 2	-	-	-		-	-
5635 - E W BROWN COMBUSTION TURBINE UNIT 5		-	-	13,122	551	-
5636 - E W BROWN COMBUSTION TURBINE UNIT 6	-	-	-	-	-	-
5637 - E W BROWN COMBUSTION TURBINE UNIT 7	-	-	-	-	-	-
5638 - E W BROWN COMBUSTION TURBINE UNIT 8	-	-	-	541	-	-
5641 - E W BROWN COMBUSTION TURBINE UNIT 11	-	-	-	-	-	-
5645 - E W BROWN CT UNIT 9 GAS PIPELINE	-	-	-	-	-	-
5651 - GHENT UNIT 1	65,052	109,153	2,852,445	532,499	7,046	-
5652 - GHENT UNIT 2	50,354	2,949			-	-
5653 - GHENT UNIT 3	4,078	4,149	7,082	15,393	1,736	-
5654 - GHENT UNIT 4	10,860	51,992	109,225	2,199,470	596,852	-
5656 - GHENT UNITS 3 & 4	-	-	-	-	-	-
5693 - HAEFLING UNIT 1	-	-	-	-	-	-
5694 - HAEFLING UNIT 2	-	-	-	-	-	-
Total Outage Expense	$ 403,662	$ 376,429	$ 5,528,900	$ 5,403,920	$ 1,298,904	$ 81,458
Normalized Outage Cost (based on eight-year average)	54,451	460,136	4,303,887	6,216,749	1,417,797	78,721
Regulatory Asset Charges - Debits	349,211	(83,707)	1,225,013	(812,829)	(118,892)	2,737
Regulatory Asset Amortization - Credits	N/A	N/A	N/A	N/A	N/A	N/A
Regulatory Asset (Liability) Balance	$ (870,927)	$ (954,634)	$ 270,379	$ (542,450)	$ (661,342)	$ (658,606)

Unit	Jul-18 Forecast	Aug-18 Forecast	Sep-18 Forecast	Oct-18 Forecast	Nov-18 Forecast	Dec-18 Forecast
0172 - CANE RUN CC GT 2016	$ -	$ -	$ -	$ 859,072	$ -	$ -
0321 - TRIMBLE COUNTY 2 - GENERATION	-	-	-	-	-	-
0432 - PADDYS RUN GT 13	-	-	-	43,877	-	-
0470 - TRIMBLE COUNTY #5 COMBUSTION TURBINE	-	-	-	-	-	-
0471 - TRIMBLE COUNTY #6 COMBUSTION TURBINE	57,610	-	-	-	-	-
0474 - TRIMBLE COUNTY #7 COMBUSTION TURBINE	-	-	-	1,099	33,529	-
0475 - TRIMBLE COUNTY #8 COMBUSTION TURBINE	-	-	-	1,099	17,056	-
0476 - TRIMBLE COUNTY #9 COMBUSTION TURBINE	-	-	-	-	-	-
0477 - TRIMBLE COUNTY #10 COMBUSTION TURBINE	-	-	-	-	-	-
5621 - E W BROWN UNIT 1	-	-	-	-	-	-
5622 - E W BROWN UNIT 2	-	-	-	-	-	-
5623 - E W BROWN UNIT 3	80,456	-	-	-	-	-
5624 - E W BROWN UNITS 1 & 2	-	-	-	-	-	-
5635 - E W BROWN COMBUSTION TURBINE UNIT 5	-	-	-	-	-	-
5636 - E W BROWN COMBUSTION TURBINE UNIT 6	-	-	-	-	14,919	-
5637 - E W BROWN COMBUSTION TURBINE UNIT 7	-	-	-	-	-	-
5638 - E W BROWN COMBUSTION TURBINE UNIT 8	-	-	-	-	-	-
5641 - E W BROWN COMBUSTION TURBINE UNIT 11	-	-	-	316,710	-	-
5645 - E W BROWN CT UNIT 9 GAS PIPELINE	-	-	-	-	-	-
5651 - GHENT UNIT 1	25,570	-	-	-	-	-
5652 - GHENT UNIT 2	-	-	-	-	1,526,653	204,798
5653 - GHENT UNIT 3	-	148,457	2.464,331	4,054,903	532,715	-
5654 - GHENT UNIT 4	18,438	-	-	-	-	-
5656 - GHENT UNITS 3 & 4	-	-	-	-	-	-
5693 - HAEFLING UNIT 1	-	-	-	-	4,713	-
5694 - HAEFLING UNIT 2	-	-	-	-	4,713	-
Total Outage Expense	$ 182,074	$ 148,457	$ 2,464,331	$ 5,276,761	$ 2,134,298	$ 204,798
Normalized Outage Cost (based on eight-year average)	55,661	37,324	665,186	4,196,615	2,688,408	319,661
Regulatory Asset Charges - Debits	126,413	111,133	1,799,145	1,080,146	(554,110)	(114,863)
Regulatory Asset Amortization - Credits	N/A	N/A	N/A	N/A	N/A	N/A
Regulatory Asset (Liability) Balance	$ (532,193)	$ (421,060)	$ 1,378,085	$ 2,458,231	$ 1,904,121	$ 1,789,258

Unit	Jan-19 Forecast	Feb-19 Forecast	Mar-19 Forecast	Apr-19 Forecast	May-19 Forecast	Jun-19 Forecast
0172 - CANE RUN CC GT 2016	$ -	$ -	$ -	$ -	$ -	$ -
0321 - TRIMBLE COUNTY 2 - GENERATION	-	133,690	659,270	583,391	8,847	-
0432 - PADDYS RUN GT 13	-	-	-	-	-	-
0470 - TRIMBLE COUNTY #5 COMBUSTION TURBINE	-	-	25,416	-	1,330	-
0471 - TRIMBLE COUNTY #6 COMBUSTION TURBINE	-	-	6,832	-	-	-
0474 - TRIMBLE COUNTY #7 COMBUSTION TURBINE	-	-	-	-	4,721	-
0475 - TRIMBLE COUNTY #8 COMBUSTION TURBINE	-	-	-	-	4,721	-
0476 - TRIMBLE COUNTY #9 COMBUSTION TURBINE	-	-	-	-	13,590	-
0477 - TRIMBLE COUNTY #10 COMBUSTION TURBINE	-	-	-	-	12,410	-
5621 - E W BROWN UNIT 1	-	-	-	-	-	-
5622 - E W BROWN UNIT 2	-	-	-	-	-	-
5623 - E W BROWN UNIT 3	-	-	-	46,873	-	-
5624 - E W BROWN UNITS 1 & 2	-	-	-			-
5635 - E W BROWN COMBUSTION TURBINE UNIT 5	-	-	-			-
5636 - E W BROWN COMBUSTION TURBINE UNIT 6	-	-	-	427,275	-	-
5637 - E W BROWN COMBUSTION TURBINE UNIT 7	-	-	-	0	-	-
5638 - E W BROWN COMBUSTION TURBINE UNIT 8	-	-	-	57,584	-	-
5641 - E W BROWN COMBUSTION TURBINE UNIT 11	-	-	-	-	-	-
5645 - E W BROWN CT UNIT 9 GAS PIPELINE	-	-	-	-	-	-
5651 - GHENT UNIT 1	-	-	22,007	2,046,632	171,264	-
5652 - GHENT UNIT 2	-	-	-	-	-	-
5653 - GHENT UNIT 3	-	-	-	-	-	-
5654 - GHENT UNIT 4	-	-	3,277,981	74,823	-	-
5656 - GHENT UNITS 3 & 4	-	-	-	-	-	-
5693 - HAEFLING UNIT 1	-	-	-	-	-	-
5694 - HAEFLING UNIT 2	-	-	-	-	-	-
Total Outage Expense	$ -	$ 133,690	$ 3,991,507	$ 3,236,577	$ 216,882	$ -
Normalized Outage Cost (based on eight-year average)	54,451	460,136	4,303,887	6,216,749	1,446,112	(59,494)
Regulatory Asset Charges - Debits	(54,451)	(326,446)	(312,380)	(2,980,172)	(1,229,231)	59,494
Regulatory Asset Amortization - Credits	N/A	N/A	N/A	N/A	19,627	19,627
Regulatory Asset (Liability) Balance	$ 1,734,807	$ 1,408,361	$ 1,095,981	$ (1,884,191)	$ (3,093,795)	$ (3,014,674)

Unit	Jul-19 Forecast	Aug-19 Forecast	Sep-19 Forecast	Oct-19 Forecast	Nov-19 Forecast	Dec-19 Forecast
0172 - CANE RUN CC GT 2016	$ -	$ -	$ 365,049	$ 608,414	$ -	$ -
0321 - TRIMBLE COUNTY 2 - GENERATION	-	-	-	-	-	-
0432 - PADDYS RUN GT 13	-	-	-	-	21,989	83,044
0470 - TRIMBLE COUNTY #5 COMBUSTION TURBINE	-	-	-	-	-	-
0471 - TRIMBLE COUNTY #6 COMBUSTION TURBINE	-	-	-	-	-	-
0474 - TRIMBLE COUNTY #7 COMBUSTION TURBINE	-	-	-	-	7,689	-
0475 - TRIMBLE COUNTY #8 COMBUSTION TURBINE	-	-	-	-	12,410	-
0476 - TRIMBLE COUNTY #9 COMBUSTION TURBINE	-	-	-	-	-	-
0477 - TRIMBLE COUNTY #10 COMBUSTION TURBINE	-	-	-	-	-	-
5621 - E W BROWN UNIT 1	-	-	-	-	-	-
5622 - E W BROWN UNIT 2	-	-	-	-	-	-
5623 - E W BROWN UNIT 3	-	-	-	3,644,753	3,644,753	-
5624 - E W BROWN UNITS 1 & 2	-	-	-	-	-	-
5635 - E W BROWN COMBUSTION TURBINE UNIT 5	-	-	-	-	-	-
5636 - E W BROWN COMBUSTION TURBINE UNIT 6	-	-	-	-	-	-
5637 - E W BROWN COMBUSTION TURBINE UNIT 7	-	-	14,712	-	-	-
5638 - E W BROWN COMBUSTION TURBINE UNIT 8	-	-	-	-	-	-
5641 - E W BROWN COMBUSTION TURBINE UNIT 11	-	-	-	-	-	-
5645 - E W BROWN CT UNIT 9 GAS PIPELINE	-	-	-	-	-	-
5651 - GHENT UNIT 1	-	-	-	-	-	-
5652 - GHENT UNIT 2	-	-	889,574	5,238,999	4,229,447	-
5653 - GHENT UNIT 3	-	-	-	-	2,621,990	159,972
5654 - GHENT UNIT 4	-	-	-	-	-	-
5656 - GHENT UNITS 3 & 4	-	-	-	-	-	-
5693 - HAEFLING UNIT 1	-	-	-	-	5,136	-
5694 - HAEFLING UNIT 2	-	-	-	-	5,136	-
Total Outage Expense	$ -	$ -	$ 1,269,335	$ 9,492,167	$ 10,548,549	$ 243,016
Normalized Outage Cost (based on eight-year average)	30,409	26,792	612,431	4,993,311	3,465,033	250,187
Regulatory Asset Charges - Debits	(30,409)	(26,792)	656,904	4,498,856	7,083,516	(7,172)
Regulatory Asset Amortization - Credits	19,627	19,627	19,627	19,627	19,627	19,627
Regulatory Asset (Liability) Balance	$ (3,025,455)	$ (3,032,621)	$ (2,356,089)	$ 2,162,393	$ 9,265,536	$ 9,277,991

Unit	Jan-20 Forecast	Feb-20 Forecast	Mar-20 Forecast	Apr-20 Forecast
0172 - CANE RUN CC GT 2016	$ -	$ 1,076,779	$ 5,699,875	$ -
0321 - TRIMBLE COUNTY 2 - GENERATION	-	114,333	1,721,533	1,620,446
0432 - PADDYS RUN GT 13	-	-	-	-
0470 - TRIMBLE COUNTY #5 COMBUSTION TURBINE	-	-	12,655	-
0471 - TRIMBLE COUNTY #6 COMBUSTION TURBINE	-	-	20,635	-
0474 - TRIMBLE COUNTY #7 COMBUSTION TURBINE	-	-	-	-
0475 - TRIMBLE COUNTY #8 COMBUSTION TURBINE	-	-	-	-
0476 - TRIMBLE COUNTY #9 COMBUSTION TURBINE	-	-	-	-
0477 - TRIMBLE COUNTY #10 COMBUSTION TURBINE	-	-	-	-
5621 - E W BROWN UNIT 1	-	-	-	
5622 - E W BROWN UNIT 2	-	-	-	
5623 - E W BROWN UNIT 3	-	-	386,884	1,160,653
5624 - E W BROWN UNITS 1 & 2	-	-	-	
5635 - E W BROWN COMBUSTION TURBINE UNIT 5	-	-	-	
5636 - E W BROWN COMBUSTION TURBINE UNIT 6	-	-	14,664	-
5637 - E W BROWN COMBUSTION TURBINE UNIT 7	-	-	14,933	-
5638 - E W BROWN COMBUSTION TURBINE UNIT 8	-	-	-	61,819
5641 - E W BROWN COMBUSTION TURBINE UNIT 11	-	-	-	
5645 - E W BROWN CT UNIT 9 GAS PIPELINE	-	-	-	
5651 - GHENT UNIT 1	-	263,483	3,459,150	-
5652 - GHENT UNIT 2	-	-	-	-
5653 - GHENT UNIT 3	-	-	-	-
5654 - GHENT UNIT 4	-	-	2,597,421	4,894,192
5656 - GHENT UNITS 3 & 4	-	-	-	
5693 - HAEFLING UNIT 1	-	-	-	-
5694 - HAEFLING UNIT 2	-	-	-	-
Total Outage Expense	**$ -**	**$ 1,454,594**	**$ 13,927,748**	**$ 7,737,109**
Normalized Outage Cost (based on eight-year average)	**103,165**	**407,775**	**6,091,359**	**5,752,433**
Regulatory Asset Charges - Debits	**(103,165)**	**1,046,819**	**7,836,389**	**1,984,676**
Regulatory Asset Amortization - Credits	**19,627**	**19,627**	**19,627**	**19,627**
Regulatory Asset (Liability) Balance	**$ 9,194,453**	**$ 10,260,900**	**$ 18,116,916**	**$ 20,121,219**

EXHIBIT ____ (LK-18)

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated November 13, 2018

Case No. 2018-00295

Question No. 53

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

Q.1-53. Refer to page 36, line 19, through page 37, line 17, of Mr. Garrett's Direct Testimony wherein he describes changes to the deferred costs and amortization of generation plant outage expenses. Please provide a schedule showing the total company 2014, 2015, 2016, 2017, 2018, base year and test year maintenance expenses recorded or budgeted if not yet incurred for generation plant maintenance and outage expenses by plant/unit and by FERC O&M expense account.

A.1-53. See attached.

