COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES, AND APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS	**)**	**CASE NO. 2025-00113**

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, AND APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS	**)**	**CASE NO. 2025-00114**

DIRECT TESTIMONY

AND EXHIBITS OF

LANE KOLLEN

ON BEHALF OF THE
OFFICE OF THE ATTORNEY GENERAL OF THE COMMONWEALTH OF KENTUCKY
AND KENTUCKY INDUSTRIAL UTILITY CUSTOMERS

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

SEPTEMBER 9, 2025

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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 College & Seminary. 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 forty years, initially as an employee of an electric and natural gas utility, then as a consultant assisting utilities in their resource planning and financial analyses, and thereafter as a consultant assisting government agencies and large users of electricity and natural gas utility services. I have testified as an expert witness on ratemaking, accounting, finance, tax, 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 (Commission) involving Kentucky Utilities Company (KU or Company), Louisville Gas and Electric Company (LG&E or Company), Kentucky Power Company (KPC), Duke Energy Kentucky, Inc. (DEK), East Kentucky Power Company (EKPC), Big Rivers Electric Corporation (BREC), Atmos Energy Corporation (Atmos), Columbia Gas of Kentucky, Inc. (Columbia), Kentucky-

American Water Company (KAW), and Water Service Corporation of Kentucky (WSCK).[1]

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Office of the Attorney General of the Commonwealth of Kentucky (AG) and Kentucky Industrial Utility Customers, Inc. (KIUC), which together represent residential and large industrial manufacturing customers taking electric and natural gas retail utility service from KU and LG&E. The AG and KIUC have been active participants in all significant KU and LG&E rate, planning, and certification proceedings for many years.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to summarize the adjustments to the Companies' requested base revenue increases recommended by AG-KIUC witnesses and to address specific issues and recommend adjustments that affect the requested increases.[2] More specifically, I address the Companies' requests to use capitalization in lieu of rate base for the *return on* component of the base revenue requirements, include construction work in progress (CWIP) in rate base in lieu of allowance for funds used during construction (AFUDC), utilize inconsistent and non-rationalized service lives for electric production plant account depreciation rates and expense, include terminal net salvage in electric production plant account depreciation rates and expense, include estimated interim retirements and interim

[1] My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).
[2] In addition to the base rate increases requested in these proceedings, the Companies request that the Commission increase the depreciation rates and return on equity reflected in the ECR.

net salvage in electric production plant account depreciation rates and expense, storm damage and vegetation management expenses and the Companies request to use regulatory deferral accounting for these expenses, among other issues.

I also address the Companies/customers sharing percentages in the Companies' off-system sales adjustment clause (OSS) rider, the recovery of purchased power expense incurred by the Companies due to the renewable (solar) purchase power agreements (RPPAs) approved by the Commission in Case 2022-00402, the extremely high load factor (EHLF) tariff proposed by the Companies for new data center loads in this proceeding and addressed in Case 2025-00045, and the proposed Mill Creek 2 and Mill Creek 6 tariffs attached to the settlement agreement among the parties pending in Case 2025-00045.

Q. Please summarize your testimony.

A. I recommend the Commission reduce KU's revised electric revenue deficiency of $219.920 million to reflect a deficiency and rate increase of no more than $20.631 million.[3]

I recommend the Commission reduce LG&E's revised electric revenue deficiency of $106.824 million to reflect a deficiency and rate increase of no more than $14.375 million.[4]

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[3] The Companies provided supplemental responses to Staff 1-54 on August 25, 2025 wherein they revised their claimed revenue deficiencies. The KU reduced its claimed revenue deficiency from $226.122 million to $219.920 million. LG&E increased its claimed electric revenue deficiency from $104.895 million to $106.824 million. LG&E increased its claimed gas revenue deficiency from $59.494 million to $60.247 million. The Companies have not sought to modify their requested increases to reflect these revisions. Nevertheless, I used their revised claimed revenue deficiencies as the starting point for the adjustments that I and other AG-KIUC witnesses recommend and for the maximum rate increase that I recommend.

[4] *Id.*

I recommend the Commission reduce LG&E's revised gas revenue deficiency of $60.247 million to a deficiency and rate increase of no more than $25.361 million.[5]

The following table lists each adjustment recommended by AG-KIUC witnesses and the effect on each Company's claimed base revenue increase. The amounts for KU are shown on a Kentucky jurisdiction basis and the amounts for LG&E are shown separately for electric and gas.[6] The table also identifies the AG-KIUC witness who addresses each issue. Although AG-KIUC witness Richard Baudino addresses the cost of capital issues, I quantify the effects of Witness Baudino's recommendations on the Companies' requested base revenue increases.

[5] *Id.*

[6] The calculations are detailed in my workpapers for each Company, which have been filed with my testimony in the form of Excel workbooks in live format.

Kentucky Utilities Company and Louisville Gas & Electric Company
Summary of Revenue Requirement Adjustments-Jurisdictional Electric and Gas Operations
Recommended by AG-KIUC
Case Nos. 2025-00113 and 2025-00114
For the Test Year Ended December 31, 2026
($ Millions)

	KU Amount	LG&E Electric Amount	LG&E Gas Amount	AG-KIUC Witness
Base Rate Increase Requested by Companies - Original Application	226.122	104.895	59.494	
August 25, 2025 Revision - Change in Revenue Deficiency	(6.202)	1.929	0.754	
Base Rate Increase Requested by Companies - Assuming August 25, 2025 Revision	219.920	106.824	60.247	
AG and KIUC Rate Base Issues				
Utilize Rate Base Instead of Capitalization to Reflect Return On Component for Base Rates	(9.062)	0.545	(4.647)	Kollen
Remove Generation and Transmission CWIP from Rate Base	(25.038)	(11.258)	(3.361)	Kollen
Modify CWC to Exclude Non-Cash Depr/Amort and Deferred Income Taxes	(5.512)	(3.589)	(0.873)	Kollen
Modify CWC to Exclude Non-Cash Coal Expense	(0.851)	(0.581)	-	Kollen
Exclude Non-Cash Pension and OPEB Related Asset and Liability Amounts, Net of ADIT	(10.923)	(9.944)	(5.616)	Kollen
Exclude All Account 184 Pension Clearing Account Amounts	(0.210)	-	(0.144)	Kollen
Adjust A/D and ADIT for Depreciation Expense Reductions-Terminal Net Salvage-Thermal	0.543	0.201	-	Kollen
Adjust A/D and ADIT for Depreciation Expense Reductions-Terminal Net Salvage-Other	0.002	0.004	-	Kollen
Adjust A/D and ADIT for Depreciation Expense Reductions-Extend Life Spans	1.386	0.111	-	Kollen
AG and KIUC Operating Income Issues				
Reduce Payroll and Related Expenses Due to Excessive O&M Expense Ratio	(9.712)	(2.289)	(1.165)	Futral
Reduce Storm Damage Expense	(6.082)	(6.962)	-	Kollen
Reduce Vegetation Management Expense	(8.816)	(4.799)	-	Kollen
Remove 401K Matching Costs for Employees Who Also Participate in Defined Benefit Plan	(0.937)	(0.657)	(0.325)	Kollen
Reduce Pension Expenses to 2024 Levels	(5.330)	(3.238)	(1.866)	Kollen
Reduce OPEB and Post-Employment Benefit Expenses to 2024 Levels	(0.532)	(0.663)	(0.113)	Kollen
Reduce Miscellaneous Steam Power Expenses in Account 506	(3.215)	(1.552)	-	Futral
Reduce Miscellaneous Transmission Expenses in Account 566	(2.466)	(0.789)	-	Futral
Reduce Maintenance of Mains in Account 863	-	-	(2.617)	Futral
Remove Long-Term Incentive Plan Expense Paid in the Form of Restricted Stock	(1.911)	(1.339)	(0.495)	Futral
Remove EEI, AGA and Related Dues	(0.533)	(0.383)	(0.261)	Futral
Reduce Depreciation Expense to Remove Terminal Net Salvage - Thermal Units	(14.454)	(5.322)	-	Kollen
Reduce Depreciation Expense to Remove Terminal Net Salvage - All Other Units	(0.041)	(0.097)	-	Kollen
Reduce Depreciation Expense to Extend Life Spans	(36.853)	(2.946)	-	Kollen
AG and KIUC Cost of Capital Issues				
Reduce LTD Rate to Reflect Actual August 2025 Issuance of $700 Million at 5.85%	(4.443)	(3.441)	(1.250)	Baudino
Reduce Return on Equity from 10.95% to 9.60%	(54.298)	(33.461)	(12.153)	Baudino
Total AG and KIUC Adjustments to Company Base Rate Request	(199.288)	(92.449)	(34.886)	
Maximum Increase in Base Rates After AG and KIUC Adjustments	20.631	14.375	25.361	

The preceding table reflects numerous changes in the timing, form, and/or methodologies for cost recovery, some in response to requests by the Companies and some that were not expressly requested by the Companies, but are necessary to ensure that rates are just and reasonable and/or required by statutory changes since the Companies' prior base rate case proceedings. First, I recommend the Commission utilize rate base instead of the Companies' request to use capitalization

for the *return on* component of the base revenue requirement. Rate base is more precise and accurate and is consistent with the use of rate base by all other large investor owned utilities regulated by the Commission.

Second, I recommend the Commission exclude all generation and transmission CWIP from rate base, or capitalization if the rate base approach is not adopted, and instead direct the Companies to capitalize their generation and transmission construction financing costs in the form of AFUDC effective when rates are reset in these proceedings. The Companies already exclude CWIP from rate base and capitalization for new generation and certain other projects where the Commission previously approved the Companies' use of AFUDC.

Third, I recommend the Commission exclude all *estimated* terminal net salvage from the electric production plant account depreciation rates and depreciation expense and instead allow the Companies to recover the *actual* terminal net salvage through the Decommissioning Rider after specific generating units are retired and the decommissioning costs are incurred. KRS 278.264 now requires Commission approval to retire *thermal* generating units and specifically prohibits the recovery of *estimated* terminal net salvage for those generating units until after the Commission approves the utility's request to retire and replace specific generating units. The recovery of terminal net salvage is a matter of timing; the Companies still will recover their actual prudent and reasonable cost of decommissioning. The use of *estimated* costs is not necessary and imposes a permanent nominal and present value penalty on customers compared to the use of *actual* costs.

In addition to the changes in timing, form, and/or methodologies for cost recovery shown in the preceding table that affect the base revenue requirements in this proceeding, I make recommendations that will affect cost recoveries in future base rate proceedings and various rider proceedings. First, I recommend the Commission reduce the Companies proposed routine storm damage expense and adopt the Companies' request for regulatory deferral accounting (reserve accounting) for storm costs, but only for routine and un-named storm costs. I recommend the Commission deny the Companies' request for regulatory deferral accounting for vegetation management costs; these costs are not volatile and do not require regulatory deferral accounting.