LG&E Outage - Not normalized Unit	FERC	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual YTD October	Base Year	Test Year
0311 - TRIMBLE COUNTY 1 - GENERATION	510	$ 111,518	$ 99,690	$ -	$ -	$ 657,584	$ -	$ -	$ -
	511	6,261	-	2,327	(987)	294,536	2,184	2,184	-
	512	945,856	4,464	2,192,311	86,660	4,191,657	74,958	18,976	2,699,137
	513	142,810	11,994	300,174	6,218	2,884,257	336,964	327,857	799,252
	514	-	-	-	-	6,324	-	-	-
0321 - TRIMBLE COUNTY 2 - GENERATION	510	-	46,072	-	66,543	-	-	-	39,187
	511	-	-	727	-	-	13,537	13,537	-
	512	533	531,445	131,801	299,329	406,179	832,993	782,958	192,178
	513	385	45,075	37,244	223,707	44,738	507,532	437,854	632,642
0401 - LGE GENERATION - COMMON	510	113,441	(213,381)	(90,334)	(7,152)	1,483	-	-	-
	513	-	-	-	-	-	-		-
0141 - CANE RUN 4 - GENERATION[1]	500	-	-	-	-	-	-	-	-
	510	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-
	512	120,277	468,671	-	-	-	-	-	-
	513	38,394	83,706	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-
0151 - CANE RUN 5 - GENERATION[1]	500	-	-	-	-	-	-	-	-
	511	-	-	-	-	-	-	-	-
	512	955,239	264,620	-	-	-	-	-	-
	513	217,596	58,038	-	-	-	-	-	-
	514	-	-	-	-	-	-	-	-
0161 - CANE RUN 6 - GENERATION[1]	510	-	-	-	-	-	-	-	-
	511	-	282	-	-	-	-	-	-
	512	319,077	589,175	707	-	-	-	-	-
	513	204,896	229,866	394	-	-	-	-	-
0211 - MILL CREEK 1 - GENERATION	510	278,017	-	426,475	-	205,869	-	-	-
	511	10,987	-	-	-	137	-	-	-
	512	2,538,798	90,155	1,969,498	190,030	2,399,835	595,185	594,837	975,000
	513	3,081,978	16,606	234,337	125,463	1,306,372	100,895	97,927	2,405,000
	514	-	-	-	-	-	1,181	1,181	-
0221 - MILL CREEK 2 - GENERATION	510	9,956	-	394,549	-	-	-	-	620,000
	511	-	-	-	-	-	-	-	-
	512	1,688	2,035,209	1,963,564	1,768,972	279,504	2,123,097	2,034,104	1,760,002
	513	2,834	235,191	622,480	1,347,379	97,951	2,272,268	2,526,632	2,160,000
	514	-	-	-	-	1,892	4,862	4,862	-
0231 - MILL CREEK 3 - GENERATION	510	338,409	283,456	-	112,896	-	-	-	1,177,500
	511	-	-	-	-	-	44,758	44,758	-
	512	3,252,673	34,968	327,318	2,942,769	192,702	2,459,145	2,474,261	1,730,000
	513	659,233	20,126	124,442	1,775,339	164,988	480,718	423,613	5,400,000
	514	124	-	-	-	-	-	-	-

LG&E Outage - Not normalized Unit	FERC	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual YTD October	Base Year	Test Year
0241 - MILL CREEK 4 - GENERATION	510	-	182,368	162,660	252,274	-	387,379	755,000	-
	511	-	-	-	12,335	8,270	24,210	-	-
	512	1,167,712	3,003,378	382,445	2,702,899	1,202,084	2,757,753	3,163,453	425,000
	513	124,182	3,756,372	123,461	574,125	163,038	1,518,116	2,650,327	220,000
	514	-	-	-	-	1,023	1,306	201	-
0172 - CANE RUN CC GT 2016	549	-	-	16,661	4,276	51,227	6,504	-	-
	551						-		137,500
	552	-	-	1,631	21,191	37,823	28,318	6,781	-
	553	-	-	43,139	219,940	431,030	169,479	(130,216)	932,338
	554	-	-	18,166	68,835	80,200	89,442	278,430	1,263,947
0431 - PADDYS RUN GT 12	553	27,835	-	-	-	-	-	-	-
	554	-	-	-	-	-	-	-	-
0432 - PADDYS RUN GT 13	553	43,835	99,436	57,388	76,976	137,702	179,512	665,111	126,452
	554	409	-	-	-	-	-	-	-
0470 - TRIMBLE COUNTY #5 COMBUSTION TURBINE	553	-	-	-	-	720	4,662	4,715	6,099
0471 - TRIMBLE COUNTY #6 COMBUSTION TURBINE	553	-	-	-	-	-	20,662	20,670	8,999
0474 - TRIMBLE COUNTY #7 COMBUSTION TURBINE	553	-	-	737	-	19,708	53,308	34,325	7,781
0475 - TRIMBLE COUNTY #8 COMBUSTION TURBINE	553	-	-	-	-	18,101	10,711	14,632	10,741
0476 - TRIMBLE COUNTY #9 COMBUSTION TURBINE	553	-	-	-	-	-	24,133	7,169	8,521
0477 - TRIMBLE COUNTY #10 COMBUSTION TURBINE	553	-	-	-	-	-	22,487	14,939	7,781
5635 - E W BROWN COMBUSTION TURBINE UNIT 5	553	-	-	-	-	243,103	-	-	-
	554	-	-	15,726	-	-	17,672	17,672	-
5636 - E W BROWN COMBUSTION TURBINE UNIT 6	551	-	-	-	-	-	-	-	-
	552	-	-	-	-	-	-	-	-
	553	16,232	44,418	12,786	4,560	(2,174)	-	27,900	9,595
	554	-	-	-	-	-	-	-	-
5637 - E W BROWN COMBUSTION TURBINE UNIT 7	553	(24,548)	91,942	(43,973)	20,726	-	-	-	19,398
							-		
Total		$ 14,706,633	$ 12,113,341	$ 9,428,840	$ 12,895,303	$ 15,527,861	$ 15,165,930	$ 17,316,650	$ 23,774,050

(1) Cane Run units 4,5 and 6 were retired in 2015.

EXHIBIT ____ (LK-19)

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated November 13, 2018

Case No. 2018-00295

Question No. 69

Responding Witness: Daniel K. Arbough

Q.1-69. Provide a schedule showing generation outage costs by generating unit and in the aggregate for each month January 2017 through the end of the test year. In addition, provide the beginning balance of the generation outage regulatory asset, expense accruals (credits) to the generation outage regulatory asset, and charges to regulatory asset (debits) for each month January 2017 through the end of the test year.

A.1-69. See attached.

Unit	Jan-17 Actuals	Feb-17 Actuals	Mar-17 Actuals	Apr-17 Actuals	May-17 Actuals	Jun-17 Actuals
0172 - CANE RUN CC GT 2016	$ 1,733	$ (34,195)	$ 8	$ -	$ -	$ 55
0211 - MILL CREEK 1 - GENERATION	5,062	(10,730)	356,467	3,545,960	43,768	(214)
0221 - MILL CREEK 2 - GENERATION	(8,566)	13,810	50,008	296,939	22,168	4,333
0231 - MILL CREEK 3 - GENERATION	1,033	39,751	322,142	39,802	2,363	(42,660)
0241 - MILL CREEK 4 - GENERATION	150,975	(196,137)	16,412	3,065	746	11,324
0311 - TRIMBLE COUNTY 1 - GENERATION	72	-	-	-	2,486	49,224
0321 - TRIMBLE COUNTY 2 - GENERATION	25,212	21,360	398,459	30,047	6,681	(3,358)
0401 - LGE GENERATION - COMMON	14,929	(14,929)	-	-	-	-
0432 - PADDYS RUN GT 13	-	-	-	-	-	-
0460 - BROWN COMBUSTION TURBINE #6	-	-	-	-	-	-
0461 - BROWN COMBUSTION TURBINE #7	-	-	-	-	-	-
0470 - TRIMBLE COUNTY #5 COMBUSTION TURBINE	-	-	-	-	-	-
0471 - TRIMBLE COUNTY #6 COMBUSTION TURBINE	-	-	-	-	-	-
0474 - TRIMBLE COUNTY #7 COMBUSTION TURBINE	-	-	-	-	-	-
0475 - TRIMBLE COUNTY #8 COMBUSTION TURBINE	-	-	-	-	-	-
0476 - TRIMBLE COUNTY #9 COMBUSTION TURBINE	-	-	-	-	-	-
0477 - TRIMBLE COUNTY #10 COMBUSTION TURBINE	-	-	-	-	-	-
5635 - E W BROWN COMBUSTION TURBINE UNIT 5	-	-	-	-	-	-
5636 - E W BROWN COMBUSTION TURBINE UNIT 6	(2,174)	-	-	-	-	-
Total Outage Expense	$ 188,275	$ (181,068)	$ 1,143,496	$ 3,915,814	$ 78,212	$ 18,703
Normalized Outage Cost (based on eight-year average)	N/A	N/A	N/A	N/A	N/A	N/A
Regulatory Asset Charges - Debits						
Regulatory Asset Amortization - Credits	N/A	N/A	N/A	N/A	N/A	N/A
Regulatory Asset (Liability) Balance	N/A	N/A	N/A	N/A	N/A	N/A

Unit	Jul-17 Actuals	Aug-17 Actuals	Sep-17 Actuals	Oct-17 Actuals	Nov-17 Actuals	Dec-17 Actuals
0172 - CANE RUN CC GT 2016	$ 5,942	$ 11,526	$ 16,562	$ 536,063	$ 49,093	$ 13,493
0211 - MILL CREEK 1 - GENERATION	552	(19,663)	(8,990)	-	-	-
0221 - MILL CREEK 2 - GENERATION	500	(29)	-	72	-	112
0231 - MILL CREEK 3 - GENERATION	(5,732)	834	-	-	156	0
0241 - MILL CREEK 4 - GENERATION	13,647	32,636	100,413	243,979	1,008,428	(11,074)
0311 - TRIMBLE COUNTY 1 - GENERATION	82,302	155,178	592,420	4,110,077	2,447,257	595,343
0321 - TRIMBLE COUNTY 2 - GENERATION	(10,589)	(24,244)	4,449	(285)	289	2,895
0401 - LGE GENERATION - COMMON	-	-	1,483	-	-	-
0432 - PADDYS RUN GT 13	-	-	-	-	91,935	45,767
0460 - BROWN COMBUSTION TURBINE #6	-	-	-	-	-	-
0461 - BROWN COMBUSTION TURBINE #7	-	-	-	-	-	-
0470 - TRIMBLE COUNTY #5 COMBUSTION TURBINE	-	521	-	-	-	198
0471 - TRIMBLE COUNTY #6 COMBUSTION TURBINE	-		-	-	-	-
0474 - TRIMBLE COUNTY #7 COMBUSTION TURBINE	-	31	6,391	12,986	299	-
0475 - TRIMBLE COUNTY #8 COMBUSTION TURBINE	-	769	10,398	6,934	-	-
0476 - TRIMBLE COUNTY #9 COMBUSTION TURBINE	-	-	-	-	-	-
0477 - TRIMBLE COUNTY #10 COMBUSTION TURBINE	-	-	-	-	-	-
5635 - E W BROWN COMBUSTION TURBINE UNIT 5	-	-	16,519	145,750	99,028	(18,195)
5636 - E W BROWN COMBUSTION TURBINE UNIT 6	-	-	-	-	-	-
Total Outage Expense	**$ 86,621**	**$ 157,560**	**$ 739,646**	**$ 5,055,576**	**$ 3,696,485**	**$ 628,541**
Normalized Outage Cost (based on eight-year average)	**$ (29,571)**	**$ 41,572**	**$ 573,624**	**$ 3,941,386**	**$ 2,631,691**	**$ 162,411**
Regulatory Asset Charges - Debits	**116,192**	**115,989**	**166,022**	**1,114,190**	**1,064,793**	**466,130**
Regulatory Asset Amortization - Credits	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
Regulatory Asset (Liability) Balance	**$ 116,192**	**$ 232,181**	**$ 398,203**	**$ 1,512,393**	**$ 2,577,186**	**$ 3,043,316**

Unit	Jan-18 Actuals	Feb-18 Actuals	Mar-18 Actuals	Apr-18 Actuals	May-18 Actuals	Jun-18 Forecast
0172 - CANE RUN CC GT 2016	$ 12,067	$ (47,750)	$ -	$ -	$ 10,827	$ 1,351
0211 - MILL CREEK 1 - GENERATION	4,497	8,617	608,199	71,831	801	-
0221 - MILL CREEK 2 - GENERATION	55,860	312,809	1,843,349	1,496,090	312,490	212,000
0231 - MILL CREEK 3 - GENERATION	26,940	52,793	73,116	2,498,505	286,278	5,000
0241 - MILL CREEK 4 - GENERATION	5,720	972	(3,722)	11,955	14,055	-
0311 - TRIMBLE COUNTY 1 - GENERATION	(51,802)	163,659	179,958	20,967	11,485	24,750
0321 - TRIMBLE COUNTY 2 - GENERATION	56,481	57,139	664,948	373,839	81,943	-
0401 - LGE GENERATION - COMMON	-	-	-	-	-	-
0432 - PADDYS RUN GT 13	23,401	-	-	-	-	-
0460 - BROWN COMBUSTION TURBINE #6	-	-	-	-	-	-
0461 - BROWN COMBUSTION TURBINE #7	-	-	-	-	-	-
0470 - TRIMBLE COUNTY #5 COMBUSTION TURBINE	-	-	4,112	603	0	-
0471 - TRIMBLE COUNTY #6 COMBUSTION TURBINE	-	-	4,613	1,728	959	(13,600)
0474 - TRIMBLE COUNTY #7 COMBUSTION TURBINE	-	11,015	-	-	-	-
0475 - TRIMBLE COUNTY #8 COMBUSTION TURBINE	-	246	-	-	2,165	-
0476 - TRIMBLE COUNTY #9 COMBUSTION TURBINE	-	-	-	145	7,024	-
0477 - TRIMBLE COUNTY #10 COMBUSTION TURBINE	-	-	-	-	14,939	-
5635 - E W BROWN COMBUSTION TURBINE UNIT 5	-	-	-	16,960	712	-
5636 - E W BROWN COMBUSTION TURBINE UNIT 6	-	-	-	-	-	-
Total Outage Expense	$ 133,164	$ 559,500	$ 3,374,572	$ 4,492,623	$ 743,678	$ 229,501
Normalized Outage Cost (based on eight-year average)	$ 48,940	$ 174,306	$ 1,606,487	$ 3,925,814	$ 995,000	$ 56,827
Regulatory Asset Charges - Debits	84,223	385,194	1,768,084	566,809	(251,322)	172,674
Regulatory Asset Amortization - Credits	N/A	N/A	N/A	N/A	N/A	N/A
Regulatory Asset (Liability) Balance	$ 3,127,539	$ 3,512,733	$ 5,280,818	$ 5,847,627	$ 5,596,305	$ 5,768,980