Second, I recommend the Commission reduce the Companies' proposed pension and OPEB expenses and authorize regulatory deferral accounting for the Companies' allowed pension and OPEB expenses. These expenses are volatile and cannot be reasonably forecast or controlled by the Companies.

Third, I recommend the Commission modify the sharing percentages for off-system sales margins through the OSS from the present 75% customers/25% Companies to 100% customers/0% Companies. This change in the sharing percentages will ensure that customers are provided the same share of these margins as they pay for the capital related costs, fuel expense, and other non-fuel expenses of the generating facilities included in the base and Environmental Cost Recovery (ECR) surcharge rates that are used to make these off-system sales.

Fourth, I recommend the Commission deny the Companies' request for new RPPA recovery riders to recover the costs of potential future renewable purchase

power agreements at this time. The Commission previously denied the same request in Case 2022-00402 as "premature." The request remains premature. There are no pending RPPAs for which recovery is at issue.[7] However, if the Commission proceeds to substantively address the Companies' request, then I recommend it deny the Companies' proposed recovery of the purchased power expense on a per kWh basis and instead adopt an allocation methodology that reflects the fact the RPPA costs are inherently fixed costs, regardless of whether the purchases are denominated on a kWh basis.

Fifth, I recommend the Commission approve the Companies' proposed EHLF tariff, subject to the modifications reflected in the terms of the settlement agreement among the parties in Case 2025-00045.

Sixth, I recommend the Commission approve the proposed MC2 and MC6 tariffs reflected in the terms of the settlement agreement among the parties in Case 2025-00045.

I address each of the preceding issues in the subsequent sections of my testimony. I also quantify the effects of Witness Baudino's recommendations.

Q. Does the Companies' use of a forecast test year ending December 31, 2026 impact the Commission's review of forecast costs and assumptions underlying their requested revenue increases?

A. Yes. Unlike a historic test year based on actual revenues and costs, a forecast test year is not tethered to actual results. It is based on the Companies' forecasts of

[7] Direct Testimony of Andrea Fackler at 36.

future revenues and operating expenses, plant in service and other rate base costs, capitalization, capital structure, cost of debt, and cost of equity based on thousands of assumptions, including programs and approaches that may or not reflect the actual costs the Companies actually will incur in the forecast months of the base period and in the 2026 test year.

In fact, utilities, in conjunction with a forecast test year, have every incentive to *understate* their revenues and *overstate* their costs (expenses, capitalized costs (CWIP and plant), and deferrals, among others), and costs of capital to maximize their requested base revenue increases. The practical reality is that these forecast revenues and costs are never trued-up to the actual revenues and costs. If the actual revenues are greater than the forecast revenues, then the Companies retain the incremental revenues. Similarly, if the Companies actually incur lower capital expenditures and operating expenses than forecast in the test year, then the Companies retain the savings.

Given this context and the opportunities available to manipulate the assumptions and forecast revenues and costs, the Commission should carefully and critically review the assumptions and forecasts driving the requested revenue increases. This is particularly critical when the utilities seek approval for new programs, or include expansions of existing programs, along with significant increases in costs, such as increases in generation, transmission and distribution capital expenditures, generation routine and major outage maintenance expenses, transmission and distribution maintenance expenses, and when they seek significant increases in payroll and benefits expenses, including the underlying

staffing levels by comparing those costs to the history and trendline of actual costs incurred in prior periods and increases in other costs, such as depreciation expense.

II. RATE BASE AND CAPITALIZATION ISSUES

A. Rate Base, Not Capitalization, Is The Most Accurate Approach To Calculate The *Return On* Component Of The Base Revenue Requirement

Q. Describe the Companies' request to use capitalization in lieu of rate base to calculate the *return on* component of the base revenue requirement.

A. The Companies used capitalization to calculate the *return on* component of the base revenue requirements and the requested increases in these proceedings. The Companies also calculated rate base, but used the rate base calculations solely to allocate KU's total capitalization between the retail and wholesale jurisdictions and LG&E's total capitalization between electric and gas operations.

The Companies' calculations of capitalization and rate base result in differences in the *return on* component of the revenue requirement. More specifically, KU calculated jurisdictional capitalization of $6,186.150 million and rate base of $6,096.080 million, a difference of $90.071 million.[8] LG&E electric calculated capitalization of $3,738.941 million and rate base of $3,744,344 million, a difference of negative $5.403 million.[9] LG&E gas calculated capitalization of $1,414.828 million and rate base of $1,368.785 million, a difference of $46.043 million.[10]

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[8] Capitalization is shown on Schedule A and rate base is shown on Schedule B-1 in each Company's filing.

[9] Capitalization is shown on Schedule A and rate base is shown on Schedule B-1 on the electric schedules in LG&E's filing.

[10] Capitalization is shown on Schedule A and rate base is shown on Schedule B-1 on the gas

Q. Has the Commission previously addressed and approved the use of rate base as superior to capitalization to calculate the *return on* component of the base revenue requirement for other utilities?

A. Yes. The Commission now consistently uses rate base to calculate the *return on* component of the base revenue requirement for all large investor-owned utilities subject to its ratemaking jurisdiction, with the exception of KU and LG&E. Most recently, the Commission approved the change to rate base from capitalization for KPC, despite its opposition.[11] In its Order, the Commission stated:

> Based upon a review of the case record and being otherwise sufficiently advised, the Commission finds that applying the capitalization method to calculate Kentucky Power's revenue requirement is not reasonable because this method measures the capital allocations to Kentucky Power from its parent company, in excess of that needed to finance Kentucky Power's direct investment rate base as determined herein. In the converse, the rate base method measures the direct investment into Kentucky Power's system, and, under the facts presented here, is a more accurate method of measuring the financial health of Kentucky Power and its operations. For these reasons, the Commission finds that rate base methodology should be used to determine revenue requirement for this proceeding. (footnote omitted).[12]

Prior to adopting this change for KPC, the Commission approved the change from capitalization to rate base at DEK's request for its gas and electric operations in Case Nos. 2018-00261 and 2019-00271, respectively. In addition to now using rate base for KPC and DEK gas and electric, the Commission historically has used rate base instead of capitalization for Atmos, Columbia, Delta, and KAW.

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schedules in LG&E's filing.

[11] Order in Case No. 2020-00174 at 5.

[12] *Id.*

Q. What reasons did Duke Energy Kentucky provide in support of its request to change to rate base from capitalization for its gas and electric operations?

A. In the DEK gas rate case, DEK witness Sara E. Lawler, Director Rates & Regulatory Planning of Duke Energy Business Services LLC, stated in Direct Testimony the "Company believes that using gas rate base to calculate the revenue requirement is the simplest and most transparent method."[13]

In the DEK electric rate case, two other DEK witnesses testified the use of rate base was superior to the use of capitalization. More specifically, Amy Spiller, the CEO of DEK, stated in Direct Testimony the following:

> Historically, the Company's electric base rates have been determined with reference to a return on capitalization. Although this methodology may have been appropriate in the past, another methodology is more common today. Specifically, and as evident in other Duke Energy Kentucky jurisdictions, a return-on-rate base approach provides a transparent and effective way to establish base rates. The Commission recently approved the return-on-rate base approach for the Company's natural gas base rates in Case No. 2018-00261.[14]

In addition, William Don Wathen, Jr., Director of Rates and Regulatory Strategy for Ohio and Kentucky, stated in Direct Testimony the "use of rate base is a more precise method for measuring the Company's actual investment in facilities and equipment to provide utility service" and that "the rate base methodology is an easier and more conventional way to represent investment in utility plant that is not only accepted by this Commission, but throughout the country."[15]

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[13] Direct Testimony of Sarah E. Lawler at 5 in Case No. 2018-00261.
[14] Direct Testimony of Amy B. Spiller at 25-26 in Case No. 2019-00271.
[15] Direct Testimony of William Don Wathen, Jr. at 11-12 in Case No. 2019-00271.

Q. Why is the use of rate base superior to capitalization to calculate the *return on* component of the base revenue requirement?

A. The use of rate base is more precise and accurate than capitalization to calculate the *return on* component of the base revenue requirement. It allows the Commission to specifically review, assess, and quantify each of the costs that will earn a *return on*, including those costs that are subtracted from rate base, such as net liability accumulated deferred income taxes (ADIT) and negative cash working capital (CWC), the normal result when CWC is properly calculated using the lead/lag approach and correctly excludes non-cash expenses.

The use of rate base also avoids the need to reconcile capitalization to rate base as a reasonableness test when using capitalization for the *return on* component of the revenue requirement. The rate base approach inherently assumes that capitalization is equivalent to the adjusted rate base authorized by the Commission rather than starting with per books capitalization and making adjustments that may or may not reflect the adjustments made directly by the Commission to the per books rate base.[16] The inherent assumption that capitalization equals the adjusted rate base also is reflected in rider filings that use the rate base approach, such as the Companies' ECR filings and RAR filings. Yet, in the Companies' base rate case filings, the rate base and capitalization never are equal, regardless of whether there was or is a historic test year or a forecast test year, and regardless of the Companies'

[16] Capitalization is used only to calculate the capital structure and the weighted cost of capital, which, in turn, is applied to rate base. This approach inherently equivalences capitalization to rate base as the basis for the *return on* component of the revenue requirement.

attempts to adjust capitalization to more closely parallel its proposed adjustments to per books rate base.

In a forecast test year, the per books and adjusted rate base and capitalization amounts never are the same for one or more of the following reasons: 1) equity and debt financings are seldom issued to precisely match the timing of rate base investment, 2) capitalization reflects financing for amounts that are not allowed or included in rate base because they are not allowed a rate of return, they are subject to recovery through a rider that has a true-up mechanism, the costs are volatile from month to month, or there is vendor financing, among others reasons, 3) capitalization does not reflect financing for amounts that the utility seeks to include in rate base, either because the amount included in rate base is a non-cash amount that was not financed or the financing costs are embedded into an expense amount, such as pension and OPEB expense, 4) the forecasts of the rate base amounts and capitalization amounts use different methodologies, 5) short term debt varies daily and generally is much higher on average than the month end short term debt amounts used to calculate the 13- month average capitalization, and 6) other reasons.

In summary, the change to rate base from capitalization for the *return on* component of the base revenue requirement will ensure consistent treatment for all calculations of the Companies' revenue requirements, both the base revenue requirements and all of the rider revenue requirements that include a rate base component, including, presently, the ECR and RAR, and, if authorized in this proceeding, the proposed new MC2 and MC6 riders.