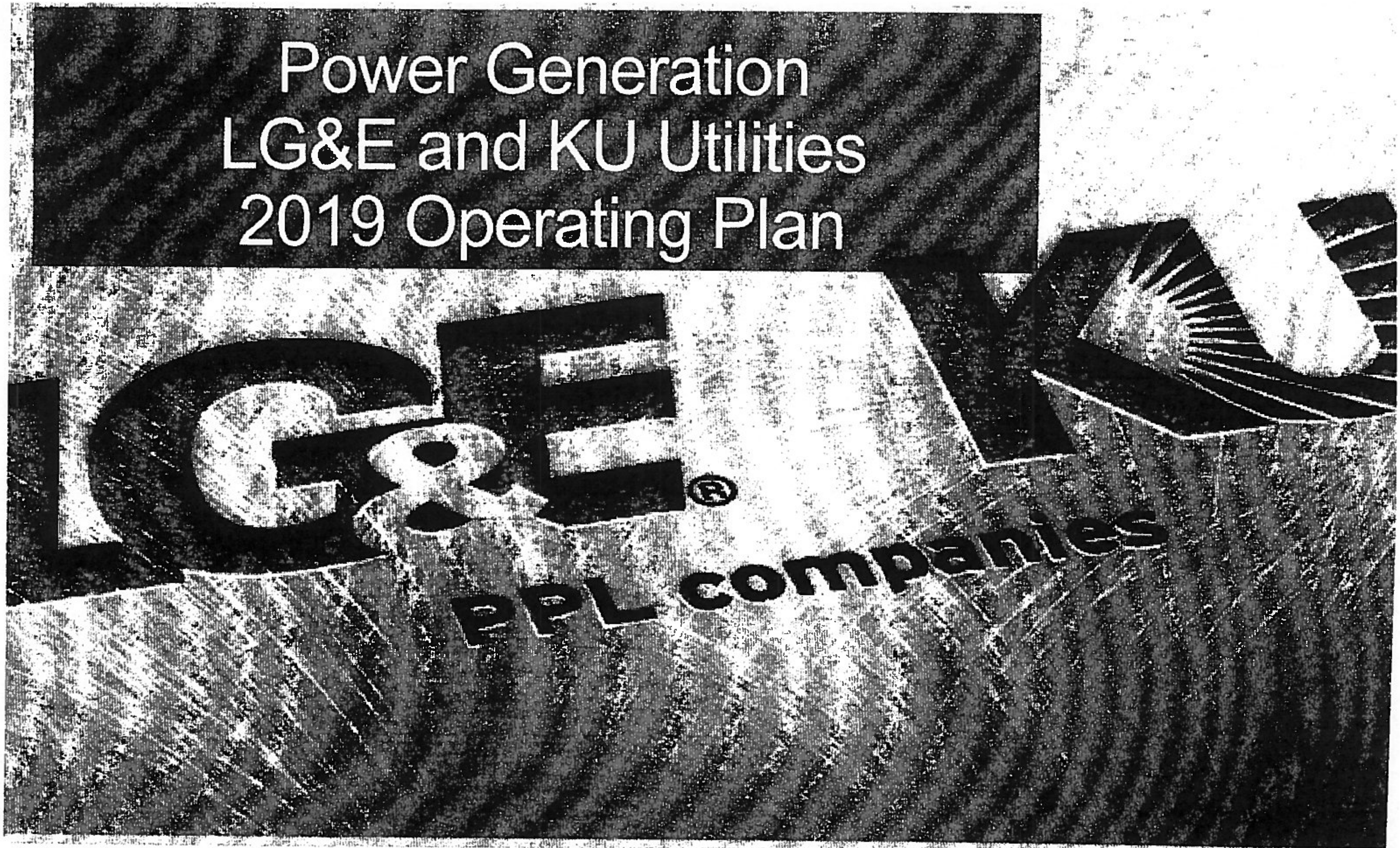
Unit	Jul-18 Forecast	Aug-18 Forecast	Sep-18 Forecast	Oct-18 Forecast	Nov-18 Forecast	Dec-18 Forecast
0172 - CANE RUN CC GT 2016	$ -	$ -	$ -	$ 178,501	$ -	$ -
0211 - MILL CREEK 1 - GENERATION	-	-	-	-	-	-
0221 - MILL CREEK 2 - GENERATION	297,000	-	36,000	-	-	-
0231 - MILL CREEK 3 - GENERATION	-	-	-	-	-	-
0241 - MILL CREEK 4 - GENERATION	75,000	-	127,000	3,148,500	2,458,500	731,000
0311 - TRIMBLE COUNTY 1 - GENERATION	-	-	-	-	-	-
0321 - TRIMBLE COUNTY 2 - GENERATION	-	-	-	-	-	-
0401 - LGE GENERATION - COMMON	-	-	-	-	-	-
0432 - PADDYS RUN GT 13	-	-	-	641,710	-	-
0460 - BROWN COMBUSTION TURBINE #6	-	-	-	-	27,900	-
0461 - BROWN COMBUSTION TURBINE #7	-	-	-	-	-	-
0470 - TRIMBLE COUNTY #5 COMBUSTION TURBINE	-	-	-	-	-	-
0471 - TRIMBLE COUNTY #6 COMBUSTION TURBINE	26,970	-	-	-	-	-
0474 - TRIMBLE COUNTY #7 COMBUSTION TURBINE	-	-	-	740	22,570	-
0475 - TRIMBLE COUNTY #8 COMBUSTION TURBINE	-	-	-	740	11,481	-
0476 - TRIMBLE COUNTY #9 COMBUSTION TURBINE	-	-	-	-	-	-
0477 - TRIMBLE COUNTY #10 COMBUSTION TURBINE	-	-	-	-	-	-
5635 - E W BROWN COMBUSTION TURBINE UNIT 5	-	-	-	-	-	-
5636 - E W BROWN COMBUSTION TURBINE UNIT 6	-	-	-	-	-	-
Total Outage Expense	$ 398,970	$ -	$ 163,000	$ 3,970,191	$ 2,520,451	$ 731,000
Normalized Outage Cost (based on eight-year average)	$ (29,571)	$ 41,572	$ 573,624	$ 3,941,386	$ 2,631,691	$ 162,411
Regulatory Asset Charges - Debits	428,541	(41,572)	(410,624)	28,806	(111,240)	568,590
Regulatory Asset Amortization - Credits	N/A	N/A	N/A	N/A	N/A	N/A
Regulatory Asset (Liability) Balance	$ 6,197,521	$ 6,155,949	$ 5,745,325	$ 5,774,131	$ 5,662,891	$ 6,231,480

Unit	Jan-19 Forecast	Feb-19 Forecast	Mar-19 Forecast	Apr-19 Forecast	May-19 Forecast	Jun-19 Forecast
0172 - CANE RUN CC GT 2016	$ -	$ -	$ -	$ -	$ -	$ -
0211 - MILL CREEK 1 - GENERATION	-	-	645,001	4,190,000	2,685,000	-
0221 - MILL CREEK 2 - GENERATION	-	-	-	725,000	-	-
0231 - MILL CREEK 3 - GENERATION	-	-	-	600,000	-	-
0241 - MILL CREEK 4 - GENERATION	-	-	-	-	-	-
0311 - TRIMBLE COUNTY 1 - GENERATION	-	-	-	-	-	-
0321 - TRIMBLE COUNTY 2 - GENERATION	-	35,625	175,678	155,459	2,205	-
0401 - LGE GENERATION - COMMON	-	-	-	-	-	-
0432 - PADDYS RUN GT 13	-	-	-	-	-	-
0460 - BROWN COMBUSTION TURBINE #6	-	-	-	300,154	-	-
0461 - BROWN COMBUSTION TURBINE #7	-	-	-	-	-	-
0470 - TRIMBLE COUNTY #5 COMBUSTION TURBINE	-	-	11,899	-	580	-
0471 - TRIMBLE COUNTY #6 COMBUSTION TURBINE	-	-	3,199	-	-	-
0474 - TRIMBLE COUNTY #7 COMBUSTION TURBINE	-	-	-	-	2,960	-
0475 - TRIMBLE COUNTY #8 COMBUSTION TURBINE	-	-	-	-	2,960	-
0476 - TRIMBLE COUNTY #9 COMBUSTION TURBINE	-	-	-	-	8,521	-
0477 - TRIMBLE COUNTY #10 COMBUSTION TURBINE	-	-	-	-	7,781	-
5635 - E W BROWN COMBUSTION TURBINE UNIT 5	-	-	-	-	-	-
5636 - E W BROWN COMBUSTION TURBINE UNIT 6	-	-	-	-	-	-
Total Outage Expense	$ -	$ 35,625	$ 835,779	$ 5,970,613	$ 2,710,007	$ -
Normalized Outage Cost (based on eight-year average)	$ 48,940	$ 174,306	$ 1,606,487	$ 3,925,814	$ 794,038	$ 56,212
Regulatory Asset Charges - Debits	(48,940)	(138,681)	(770,709)	2,044,799	1,915,970	(56,212)
Regulatory Asset Amortization - Credits	N/A	N/A	N/A	N/A	$ (76,229)	$ (76,229)
Regulatory Asset (Liability) Balance	$ 6,182,540	$ 6,043,859	$ 5,273,151	$ 7,317,950	$ 9,157,691	$ 9,025,250

Unit	Jul-19 Forecast	Aug-19 Forecast	Sep-19 Forecast	Oct-19 Forecast	Nov-19 Forecast	Dec-19 Forecast
0172 - CANE RUN CC GT 2016	$ -	$ -	$ 109,927	$ 183,211	$ -	$ -
0211 - MILL CREEK 1 - GENERATION	-	-	-	-	-	-
0221 - MILL CREEK 2 - GENERATION	-	-	-	-	-	-
0231 - MILL CREEK 3 - GENERATION	-	-	355,000	4,438,750	3,463,750	50,000
0241 - MILL CREEK 4 - GENERATION	-	-	645,000	-	-	-
0311 - TRIMBLE COUNTY 1 - GENERATION	-	-	187,500	1,823,764	1,249,692	237,433
0321 - TRIMBLE COUNTY 2 - GENERATION	-	-	-	-	-	-
0401 - LGE GENERATION - COMMON	-	-	-	-	-	-
0432 - PADDYS RUN GT 13	-	-	-	-	26,472	99,980
0460 - BROWN COMBUSTION TURBINE #6	-	-	-	-	-	-
0461 - BROWN COMBUSTION TURBINE #7	-	-	9,627	-	-	-
0470 - TRIMBLE COUNTY #5 COMBUSTION TURBINE	-	-	-	-	-	-
0471 - TRIMBLE COUNTY #6 COMBUSTION TURBINE	-	-	-	-	-	-
0474 - TRIMBLE COUNTY #7 COMBUSTION TURBINE	-	-	-	-	4,821	-
0475 - TRIMBLE COUNTY #8 COMBUSTION TURBINE	-	-	-	-	7,781	-
0476 - TRIMBLE COUNTY #9 COMBUSTION TURBINE	-	-	-	-	-	-
0477 - TRIMBLE COUNTY #10 COMBUSTION TURBINE	-	-	-	-	-	-
5635 - E W BROWN COMBUSTION TURBINE UNIT 5	-	-	-	-	-	-
5636 - E W BROWN COMBUSTION TURBINE UNIT 6	-	-	-	-	-	-
Total Outage Expense	$ -	$ -	$ 1,307,054	$ 6,445,725	$ 4,752,516	$ 387,413
Normalized Outage Cost (based on eight-year average)	$ 21,494	$ 19,730	$ 469,208	$ 3,958,215	$ 3,169,012	$ 284,232
Regulatory Asset Charges - Debits	(21,494)	(19,730)	837,846	2,487,510	1,583,504	103,181
Regulatory Asset Amortization - Credits	$ (76,229)	$ (76,229)	$ (76,229)	$ (76,229)	$ (76,229)	$ (76,229)
Regulatory Asset (Liability) Balance	$ 8,927,528	$ 8,831,569	$ 9,593,186	$ 12,004,468	$ 13,511,743	$ 13,538,696

Unit	Jan-20 Forecast	Feb-20 Forecast	Mar-20 Forecast	Apr-20 Forecast
0172 - CANE RUN CC GT 2016	$ -	$ 324,250	$ 1,716,397	$ -
0211 - MILL CREEK 1 - GENERATION	-	-	25,000	670,000
0221 - MILL CREEK 2 - GENERATION	-	-	370,001	4,170,001
0231 - MILL CREEK 3 - GENERATION	-	-	-	-
0241 - MILL CREEK 4 - GENERATION	-	-	-	-
0311 - TRIMBLE COUNTY 1 - GENERATION	-	-	-	-
0321 - TRIMBLE COUNTY 2 - GENERATION	-	28,500	429,148	404,154
0401 - LGE GENERATION - COMMON	-	-	-	-
0432 - PADDYS RUN GT 13	-	-	-	-
0460 - BROWN COMBUSTION TURBINE #6	-	-	9,595	-
0461 - BROWN COMBUSTION TURBINE #7	-	-	9,771	-
0470 - TRIMBLE COUNTY #5 COMBUSTION TURBINE	-	-	5,519	-
0471 - TRIMBLE COUNTY #6 COMBUSTION TURBINE	-	-	8,999	-
0474 - TRIMBLE COUNTY #7 COMBUSTION TURBINE	-	-	-	-
0475 - TRIMBLE COUNTY #8 COMBUSTION TURBINE	-	-	-	-
0476 - TRIMBLE COUNTY #9 COMBUSTION TURBINE	-	-	-	-
0477 - TRIMBLE COUNTY #10 COMBUSTION TURBINE	-	-	-	-
5635 - E W BROWN COMBUSTION TURBINE UNIT 5	-	-	-	-
5636 - E W BROWN COMBUSTION TURBINE UNIT 6	-	-	-	-
Total Outage Expense	$ -	$ 352,750	$ 2,574,430	$ 5,244,155
Normalized Outage Cost (based on eight-year average)	$ 79,683	$ 153,897	$ 2,108,796	$ 3,944,802
Regulatory Asset Charges - Debits	(79,683)	198,853	465,634	1,299,354
Regulatory Asset Amortization - Credits	$ (76,229)	$ (76,229)	$ (76,229)	$ (76,229)
Regulatory Asset (Liability) Balance	$ 13,382,784	$ 13,505,408	$ 13,894,814	$ 15,117,939

EXHIBIT ____ (LK-20)


Power Generation
LG&E and KU Utilities
2019 Operating Plan
LG&E
KU
PPL companies

August 2018

Major Operational Assumptions

- No generation capacity additions are in the plan through 2023.
- Brown 1 and 2 to be retired March 1, 2019. Capital spend is based on a Unit 3 only generation profile beginning in spring 2018.
- The next turbine overhauls by unit are as follows:
  - 2018: Ghent 3, Mill Creek 2, Trimble 2 (HP rotor and IP rotors)
  - 2019: Brown 3, Ghent 2, Mill Creek 1, Mill Creek 3, Trimble 2 (both LP rotors)
  - 2020: Trimble 2 (Generator), Ghent 4
  - 2021: Ghent 1.
  - 2022: Mill Creek 4.
  - 2023: None
- Demolition Timing:
  - Paddy's Run Coal Plant was completed in 2017.
  - Cane Run Coal Plant is contracted for 2017-2019.
  - Green River planned for 2018-2019.
  - Pineville Station planned for 2018-2019.
  - Tyrone Station planned for 2018-2019.
  - Canal Station planned for 2020-2021.

EXHIBIT ____ (LK-21)

KENTUCKY UTILITIES COMPANY

Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018

Case No. 2018-00294

Question No. 84

Responding Witness: Daniel K. Arbough

Q-84. Does the Company use credit cards that include rebates? If the response is in the affirmative, provide the following items:

a. Amount of rebate reflected in the cost of service base year and forecasted period. If the amount is allocated, provide the allocations.

b. Actual credit card rebates by year for 2016, 2017, and 2018 YTD. For each year, state the expense accounts where these credit card rebates are reflected and provide a detailed breakdown of those expense accounts.

A-84. Yes.

a. Zero is reflected in the cost of service for the base and forecasted period.

b. The rebate for 2016 was $205,999.93 and the 2017 rebate was $210,764.05. The rebates are recorded in account 921. The rebate for 2018 has not yet been received.

EXHIBIT ____ (LK-22)

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 84

Responding Witness: Daniel K. Arbough

Q-84. Does the Company use credit cards that include rebates? If the response is in the affirmative, provide the following items:

a. Amount of rebate reflected in the cost of service base year and forecasted period. If the amount is allocated, provide the allocations.

b. Actual credit card rebates by year for 2016, 2017, and 2018 YTD. For each year, state the expense accounts where these credit card rebates are reflected and provide a detailed breakdown of those expense accounts.

A-84. Yes.

a. Zero is reflected in the cost of service for the base and forecasted period.

b. The rebate for 2016 was $237,347.75 and the 2017 rebate was $242,836.84. The rebates are recorded in account 921. The rebate for 2018 has not yet been received.

EXHIBIT ____ (LK-23)

KENTUCKY UTILITIES COMPANY

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated November 13, 2018

Case No. 2018-00294

Question No. 60

Responding Witness: Gregory J. Meiman

Q.1-60. Refer to the disallowance of costs referenced on pages 13-15 of the June 22, 2017 Order in Kentucky Utilities, Inc. Case No. 2016-00370 and to pages 16-17 of the June 22, 2017 Order in Louisville Gas and Electric Company Case No. 2016-00371. For employees who participate in a defined benefit plan, please provide the total and jurisdictional amount of matching contributions made on behalf of employees who also participate in any 40 l (k) retirement savings account if the Commission applied the same methodology for a similar disallowance in the instant proceeding.

A.1-60. In response to the Commission's order, the Company commissioned two independent studies to assess (1) the reasonableness of the benefit offerings and (2) the level of retirement benefits. Based upon those studies, the Company believes that the cost of providing retirement benefits is not excessive and should be a recoverable expense.

Although the Company disagrees with the assertion that this should be disallowed, in order to be responsive to this question the total match for employees who also participate in a defined benefit plan is $2,152,591. Of this amount, the KU jurisdictional piece is $2,018,838.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated November 13, 2018

Case No. 2018-00295

Question No. 52

Responding Witness: Gregory J. Meiman

Q.1-52. Refer to the disallowance of costs referenced on pages 13-15 of the June 22, 2017 Order in Kentucky Utilities, Inc. Case No. 2016-00370 and to pages 16-17 of the June 22, 2017 Order in Louisville Gas and Electric Company Case No. 2016-00371. For employees who participate in a defined benefit plan, please provide the total and jurisdictional amount of matching contributions made on behalf of employees who also participate in any 40 1 (k) retirement savings account if the Commission applied the same methodology for a similar disallowance in the instant proceeding. Further distinguish jurisdictional costs between gas and electric operations.

A.1-52. In response to the Commission's order, the Company commissioned two independent studies to assess (1) the reasonableness of the benefit offerings and (2) the level of retirement benefits. Based upon those studies, the Company believes that the cost of providing retirement benefits is not excessive and should be a recoverable expense.

Although the Company disagrees with the assertion that this should be disallowed, in order to be responsive to this question the total match for employees who also participate in a defined benefit plan is $1,802,247. Of this amount, $1,369,708 dollars are allocated to electric and $432,539 are allocated to gas.

EXHIBIT ____ (LK-24)

KENTUCKY UTILITIES COMPANY

Response to First Set of Data Requests of Kentucky Industrial Utility Customers, Inc. Dated November 13, 2018

Case No. 2018-00294

Question No. 35

Responding Witness: Christopher M. Garrett / John J. Spanos

Q.1-35. Refer to the present and proposed depreciation rates shown on the Excel spreadsheet titled Att_KU_PSC_1-65_Depreciation_Exp_Wkpr provided in response to PSC Staff 1-65. Refer further to cell C66, which reflects a depreciation rate of 24.68% being used to depreciate this Ash Pond asset described as "KU-131200-EWB 1 Boil - Ash Pond." Refer also to the depreciation rates for all three EW Brown units reflected on page VI-4 of Exhibit JJS-KU-1 (Depreciation Study attached to Mr. Spanos' Direct Testimony) associated with the Ash Ponds, the costs for which are included in account 312.10.

a. Confirm that the asset amount for the asset in cell row 66 in "Att_KU_PSC_1-65_Depreciation_Exp_Wkpr" contains the asset amount of $13,208,176.87 for all month in the test year.

b. Confirm that the original cost amounts in account 312 on page VI-4 of Exhibit JJS-KU-1 associated with Brown Unit 1 and Brown Unit 2 of $9,299,115.00 and $3,909,061.87 sum to $$13,208,176.87.

c. Confirm that the depreciation rates determined for Brown Unit 1 and Brown Unit 2 on page VI-4 of Exhibit JJS-KU-1 were 0% and 7.82%, respectively.

d. Please indicate whether an error was made in cell row 66 in "Att_KU_PSC_1-65_Depreciation_Exp_Wkpr" to reflect the 24.68% depreciation rate instead of a blended rate for the Brown 1 and Brown 2 Ash Pond rates determined for account 312.10. If so, please recompute the appropriate rate and provide the reduction in total company and jurisdictional depreciation expense to correct. If not an error, please explain.

A.1-35.

a. Yes, the asset amount in cell row 66 of attachment, "Att_KU_PSC_1-65_Depreciation_Exp_Wkpr.xlsx" contains the asset amount of $13,208,176.87 for all months in the test year.

b. The amounts referenced in the question are reflected in Account 312.1 and do sum to $13,208,176.87.

c. The depreciation rates for Brown Unit 1 and Brown Unit 2 in Account 312.1 are confirmed in Exhibit JJS-KU-1.

d. An incorrect amount was presented in cell row 66 in "Att_KU_PSC_1-65_Depreciation_Exp_Wkpr" which reflects the 24.68% depreciation rate instead of a blended rate for Brown 1 and Brown 2 ash pond. The correct depreciation accrual rate should be 2.32% and the depreciable base amount should be $13,208,176.67. Therefore, the monthly depreciation expense beginning in May 2019 should be $25,490.25.

EXHIBIT ____ (LK-25)

KENTUCKY UTILITIES COMPANY

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated November 13, 2018

Case No. 2018-00294

Question No. 33

Responding Witness: David S. Sinclair / Christopher M. Garrett

Q.1-33. Refer to page 20 of 50 of Attachment H to Tab 16 of 807 KAR5:001 Section 16(7)(c), which shows the proposed retirement dates for coal generating units assuming a 65-year life used for planning purposes. Refer also to pages III-4 and III-5 of Exhibit JJS-KU-1 (Depreciation Study attached to Mr. Spanos' Direct Testimony). For each of KU's units, please provide an explanation as to why the retirement dates assumed in the depreciation study are sooner than that assumed for planning purposes.

A.1-33.

Referring to page 20 of 50 of Attachment H to Tab 16 of 807 KAR5:001 Section 16 (7)(c), the assumption of 65 years of unit operation from the date of commercial operation is based on the upper end of the age range of recently retired coal units in both the U.S. and the Companies' own fleet. In other analyses such as the recently filed 2018 Integrated Resource Plan and the 2017 PPL Climate Assessment report, the Companies evaluated a range of 55 to 65 years.

The depreciation study in Mr. Spanos's direct testimony contains a more detailed engineering analysis of each unit, as opposed to the general age assumption applied in Attachment H. For each unit, the depreciation study resulted in the retirement date occurring at the lower end of the industry life span range for coal units. This higher level of detail is the reason that the dates shown in the depreciation study occur sooner than the assumed age in Attachment H.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated November 13, 2018

Case No. 2018-00295

Question No. 30

Responding Witness: David S. Sinclair / Christopher M. Garrett

Q.1-30. Refer to page 20 of 50 of Attachment H to Tab 16 of 807 KAR5:001 Section 16(7)(c), which shows the proposed retirement dates for coal generating units assuming a 65-year life used for planning purposes. Refer also to pages III-4 and III-5 of Exhibit JJS-LG&E-1 (Depreciation Study attached to Mr. Spanos' Direct Testimony). For each of LG&E's units, please provide an explanation as to why the retirement dates assumed in the depreciation study are sooner than that assumed for planning purposes.

A.1-30. Referring to page 20 of 50 of Attachment H to Tab 16 of 807 KAR5:001 Section 16 (7)(c), the assumption of 65 years of unit operation from the date of commercial operation is based on the upper end of the age range of recently retired coal units in both the U.S. and the Companies' own fleet. In other analyses such as the recently filed 2018 Integrated Resource Plan and the 2017 PPL Climate Assessment report, the Companies evaluated a range of 55 to 65 years.

The depreciation study in Mr. Spanos's direct testimony contains a more detailed engineering analysis of each unit, as opposed to the general age assumption applied in Attachment H. For each unit, the depreciation study resulted in the retirement date occurring at the lower end of the industry life span range for coal units. This higher level of detail is the reason that the dates shown in the depreciation study occur sooner than the assumed age in Attachment H.

EXHIBIT ____ (LK-26)

KENTUCKY UTILITIES COMPANY

Response to First Request for Information of the U. S. Department of Defense Dated November 13, 2018

Case No. 2018-00294

Question No. 29

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

Q-29. Please refer to the probable retirement years for each plant shown on pages 36 and 37 of Exhibit JJS-KU-1.

a. Please provide all supporting studies, analyses, and/or documents that justify these retirement dates.

b. Please explain if the retirement dates shown here differ from those assumed with the currently approved depreciation rates.

A-29.

a. See attached. The attached file explains the methodology that was used to derive the dates set forth in Exhibit JJS-KU-1, pages 36 and 37.

b. See attached. The attached file sets forth the retirement date changes from those currently approved.

Generation Services Engineering 2018 Steam Only Depreciation Study Evaluation

5/25/18

Methodology

Many factors influence the end of life for a generating station. To complete this analysis the following assumptions were made regarding factors outside the direct technical evaluation:

- All necessary environmental permits and licenses will be maintained
- Future changes in environmental regulations are a consideration for unit retirement
- Units will continue to operate in a manner that is consistent with recent operating practices, with a similar number of annual starts and stops, and annual generation
- Units will continue to be operated in accordance with good industry practices with required renewals and replacements made in a timely manner

The steam generating units were reviewed at a high level and although many individual components could fail it was decided that those would not constitute an "end of life" event and could be mitigated. The boiler drum and turbine/generator were the two components/systems identified where catastrophic failure would be consideration for retirement.

Although the boiler is a complex system with many elements, the boiler drum is a large single component with approximately 240k hours of defined life and is significantly influenced by thermal cycling. Electric Power Research Institute (EPRI) studies indicate that after approximately 1,700 normal start/stop cycles the risk of a critical flaw developing is greatly increased.

The turbine/generator is a single system, whose failure could lead to significant downtime and repair/replacement costs. Several key factors are taken into consideration when evaluating the generator such as insulation type, winding age, recent inspection findings, and test results. Wear, cracking, and blade condition are key considerations for the turbine.

Review

The depreciation review process conducted by Generation Engineering consisted of evaluating key parameters (i.e. pressures, temperatures, voltages etc..) with equipment condition (i.e. inspection data, EPRI, IEEE, etc..) to provide a risk based assessment regarding the likelihood of equipment failure as compared to industry norms.

KENTUCKY UTILITIES COMPANY

Response to Supplemental Request for Information of the U. S. Department of Defense
Dated December 13, 2018

Case No. 2018-00294

Question No. 2

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

Q-2. Please refer to KU's response to KIUC Data Request Set 1, Question No. 33, where it states, "The depreciation study in Mr. Spanos's direct testimony contains a more detailed engineering analysis of each unit, as opposed to the general age assumption applied in Attachment H. For each unit, the depreciation study resulted in the retirement date occurring at the lower end of the industry life span range for coal units. This higher level of detail is the reason that the dates shown in the depreciation study occur sooner than the assumed age in Attachment H."

a. Please provide the "more detailed engineering analysis for each unit" in their complete electronic format.

b. Please provide a detailed narrative explaining the methodology utilized for the detailed engineering analysis for each unit that was conducted to determine the probable retirement date.

c. Please provide the citation to Gannet Fleming's contract (provided in response to Attachment 1 to Response to US DOD-1 Question No. 26) with KU that describes the scope of this detailed engineering analysis.

d. Please identify who conducted this analysis.

A-2.

a. See the attachment provided in response to US DOD 1-29(a).

b. See the attached for a discussion on the methodology.

c. The analysis was an internal review performed by LG&E and KU personnel, and is not cited in Gannet Fleming's contract.

d. The analysis was conducted by LG&E and KU personnel.

Methodology:

As referenced in LG&E's response to KIUC Data Request Set 1, Question No. 30 (KU's response to KIUC Data Request Set 1, Question No. 33), the depreciation study utilizes a 'more detailed engineering analysis' to evaluate each unit.

The steps utilized in the evaluation process are as follows:

1. Define a starting point for the life of the unit. In this case, the starting point is the year that each unit started commercial operation.
2. Define an estimated life span (and estimated retirement year) for each unit based on industry best practices. In this case the range of estimated life for each unit is based on industry data for coal unit age at retirement or announced retirement. This data is presented in Figure 1 on page 9 of the 2018 IRP Long-Term Resource Planning Analysis (submitted to PSC under Case No. 2018-00394, LGE_KU_2018_IRP-Volume III, page 71 of 93).
3. Periodically evaluate the life span for each unit, looking for anything that would present a risk to the estimated life. Aspects considered in these evaluations are:
    - Equipment age
    - Physical assessments/inspections
    - Operational factors (ie – number of startups/shutdowns)
    - Operating conditions (temperatures, pressures, voltages, etc)
    - Maintenance and repair history
    - Component replacement history
4. Identify from these evaluations any indication of an End of Life event. End of Life event is defined as a catastrophic failure that would be consideration for retirement.
    - Based on industry best practices, and recommendations from the Electric Power Research Institute (EPRI), the components identified that would fail to such extent are the steam drum (major boiler component) and the turbine/generator set.
    - The steam drum is considered due to the large influence of thermal cycling and subsequent risk of developing a critical flaw
    - The turbine/generator set is considered as a single system whose failure could lead to significant repair or replacement costs
5. Shorten the estimated retirement year and estimated life span appropriately based on any indications of a possible End of Life event

When analyzing the units and these specific components, the following assumptions are made regarding factors outside the direct technical evaluation:

- All necessary environmental permits and licenses will be maintained

- Future compliance with environmental regulations is a consideration for unit retirement
- Units will continue to operate in a manner that is consistent with recent operating practices, with a similar number of annual starts and stops, and annual generation
- Units will continue to be operated/maintained in accordance with good industry practices with required renewals and replacements made in a timely manner

The analysis is approached with the understanding that any deviation from these assumptions may shorten the estimated life of any unit.

EXHIBIT ____ (LK-27)

2019 Business Plan: Coal Inventory Limits and Generation & OSS Forecast

Generation Planning & Analysis
June 14, 2018

Coal generating units are assumed to have a 65-year life for planning purposes

Unit	Retirement w/ 65-Year Planning Assumption
Brown 1	2022[1]
Brown 2	2028[1]
Brown 3	2036
Mill Creek 1	2037
Ghent 1	2039
Mill Creek 2	2039
Ghent 2	2042
Mill Creek 3	2043
Ghent 3	2046
Mill Creek 4	2047
Ghent 4	2049
Trimble County 1	2055
Trimble County 2	2076

1) Brown 1-2 are assumed to retire on February 28, 2019 in the 2019 BP

EXHIBIT ____ (LK-28)

KENTUCKY UTILITIES COMPANY

Response to First Request for Information of the U. S. Department of Defense Dated November 13, 2018

Case No. 2018-00294

Question No. 29

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

Q-29. Please refer to the probable retirement years for each plant shown on pages 36 and 37 of Exhibit JJS-KU-1.

a. Please provide all supporting studies, analyses, and/or documents that justify these retirement dates.

b. Please explain if the retirement dates shown here differ from those assumed with the currently approved depreciation rates.

A-29.

a. See attached. The attached file explains the methodology that was used to derive the dates set forth in Exhibit JJS-KU-1, pages 36 and 37.

b. See attached. The attached file sets forth the retirement date changes from those currently approved.

KENTUCKY UTILITIES COMPANY

RETIREMENT DATE CHANGES

LOCATION	APPROVED PROBABLE RETIREMENT DATE	PROPOSED PROBABLE RETIREMENT DATE
BROWN UNIT 1	06-2023	02-2019
BROWN UNIT 2	06-2029	02-2019
TRIMBLE COUNTY UNIT 2 SCRUBBER ASH POND	06-2066	12-2023
GHENT UNIT 1 SCRUBBER ASH POND	06-2034	12-2020
GHENT UNIT 1 ASH POND	06-2034	12-2022
TYRONE UNIT 3 ASH POND	12-2015	12-2019
GREEN RIVER UNIT 3 ASH POND	12-2015	12-2019
PINEVILLE UNIT 3 ASH POND	12-2015	12-2019
BROWN UNIT 1 ASH POND	06-2023	12-2020
BROWN UNIT 2 ASH POND	06-2029	12-2020
BROWN UNIT 3 ASH POND	06-2035	12-2020
GHENT UNIT 4 ASH POND	06-2038	12-2021
GHENT UNIT 2 SCRUBBER ASH POND	06-2034	12-2020

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to First Request for Information of the U. S. Department of Defense
Dated November 13, 2018

Case No. 2018-00295

Question No. 10

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

Q-10. Please refer to the probable retirement years for each plant shown on pages 36 and 37 of Exhibit JJS-LG&E-1.

a. Please provide all supporting studies, analyses, and/or documents that justify these retirement dates.

b. Please explain if the retirement dates shown here differ from those assumed with the currently approved depreciation rates.

A-10.

a. See attached. The attached file explains the methodology that was used to derive the dates set forth in Exhibit JJS-LG&E-1, pages 36 and 37.

b. See attached. The attached file sets forth the retirement date changes from those currently approved.

Generation Services Engineering 2018 Steam Only Depreciation Study Evaluation

5/25/18

Methodology

Many factors influence the end of life for a generating station. To complete this analysis the following assumptions were made regarding factors outside the direct technical evaluation:

- All necessary environmental permits and licenses will be maintained
- Future changes in environmental regulations are a consideration for unit retirement
- Units will continue to operate in a manner that is consistent with recent operating practices, with a similar number of annual starts and stops, and annual generation
- Units will continue to be operated in accordance with good industry practices with required renewals and replacements made in a timely manner

The steam generating units were reviewed at a high level and although many individual components could fail it was decided that those would not constitute an "end of life" event and could be mitigated. The boiler drum and turbine/generator were the two components/systems identified where catastrophic failure would be consideration for retirement.

Although the boiler is a complex system with many elements, the boiler drum is a large single component with approximately 240k hours of defined life and is significantly influenced by thermal cycling. Electric Power Research Institute (EPRI) studies indicate that after approximately 1,700 normal start/stop cycles the risk of a critical flaw developing is greatly increased.

The turbine/generator is a single system, whose failure could lead to significant downtime and repair/replacement costs. Several key factors are taken into consideration when evaluating the generator such as insulation type, winding age, recent inspection findings, and test results. Wear, cracking, and blade condition are key considerations for the turbine.

Review

The depreciation review process conducted by Generation Engineering consisted of evaluating key parameters (i.e. pressures, temperatures, voltages etc..) with equipment condition (i.e. inspection data, EPRI, IEEE, etc..) to provide a risk based assessment regarding the likelihood of equipment failure as compared to industry norms.

Boiler

EPRI states:

- A critical flaw size crack appears on average at around 30 years of service (240,000 hours).
- The average number of cycles of a coal drum unit is expected to be 1,700 normal starts/stops to drive a critical flaw to failure.
- Natural Circulation boilers are more susceptible to ligament cracking than are Forced Circulation boilers.

The boiler review included previous inspection reports and a review of design vs typical operating temperatures and pressures.

Generator

Generators are regularly inspected and electrically tested. Those results were reviewed along with any other known issues. In most cases where the generator winding was beyond design life, no known issues have been observed and no concerns exist regarding condition.