Q. Did the Companies provide a reconciliation between capitalization and rate base for the test year?

A. Yes. The Companies provided these reconciliations in their Minimum Filing Requirements (MFR)[17] and provided additional detail for certain line items in response to AG-KIUC discovery.

Q. What do these reconciliations demonstrate?

A. They demonstrate the use of rate base is a more precise and accurate approach. The use of capitalization is less precise and less accurate because it is essentially a simplistic "all-in" approach calculated as total assets less total liabilities other than capitalization, albeit with certain limited ratemaking adjustments. Of course, not all assets and liabilities are cash costs nor should all assets and liabilities be included (added if an asset or subtracted if a liability) in the calculation of the *return on* component of the revenue requirement. This is readily apparent from even a cursory review of each Companies' reconciliation of capitalization and rate base where there are many assets and many liabilities from the Company's balance sheet accounts that are not included in the calculation of rate base, but are included in capitalization under the "all-in" approach, albeit with certain limited ratemaking adjustments.

Q. What is your recommendation?

A. I recommend the Commission calculate the *return on* component of the base revenue requirement using rate base rather than capitalization for the reasons I

[17] MFR Tab 13 – 807 KAR 5:001 Section 16(6)(f) Reconciliation of Capitalization and Rate Base. I have attached a copy of the Companies' as filed reconciliations as my Exhibit___(LK-2).

cited, several of which also were cited by the Commission in the DEK and KPC Orders approving the change to rate base from capitalization for those utilities.

In addition to using rate base instead of capitalization, I recommend the Commission make a series of corrections to the Companies' calculations of rate base to establish the parameters for these calculations in the pending and in future base rate proceedings. The Commission has not previously closely reviewed the Companies' calculations of rate base because rate base was not used directly to calculate the *return on* component of the base revenue requirement.

Q. What are the effects of your recommendations to use rate base instead of capitalization, without the effects of other ratemaking adjustments and necessary corrections to the Companies' calculations of rate base?

A. This will reduce KU's requested base rate increase by $9.062 million, increase LG&E's requested electric base rate increase by $0.545 million, and reduce LG&E's requested gas base rate increase by $4.647 million based solely on the differences in the Companies' calculations of rate base compared to capitalization and without removing CWIP and without any of the necessary corrections to the Companies' calculations of rate base that I subsequently address and recommend.

B. Rate Base And Capitalization Should Be Reduced To Remove Generation And Transmission CWIP; The Construction Financing Costs Should Be Capitalized As AFUDC

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

A. The Companies seek current recovery of construction financing costs before the construction is completed and placed in service instead of capitalizing these costs

as AFUDC, including the AFUDC in CWIP, and then recovering the costs, including the AFUDC, over the service lives of the assets after construction is completed and the CWIP is closed to plant in service. The Companies do not seek current recovery of the financing costs for certain generation and other CWIP projects the Commission previously approved for AFUDC.

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

A. The financing costs incurred during construction are capitalized and added to the cost of CWIP under the AFDUC approach, then included in plant in service when construction is completed. 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 set forth in the Uniform System of Accounts (USOA), 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. In fact, the Companies proposed and the Commission authorized the use of AFUDC for the Mercer Solar and Mill Creek 5 resources in CPCN Case 2022--00402. The

Companies proposed and the Commission authorized the use of AFUDC for their AMI buildouts in the prior base rate Cases 2020-00349 and 2020-00350. The Companies also proposed the use of AFUDC for the Brown 12, Mill Creek 6, and Cane run BESS resources in CPCN Case 2025-00045.

The Companies recognized the legitimacy and usefulness of the AFUDC approach for new resources in the three CPCN and base rate proceedings as one element of their proposed ratemaking for the costs of those resources. Among other benefits of the AFUDC approach, the construction financing costs are recovered over the service lives of the assets, rather than prematurely recovered over a relatively short construction period and before the assets are completed or provide service.

It makes sense to broaden the use of the AFUDC approach to all generation and transmission construction costs rather than applying it on an ad hoc basis and only to certain construction projects. The ad hoc approach results in a hybrid form of ratemaking and accounting, using AFUDC for certain construction projects and CWIP in rate base for all other construction projects. This hybrid form of ratemaking is not necessary or rational either for ratemaking or for accounting purposes. Nor is it consistent with the exclusive use of the AFUDC approach by the Commission for other investor-owned utilities, including DEK and KPC.

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 solely during the construction

period rather than the AFUDC approach, which provides no recovery during the construction period, but provides recovery 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 through CWIP in rate base during the construction period. On long lead time construction projects, the CWIP approach may allow a utility to recover as much as 30% or 40% of the total construction costs during the construction period.

The AFUDC approach is consistent with the GAAP requirement to capitalize construction financing costs and then depreciate the costs over the asset's service life. In that manner, 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 harm to customers from the continued use of the CWIP approach instead of the AFUDC approach?

A. Yes. The CWIP approach causes immediate and continuing economic harm compared to the AFUDC approach on both a nominal and present value basis starting during the construction period and continuing throughout the entirety of the asset's service life. The economic harm is caused by an asset ADIT for the tax effect of tax/book temporary differences. More specifically, federal tax law requires the utility to capitalize interest using a debt rate of return on the entirety of the

CWIP balance during construction. This requirement increases the tax basis of the asset compared to the book cost of the asset. Under the CWIP approach, none of the actual interest incurred is capitalized to the book basis because it is expensed as incurred. Under the AFUDC approach the interest incurred is capitalized to CWIP (book basis) as AFUDC – borrowed funds, thus resulting in a lower asset ADIT included in rate base and lower cost to customers, all else equal.

Under the CWIP approach, the asset ADIT is greater than under the AFUDC approach and harms customers through increased costs not only during the construction period, but also over the entire service life of the asset. The AFUDC approach avoids this incremental and unnecessary cost.

Q. Does the CWIP in rate base approach further harm customers if they have a higher cost of capital than the utility?

A. Yes. The CWIP in rate base approach requires customers essentially to finance on behalf of the utility at their higher marginal cost of capital in lieu of the utility's lower weighted average cost of capital. The cost of consumer credit card debt is approximately 30% compared to KU's requested 7.92% WACC and LG&E's requested 7.80% WACC. Many businesses have a minimum internal rate of return of 30% or more to invest in new capital projects. The CWIP approach essentially imposes a higher cost on customers than the AFUDC approach simply because the utility is able to finance at extremely low costs due to its status as a monopoly subject to rate regulation.

Q. What is your recommendation?

A. I recommend the Commission exclude all generation and transmission CWIP from rate base (if the AG and KIUC recommendation to use rate base is adopted) or capitalization (if the AG and KIUC recommendation to use rate base is not adopted) and direct the Companies to accrue AFUDC on the generation and transmission CWIP projects not already excluded from CWIP in rate base starting with the 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 generation and transmission 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 the construction financing costs over the service lives of the assets when they are used and useful.

The AFUDC approach is also lower cost than the CWIP in rate base approach on both a nominal and present value basis due to the *return on* the higher asset ADIT under the CWIP in rate base approach. The AFUDC approach also provides customers the benefits of the utility's lower cost of financing not only throughout the construction period, but also continuing throughout the service lives of the assets.

Q. What are the effects of your recommendation?

A. The effects are a reduction in the KU revenue requirement of $25.038 million, a reduction in the LG&E electric revenue requirement of $11.258 million, and a reduction in the LG&E gas revenue requirement of $3.361 million.

C. Rate Base Is Overstated: Corrections Are Necessary

1. Summary of Corrections to Rate Base

Q. What corrections to the Companies' calculations of rate base are necessary?

A. The Companies' calculations of rate base are overstated due to at least five errors, which I first summarize and then explain in more detail. First, cash working capital (CWC) should be corrected to exclude all non-cash expenses, and, more specifically, corrected to exclude all depreciation expense, amortization expense, deferred income tax expense, and non-cash fuel-coal expense. This is consistent with the Commission Orders and/or utility filings in other investor owned utility base rate proceedings wherein CWC was calculated using the lead/lag approach and *all* non-cash expenses were excluded.

Second, all pension and OPEB related assets and liabilities should be excluded from rate base. The Companies did not finance these balance sheet amounts, except to the extent the returns on the trust fund assets and the interest expense on the obligations are already specifically reflected in the calculations of pension and OPEB costs in accordance with GAAP and USOA accounting requirements. There are no additional financing costs to recover. The Commission should exclude all pension and OPEB related assets and liabilities from rate base consistent with its decision to do so in Case No. 2020-00174. I also note that a portion of the pension and OPEB costs is included in expense and another portion is capitalized to CWIP and plant in service. If the Commission does not exclude all pension and OPEB related assets and liabilities from rate base, then it should at least exclude the amounts related to and allocable to CWIP and plant in service.

Third, account 184 *Pension Clearing Account* should be excluded from the rate base calculation for the simple reason that under the clearing account conceptual structure, all costs accumulated in account 184 are charged out to other capital and expense accounts so that the balance averages to $0 over time. If the clearing account is operating correctly, then in some months there may be a small asset or small liability balance, but, again, the balance by design and practice should averages to $0 over time and be set to $0 for ratemaking purposes.

2. **Overview of Companies' Cash Working Capital Calculations**

Q. Provide an overview of the Companies' calculation of CWC.

A. The Companies' calculation of CWC consists primarily of two components identified as "Cash Working Capital (Lead/Lag)" and "Cash Working Capital (Balance Sheet Items)." The balance sheet items typically are not identified by utilities as "cash working capital," but rather typically are identified as "working capital" in order to distinguish the CWC based on the leads and lags in revenues and expenses from the balance sheet items included in rate base. Nevertheless, I will use the Companies' terminology to address the problems with their calculations and the corrections that are necessary.

The Companies' CWC (lead/lag) component is based on a lead/lag approach that calculates the net investor supplied funds (positive) or customer supplied funds (negative) based on the average daily revenues and expenses using lead days and lag days. The Companies included both cash expenses and non-cash expenses in the calculation of this component, despite the Commission precedent to exclude all non-cash expenses. Companies witness Andrea Fackler

acknowledged the Commission precedent, but included the non-cash expenses anyway.[18]

KU included $38.306 million in rate base for this first CWC (lead/lag) component, of which $54.788 million is for non-cash depreciation, amortization, and deferred income tax expenses, and LG&E included $19.223 million (electric), of which $35.563 million is for depreciation, amortization, and deferred income tax expenses, and $1.730 million (gas), of which $8.653 million is for depreciation, amortization, and deferred income tax expenses.[19] Simply removing the non-cash depreciation, amortization, and deferred income tax expenses from the Companies' calculations of CWC (lead/lag) turns their positive amounts (additions to rate base) into negative amounts (subtractions from rate base).