Turbine

Turbines are inspected on a routine basis with periodic repairs/overhauls to bring the unit to as designed operation. To-date, no issues have been observed which did not allow a return to as designed operation.

Summary

Based on EPRI's research and the Generation Services Engineering review of units comparing their data, the boiler drum should not reduce the retirement year of each unit. While the EPRI "average end of drum life" for MC3 & MC4 are just short of the previous end of life depreciation study, the difference is not significant when considering these are typical and average numbers used from the analysis.

There are no known concerns regarding generator or turbine condition impacting unit end of life across the fleet.

No changes are recommended to existing unit retirement dates as identified in the 2015 study.

2018 Generation Services Engineering Depreciation Study
(Steam Units Only)

Station	Unit	2018 Retirement Dates
MC	1	2032
MC	2	2034
MC	3	2038
MC	4	2042
TC	1	2050
TC	2	2066
BR	1	2019
BR	2	2019
BR	3	2035
GH	1	2034
GH	2	2034
GH	3	2037
GH	4	2038

LOUISVILLE GAS & ELECTRIC COMPANY

RETIREMENT DATE CHANGES

LOCATION	APPROVED PROBABLE RETIREMENT DATE	PROPOSED PROBABLE RETIREMENT DATE
MILL CREEK UNIT 1 ASH POND	06-2032	12-2021
MILL CREEK UNIT 3 ASH POND	06-2038	06-2019
TRIMBLE COUNTY UNIT 1 ASH POND	06-2050	12-2023
TRIMBLE COUNTY UNIT 2 ASH POND	06-2050	12-2021

EXHIBIT ____ (LK-29)

KENTUCKY UTILITIES COMPANY

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated November 13, 2018

Case No. 2018-00294

Question No. 75

Responding Witness: Daniel K. Arbough

Q.1-75. Refer to the Direct Testimony of Mr. Arbough at page 14, Lines 7-8, related to the expectation of KU to issue First Mortgage bonds in May 2019 of $300 million. Refer also to Schedule J-3 line 16 reflecting the expected $300 million issue with a coupon interest rate of 4.90%. Please explain how the 4.90% estimated interest rate was derived and provide copies of all workpapers and/or analyses in the Company's possession utilized by the Company in the rate determination.

A.1-75. The 4.90% estimated interest rate is the sum of the forecasted 30-Year Treasury Rate of 3.65% and forecasted credit spread of 1.25%. The forecasted Treasury Rate was based on the 30-yr treasury rates provided by various banks. The credit spread was the indicative credit spread as of June 29, 2018 of 1.15% plus a forecasted new issuance spread of 10bps. See attached for copies of all workpapers and analyses used by the Company in the determination of the rate.

30 YR TREASURY

Counterparty	Current	Q3 18	Q4 18	Q1 19	Q2 19	Q3 19	Q4 19	Q1 20	Q2 20	Q3 20	Last Update
Bank A	2.98%	3.23%	3.26%	3.30%	3.35%						6/8/2018
Bank B	2.98%	3.25%	3.35%	3.45%	3.50%	3.50%	3.55%	3.60%			6/8/2018
Bank C	2.98%	3.30%	3.40%	3.50%	3.50%	3.50%	3.60%	3.65%	3.65%	3.65%	6/8/2018
Bank D	2.98%	3.00%	2.90%	2.80%	2.80%	2.80%	2.80%				6/8/2018
Bank E	2.98%	3.10%	3.10%	3.20%	3.35%	3.45%	3.60%				6/8/2018
Bank F	2.98%	3.10%	3.15%	3.20%	3.25%	3.30%	3.35%	3.40%			6/8/2018
Bank G	2.98%	3.12%	3.30%	3.45%	3.64%	3.70%	3.74%	3.78%			6/8/2018
Median	2.98%	3.12%	3.26%	3.30%	3.35%	3.48%	3.58%	3.63%	3.65%	3.65%	
High	2.98%	3.30%	3.40%	3.50%	3.64%	3.70%	3.74%	3.78%	3.65%	3.65%	
Low	2.98%	3.00%	2.90%	2.80%	2.80%	2.80%	2.80%	3.40%	3.65%	3.65%	
Budget	2.98%	3.02%	3.15%	3.28%	3.40%	3.53%	3.65%	3.78%	3.90%	4.03%	

ppl

Debt Capital Markets Coverage Team:
Jim Williams, *Managing Director, Debt Capital Markets* — (704) 410-4772 / (704) 517-2046
Odon von Werssowetz, *Associate, Debt Capital Markets* — (704) 410-4828 / (704) 533-0401
Luke Barbour, *Vice President, Syndicate* — (704) 410-4812 / (704) 840-7341

Work / Cell Phone Number:

Friday, June 29, 2018

Current Trading Levels - Benchmark

	Outst. ($mm)	Coupon	Maturity	Security	Rating	Spread at Issue	T-Spread	Weekly Change	G-Spread
PPL Capital Funding	$650	3.100%	5/15/2026	Sr. Unsecured	Baa2/BBB+	135 bps	126 bps	0 bps	129 bps
	$500	4.000%	9/15/2047	Sr. Unsecured	Baa2/BBB+	135 bps	149 bps	2 bps	[illegible]
PPL Electric Utilities	$250	2.500%	9/1/2022	First Mortgage	A1/A	70 bps	68 bps	1 bps	72 bps
	$400	4.150%	6/15/2048	First Mortgage	A1/A	108 bps	110 bps	0 bps	[illegible]
Louisville Gas & Electric	$300	3.300%	10/1/2025	First Mortgage	A1/A	110 bps	80 bps	2 bps	84 bps

New Issue Levels (Re-Offer)

			Institutional			$25 Par				
			Fixed	Fixed	Fixed	Fixed	Fixed-to-Float	Fixed-to-Float	Fixed	Fixed
Issuer	Structure/Ratings		5 Year	10 Year	30 Year	40NC5	PerpNC10 Pfd.	60NC10 Jr. Sub.	PerpNC5 Pfd.	60NC5 Jr. Sub.
PPL Capital Funding	Sr. Unsecured	Baa2/BBB+	110 bps	135 bps	160 bps	5.500%	5.750%	5.500%	5.875%	5.625%
	Jr. Sub Notes	Baa3/BBB								
	Preferred	Ba1/BBB								
PPL Electric Utilities	First Mortgage	A1/A	70 bps	90 bps	115 bps					
	Preferred	Baa2/BBB								
Kentucky Utilities or Louisville Gas & Electric	First Mortgage	A1/A	70 bps	90 bps	115 bps					
	Preferred	Baa2/BBB								

Current Credit Indices

		Change in Value		
Index	Spread	Weekly	Mo. To Dat.	Yr. To Dat.
U.S. Agg. Corp. Index	124 bps	5	9	31
"A" 10YR Utility Index	104 bps	4	8	16
"BBB+" 10YR Utility Index	128 bps	3	10	24
"A" Credit Index	105 bps	3	7	23
"BBB" Credit Index	164 bps	5	11	34
IG(25) CDS Index	68 bps	6	3	19

Market Rates

	2 Year	5 Year	10 Year	30 Year
Treasury	2.52%	2.73%	2.85%	2.97%
Mid-Swap	2.79%	2.88%	2.92%	2.92%
3 Month LIBOR:			2.34%	
Dow Jones Ind. Average, weekly change:			24,216.1	-364.8

Notable Deals in the Market

Date	Issuer	Security	Ratings Moody's	Ratings S&P	Amount ($ Millions)	Tenor	Coupon	Spread At Issue	Implied New Issue Premium	Market
6/28/2018	Charter Communications Operating LLC	Senior Unsecured FRN	Ba1	BBB-	$400	5.5yrs	3ml+165	165 bps	15 bps	Institutional
6/28/2018	Charter Communications Operating LLC	Senior Unsecured	Ba1	BBB-	$1,100	5.5yrs	4.500%	180 bps	15 bps	Institutional
6/27/2018	Principal Life Global Funding	Senior Unsecured FRN	A1	A+	$300	2.0yrs	3ml+30	30 bps	N/A	Institutional
6/26/2018	Penske Truck Leasing Co. LP	Senior Unsecured	Baa2	BBB	$500	5.0yrs	4.125%	138 bps	20 bps	Institutional
6/26/2018	USAA Capital Corp.	Senior Unsecured	Aa1	AA	$400	2.0yrs	3.000%	53 bps	3 bps	Institutional
6/26/2018	IHC Health Services Inc.	Taxable Muni Notes	Aa1	AA+	$227	30.0yrs	4.131%	110 bps	N/A	Institutional
6/26/2018	FLNG Liquefaction 3, LLC	Amortizing Senior Secured	NR	BBB-	$600	20F/12.9AL	5.550%	265 bps	N/A	Institutional

Market Commentary

- A quiet week before the 4th of July holiday resulted in only $3.5 billion in total volume from six issuers. Many potential borrowers backed down due to the volatile market as tensions continue to rise in the global trade war.
  - Double digit concessions remain the norm as investor appetite waned for both new issue and secondary paper.
    - Penske Truck Leasing's $500 million 5-year note was unable to move from whisper levels pricing at T+137.5 bps and with 18.5 bps of new issue concession.
      - Its orderbook consisted almost entirely of high quality investors (with many stipulating interest only at initial price thoughts). The market environment has kept hedge fund and total return accounts on the sidelines limiting orderbook leverage.
    - Freeport LNG's FLNG Liquefaction 3, LLC priced a $600 million amortizing 20-year final, 12.9-year weighted average life Senior Secured Notes deal (NR/BBB-/BBB-) 2.5 bps wide of whisper levels at T+265 bps. Amortization begins in 2021 and is tailored to debt service coverage.
    - Charter Communications was the only company to issue on Thursday, pricing $1.5 billion of 5.5-year Senior Secured Notes deal (Ba1/BBB-/BBB-) across fixed and floating rate tranches with 15 bps of concession.
      - The transaction received good sponsorship from the buyside given its secured status and the additional yield it offered for being crossover-rated allowing it to move 15 bps tighter through marketing.
        - The orderbook topped out at over $3 billion split approximately $600 million for the floater and $2.6 billion for the fixed rate tranche.
- WFS expects no issuance next week and for new issue activity to pick back up the week of the 11th.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated November 13, 2018

Case No. 2018-00295

Question No. 64

Responding Witness: Daniel K. Arbough

Q.1-64. Refer to the Direct Testimony of Mr. Arbough at page 14, Lines 7-8, related to the expectation of LG&E to issue First Mortgage bonds in May 2019 of $500 million. Refer also to Schedule J-3 line 16 reflecting the expected $500 million issue with a coupon interest rate of 4.90%. Please explain how the 4.90% estimated interest rate was derived and provide copies of all workpapers and/or analyses in the Company's possession utilized by the Company in the rate determination.

A.1-64. The 4.90% estimated interest rate was is the sum of the forecasted 30-Year Treasury Rate of 3.65% and forecasted credit spread of 1.25%. The forecasted Treasury Rate was based on the 30-yr treasury rates provided by various banks. The credit spread was the indicative credit spread as of June 29, 2018 of 1.15% plus a forecasted new issuance spread of 10bps. Please see attached for copies of all workpapers and analyses used by the Company in the determination of the rate.

30 YR TREASURY

Counterparty	Current	Q3 18	Q4 18	Q1 19	Q2 19	Q3 19	Q4 19	Q1 20	Q2 20	Q3 20	Last Update
Bank A	2.98%	3.23%	3.26%	3.30%	3.35%						6/8/2018
Bank B	2.98%	3.25%	3.35%	3.45%	3.50%	3.50%	3.55%	3.60%			6/8/2018
Bank C	2.98%	3.30%	3.40%	3.50%	3.50%	3.50%	3.60%	3.65%	3.65%	3.65%	6/8/2018
Bank D	2.98%	3.00%	2.90%	2.80%	2.80%	2.80%	2.80%				6/8/2018
Bank E	2.98%	3.10%	3.10%	3.20%	3.35%	3.45%	3.60%				6/8/2018
Bank F	2.98%	3.10%	3.15%	3.20%	3.25%	3.30%	3.35%	3.40%			6/8/2018
Bank G	2.98%	3.12%	3.30%	3.45%	3.64%	3.70%	3.74%	3.78%			6/8/2018
Median	2.98%	3.12%	3.26%	3.30%	3.35%	3.48%	3.58%	3.63%	3.65%	3.65%	
High	2.98%	3.30%	3.40%	3.50%	3.64%	3.70%	3.74%	3.78%	3.65%	3.65%	
Low	2.98%	3.00%	2.90%	2.80%	2.80%	2.80%	2.80%	3.40%	3.65%	3.65%	
Budget	2.98%	3.02%	3.15%	3.28%	3.40%	3.53%	3.65%	3.78%	3.90%	4.03%	

Debt Capital Markets Coverage Team:

	Work / Cell Phone Number:
Jim Williams, *Managing Director, Debt Capital Markets*	(704) 410-4772 / (704) 517-2046
Odon von Werssowetz, *Associate, Debt Capital Markets*	(704) 410-4828 / (704) 533-0401
Luke Barbour, *Vice President, Syndicate*	(704) 410-4812 / (704) 840-7341

Friday, June 29, 2018

Current Trading Levels - Benchmark

	Outst. ($mm)	Coupon	Maturity	Security	Rating	Spread at Issue	T-Spread	Weekly Change	G-Spread
PPL Capital Funding	$650	3.100%	5/15/2026	Sr. Unsecured	Baa2/BBB+	135 bps	126 bps	0 bps	129 bps
	$500	4.000%	9/15/2047	Sr. Unsecured	Baa2/BBB+	135 bps	149 bps	2 bps	[illegible]
PPL Electric Utilities	$250	2.500%	9/1/2022	First Mortgage	A1/A	70 bps	68 bps	1 bps	72 bps
	$400	4.150%	6/15/2048	First Mortgage	A1/A	108 bps	110 bps	0 bps	[illegible]
Louisville Gas & Electric	$300	3.300%	10/1/2025	First Mortgage	A1/A	110 bps	80 bps	2 bps	84 bps

New Issue Levels (Re-Offer)

			Institutional			$25 Par				
Issuer	Structure/Ratings		Fixed 5 Year	Fixed 10 Year	Fixed 30 Year	Fixed 40NC5	Fixed-to-Float PerpNC10 Pfd.	Fixed-to-Float 60NC10 Jr. Sub.	Fixed PerpNC5 Pfd.	Fixed 60NC5 Jr. Sub.
PPL Capital Funding	Sr. Unsecured	Baa2/BBB+	110 bps	135 bps	160 bps	5.500%	5.750%	5.500%	5.875%	5.625%
	Jr. Sub Notes	Baa3/BBB								
	Preferred	Ba1/BBB								
PPL Electric Utilities	First Mortgage	A1/A	70 bps	90 bps	115 bps					
	Preferred	Baa2/BBB								
Kentucky Utilities or Louisville Gas & Electric	First Mortgage	A1/A	70 bps	90 bps	115 bps					
	Preferred	Baa2/BBB								

Current Credit Indices

		Change in Value		
Index	Spread	Weekly	Mo. To Dat.	Yr. To Dat.
U.S. Agg. Corp. Index	124 bps	5	9	31
"A" 10YR Utility Index	104 bps	4	8	16
"BBB+" 10YR Utility Index	128 bps	3	10	24
"A" Credit Index	105 bps	3	7	23
"BBB" Credit Index	164 bps	5	11	34
IG(25) CDS Index	68 bps	6	3	19

Market Rates

	2 Year	5 Year	10 Year	30 Year
Treasury	2.52%	2.73%	2.85%	2.97%
Mid-Swap	2.79%	2.88%	2.92%	2.92%
3 Month LIBOR:			2.34%	
Dow Jones Ind. Average, weekly change:			24,216.1	-364.8

Notable Deals in the Market

Date	Issuer	Security	Ratings Moody's	Ratings S&P	Amount ($ Millions)	Tenor	Coupon	Spread At Issue	Implied New Issue Premium	Market
6/28/2018	Charter Communications Operating LLC	Senior Unsecured FRN	Ba1	BBB-	$400	5.5yrs	3ml+165	165 bps	15 bps	Institutional
6/28/2018	Charter Communications Operating LLC	Senior Unsecured	Ba1	BBB-	$1,100	5.5yrs	4.500%	180 bps	15 bps	Institutional
6/27/2018	Principal Life Global Funding	Senior Unsecured FRN	A1	A+	$300	2.0yrs	3ml+30	30 bps	N/A	Institutional
6/26/2018	Penske Truck Leasing Co. LP	Senior Unsecured	Baa2	BBB	$500	5.0yrs	4.125%	138 bps	20 bps	Institutional
6/26/2018	USAA Capital Corp.	Senior Unsecured	Aa1	AA	$400	2.0yrs	3.000%	53 bps	3 bps	Institutional
6/26/2018	IHC Health Services Inc.	Taxable Muni Notes	Aa1	AA+	$227	30.0yrs	4.131%	110 bps	N/A	Institutional
6/26/2018	FLNG Liquefaction 3, LLC	Amortizing Senior Secured	NR	BBB-	$600	20F/12.9AL	5.550%	265 bps	N/A	Institutional

Market Commentary

- A quiet week before the 4th of July holiday resulted in only $3.5 billion in total volume from six issuers. Many potential borrowers backed down due to the volatile market as tensions continue to rise in the global trade war.
  - Double digit concessions remain the norm as investor appetite waned for both new issue and secondary paper.
    - Penske Truck Leasing's $500 million 5-year note was unable to move from whisper levels pricing at T+137.5 bps and with 18.5 bps of new issue concession.
      - Its orderbook consisted almost entirely of high quality investors (with many stipulating interest only at initial price thoughts). The market environment has kept hedge fund and total return accounts on the sidelines limiting orderbook leverage.
    - Freeport LNG's FLNG Liquefaction 3, LLC priced a $600 million amortizing 20-year final, 12.9-year weighted average life Senior Secured Notes deal (NR/BBB-/BBB-) 2.5 bps wide of whisper levels at T+265 bps. Amortization begins in 2021 and is tailored to debt service coverage.
    - Charter Communications was the only company to issue on Thursday, pricing $1.5 billion of 5.5-year Senior Secured Notes deal (Ba1/BBB-/BBB-) across fixed and floating rate tranches with 15 bps of concession.
      - The transaction received good sponsorship from the buyside given its secured status and the additional yield it offered for being crossover-rated allowing it to move 15 bps tighter through marketing.
        - The orderbook topped out at over $3 billion split approximately $600 million for the floater and $2.6 billion for the fixed rate tranche.
- WFS expects no issuance next week and for new issue activity to pick back up the week of the 11th.

EXHIBIT ____ (LK-30)

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated November 13, 2018

Case No. 2018-00294

Question No. 39

Responding Witness: Daniel K. Arbough

Q-39. Refer to the McKenzie Testimony, page 63. Provide the most recent awarded ROEs as published by RRA.

A-39. See attached.

S&P Global
Market Intelligence

October 11, 2018
spglobal.com/marketintelligence

RRA Regulatory Focus
Major Rate Case Decisions – January – September 2018

The average ROE authorized electric utilities was 9.64% in rate cases decided in the first three quarters of 2018, somewhat below the 9.74% average for cases decided in calendar-2017. There were 37 electric ROE determinations in the first nine months of 2018 versus 53 in the full year 2017. This data includes several limited-issue rider cases. Excluding these cases from the data, the average authorized ROE was 9.59% in rate cases decided in the first nine months of 2018, somewhat below the 9.68% average for the full year 2017. The difference between the ROE averages including rider cases and those excluding the rider cases is largely driven by ROE premiums of up to 200 basis points approved by the Virginia State Corporation Commission in riders related to certain generation projects (see the Virginia Commission Profile).

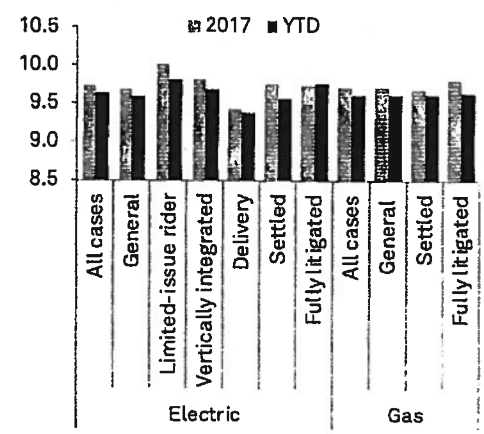
The average ROE authorized gas utilities was 9.62% in cases decided during the first three quarters of 2018 versus 9.72% in full-year 2017. There were 26 gas cases that included an ROE determination in the first nine months of 2018, versus 24 in full-year 2017. RRA notes that the 2017 data includes an 11.88% ROE determination for an Alaska utility. Absent this "outlier," the 2017 gas ROE average is 9.63%.

In the first nine months of 2018, the median authorized ROE in all electric utility rate cases was 9.7%, up from 9.6% from full-year 2017. For gas utilities, the median authorized ROE in cases decided in the first nine months of 2018 was 9.55%, versus 9.6% in 2017.

Over the last several years, the persistently low-interest-rate environment has put downward pressure on authorized ROEs. As shown in the graph below, the annual average ROE has generally declined since 1990 and has been below 10% for electric utilities since 2014 and below 10% for gas utilities since 2011.

After a busy 2017, when more than 130 cases were decided, there were 84 electric and gas cases in which a decision was rendered in the first three quarters of 2018, including cases where no ROEs were specified. With over 85 rate cases pending, 55 of which are likely to be decided by year end, 2018 is shaping up to be another busy year for regulators. Rate case activity has been quite robust, with more than 100 cases decided in several of the last full calendar years.

Authorized return on equity (%)
Dashboard



Electric	2017	YTD
All cases	9.74	9.64 ▼
General rate cases	9.68	9.59 ▼
Limited-issue rider cases	10.01	9.80 ▼
Vertically integrated cases	9.80	9.69 ▼
Delivery cases	9.43	9.38 ▼
Settled cases	9.75	9.55 ▼
Fully litigated cases	9.73	9.75 ▲
Gas	**2017**	**YTD**
All cases	9.72	9.62 ▼
General rate cases	9.72	9.62 ▼
Settled cases	9.68	9.61 ▼
Fully litigated cases	9.82	9.63 ▼

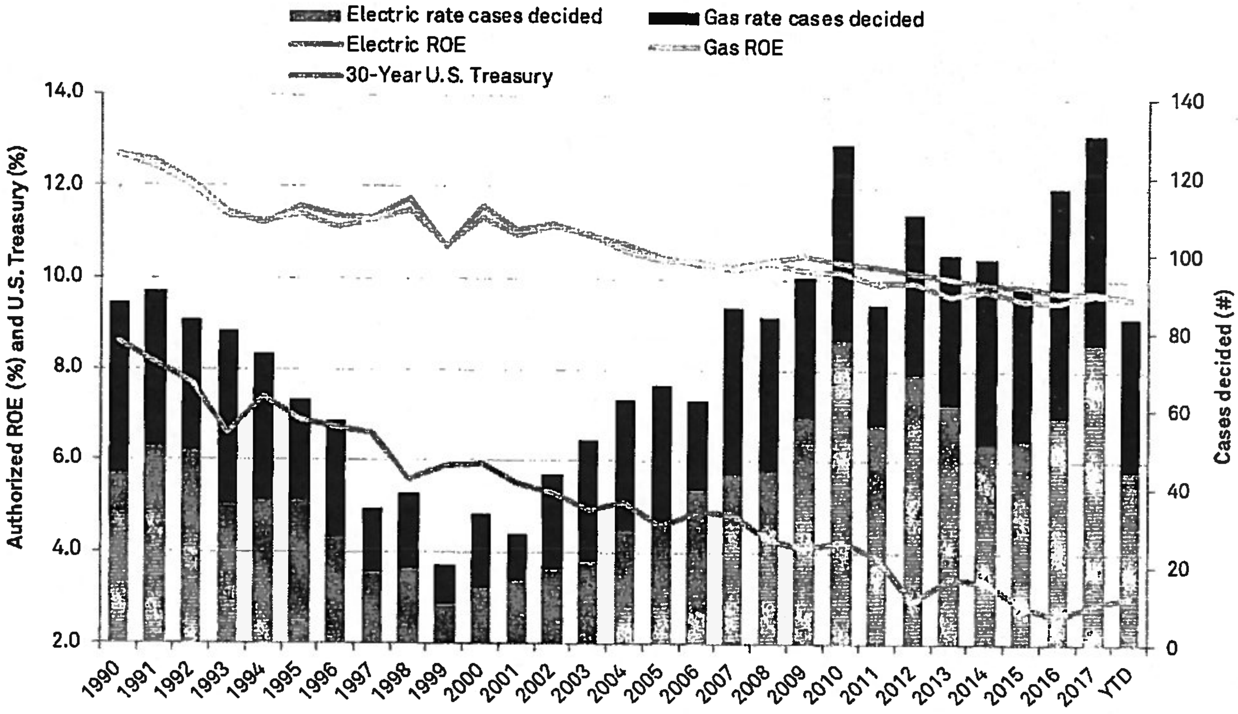
Data compiled Oct. 10, 2018.
YTD = year-to-date, through Sept. 30, 2018.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Lisa Fontanella
Principal Analyst

Sales & subscriptions
Sales_NorthAm@spglobal.com

Enquiries
support.mi@spglobal.com

Average electric and gas authorized ROEs and number of rate cases decided



Data compiled Oct. 10, 2018.
YTD = year-to-date, through Sept. 30, 2018.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Increased costs associated with environmental compliance, generation and delivery infrastructure upgrades and expansion, renewable generation mandates and employee benefits argue for the continuation of an active rate case agenda over the next few years. In addition, the need to address the impacts of the federal tax reform is causing rate case agendas to be more active than previously expected.

In addition, rising interest rates could also contribute to increased rate case activity. If the U.S. Federal Reserve, or the Fed, continues its policy initiated in 2015 to gradually raise the federal funds rate, utilities will likely face higher capital costs and need to initiate rate cases to reflect the higher capital costs in rates.

In September 2018, the Fed raised the benchmark federal funds rate by a quarter point, bringing the rate to a target range of 2.00% to 2.25%. The latest hike was the third increase in 2018 and the eighth since the Fed's tightening cycle began in 2015. One more hike is anticipated in December 2018, and as the U.S. economy continues to expand and labor markets remain strong, the Fed is expected to continue to gradually raise the federal fund rates in 2019.

A more granular look at ROE trends

The discussion thus far has looked broadly at trends in authorized ROEs; the sections that follow provide a more granular view based upon the types of proceedings/decisions in which these ROEs were established.

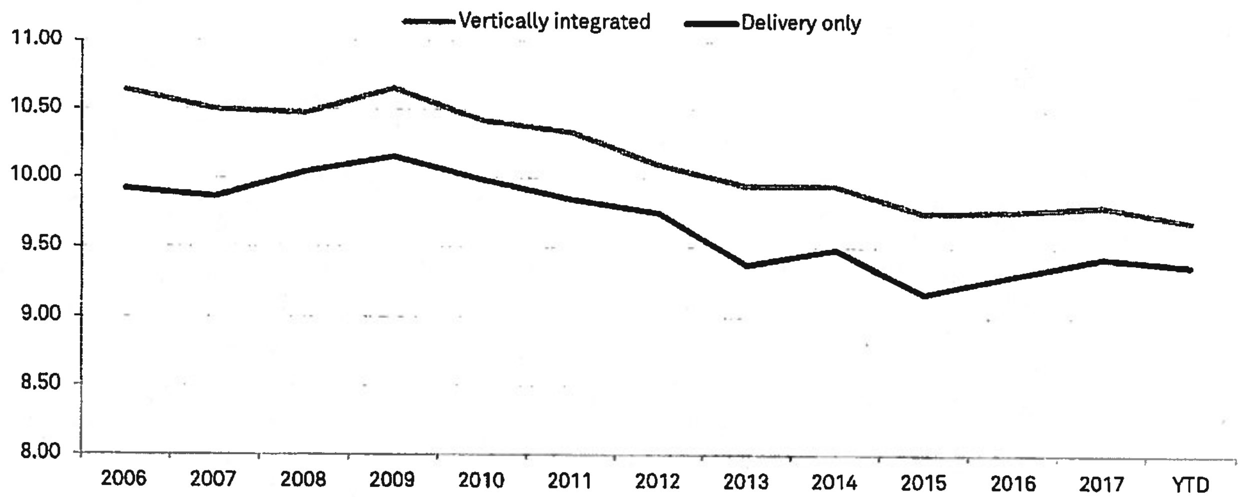
RRA has observed that there can be significant differences between the ROE averages from one subcategory of cases to another.

As a result of electric industry restructuring, certain states unbundled electric rates and implemented retail competition for generation. Commissions in those states now have jurisdiction only over the revenue requirement and return parameters for delivery operations.

Comparing electric vertically integrated cases versus delivery-only proceedings, RRA finds that the annual average authorized ROEs in vertically integrated cases typically are about 30 to 70 basis points higher than in delivery-only cases, arguably reflecting the increased risk associated with ownership and operation of generation assets.

For vertically integrated electric utilities, the average ROE authorized was 9.69% in cases decided during the first three quarters of 2018 versus 9.8% for cases decided in calendar-2017. For electric distribution-only utilities, the average ROE authorized in the first three quarters of 2018 was 9.38% versus 9.43% in all of 2017.

Average authorized electric ROEs



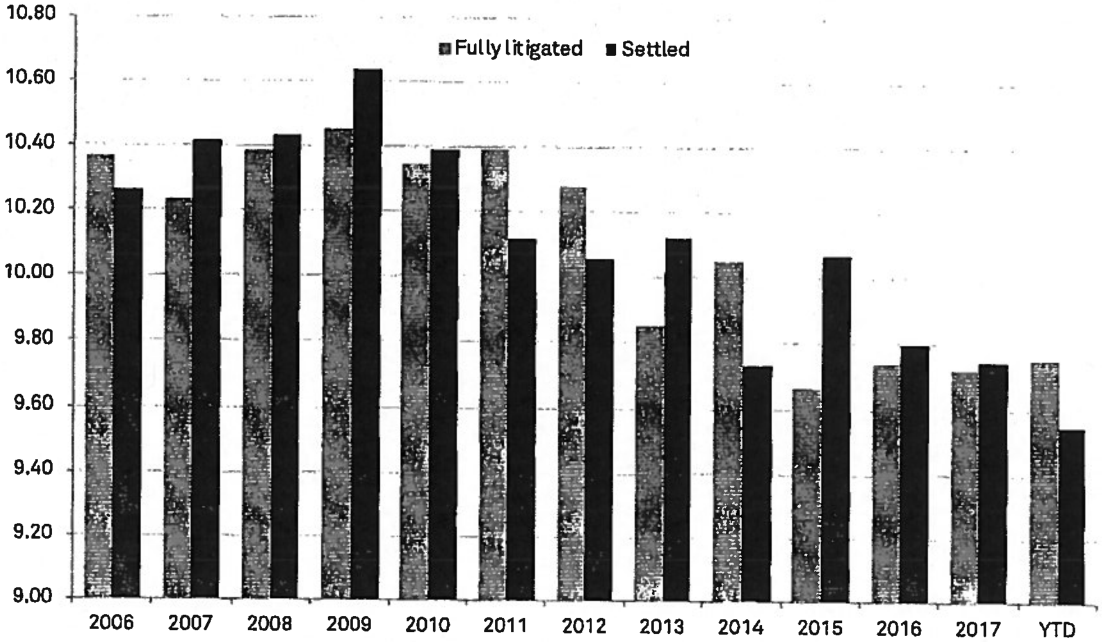
Data compiled Oct. 10, 2018.
YTD = year-to-date, through Sept. 30, 2018.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Settlements have frequently been used to resolve rate cases over the last several years, and in many cases, these settlements are "black box" in nature and do not specify the ROE and other typical rate case parameters underlying the stipulated rate change. However, some states preclude this type of treatment, and so, settlements must specify these values if not the specific adjustments from which these values were derived.

For both electric and gas cases, RRA has found no discernible pattern in the average authorized ROEs in cases that were settled versus those that were fully litigated. In some years, the average authorized ROE was higher for fully litigated cases, in others, it was higher for settled cases, and in a handful of years, the authorized ROE was similar for both fully litigated and settled cases.