For ease of reference in my explanations of the Companies' errors and my recommendations to correct those errors, I have replicated the following tables from the Companies' calculations of the CWC (lead/lag) components separately for KU, LG&E electric, and LG&E gas.[20]

[18] Direct Testimony of Andrea Fackler at 54-55 wherein Witness Fackler refers to an Order received from the Virginia Corporate Commission for KU and argues that non-cash expenses are not really non-cash expenses, an argument the Commission has consistently rejected in other utility proceedings.

[19] The LG&E electric and gas CWC (Lead/Lag) amounts would be negative if the non-cash amortization and depreciation expense are excluded.

[20] Schedule B-5.2.1 F for KU, LG&E electric, and LG&E gas, respectively.

KENTUCKY UTILITIES COMPANY
CASE NO. 2025-00113
CASH WORKING CAPITAL COMPONENTS
FORECAST PERIOD FOR THE 12 MONTHS ENDED DECEMBER 31, 2026

DATA:___BASE PERIOD__X__FORECASTED PERIOD
TYPE OF FILING: ___ ORIGINAL _____ UPDATED __X__ REVISED
WORKPAPER REFERENCE NO(S).:

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Line No.	Description	Total Company	Allocation Factor	Forecast Period Jurisdictional	Average Daily Amount	Revenue Lag Days	Expense (Lead)/Lag Days	Net (Lead)/Lag Days	Working Capital (Provided)/ Required
	O&M Expenses:								
1	Fuel: Coal	$ 395,821,642	94.69%	$ 374,793,656	$ 1,026,129	45.01	(36.77)	8.24	$ 8,453,888
2	Fuel: Gas	167,512,159	94.69%	158,613,093	434,259	45.01	(36.91)	8.10	3,517,498
3	Fuel: Oil	-	94.69%	-	-	45.01	(36.77)	8.24	-
4	Other Non-Fuel Commodities	28,639,898	94.69%	27,118,406	74,246	45.01	(36.77)	8.24	611,686
5	Purchased Power	51,084,534	94.57%	48,311,857	132,271	45.01	(23.28)	21.73	2,874,241
6	Payroll Expense	42,590,347	94.35%	40,182,620	110,014	45.01	(12.00)	33.01	3,631,563
7	Pension Expense	(1,992,359)	94.35%	(1,879,727)	(5,146)	45.01	-	45.01	(231,640)
8	OPEB Expense	123,293	94.35%	116,323	318	45.01	-	45.01	14,335
9	Short-Term Incentive Compensation	3,537,982	94.35%	3,337,972	9,139	45.01	(236.23)	(191.22)	(1,747,534)
10	401k Match Expense	1,543,087	94.35%	1,455,853	3,986	45.01	(20.48)	24.53	97,774
11	Retirement Income Account Expense	1,431,799	94.35%	1,350,856	3,698	45.01	(12.00)	33.01	122,085
12	Uncollectible Expense	5,379,216	95.19%	5,120,705	14,020	45.01	(153.10)	(108.09)	(1,515,392)
13	Major Storm Damage Expense	-	94.46%	-	-	45.01	-	45.01	-
14	Charges from Affiliates	224,984,938	94.41%	212,410,966	581,550	45.01	(36.73)	8.28	4,815,230
15	Other O&M	162,639,969	93.11%	151,437,857	414,614	45.01	(43.01)	2.00	829,229
16	Total O&M Expenses	$ 1,083,296,505		$ 1,022,370,438					$ 21,472,962
	Depreciation and Amortization Expense:								
17	Depreciation and Amortization	$ 460,965,281	93.52%	$ 431,086,685	$ 1,180,251	45.01	-	45.01	$ 53,123,098
18	Regulatory Debits	15,946,433	96.49%	15,387,249	42,128	45.01	-	45.01	1,896,181
19	Amortization of KY Regulatory Assets	15,795,293	100%	15,795,293	43,245	45.01	-	45.01	1,946,464
20	Amortization of KY Regulatory Liabilities	(8,947,196)	100%	(8,947,196)	(24,496)	45.01	-	45.01	(1,102,569)
21	Total Depreciation and Amortization Expense	$ 483,759,811		$ 453,322,032					$ 55,863,175
	Income Tax Expense:								
22	Current: Federal	$ 52,462,477	93.38%	$ 48,990,508	$ 134,129	45.01	(38.50)	6.51	$ 873,178
23	Current: State	10,033,405	93.38%	9,369,394	25,652	45.01	(38.50)	6.51	166,995
24	Deferred: Federal and State (Including ITC)	(9,342,136)	93.38%	(8,723,873)	(23,885)	45.01	-	45.01	(1,075,049)
25	Total Income Tax Expense	$ 53,153,746		$ 49,636,029					$ (34,876)
	Taxes Other Than Income:								
26	Property Tax Expense	$ 54,088,217	93.81%	$ 50,738,949	$ 138,916	45.01	(195.02)	(150.01)	$ (20,838,740)
27	Payroll Tax Expense	10,706,108	94.35%	10,100,868	27,655	45.01	(36.41)	8.60	237,830
28	Other Taxes (KPSC)	2,948,721	100%	2,948,721	8,073	45.01	154.63	199.64	1,611,725
29	Total Taxes Other Than Income	$ 67,743,046		$ 63,788,537					$ (18,989,185)
	AFUDC:								
30	Interest-AFUDC-Borrowed	$ (15,562,236)	100%	$ (15,562,236)	$ (42,607)	45.01	(45.01)	-	$ -
31	Interest-AFUDC-Equity	(23,551,693)	100%	(23,551,693)	(64,481)	45.01	(45.01)	-	-
32	Regulatory Credit-AFUDC-Borrowed	2,098,166	100%	2,098,166	5,744	45.01	(45.01)	-	-
33	Regulatory Credit-AFUDC-Equity	(11,045,362)	100%	(11,045,362)	(30,241)	45.01	(45.01)	-	-
34	Total AFUDC	$ (48,061,125)		$ (48,061,125)					$ -
35	(Gain)/Loss on Disposition of Property	$ -	0.00%	$ -	$ -	45.01	(45.01)	-	$ -
36	(Gain)/Loss on Disposition of Allowances	$ (290,953)	94.15%	$ (273,929)	$ (750)	45.01	(45.01)	-	$ -
37	Charitable Donations	$ 765,400	0.00%	$ -	$ -	45.01	(45.01)	-	$ -
38	Interest on Customer Deposits	$ 1,652,081	0.00%	$ -	$ -	-	-	-	$ -
39	Other (Income)/Expense	$ (2,805,107)	0.00%	$ -	$ -	45.01	(45.01)	-	$ -
40	Other Interest Expense/(Income)	$ 0	0.00%	$ -	$ -	45.01	(45.01)	-	$ -
41	Interest Expense	$ 182,640,960	93.63%	$ 171,009,340	$ 468,198	45.01	(88.50)	(43.49)	$ (20,361,933)
42	Income Available for Common Equity	$ 302,935,356		$ 287,393,560	$ 786,841	45.01	(45.01)	-	$ -
43	Total	$ 2,124,789,720		$ 1,999,184,882	$ 1,254,289			-	$ 37,950,142
44	Sales Taxes	$ 44,149,110	100%	$ 44,149,110	$ 120,874	45.01	(39.93)	5.08	$ 614,038
45	School Taxes	$ 46,557,925	100%	$ 46,557,925	$ 127,469	45.01	(34.74)	10.27	$ 1,309,103
46	Franchise Fees	$ 35,269,681	100%	$ 35,269,681	$ 96,563	45.01	(61.24)	(16.23)	$ (1,567,220)
47	Cash Working Capital (Lead/Lag)								$ 38,306,064

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LOUISVILLE GAS AND ELECTRIC COMPANY
CASE NO. 2025-00114 - ELECTRIC
CASH WORKING CAPITAL COMPONENTS
FORECAST PERIOD FOR THE 12 MONTHS ENDED DECEMBER 31, 2026

DATA:___BASE PERIOD__X__FORECASTED PERIOD
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WORKPAPER REFERENCE NO(S).:

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LINE NO.	DESCRIPTION	TOTAL COMPANY - ELECTRIC	ALLOCATION FACTOR	FORECAST PERIOD JURISDICTIONAL	AVERAGE DAILY AMOUNT	REVENUE LAG DAYS	EXPENSE (LEAD)/LAG DAYS	NET (LEAD)/LAG DAYS	WORKING CAPITAL (PROVIDED)/ REQUIRED	
	O&M Expenses:									
1	Fuel: Coal	$ 268,549,098	100%	$ 268,549,098	$ 735,247	44.49	(36.67)	7.82	$ 5,753,284	
2	Fuel: Gas	63,639,740	100%	63,639,740	174,236	44.49	(39.51)	4.98	867,696	
3	Fuel: Oil	-	100%	-	-	44.49	(36.67)	7.82	-	
4	Other Non-Fuel Commodities	18,558,297	100%	18,558,297	50,810	44.49	(36.67)	7.82	397,585	
5	Purchased Power	55,395,460	100%	55,395,460	151,665	44.49	(23.09)	21.40	3,245,620	
6	Payroll Expense	32,296,336	100%	32,296,336	88,423	44.49	(12.00)	32.49	2,872,849	
7	Pension Expense	172,481	100%	172,481	472	44.49	-	44.49	21,009	
8	OPEB Expense	1,306,237	100%	1,306,237	3,576	44.49	-	44.49	159,109	
9	Short-Term Incentive Compensation	3,176,286	100%	3,176,286	8,696	44.49	(236.26)	(191.77)	(1,667,670)	
10	401k Match Expense	1,316,593	100%	1,316,593	3,605	44.49	(21.39)	23.10	83,267	
11	Retirement Income Account Expense	1,283,666	100%	1,283,666	3,514	44.49	(12.00)	32.49	114,186	
12	Uncollectible Expense	2,937,423	100%	2,937,423	8,042	44.49	(182.72)	(138.23)	(1,111,677)	
13	Major Storm Damage Expense	-	100%	-	-	44.49	-	44.49	-	
14	Charges from Affiliates	113,921,655	100%	113,921,655	311,900	44.49	(36.67)	7.82	2,439,062	
15	Other O&M	93,620,324	100%	93,620,324	256,318	44.49	(42.77)	1.72	440,868	
16	Total O&M Expenses	$ 656,173,597		$ 656,173,597					$ 13,615,188	
		-								
17	Depreciation and Amortization Expense									
18	Depreciation and Amortization	$ 283,110,535	100%	$ 283,110,535	$ 775,114	44.49	-	44.49	$ 34,484,840	
19	Regulatory Debits	14,418,018	100%	14,418,018	39,474	44.49	-	44.49	1,756,215	
20	Amortization of Regulatory Assets	4,600,254	100%	4,600,254	12,595	44.49	-	44.49	560,343	
21	Amortization of Regulatory Liabilities	(8,857,369)	100%	(8,857,369)	(24,250)	44.49	-	44.49	(1,078,889)	
22	Total Depreciation and Amortization Expense	$ 293,271,439		$ 293,271,439					$ 35,722,509	
23	Income Tax Expense:									
24	Current: Federal	$ 27,769,302	100%	$ 27,769,302	$ 76,028	44.49	(38.50)	5.99	$ 455,409	
25	Current: State	9,305,386	100%	9,305,386	25,477	44.49	(38.50)	5.99	152,606	
26	Deferred: Federal and State (Including ITC)	(1,311,968)	100%	(1,311,968)	(3,592)	44.49	-	44.49	(159,807)	
27	Total Income Tax Expense	$ 35,762,720		$ 35,762,720					$ 448,208	
28	Taxes Other Than Income									
29	Property Tax Expense	$ 41,199,921	100%	$ 41,199,921	$ 112,799	44.49	(224.87)	(180.38)	$ (20,346,726)	
30	Payroll Tax Expense	7,165,253	100%	7,165,253	19,617	44.49	(39.15)	5.34	104,757	
31	Other Taxes	1,947,595	100%	1,947,595	5,332	44.49	155.22	199.71	1,064,899	
32	Total Taxes Other Than Income	$ 50,312,770		$ 50,312,770					$ (19,177,071)	
33	AFUDC	$ -	0%	$ -	$ -	44.49	(44.49)	-	$ -	
34	(Gain)/Loss on Disposition of Property	$ -	0%	$ -	$ -	44.49	(44.49)	-	$ -	
35	(Gain)/Loss on Disposition of Allowances	$ (186,019)	100%	$ (186,019)	$ (509)	44.49	(44.49)	-	$ -	
36	Charitable Donations	$ 405,223	0%	$ -	$ -	44.49	(44.49)	-	$ -	
37	Interest on Customer Deposits	$ 1,173,618	0%	$ -	$ -	-	-	-	$ -	
38	Other (Income)/Expense	$ (26,679,806)	0%	$ -	$ -	44.49	(44.49)	-	$ -	
39	Other Interest Expense/(Income)	$ 1,487,844	0%	$ -	$ -	44.49	(44.49)	-	$ -	
40	Interest Expense	$ 96,528,927	100%	$ 96,528,927	$ 264,282	44.49	(88.91)	(44.42)	$ (11,739,398)	
41	Income Available for Common Equity	$ 202,946,846		$ 184,987,837	$ 506,469	44.49	(44.49)	-	$ -	
42	Total	$ 1,311,197,159		$ 1,316,851,270	$ 770,242				$ 18,869,436	
43	Sales Taxes	$ 29,893,211	100%	$ 29,893,211	$ 81,843	44.49	(39.92)	4.57	$ 374,023	#
44	Gross Receipts Taxes	$ 3,310,736	100%	$ 3,310,736	$ 9,064	44.49	(34.75)	9.74	$ 88,286	#
45	Franchise Fees	$ 1,068,593	100%	$ 1,068,593	$ 2,926	44.49	(81.66)	(37.17)	$ (108,746)	
46	Cash Working Capital (Lead/Lag)								$ 19,222,999	

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LOUISVILLE GAS AND ELECTRIC COMPANY
CASE NO. 2025-00114 - GAS
CASH WORKING CAPITAL COMPONENTS
FORECAST PERIOD FOR THE 12 MONTHS ENDED DECEMBER 31, 2026

DATA:___BASE PERIOD__X__FORECASTED PERIOD
TYPE OF FILING: ____ ORIGINAL _____ UPDATED __X__ REVISED
WORKPAPER REFERENCE NO(S).:

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WITNESS: A. M. FACKLER

LINE NO.	DESCRIPTION	LG&E Gas	Allocation Factor	Forecast Period Jurisdictional	Average Daily Amount	Revenue Lag Days	Expense (Lead) / Lag Days	Net (Lead) / Lag Days	Working Capital (Provided) / Required
	O&M Expenses:								
1	Purchased Gas	$ 143,573,427	100%	$ 143,573,427	$ 393,083	45.00	(40.04)	4.96	$ 1,949,690
2	No-Notice Storage Injections and Withdraw	(3,283,585)	100%	(3,283,585)	(8,990)	45.00	-	45.00	(404,548)
3	Payroll Expense	24,653,888	100%	24,653,888	67,499	45.00	(12.00)	33.00	2,227,456
4	Pension Expense	379,291	100%	379,291	1,038	45.00	-	45.00	46,730
5	OPEB Expense	606,150	100%	606,150	1,660	45.00	-	45.00	74,680
6	Short-Term Incentive Compensation	2,269,452	100%	2,269,452	6,213	45.00	(236.26)	(191.26)	(1,188,379)
7	401k Match Expense	1,021,887	100%	1,021,887	2,798	45.00	(21.39)	23.61	66,055
8	Retirement Income Account Expense	995,048	100%	995,048	2,724	45.00	(12.00)	33.00	89,902
9	Uncollectible Expense	912,817	100%	912,817	2,499	45.00	(129.71)	(84.71)	(211,704)
10	Major Storm Damage Expense	-	100%	-	-	45.00	-	45.00	-
11	Charges from Affiliates	38,885,199	100%	38,885,199	106,462	45.00	(36.67)	8.33	886,827
12	Other O&M	37,394,306	100%	37,394,306	102,380	45.00	(42.77)	2.23	228,307
13	Total O&M Expenses	$ 247,407,881		$ 247,407,881					$ 3,765,016
		-							
14	Depreciation and Amortization Expense								
15	Depreciation and Amortization	$ 70,518,279	100%	$ 70,518,279	$ 193,069	45.00	-	45.00	$ 8,688,084
16	Regulatory Debits	(282,915)	100%	(282,915)	(775)	45.00	-	45.00	(34,856)
17	Amortization of Regulatory Assets	-	100%	-	-	45.00	-	45.00	-
18	Amortization of Regulatory Liabilities	-	100%	-	-	45.00	-	45.00	-
19	Total Depreciation and Amortization Expens	$ 70,235,364		$ 70,235,364					$ 8,653,228
20	Income Tax Expense:								
21	Current: Federal	$ 9,755,378	100%	$ 9,755,378	$ 26,709	45.00	(38.50)	6.50	$ 173,607
22	Current: State	2,397,315	100%	2,397,315	6,563	45.00	(38.50)	6.50	42,663
23	Deferred: Federal and State (Including ITC)	-	100%	-	-	45.00	-	45.00	-
24	Total Income Tax Expense	$ 12,152,693		$ 12,152,693					$ 216,270
		-							
25	Taxes Other Than Income								
26	Property Tax Expense	$ 14,896,770	100%	$ 14,896,770	$ 40,785	45.00	(224.87)	(179.87)	$ (7,336,022)
27	Payroll Tax Expense	3,155,522	100%	3,155,522	8,639	45.00	(39.15)	5.85	50,540
28	Other Taxes	613,188	100%	613,188	1,679	45.00	155.22	200.22	336,133
29	Total Taxes Other Than Income	$ 18,665,480		$ 18,665,480					$ (6,949,349)
30	AFUDC	$ -	0%	$ -	$ -	45.00	(45.00)	-	$ -
31	(Gain)/Loss on Disposition of Property	$ -	0%	$ -	$ -	45.00	(45.00)	-	$ -
32	(Gain)/Loss on Disposition of Allowances	$ -	0%	$ -	$ -	45.00	(45.00)	-	$ -
33	Charitable Donations	$ 149,877	0%	$ -	$ -	45.00	(45.00)	-	$ -
34	Interest on Customer Deposits	$ 354,818	0%	$ -	$ -	-	-	-	$ -
35	Other (Income)/Expense	$ 115,343	0%	$ -	$ -	45.00	(45.00)	-	$ -
36	Other Interest Expense/(Income)	$ 462,933	0%	$ -	$ -	45.00	(45.00)	-	$ -
37	Interest Expense	$ 33,890,534	100%	$ 33,890,534	$ 92,787	45.00	(88.91)	(43.91)	$ (4,074,287)
38	Income Available for Common Equity	$ 41,841,699		$ 43,252,853	$ 118,420	45.00	(45.00)	-	$ -
39	Total	$ 425,276,623		$ 425,604,806	$ 211,207				$ 1,610,877
40	Sales Taxes	$ 7,011,988	100%	$ 7,011,988	$ 19,198	45.00	(39.92)	5.08	$ 97,525
41	School Taxes	$ 776,592	100%	$ 776,592	$ 2,126	45.00	(34.75)	10.25	$ 21,793
42	Franchise Fees	$ -	100%	$ -	$ -	45.00	(81.66)	(36.66)	$ -
43	Cash Working Capital (Lead/Lag)								$ 1,730,195

The Companies' CWC (Balance Sheet Items) component is based on a balance sheet approach that calculates the net amount of certain asset accounts and

certain liability accounts. For ease of reference in my explanations of the Companies' errors and my recommendations to correct those errors, I have replicated the following tables from the Companies' CWC (Balance Sheet Items) component separately for KU, LG&E electric, and LG&E gas.[21]

KENTUCKY UTILITIES COMPANY
CASE NO. 2025-00113
CASH WORKING CAPITAL COMPONENTS
FORECAST PERIOD FOR THE 12 MONTHS ENDED DECEMBER 31, 2026

DATA:____BASE PERIOD__X__FORECASTED PERIOD — SCHEDULE B-5.2
TYPE OF FILING: _____ ORIGINAL _____ UPDATED __X__ REVISED — PAGE 5 OF 6
WORKPAPER REFERENCE NO(S).: — WITNESS: A. M. FACKLER

LINE NO.	ACCT. NO.	DESCRIPTION	13 MONTH AVERAGE	JURIS. PERCENT	JURISDICTIONAL AMOUNT
		ADDITIONAL USES OF CASH WORKING CAPITAL:			
1	128	PREPAID PENSION	64,883,641	94.347%	61,215,625
2	182	REGULATORY ASSET - FAS 158 PENSION	138,181,177	94.347%	130,369,488
3	183	PRELIMINARY SURVEY	10,098,809	93.631%	9,455,659
4	184	PENSION CLEARING	2,207,761	94.347%	2,082,951
5	186	MISC DEFERRED DEBITS	22,255,784	94.347%	20,997,615
6	188	RESRCH/DEV/DEMO EXP	-	94.347%	-
7		TOTAL USES OF CASH WORKING CAPITAL	237,627,172		224,121,338