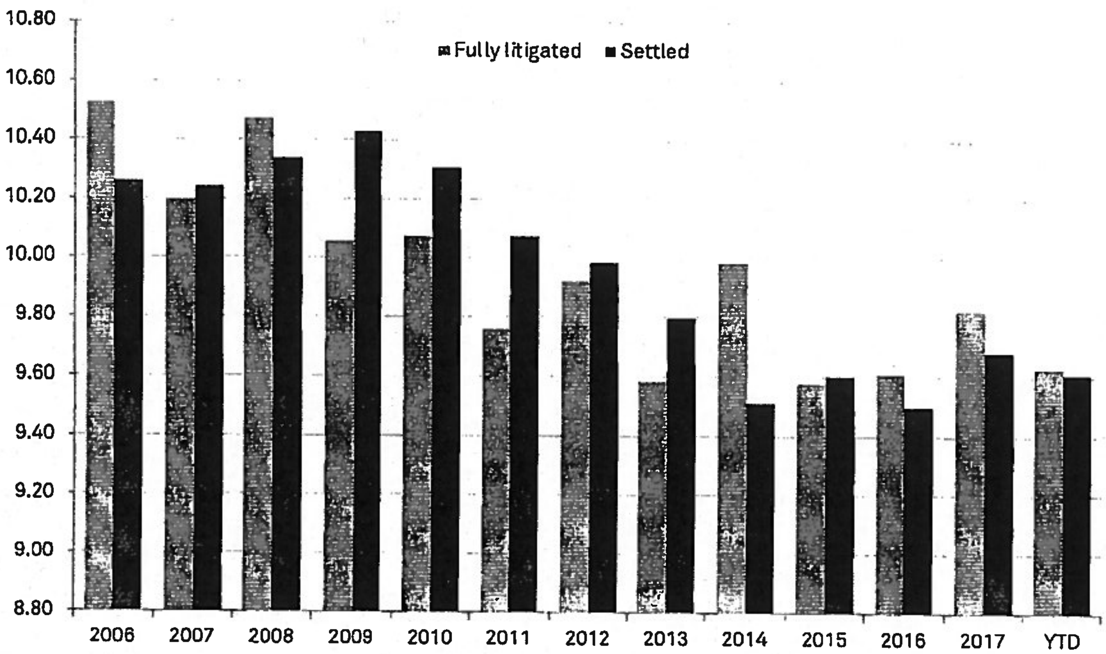
Over the last several years, the annual average authorized ROEs in electric cases that involve limited-issue riders was typically at least 70 basis points higher than in general rate cases, driven by the ROE premiums authorized in Virginia. Limited-issue rider cases in which an ROE is determined have had extremely limited use in the gas industry.

Average authorized electric ROEs, settled versus fully litigated cases



Data compiled Oct. 10, 2018.
YTD = year-to-date, through Sept. 30, 2018.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Average authorized gas ROEs, settled versus fully litigated cases



Data compiled Oct. 10, 2018.
YTD = year-to-date, through Sept. 30, 2018.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

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The table on page 6 shows the average ROE authorized in major electric and gas rate decisions annually since 1990 and by quarter since 2014, followed by the number of observations in each period. The tables on page 7 indicate the composite electric and gas industry data for all major cases, summarized annually since 2004 and by quarter for the past six quarters.

Included in the tables beginning on page 8 of this report are comparisons, since 2006, of average authorized ROEs for settled versus fully litigated cases, general rate cases versus limited issue rider proceedings and vertically integrated cases versus delivery-only cases.

The individual electric and gas cases decided in 2018 are listed on pages 10 and 11, with the decision date shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return, or ROR, the ROE and the percentage of common equity in the adopted capital structure. Next, we indicate the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered at the time decisions were rendered. Fuel adjustment clause rate changes are not reflected in this study.

The simple mean is utilized for the return averages. In addition, the average equity returns indicated in this report reflect the ROEs approved in cases that were decided during the specified time periods and are not necessarily representative of either the average currently authorized ROEs for utilities industrywide or the returns actually earned by the utilities.

Please note: In an effort to align data presented in this report with data available in S&P Global Market Intelligence's online database, earlier historical data provided in previous reports may not match historical data in this report due to certain differences in presentation, including the treatment of cases that were withdrawn or dismissed.

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ROEs authorized January 1990 - September 2018

		Electric utilities			Gas utilities		
Year	Period	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
1990	Full year	12.70	12.77	38	12.68	12.75	33
1991	Full year	12.54	12.50	42	12.45	12.50	31
1992	Full year	12.09	12.00	45	12.02	12.00	28
1993	Full year	11.46	11.50	28	11.37	11.50	40
1994	Full year	11.21	11.13	28	11.24	11.27	24
1995	Full year	11.58	11.45	28	11.44	11.30	13
1996	Full year	11.40	11.25	18	11.12	11.25	17
1997	Full year	11.33	11.58	10	11.30	11.25	12
1998	Full year	11.77	12.00	10	11.51	11.40	10
1999	Full year	10.72	10.75	6	10.74	10.65	6
2000	Full year	11.58	11.50	9	11.34	11.16	13
2001	Full year	11.07	11.00	15	10.96	11.00	5
2002	Full year	11.21	11.28	14	11.17	11.00	19
2003	Full year	10.96	10.75	20	10.99	11.00	25
2004	Full year	10.81	10.70	21	10.63	10.50	22
2005	Full year	10.51	10.35	24	10.41	10.40	26
2006	Full year	10.32	10.23	26	10.40	10.50	15
2007	Full year	10.30	10.20	38	10.22	10.20	35
2008	Full year	10.41	10.30	37	10.39	10.45	32
2009	Full year	10.52	10.50	40	10.22	10.26	30
2010	Full year	10.37	10.30	61	10.15	10.10	39
2011	Full year	10.29	10.17	42	9.92	10.03	16
2012	Full year	10.17	10.08	58	9.94	10.00	35
2013	Full year	10.03	9.95	49	9.68	9.72	21
	1st quarter	10.23	9.86	8	9.54	9.60	6
	2nd quarter	9.83	9.70	5	9.84	9.95	8
	3rd quarter	9.87	9.78	12	9.45	9.33	6
	4th quarter	9.78	9.80	13	10.28	10.20	6
2014	Full year	9.91	9.78	38	9.78	9.78	26
	1st quarter	10.37	9.83	9	9.47	9.05	3
	2nd quarter	9.73	9.60	7	9.43	9.50	3
	3rd quarter	9.40	9.40	2	9.75	9.75	1
	4th quarter	9.62	9.55	12	9.68	9.75	9
2015	Full year	9.85	9.65	30	9.60	9.68	16
	1st quarter	10.29	10.50	9	9.48	9.50	6
	2nd quarter	9.60	9.60	7	9.42	9.52	6
	3rd quarter	9.76	9.80	8	9.47	9.50	4
	4th quarter	9.57	9.58	18	9.68	9.73	10
2016	Full year	9.77	9.75	42	9.54	9.50	26
	1st quarter	9.87	9.60	15	9.60	9.25	3
	2nd quarter	9.63	9.50	14	9.47	9.60	7
	3rd quarter	9.66	9.60	5	10.14	9.90	6
	4th quarter	9.73	9.60	19	9.68	9.55	8
2017	Full year	9.74	9.60	53	9.72	9.60	24
	1st quarter	9.75	9.90	13	9.68	9.80	6
	2nd quarter	9.54	9.50	13	9.43	9.50	7
	3rd quarter	9.63	9.70	11	9.69	9.60	13
2018	Year-to-date	9.64	9.70	37	9.62	9.55	26

Year-to-date, through Sept. 30, 2018.
Data compiled Oct. 10, 2018
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

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RRA Regulatory Focus: Major Rate Case Decisions

Electric and gas utilities — summary table

	Period	ROR (%)	Number of observations	ROE (%)	Number of observations	Common equity to total capital (%)	Number of observations	Rate change amount ($M)	Number of observations
Electric utilities									
2004	Full year	8.71	20	10.81	21	46.96	19	1,806.3	29
2005	Full year	8.44	23	10.51	24	47.34	23	936.1	31
2006	Full year	8.32	26	10.32	26	48.54	25	1,318.1	39
2007	Full year	8.18	37	10.30	38	47.88	36	1,405.7	43
2008	Full year	8.21	39	10.41	37	47.94	36	2,823.2	44
2009	Full year	8.24	40	10.52	40	48.57	39	4,191.7	58
2010	Full year	8.01	62	10.37	61	48.63	57	4,921.9	78
2011	Full year	8.00	43	10.29	42	48.26	42	2,595.1	56
2012	Full year	7.95	51	10.17	58	50.69	52	3,080.7	69
2013	Full year	7.66	45	10.03	49	49.25	43	3,328.6	61
2014	Full year	7.60	32	9.91	38	50.28	35	2,053.7	51
2015	Full year	7.38	35	9.85	30	49.54	30	1,891.5	52
2016	Full year	7.28	41	9.77	42	48.91	41	2,332.1	57
	1st quarter	6.97	15	9.87	15	47.95	15	1,028.3	24
	2nd quarter	7.11	9	9.63	14	48.77	9	597.0	19
	3rd quarter	7.43	5	9.66	5	49.63	5	558.6	10
	4th quarter	7.32	19	9.73	19	49.51	19	563.8	24
2017	Full year	7.18	48	9.74	53	48.90	48	2,747.7	77
	1st quarter	6.89	13	9.75	13	48.89	13	592.6	14
	2nd quarter	6.78	13	9.54	13	47.94	13	372.4	18
	3rd quarter	7.10	11	9.63	11	51.15	11	269.2	13
2018	Year-to-date	6.91	37	9.64	37	49.23	37	1,234.2	45
Gas utilities									
2004	Full year	8.51	23	10.63	22	45.81	22	306.0	33
2005	Full year	8.24	29	10.41	26	48.40	24	465.4	35
2006	Full year	8.44	17	10.40	15	47.24	16	392.5	23
2007	Full year	8.11	31	10.22	35	48.47	28	645.3	43
2008	Full year	8.49	33	10.39	32	50.35	32	700.0	40
2009	Full year	8.15	29	10.22	30	48.49	29	438.6	36
2010	Full year	7.99	40	10.15	39	48.70	40	776.5	50
2011	Full year	8.09	18	9.92	16	52.49	14	367.0	31
2012	Full year	7.98	30	9.94	35	51.13	32	264.0	41
2013	Full year	7.43	21	9.68	21	50.60	20	498.7	40
2014	Full year	7.65	27	9.78	26	51.11	28	544.2	48
2015	Full year	7.34	16	9.60	16	49.93	16	494.1	40
2016	Full year	7.08	28	9.54	26	50.06	26	1,263.8	59
	1st quarter	7.20	2	9.60	3	51.57	3	71.0	9
	2nd quarter	7.27	5	9.47	7	49.15	5	85.3	13
	3rd quarter	7.07	8	10.14	6	46.58	7	128.6	17
	4th quarter	7.43	9	9.68	8	52.30	9	125.8	15
2017	Full year	7.26	24	9.72	24	49.88	24	410.7	54
	1st quarter	7.14	5	9.68	6	51.05	6	198.0	9
	2nd quarter	7.08	7	9.43	7	50.83	6	73.8	11
	3rd quarter	6.86	15	9.69	13	48.55	15	272.8	20
2018	Year-to-date	6.97	27	9.62	26	49.61	27	544.6	40

Year-to-date, through Sept. 30, 2018.
Data compiled Oct. 10, 2018
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

S&P Global
Market Intelligence

Electric authorized ROEs: 2006 - September 2018

Settled versus fully litigated cases

	All cases			Settled cases			Fully litigated cases		
Year	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
2006	10.32	10.23	26	10.26	10.25	11	10.37	10.12	15
2007	10.30	10.20	38	10.42	10.33	14	10.23	10.15	24
2008	10.41	10.30	37	10.43	10.25	17	10.39	10.54	20
2009	10.52	10.50	40	10.64	10.62	16	10.45	10.50	24
2010	10.37	10.30	61	10.39	10.30	34	10.35	10.10	27
2011	10.29	10.17	42	10.12	10.07	16	10.39	10.25	26
2012	10.17	10.08	58	10.06	10.00	29	10.28	10.25	29
2013	10.03	9.95	49	10.12	9.98	32	9.85	9.75	17
2014	9.91	9.78	38	9.73	9.75	17	10.05	9.83	21
2015	9.85	9.65	30	10.07	9.72	14	9.66	9.62	16
2016	9.77	9.75	42	9.80	9.85	17	9.74	9.60	25
2017	9.74	9.60	53	9.75	9.60	29	9.73	9.56	24
2018 YTD	9.64	9.70	37	9.55	9.62	20	9.75	9.73	17

General rate cases versus limited-issue riders

	All cases			General rate cases			Limited issue riders		
Year	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
2006	10.32	10.23	26	10.34	10.25	25	9.80	9.80	1
2007	10.30	10.20	38	10.32	10.23	36	9.90	9.90	1
2008	10.41	10.30	37	10.37	10.30	35	11.11	11.11	2
2009	10.52	10.50	40	10.52	10.50	38	10.55	10.55	2
2010	10.37	10.30	61	10.29	10.26	58	11.87	12.30	3
2011	10.29	10.17	42	10.19	10.14	40	12.30	12.30	2
2012	10.17	10.08	58	10.02	10.00	51	11.57	11.40	6
2013	10.03	9.95	49	9.82	9.82	40	11.34	11.40	7
2014	9.91	9.78	38	9.76	9.75	32	10.96	11.00	5
2015	9.85	9.65	30	9.60	9.53	23	10.87	11.00	6
2016	9.77	9.75	42	9.60	9.60	32	10.31	10.55	10
2017	9.74	9.60	53	9.68	9.60	42	10.01	9.95	10
2018 YTD	9.64	9.70	37	9.59	9.62	28	9.80	10.20	9

Vertically integrated cases versus delivery-only cases

	All cases			Vertically integrated cases			Delivery only cases		
Year	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
2006	10.32	10.23	26	10.63	10.54	15	9.91	10.03	10
2007	10.30	10.20	38	10.50	10.45	26	9.86	9.98	10
2008	10.41	10.30	37	10.48	10.47	26	10.04	10.25	9
2009	10.52	10.50	40	10.66	10.66	28	10.15	10.30	10
2010	10.37	10.30	61	10.42	10.40	41	9.98	10.00	17
2011	10.29	10.17	42	10.33	10.20	28	9.85	10.00	12
2012	10.17	10.08	58	10.10	10.20	39	9.75	9.73	12
2013	10.03	9.95	49	9.95	10.00	31	9.37	9.36	9
2014	9.91	9.78	38	9.94	9.90	19	9.49	9.55	13
2015	9.85	9.65	30	9.75	9.70	17	9.17	9.07	6
2016	9.77	9.75	42	9.77	9.78	20	9.31	9.33	12
2017	9.74	9.60	53	9.80	9.65	28	9.43	9.55	14
2018 YTD	9.64	9.70	37	9.69	9.77	19	9.38	9.35	9

YTD = year-to-date, through Sept. 30, 2018.
Data compiled Oct. 10, 2018
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Gas average authorized ROEs: 2006 - September 2018

Settled versus fully litigated cases

	All cases			Settled cases			Fully litigated cases		
Year	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
2006	10.40	10.50	15	10.26	10.20	7	10.53	10.80	8
2007	10.22	10.20	35	10.24	10.18	22	10.20	10.40	13
2008	10.39	10.45	32	10.34	10.28	20	10.47	10.68	12
2009	10.22	10.26	30	10.43	10.40	13	10.05	10.15	17
2010	10.15	10.10	39	10.30	10.15	12	10.08	10.10	27
2011	9.92	10.03	16	10.08	10.08	8	9.76	9.80	8
2012	9.94	10.00	35	9.99	10.00	14	9.92	9.90	21
2013	9.68	9.72	21	9.80	9.80	9	9.59	9.60	12
2014	9.78	9.78	26	9.51	9.50	11	9.98	10.10	15
2015	9.60	9.68	16	9.60	9.60	11	9.58	9.80	5
2016	9.54	9.50	26	9.50	9.50	16	9.61	9.58	10
2017	9.72	9.60	24	9.68	9.60	17	9.82	9.50	7
2018 YTD	9.62	9.55	26	9.61	9.60	15	9.63	9.50	11

General rate cases versus limited issue riders

	All cases			General rate cases			Limited issue riders		
Year	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
2006	10.40	10.50	15	10.40	10.50	15	—	—	0
2007	10.22	10.20	35	10.22	10.20	35	—	—	0
2008	10.39	10.45	32	10.39	10.45	32	—	—	0
2009	10.22	10.26	30	10.22	10.26	30	—	—	0
2010	10.15	10.10	39	10.15	10.10	39	—	—	0
2011	9.92	10.03	16	9.91	10.05	15	10.00	10.00	1
2012	9.94	10.00	35	9.93	10.00	34	10.40	10.40	1
2013	9.68	9.72	21	9.68	9.72	21	—	—	0
2014	9.78	9.78	26	9.78	9.78	26	—	—	0
2015	9.60	9.68	16	9.60	9.68	16	—	—	0
2016	9.54	9.50	26	9.53	9.50	25	9.70	9.70	1
2017	9.72	9.60	24	9.72	9.60	24	—	—	0
2018 YTD	9.62	9.55	26	9.62	9.60	25	9.50	9.50	1

YTD = year-to-date, through Sept. 30, 2018.
Data compiled Oct. 10, 2018.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

S&P Global
Market Intelligence

RRA Regulatory Focus: Major Rate Case Decisions

Electric utility decisions

Date	Company	State	ROR (%)	ROE (%)	Common equity as % of capital	Test year	Rate base	Rate change amount ($)	Footnotes
1/18/18	Kentucky Power Company	KY	6.44	9.70	41.68	2/17	Year-end	12.3	B
1/31/18	Public Service Company of Oklahoma	OK	6.88	9.30	48.51	12/16	Year-end	75.5	R
2/2/18	Interstate Power and Light Company	IA	7.49	9.98	49.02	12/16	Average	130.0	B, I
2/6/18	Mississippi Power Company	MS	6.62	8.58	50.45	12/18	Average	—	B, LIR, 1
2/9/18	Delmarva Power & Light Company	MD	—	—	—	9/17	—	13.4	B, D
2/9/18	Virginia Electric and Power Company	VA	7.21	10.20	50.23	3/19	Average	-6.0	LIR,2
2/14/18	Virginia Electric and Power Company	VA	7.21	10.20	50.23	3/19	Average	-11.5	LIR,3
2/20/18	Virginia Electric and Power Company	VA	7.21	10.20	50.23	3/19	Average	-24.6	LIR,4
2/21/18	Virginia Electric and Power Company	VA	6.71	9.20	50.23	3/19	Average	0.2	LIR,5
2/23/18	Duke Energy Progress, LLC	NC	7.09	9.90	52.00	12/16	Year-end	194.0	B
2/27/18	Virginia Electric and Power Company	VA	7.20	11.20	50.23	3/19	Average	14.9	LIR,6
3/12/18	ALLETE (Minnesota Power)	MN	7.06	9.25	53.81	12/17	Average	12.0	I
3/15/18	Niagara Mohawk Power Corporation	NY	6.53	9.00	48.00	3/19	Average	160.0	B, D, Z
3/20/18	Georgia Power Company	GA	—	—	—	12/18	—	-50.0	LIR,7
3/29/18	Consumers Energy Company	MI	5.89	10.00	40.89	9/18	Average	72.3	I,R,*
2018	**1st quarter: averages/total**		**6.89**	**9.75**	**48.89**			**592.6**	
	Observations		**13**	**13**	**13**			**14**	
4/2/18	Appalachian Power Company	VA	—	—	—	—	—	—	LIR,8
4/12/18	Indiana Michigan Power Company	MI	5.76	9.90	36.38	12/18	Average	49.1	*
4/13/18	Duke Energy Kentucky, Inc.	KY	6.83	9.73	49.25	3/19	Average	8.4	
4/18/18	Connecticut Light and Power Company	CT	7.09	9.25	53.00	12/16	Average	124.7	B, D, Z
4/18/18	DTE Electric Company	MI	5.34	10.00	36.84	10/18	Average	74.4	I, R, *
4/26/18	Public Service Company of Colorado	CO	—	—	—	—	—	—	9
4/26/18	Avista Corporation	WA	7.50	9.50	48.50	12/16	Average	10.8	
5/8/18	Kentucky Utilities Company	VA	—	—	—	12/16	—	1.8	B
5/10/18	Virginia Electric and Power Company	VA	6.71	9.20	50.23	6/18	—	2.8	LIR,10
5/16/18	Appalachian Power Company	VA	—	—	—	6/19	—	1.0	LIR,11
5/23/18	Southern Indiana Gas and Electric Company, Inc.	IN	—	—	—	10/17	Year-end	1.9	LIR
5/30/18	Indiana Michigan Power Company	IN	5.51	9.95	35.73	12/18	Year-end	153.4	B,Z
5/30/18	Northern Indiana Public Service Company	IN	—	—	—	11/17	Year-end	12.6	LIR
5/31/18	Potomac Electric Power Company	MD	7.03	9.50	50.44	12/17	—	-15.0	B, D
6/14/18	Central Hudson Gas & Electric Corporation	NY	6.44	8.80	48.00	6/19	Average	19.7	B, D, Z
6/19/18	Oklahoma Gas and Electric Company	OK	—	—	—	9/17	—	-64.0	B,12
6/22/18	Hawaiian Electric Company, Inc.	HI	7.57	9.50	57.10	12/17	Average	-0.6	B, I
6/22/18	Duke Energy Carolinas, LLC	NC	7.35	9.90	52.00	12/16	Year-end	-13.0	B,R
6/28/18	Emera Maine	ME	7.18	9.35	49.00	12/16	Average	4.5	D
6/29/18	Hawaii Electric Light Company, Inc.	HI	7.80	9.50	56.69	12/16	Average	-0.1	B, I
	2nd quarter: averages/total		**6.78**	**9.54**	**47.94**			**372.4**	
	Observations		**13**	**13**	**13**			**18**	
7/3/18	Virginia Electric and Power Company	VA	6.71	9.20	50.23	8/19	Average	3.3	LIR,13
7/3/18	Virginia Electric and Power Company	VA	7.21	10.20	50.23	8/19	Average	-11.1	LIR,14
7/10/18	Duke Energy Florida, LLC	FL	—	—	—	—	—	200.5	B, LIR, Z,15
7/25/18	Atlantic City Electric Company	NJ	—	—	—	12/18	—	—	D,16
8/8/18	Potomac Electric Power Company	DC	7.45	9.53	50.44	12/17	—	-24.1	B, D
8/21/18	Delmarva Power & Light Company	DE	6.78	9.70	50.52	12/17	—	-6.9	B, D, I
8/24/18	Narragansett Electric Company	RI	6.97	9.28	50.95	6/17	Average	28.9	B, D, Z,
8/31/18	Appalachian Power Company	WV	—	—	—	12/17	—	91.6	B, LIR, 17
9/5/18	Southwestern Public Service Company	NM	6.85	9.10	51.00	6/18	Year-end	8.1	
9/14/18	Wisconsin Power and Light Company	WI	7.09	10.00	52.00	12/20	Average	0.0	B,18
9/20/18	Madison Gas and Electric Company	WI	7.10	9.80	56.06	12/20	Average	-8.0	B
9/26/18	Otter Tail Power Company	ND	7.64	9.77	52.50	12/18	Average	7.4	B, I
9/26/18	Dayton Power and Light Company	OH	7.27	10.00	47.52	5/16	Date Certain	29.8	B, D
9/27/18	Westar Energy, Inc.	KS	7.06	9.30	51.24	6/17	Year-end	-50.3	B
2018	**3rd quarter: averages/total**		**7.10**	**9.63**	**51.15**			**269.2**	
	Observations		**11**	**11**	**11**			**13**	
2018	**YTD: averages/total**		**6.91**	**9.64**	**49.23**			**1,234.2**	
	Observations		**37**	**37**	**37**			**45**	

YTD = year-to-date, through Sept. 30, 2018.
Data compiled Oct. 10, 2018.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

S&P Global
Market Intelligence

Gas utility decisions

Date	Company	State	ROR (%)	ROE (%)	Common equity as % of capital	Test year	Rate base	Rate change amount ($)	Footnotes
1/24/18	Indiana Gas Company, Inc.	IN	—	—	—	6/17	Year-end	8.4	LIR,19
1/24/18	Southern Indiana Gas and Electric Company, Inc.	IN	—	—	—	6/17	Year-end	1.3	LIR,19
1/31/18	Northern Illinois Gas Company	IL	7.26	9.80	52.00	12/18	Average	93.5	R
2/21/18	Missouri Gas Energy	MO	7.20	9.80	54.16	12/16	Year-end	15.2	
2/21/18	Spire Missouri Inc.	MO	7.20	9.80	54.16	12/16	Year-end	18.0	
2/27/18	Atmos Energy Corporation	KS	—	—	—	9/17	—	0.8	LIR,20
2/28/18	Northern Utilities, Inc.	ME	7.53	9.50	50.00	12/16	Average	-0.1	
3/15/18	Niagara Mohawk Power Corporation	NY	6.53	9.00	48.00	3/19	Average	45.5	B, Z
3/26/18	Pivotal Utility Holdings, Inc.	FL	—	10.19	48.00	12/18	—	15.3	B, Z, I
2018	**1st quarter: averages/total**		**7.14**	**9.68**	**51.05**			**198.0**	
	Observations		**5**	**6**	**6**			**9**	
4/26/18	Avista Corporation	WA	7.50	9.50	48.50	12/16	Average	-2.1	
4/27/18	Liberty Utilities (EnergyNorth Natural Gas) Corp.	NH	6.80	9.30	49.21	12/16	Year-end	8.1	Z, I
5/2/18	Northern Utilities, Inc.	NH	7.59	9.50	51.70	12/16	Year-end	0.9	B, Z, I
5/3/18	Atmos Energy Corporation	KY	7.41	9.70	52.57	3/19	Average	-1.9	
5/10/18	CenterPoint Energy Resources Corp.	MN	7.12	—	—	9/18	Average	3.9	B, I
5/15/18	Atlanta Gas Light Company	GA	—	—	55.00	12/18	—	-16.0	B
5/29/18	MDU Resources Group, Inc.	MT	—	9.40	—	—	—	1.0	B
5/30/18	Baltimore Gas and Electric Company	MD	6.69	—	—	12/23	—	68.0	LIR, Z,21
6/6/18	Liberty Utilities (Midstates Natural Gas) Corp	MO	—	9.80	—	6/17	Year-end	4.6	B
6/14/18	Central Hudson Gas & Electric Corporation	NY	6.44	8.80	48.00	6/19	Average	6.7	B, Z
6/19/18	Black Hills Kansas Gas Utility Company, LLC	KS	—	—	—	2/18	Year-end	0.6	LIR
	2nd quarter: averages/total		**7.08**	**9.43**	**50.83**			**73.8**	
	Observations		**7**	**7**	**6**			**11**	
7/16/18	Black Hills Northwest Wyoming Gas Utility Company, LLC	WY	7.75	9.60	54.00	6/17	Year-end	1.0	B
7/20/18	Cascade Natural Gas Corporation	WA	7.31	9.40	49.00	12/16	Average	-2.9	B
8/15/18	Virginia Natural Gas, Inc.	VA	6.86	9.50	48.74	8/19	Average	3.2	LIR,22
8/21/18	Delta Natural Gas Company, Inc.	KY	—	—	—	12/17	Year-end	2.2	LIR,23
8/22/18	Northern Indiana Public Service Company	IN	—	—	—	12/17	Year-end	14.2	LIR,24
8/24/18	Narragansett Electric Company	RI	7.15	9.28	50.95	6/17	Average	17.4	B, Z
8/28/18	Consumers Energy Company	MI	5.86	10.00	40.91	6/19	Average	10.6	B,*
9/5/18	Indiana Gas Company, Inc.	IN	—	—	—	12/17	Year-end	9.8	LIR,25
9/5/18	Southern Indiana Gas and Electric Company, Inc.	IN	—	—	—	12/17	Year-end	2.2	LIR,26
9/11/18	CenterPoint Energy Resources Corp.	AR	4.69	—	31.52	9/19	Year-end	5.1	B,*
9/13/18	DTE Gas Company	MI	5.56	10.00	38.30	9/19	Average	9.0	*
9/14/18	Wisconsin Power and Light Company	WI	6.97	10.00	52.00	12/18	Average	0.0	B,27
9/19/18	Northern Indiana Public Service Company	IN	6.50	9.85	46.88	12/18	Year-end	107.3	B, Z
9/19/18	Bay State Gas Company	MA	—	—	—	—	—	—	28
9/20/18	Madison Gas and Electric Company	WI	7.10	9.80	56.06	12/20	Average	4.1	B,Z
9/26/18	MDU Resources Group, Inc.	ND	7.24	9.40	51.00	12/18	Average	2.5	B, I
9/26/18	Piedmont Natural Gas Company, Inc.	SC	7.60	10.20	53.00	3/18	Year-end	-13.9	B,M
9/26/18	South Carolina Electric & Gas Co.	SC	8.05	—	49.83	3/18	Year-end	-19.7	M
9/28/18	Boston Gas Company	MA	7.01	9.50	53.04	12/16	Year-end	100.8	
9/28/18	Colonial Gas Company	MA	7.18	9.50	53.04	12/16	Year-end	17.8	
9/28/18	Columbia Gas of Maryland, Incorporated	MD	—	—	—	12/19	Average	2.0	B, LIR,29
2018	**3rd quarter: averages/total**		**6.86**	**9.69**	**48.55**			**272.8**	
	Observations		**15**	**13**	**15**			**20**	
2018	**YTD: averages/total**		**6.97**	**9.62**	**49.61**			**544.6**	
	Observations		**27**	**26**	**27**			**40**	

YTD = year-to-date, through Sept. 30, 2018.
Data compiled Oct. 10, 2018.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Footnotes

A Average.

B Order followed stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.

CWIP Construction work in progress.

D Applies to electric delivery only.

DCt Date-certain rate base valuation.

E Estimated.

F Return on fair value rate base.

Hy Hypothetical capital structure utilized.

I Interim rates implemented prior to the issuance of final order, normally under bond and subject to refund.

LIR Limited-issue rider proceeding.

M "Make-whole" rate change based on return on equity or overall return authorized in previous case.

R Revised.

Te Temporary rates implemented prior to the issuance of final order.

Tr Applies to transmission service.

U Double leverage capital structure utilized.

YE Year-end.

Z Rate change implemented in multiple steps.

* Capital structure includes cost-free items or tax credit balances at the overall rate of return.

1 Decision adopted a company filing specifying a $99.3 million plant-specific retail revenue requirement. According to the company, this results in an annual rate reduction of approximately $26.8 million.

2 Rate change was approved under Rider R, which is the mechanism through which the company recovers its investment in the Bear Garden power plant.

3 Rate change was approved under Rider W, which is the mechanism through which the company recovers its investment in the Warren County generation facility.

4 Rate change was approved under Rider S, which is the mechanism through which the company recovers its investment in the Virginia City Hybrid Energy Center.

5 Rate change was approved under Rider GV, which is the mechanism through which the company recovers its investment in the Greensville County generation facility.

6 Rate change was approved under Rider B, which is the mechanism through which the company recovers the costs associated with the conversion of the Altavista, Hopewell and Southampton Power Stations to burn biomass fuels.

7 Reduction ordered to the nuclear construction cost recovery tariff associated with the company's two new units being built at its Vogtle plant.

8 Proposed acquisition of the Beech Ridge II and Hardin wind generation facilities, and an associated rider was rejected. No initial revenue requirement had been proposed.

9 Rate case dismissed.

10 Rate change was approved under Rider DSM, which is the mechanism through which the company is permitted to collect a cash return on demand-side management program costs.

11 Rate change was approved under Rider RAC-EE, which is the mechanism through which the company recovers its investment in energy efficiency programs.

12 ROE to be used for certain riders and AFUDC purposes is 9.5%.

13 Rate change was approved under Rider US-2, which is the mechanism through which the company recovers its investment in three utility-scale solar facilities: Scott Solar, Whitehouse Solar and Woodland Solar.

14 Rate change was approved under Rider BW, which is the mechanism through which the company recovers its investment in the Brunswick Power Station.

15 Rate change pertains to the company's Citrus County CC natural gas plant that is nearing completion.

16 Case was dismissed without prejudice.

17 Rate change was approved under the company's joint expanded net energy cost proceeding.

18 Decision freezes electric rates at 2017 levels for 2018 and 2019.

19 Case established the rates to be charged to customers under the company's compliance and system improvement adjustment, or CSIA, mechanism, which includes both federally mandated pipeline-safety initiatives and projects that are permitted under the state's transmission, distribution and storage system improvement charge, or TDSIC, statute.

20 Reflects updates to the company's gas system reliability surcharge rider since its most recent base rate case.

21 Rate change was approved under the company's Strategic Infrastructure Development and Enhancement, or STRIDE, rider.

22 Case involves the company's investment made under Virginia Steps to Advance Virginia Energy infrastructure program.

23 Case involves the company's pipe replacement program rider.

24 Case involves company's TDSIC rate adjustment mechanism.

25 Case involves the company's CSIA mechanism and projects that are permitted under the state's TDSIC statute.

26 Pertains to investments made under the company's CSIA mechanism and projects that are permitted under the state's TDSIC statute.

27 Freezes gas rates at 2017 levels for 2018 and 2019.

28 Rate case withdrawn.

29 Case relates to the company's investment in its STRIDE program.

30 Rate change was approved under the company's infrastructure replacement and improvement surcharge, or IRIS, rider through which the company recovers costs associated with its STRIDE plan.