LINE NO.	ACCT. NO.	DESCRIPTION	13 MONTH AVERAGE	JURIS. PERCENT	JURISDICTIONAL AMOUNT
		ADDITIONAL SOURCES OF CASH WORKING CAPITAL:			
8	228.2	MISC LONG TERM LIABILITIES	(2,424,586)	94.347%	(2,287,519)
9	228.3	ACCUM PROVISION FOR POST RETIREMENT BENEFITS	(12,881,941)	94.347%	(12,153,696)
10	242	MISC LIABILITY	(18,030,499)	94.347%	(17,011,195)
11	253	OTHER DEFERRED CREDITS	(1,550,002)	93.631%	(1,451,289)
12	254	REGULATORY LIABILITY - POST RETIREMENT	(36,861,113)	94.347%	(34,777,272)
13	143/232	NET ACCRUED CWIP	(52,094,329)	93.631%	(48,776,664)
14	143/232	NET ACCRUED RWIP	(2,325,899)	93.631%	(2,177,772)
15		TOTAL SOURCES OF CASH WORKING CAPITAL	(126,168,369)		(118,635,408)
16		TOTAL USES / (SOURCES) OF CASH WORKING CAPITAL (LINE 7 + 15)	111,458,803		105,485,930

[21] Schedule B-5.2.2 F for KU, LG&E electric, and LG&E gas, respectively.

LOUISVILLE GAS AND ELECTRIC COMPANY
CASE NO. 2025-00114 - ELECTRIC
CASH WORKING CAPITAL COMPONENTS
FORECAST PERIOD FOR THE 12 MONTHS ENDED DECEMBER 31, 2026

DATA:____BASE PERIOD__X__FORECASTED PERIOD — SCHEDULE B-5.2
TYPE OF FILING: _____ ORIGINAL _____ UPDATED __X__ REVISED — PAGE 5 OF 6
WORKPAPER REFERENCE NO(S).: — WITNESS: A. M. FACKLER

LINE NO.	ACCT NO.	DESCRIPTION	13 MONTH AVERAGE	JURIS. PERCENT	JURISDICTIONAL AMOUNT
		Additional Uses of Cash Working Capital:			
1	128	Prepaid Pension	30,740,405	100%	30,740,405
2	182	Regulatory Asset - FAS 158 Pension	136,140,228	100%	136,140,228
3	183	Preliminary Survey	7,318,200	100%	7,318,200
4	184	Clearing Accts - Pension	-	100%	-
5	186	Misc Deferred Debits	6,787,874	100%	6,787,874
6	188	Research/Dev/Demo Exp	-	100%	-
7		Total Uses of Cash Working Capital	180,986,707		180,986,707

LINE NO.	ACCT NO.	DESCRIPTION	13 MONTH AVERAGE	JURIS. PERCENT	JURISDICTIONAL AMOUNT
		Additional Sources of Cash Working Capital:			
8	228.2	Misc Long Term Liabilities	(3,191,276)	100%	(3,191,276)
9	228.3	Accum Provision For Post Retirement Benefits	(35,600,634)	100%	(35,600,634)
10	242	Misc Liability	(7,590,348)	100%	(7,590,348)
11	253	Other Deferred Credits	(3,385,098)	100%	(3,385,098)
12	143/232	Net Accrued CWIP	(35,703,029)	100%	(35,703,029)
13	143/232	Net Accrued RWIP	(934,012)	100%	(934,012)
14		Total Sources of Cash Working Capital	(86,404,398)		(86,404,398)
15		Total Uses / (Sources) of Cash Working Capital (Line 7 + 14)	94,582,309		94,582,309

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LOUISVILLE GAS AND ELECTRIC COMPANY
CASE NO. 2025-00114 - GAS
CASH WORKING CAPITAL COMPONENTS
FORECAST PERIOD FOR THE 12 MONTHS ENDED DECEMBER 31, 2026

DATA:____BASE PERIOD__X__FORECASTED PERIOD — SCHEDULE B-5.2
TYPE OF FILING: _____ ORIGINAL _____ UPDATED __X__ REVISED — PAGE 4 OF 4
WORKPAPER REFERENCE NO(S).: — WITNESS: A. M. FACKLER

LINE NO.	ACCT. NO.	DESCRIPTION	13 MONTH AVERAGE	JURIS. PERCENT	JURISDICTIONAL AMOUNT
		ADDITIONAL USES OF CASH WORKING CAPITAL:			
1	128	PREPAID PENSION	16,980,739	100%	16,980,739
2	182	REGULATORY ASSET - FAS 158 PENSION	69,044,743	100%	69,044,743
3	183	PRELIMINARY SURVEY	97,183	100%	97,183
4	184	CLEARING ACCTS - PENSION	1,422,139	100%	1,422,139
5	186	MISC DEFERRED DEBITS	1,910,450	100%	1,910,450
6	188	RESRCH/DEV/DEMO EXP	-	100%	-
7		TOTAL USES OF CASH WORKING CAPITAL	89,455,253		89,455,253

LINE NO.	ACCT. NO.	DESCRIPTION	13 MONTH AVERAGE	JURIS. PERCENT	JURISDICTIONAL AMOUNT
		ADDITIONAL SOURCES OF CASH WORKING CAPITAL:			
8	228.2	MISC LONG TERM LIABILITIES	(460,150)	100%	(460,150)
9	228.3	ACCUM PROVISION FOR POST RETIREMENT BENEFITS	(11,880,076)	100%	(11,880,076)
10	242	MISC LIABILITY	(18,322,066)	100%	(18,322,066)
11	253	OTHER DEFERRED CREDITS	541,499	100%	541,499
12	143/232	NET ACCRUED CWIP EXCL. MECH	(5,295,706)	100%	(5,295,706)
13	143/232	NET ACCRUED RWIP EXCL. MECH	(55,720)	100%	(55,720)
14		TOTAL SOURCES OF CASH WORKING CAPITAL	(35,472,218)		(35,472,218)
15		TOTAL USES / (SOURCES) OF CASH WORKING CAPITAL (LINE 7 + 14)	53,983,035		53,983,035

I subsequently address each of the errors included in the Companies' calculations of the two CWC components. The preceding tables provide ease of reference to the Companies' schedules as I sequentially address the errors.

2. Depreciation, Amortization, And Deferred Income Tax Expenses Are Inherently Non-Cash Expenses That Should Be Excluded From The CWC (Lead/Lag) Component Of Rate Base

Q. Should the Commission include depreciation, amortization, and deferred income tax expenses in the CWC (lead/lag) component?

A. No. These are non-cash expenses. The Commission has repeatedly found that non-cash expenses should be excluded from the CWC calculations. The non-cash expenses include, but are not limited to, depreciation, amortization, and deferred income expenses.

Q. Does the Companies' use of 0 expense lag days correctly reflect the non-cash character of these expenses?

A. No. The Companies should exclude all non-cash expenses. The Companies' use of 0 expense lag days in lieu of properly excluding these expenses still results in CWC amounts included in rate base instead of $0 for these expenses. The Companies' use of 0 days is incorrect because it assumes that the depreciation, amortization, and deferred income tax expenses actually are paid in cash *and* paid in cash instantaneously at the beginning of the month in which the expenses are recorded. These assumptions are unequivocally wrong because the Companies *never* disburse cash for these expenses, let alone instantaneously.

The Companies disburse cash only one time - when they acquire and pay for the underlying assets, whether plant in service, prepayments, regulatory assets, miscellaneous deferred debits, and/or other assets. The depreciation and amortization expenses are simply the non-cash allocation of the asset costs recorded to expense for accounting purposes over the service lives of the assets or the amortization periods for other costs.

Similarly, the Companies disburse cash only one time for income tax expense. This cash disbursement is recorded in current income tax expense. There are no cash disbursements for deferred income tax expense.

Q. What is the correct expense lag days if non-cash expenses are included in the CWC (lead/lag) calculations?

A. If non-cash expenses are included in the CWC (lead/lag) calculations, which I strongly oppose and the Commission has previously denied, then the correct expense lag days is infinity days, which properly assumes the non-cash expenses are never paid in cash. If the non-cash expenses are included rather than properly excluded, but with infinity expense lag days, then the expense lag days far exceed the revenue lag days and the amount included in rate base will never be greater than $0, the same result as if the non-cash expenses were properly excluded altogether.

Q. What is your recommendation regarding the non-cash depreciation, amortization, and deferred income tax expenses?

A. I recommend the Commission exclude these expenses from the Companies' calculations of CWC (lead/lag). These are inherently non-cash expenses. The related balance sheet amounts that required cash disbursements are separately included in rate base and properly earn a *return on* in that manner. The Commission has already decided these issues in numerous other utility proceedings and should treat the issues in these proceedings consistently with the Orders in the other utility proceedings.

Q. What are the effects of your recommendations?

A. The effects are a reduction in the KU revenue requirement of $5.512 million, a reduction in the LG&E electric revenue requirements of $3.589 million, and a reduction in the LG&E gas revenue requirements of $0.873 million.

3. Fuel-Coal Expense Is Inherently A Non-Cash Expense That Should Be Excluded From CWC (Lead/Lag)

Q. Should the Commission also exclude the non-cash fuel-coal expenses from the CWC (lead/lag) component?

A. Yes. The fuel-coal expense also is inherently a non-cash expense. There is no cash working capital requirement for the fuel-coal expense incurred by KU and LG&E electric. The fuel-coal expense represents an allocation of the balance sheet fuel-coal inventory amounts recorded to expense for accounting purposes as the fuel-coal inventory is consumed. The only disbursement of cash occurs when the fuel-coal inventories are purchased and the vendor is subsequently paid. The balance sheet fuel inventories are already included as separate components in the rate base. There is no second disbursement of cash when the inventories are consumed and recorded to expense.

Q. Do the Companies' calculations and the expense lag days for the fuel-coal expense correctly reflect the fact this expense is a non-cash expense?

A. No. The fuel-coal expense is a non-cash expense and is not properly included in the CWC (lead/lag) regardless of the claimed expense lag days. KU assumed 36.77 expense lag days and LG&E electric assumed 36.67 expense lag days for the fuel-coal expense. However, there are and can be no expense lag days for non-cash expenses. The payment lag for the balance sheet fuel inventories is measured by the related accounts payable and related disbursement of cash for the purchases of coal and oil fuel inventories, which is properly subtracted from the coal fuel inventories included in rate base.

Q. What is your recommendation regarding the non-cash fuel-coal expense?

A. I recommend the Commission exclude this expense from the calculation of CWC (lead/lag). This is a non-cash expense. The inventory costs and related accounts payable are already separately included in rate base.

Q. What are the effects of your recommendations?

A. The effects are a reduction in the KU revenue requirement of $0.851 million and a reduction in the LG&E electric revenue requirements of $0.581 million.

4. Non-Cash Pension and OPEB Related Assets and Liabilities

Q. Describe the pension and OPEB related assets and liabilities included in the Companies' CWC (Balance Sheet Items) component of cash working capital.

A. The Companies included three pension related assets for KU, two OPEB related liabilities for KU, two pension related assets for LG&E (electric and gas), and two OPEB related liabilities for LG&E (electric and gas) in the CWC (Balance Sheet Items) component of cash working capital as shown on the tables in the preceding section.

The pension related assets include account 128 *Prepaid Pension,* account 182 *Regulatory Asset – FAS 158 Pension,* and account 184 *Pension Clearing*. KU included $61.216 million in account 128, $130.369 million in account 182, and $2.083 million in account 184. LG&E electric included $30.741 million in account 128, $136.140 million in account 182, and $0 in account 184. LG&E gas included $16.981 million in account 128, $69.045 million in account 182, and $1.422 million in account 184.

The OPEB related liabilities include account 228.3 *Accumulated Provision for Post Retirement Benefits,* account 254 *Regulatory Liability – Postretirement*. KU included $12.154 million in account 228.3 and $34.777 million in account 254. LG&E electric included $35.601 million in account 228.3 and $0 in account 254. LG&E gas included $11.880 million in account 228.3 and $0 in account 254.

Q. Describe the amounts included in account 128 *Prepaid Pension*.

A. These amounts included in account 128 represent the net excess of the pension trust fund assets at fair value over the pension benefit obligation.[22] The asset amounts included in account 128 means the pension trust funds are overfunded compared to the present value of the pension liabilities.

Q. How do the pension (and OPEB) trust funds become overfunded or underfunded?

A. The net pension funding amounts in account 128 and the OPEB underfunding in account 228.3 are the net of the pension trust fund assets offset by the pension obligation (present value of the future pension liability), and the net of the OPEB trust fund assets offset the OPEB obligation (present value of the future OPEB liability).

The pension trust fund and pension obligations and OPEB trust fund and OPEB obligations were forecast for the test year based on the Companies' actuarial return assumptions calculated specifically for these rate case proceedings, outside

[22] Response to AG-KIUC 1-85(b). I have attached a copy of all parts of the response from KU (narrative and selected pages only) as Exhibit LK-3. I have not attached a copy of the response from LG&E in the interest of limiting the pages in the exhibit.

of the normal course of business, and were not developed by their actuary for actual accounting purposes. The pension trust fund is funded and becomes overfunded through 1) the cumulative actual and forecast realized gains in trust fund assets, 2) cumulative actual and forecast earnings on trust fund investments, and 3) cumulative actual and forecast contributions and payments made by the Companies.

The pension and OPEB obligation components also affect the calculations of the net funded status. The pension obligation is increased each year based on the Companies' actuarial discount rate assumptions and forecast changes in employee related pay and other actuarial obligations and reduced by actual and forecast future payments to participants discounted to the present value liability using the actuarial discount rate. The OPEB obligation is increased each year based on the Companies' actuarial discount rate assumptions and forecast changes in the actuarial obligations, reduced by actual and forecast future payments to or on behalf of participants discounted to the present value liability using the actuarial discount rate.

Q. Is it reasonable to include the pension trust fund assets in excess of the pension obligation in rate base or subtract the OPEB obligation in excess of the OPEB trust fund assets from rate base?

A. No. First, and perhaps most importantly, the Companies have provided no evidence that the excess trust fund assets were solely, or in any respect, the result of excessive contributions by the Companies. In response to AG-KIUC discovery, the Companies acknowledged that the excess trust fund assets include realized and

unrealized gains in the trust fund assets, earnings on the trust fund assets, and changes in the pension obligation.[23] In fact, these other factors have reduced the minimum contributions required by the Companies under the ERISA minimum funding requirements to the point where the Companies will make no contributions to the pension fund this year or in the test year.[24] Second, to the extent the excess trust fund assets were the result of realized and unrealized gains and realized earnings, then the Companies' customers are entitled to the reductions in pension costs resulting from those sources; the Companies are not somehow entitled to include those accumulated gains and earnings in rate base. Third, the trust fund assets earn a return within the GAAP formula used to calculate pension costs.[25] Fourth, the Company did not finance the pension amounts in account 128, nor did customers finance the OPEB amounts in account 228.3. In their most recent rate cases, neither KPC nor DEK added or subtracted these amounts from rate base.

Q. Describe the amounts included in account 182 *Regulatory Asset – FAS 158 Pension*.

A. These amounts represent the accumulated unamortized prior service costs and net actuarial losses of the plan.[26]

Q. Is it reasonable to include the accumulated unamortized prior service costs of the pension plan in rate base?

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[23] Responses to AG-KIUC 2-19(c). I have attached a copy of the responses as Exhibit LK-4.
[24] Responses to AG-KIUC 2-19(b). Refer to Exhibit LK-4.
[25] Responses to AG-KIUC 1-85(a). Refer to Exhibit LK-3.
[26] Responses to AG-KIUC 1-85(d). Refer to Exhibit LK-3.

A. No. The accumulated unamortized prior service costs represent the pension obligation amounts that have not yet been amortized to pension cost. This amount is best viewed as a subset of the pension obligation that has not yet been amortized to pension cost. The interest on the entirety of the pension obligation is included in the calculation of pension cost. The amortization of the prior service costs also is included in the calculation of pension cost. However, there is no return on prior service costs included in the calculation of pension costs. That is because this asset does not reduce the pension obligation or the interest on the entirety of the pension obligation included in the calculation of the pension cost.

Q. Do the Companies agree that the unamortized prior service cost is a subset or component of the pension obligation and agree that the interest on this obligation already is included in the calculation of pension cost?

A. Yes. In response to AG-KIUC discovery, the Companies acknowledged that "These amounts are not financed by the Companies."[27] The Companies also acknowledged that "unamortized prior service cost is a component of the entire pension liability" and that "the calculation of the pension cost *does include* interest on the unamortized prior service cost" (emphasis added).[28] In other words, the Companies acknowledge that including this component of account 182 *Regulatory Asset – FAS 158 Pension* in rate base double counts the return in the revenue requirement,

[27] Responses to AG-KIUC 2-20. I have attached a copy of the responses as Exhibit LK-5.
[28] Responses to AG-KIUC 2-14 in Cases 2020-00349 and 2020-00350. I have attached a copy of the responses as Exhibit LK-6.

meaning the interest on the liability would be included in the pension cost/expense included in the revenue requirement and then the grossed-up WACC *return on* account 182 *Regulatory Asset – FAC 158* also would be included in the revenue requirement.

Q. Is it reasonable to include the net actuarial losses of the pension plan in rate base?

A. No. There is no *return on* net actuarial losses of the plan included in the calculation of pension cost. The only return included in the calculation of pension cost is the return on the fair value of trust fund assets.

Q. Do the Companies also acknowledge this fact?

A. Yes. Thus, it is unnecessary and inappropriate to include this component of account 182 *Regulatory Asset – FAS 158 Pension* in rate base because no financing cost is incurred and no return is included in the calculation of pension cost.

Q. Describe the amounts included in account 228.3 *Accumulated Provision for Post Retirement Benefits.*

A. These amounts included in account 228.3 represent the net excess of the OPEB obligation over the OPEB trust fund assets at fair value.[29] The liability amounts included in account 228.3 means the OPEB trust funds are underfunded compared to the present value of the OPEB liabilities.

Q. Is it reasonable to subtract the OPEB underfunding from rate base?

[29] Response to AG-KIUC 1-85(f). Refer to Exhibit LK-3.

A. No. In fact, this highlights the absurdity of the Companies' position with respect to including the pension overfunding in rate base. In the case of the OPEB underfunding, the interest on the entire OPEB obligation is included in the calculation of the OPEB cost. The Companies include interest at an actuarial interest rate of 5.30% in the calculation of the OPEB cost, but then subtract the underfunding from rate base so that customers are provided the requested grossed-up rate of return of 10.07% for KU and 10.08% for LG&E (electric and gas). The only thing reasonable about this is that it partially mitigates the Companies' proposal to include the pension overfunding in rate base. In fact, neither proposal is reasonable, although the Companies at least were consistent. Nevertheless, if the Commission includes the amounts in account 128 *Prepaid Pension* in rate base, then it also should subtract the amounts in account 228.3 *Accumulated Provision for Post Retirement Benefits* from rate base, again, as a matter of consistency.

Q. Describe the amounts included in account 254 *Regulatory Liability – Postretirement.*

A. These amounts represent the accumulated unamortized prior service costs and net actuarial gains of the OPEB plan.[30] These amounts are similar in concept to the accumulated unamortized prior service costs and net actuarial losses of the pension plan that I previously described.

Q. Is it reasonable to subtract the accumulated unamortized prior service costs and net actuarial gains of the OPEB plan from rate base?

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[30] KU's response to AG-KIUC 1-85(h). Refer to Exhibit LK-3.

A. No. It is not reasonable to subtract the unamortized prior service costs and net actuarial gains of the OPEB plan from rate base for the same reasons that it is not reasonable to add the asset amounts related to the pension plan to rate base.

Q. What is your recommendation?

A. I recommend that the Commission reject the Companies' proposals to include the amounts in accounts 128 *Prepaid Pension,* 182 *Regulatory Asset – FAS 158 Pension,* and 184 *Pension Clearing Account* in rate base and subtract the amounts in accounts 228.3 *Accumulated Provision for Post Retirement Benefits* and 254 *Regulatory Liability – Postretirement* from rate base for the reasons that I previously described.

Q. What are the effects of your recommendations?

A. The effects of the removals, net of the related offsetting ADIT, are a reduction in the KU revenue requirement of $10.923 million and a reduction in the LG&E electric revenue requirement of $9.944 million and a reduction in the LG&E gas revenue requirement of $5.616 million.

Q. Is your recommendation consistent with DEK's requests and the Commission decisions in Cases 2022-00372 and 2021-00190 and DEK's requests pending in Cases 2024-00354 and 2025-00125?

A. Yes. DEK excluded all pension and OPEB assets and liabilities from rate base in those cases, the same as my recommendation in these cases.

Q. Is your recommendation to exclude all pension and OPEB assets and liabilities from rate base also consistent with the Commission's decision in KPC Case 2020-00174?

A. Yes. In the KPC case, the Commission excluded all pension and OPEB assets and liabilities recorded by KPC for accounting purposes from rate base, the same as it excluded these amounts recorded by DEK for accounting purposes from rate base. In the KPC case, however, the Commission included an adjustment to increase pension expense based on an asset amount recorded in account 165 prepayments without consideration of the offsetting equivalent liability amount also recorded in account 165 prepayments. The account 165 prepayments accounting entries at issue in the KPC rate case were and are unique to KPC and other AEP utility affiliates. KU and LG&E do not record similar amounts in account 165 for accounting purposes and opposed any such an adjustment for ratemaking purposes in their prior rate cases, each stating in response to AG-KIUC discovery "The Company does not agree with the use of this methodology in this proceeding."[31]

5. Pension Clearing Account

Q. Describe the amounts in account 184 *Pension Clearing Accounts.*

A. KU included $2.083 million, LG&E electric included $0, and LG&E gas included $1.422 million in the CWC (Balance Sheet Items) included in rate base.

Q. What are clearing accounts?

A. Clearing accounts are used to accumulate costs for certain activities, such as vehicle costs, which then are charged out to expense or capital based on various allocation or usage factors, such as square footage for building costs or daily usage for vehicle costs. The objective with clearing accounts is to charge out each month an amount

[31] Responses to AG-KIUC 2-11 in Cases 2020-00349 and 2020-00350. I have attached a copy of the narrative portion of the responses as Exhibit LK-7.

equivalent to the costs incurred and recorded in the clearing account so that the balance is $0 on average over time, recognizing that in any single month the amounts incurred and the amounts charged out may not precisely match.

The FERC Uniform System of Accounts ("USOA") defines account 184 *Clearing Accounts* as follows.

> This [account] shall include undistributed balances in clearing accounts at the date of the balance sheet. Balances in clearing account shall be substantially cleared not later than the end of the calendar year unless items held therein relate to a future period.

Q. What is the basis for the Companies' forecast of the account 184 amounts in the test year?

A. The Companies simply used the actual amounts as of February 28, 2025 and held the amounts constant through the end of the test year.[32]

Q. Is that a reasonable basis for the forecast of the account 184 amounts in the test year?

A. No. There is no conceptual basis for assuming that a clearing account balance will remain the same for 22 months from February 2025 through December 2026. All clearing accounts should be forecast and included at $0 in the test year, consistent with the manner in which such accounts are used and consistent with the expectation that the accounts will be cleared to $0 on average over time.

Q. What is your recommendation?

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[32] Schedules B-5.2.2B and B-5.2.2F for each Company in electronic format showing the sum of the monthly balances for account 184 during the base year and test year. The electronic versions of the schedules were provided in response to Staff 1-54 for each Company.

A. I recommend that the Commission either set the clearing accounts to $0 or simply exclude them from rate base. The clearing accounts should revert to $0 over time, especially in a forecast test year. There is no justification for non-$0 amounts in the forecast test year.

Q. What are the effects of your recommendation?

A. The effects are a reduction in the KU revenue requirement of $0.210 million, a reduction in the LG&E electric revenue requirement of $0 (electric), and a reduction in the LG&E gas revenue requirement of $0.144 million.

III. OPERATING INCOME ISSUES

A. Storm Damage Expense Is Overstated; Reserve Accounting Is Reasonable Only For Deferral And Tracking Of Incremental Major Storm Expenses Not Deferred To Regulatory Assets

Q. Describe briefly the Companies' request for storm damage expense and the request for reserve accounting.

A. The Companies provided no testimony, schedules, or workpapers in their filings that provide the amount or calculations of the storm damage expense requested. The Companies' request for reserve accounting is generally described by Witness Conroy as follows: "the Companies request authority in these proceedings to net actual storm damage restoration and vegetation management costs against the respective amounts in base rates in the forecasted test period and record a regulatory asset or liability for the difference."[33]

[33] Direct Testimony of Robert Conroy at 9-10.

Witness Conroy provides no further detail as to the "respective amounts in base rates" that would be used as the baseline for the deferrals, including the estimates/calculations of the routine/unnamed storm costs and the non-routine/named storm costs, the actual costs that would be charged (debited) against such a storm reserve, and whether the Companies still would seek Commission authorization to defer major named storm costs, as is presently practiced.[34] In other words, the Companies' filings fail to describe the full scope of their request and fail to provide even the basic information necessary to inform the Commission regarding the request.

Q. Did the Companies provide historic calendar year storm expenses in response to discovery?

A. Yes. The Companies provided the following historic actual expenses for "minor storms," "major storms" excluding deferrals to regulatory assets, and major storm deferrals to "regulatory assets."[35] The historic expenses provide context for the Companies' requests.

[34] *Id.*

[35] Attachment to response to AG-KIUC 2-35 for minor storms, Attachment to response to AG-KIUC 2-37 for major storms not deferred to regulatory assets, and Attachment to response to AG-KIUC 2-36 for major storms deferred to regulatory assets. I have attached these responses and the attachments for both Companies as my Exhibit LK-8.

Kentucky Utilities Company Storm Expense ($000)										
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Minor Storms	2,033	2,195	1,764	1,521	1,989	2,146	2,509	3,715	2,748	3,231
Major Storms No Reg Asset	2,162	954	944	1,557	350	417	6,601	5,800	5,121	998
Major Storms Reg Asset	0	0	0	4,921	3	0	0	0	11,668	16,551

Louisville Gas & Electric Company - Electric Storm Expense ($000)										
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Minor Storms	3,683	1,731	1,863	2,415	2,265	1,740	2,134	1,230	1,614	2,600
Major Storms No Reg Asset	1,304	657	504	3,413	3,139	1,054	1,339	8,081	10,150	2,561
Major Storms Reg Asset	0	0	0	8,945	209	0	0	0	8,916	6,257

Q. Did the Companies finally provide their calculations of the forecast storm expense for the test year in response to AG-KIUC discovery?

A. Yes. The Companies initially failed to provide their calculations of storm expense in response to Staff 1-54. The AG and KIUC then specifically requested the Companies' workpapers and calculations in supplemental discovery.[36] Although the Companies provided the workpapers and calculations in response to the supplemental discovery, there was no opportunity for follow-up discovery.

As shown in their workpapers provided in response to the AG-KIUC discovery, the Companies calculated an inflation adjusted average of minor and major storm expenses, excluding the expenses deferred to regulatory assets, using actual historic data for the years 2019-2023 and CPI for the inflation metric.[37]

[36] Responses to AG-KIUC 2-39. I have attached a copy of the responses and attachments as Exhibit LK-9.

[37] *Id.*

Q. Did the Companies explain why they used 2019-2023 for the five years of historic data instead of 2020-2024 or some longer period of historic data, such as ten years?

A. No. The Companies had available ten years of historic data, including 2024. If they had calculated the five-year average for the years 2020-2024 or any longer period over the ten years of historic data, the calculated average storm expense would have been less in the aggregate, all else equal.[38]

Q. Is it reasonable to include minor storm expense in the storm damage expense accrual?

A. No. The Companies provided no evidence that the minor storms caused or will cause incremental expenses. The Companies already include forecast payroll and other non-payroll expenses in the test year revenue requirement apparently without reduction for the costs of minor storms that would be charged to the storm reserve instead of recorded to expense. In other words, the Companies' proposal will provide double recovery of the minor storm expenses.

Q. Is it reasonable to include major storm expense that is not deferred to a regulatory asset in the storm damage expense accrual?

A. No, at least not based on the information and workpapers provided by the Companies in response to the AG-KIUC discovery. Like the minor storm expense, the Companies calculated the major storm expense not specifically deferred to a

[38] Attachment to response to AG-KIUC 2-35 for minor storms, Attachment to response to AG-KIUC 2-37 for major storms not deferred to regulatory assets, and Attachment to response to AG-KIUC 2-36 for major storms deferred to regulatory assets. Refer to Exhibit LK-8.

regulatory asset apparently without any reduction to the forecast expenses as if the entirety of major storm expenses were, in fact, incremental to the payroll and other non-payroll expenses already included in the base revenue requirement. The major storm expense, if it is allowed in the storm damage expense accrual, should be limited to expenses that are incremental to the expenses already recovered through base revenues. In addition, if the Commission allows storm reserve accounting, then the actual expenses charged against the storm reserve should be limited to the incremental expenses not already recovered through the base revenue requirement.

The future major storm expenses are unknown and cannot be estimated with any certainty. Each storm and the costs incurred to respond to each storm are unique. If allowed preemptively, any estimate of these costs would be inherently arbitrary. For example, the Companies incurred major storm expense not deferred to a regulatory asset of more than $1 million in only four years during the ten years from 2015 through 2024, and more than $2 million in only three of those 10 years. Further, the Companies will retain the right to seek an accounting order to defer significant major named storm costs to a regulatory asset, the same right they have now in the absence of storm reserve accounting.

Q. What are your recommendations?

A. I recommend the Commission deny recovery of minor storm expense and major storm expense not deferred to a regulatory asset unless the Companies can demonstrate on rebuttal there are, in fact, incremental expenses, and quantify the expenses, if any, that are incremental to the payroll expenses and other non-payroll expenses included in the forecast test year expenses. I recommend the Commission

authorize the Companies to defer only incremental major storm expenses not specifically deferred to a regulatory asset as charges against the storm reserve and then determine recovery of the storm expenses specifically deferred to the storm reserve in a future base revenue proceeding.

Q. What are the effects of your recommendations?

A. The effect is a reduction in storm expense for KU of $6.056 million and for LG&E electric of $6.935 million.[39] The effects are a reduction in the KU revenue requirement of $6.082 million and the LG&E revenue requirement of $6.962 million after gross up for bad debt expense and Commission fees.

B. Vegetation Management Expense Is Overstated; Reserve Accounting Is Not Reasonable for Deferral and Tracking Of Vegetation Management Expenses

Q. Describe briefly the Companies' request for vegetation management expense and the request for reserve accounting.

A. The Companies provided no testimony, schedules, or workpapers in their filings that provide the amount or calculations of the vegetation management expense requested. The Companies' request for vegetation management reserve accounting is paired with its request for storm reserve accounting in both Witness Conroy's and Witness Waldrab's general descriptions of the request.[40]

Similar to the requests related to storm damage expense, neither Witness Conroy nor any other Companies witness provided any further detail as to the

[39] Attachment to responses to AG-KIUC 2-39. Refer to Exhibit LK-9. KU's reported expenses are on a total Company basis.

[40] Direct Testimony of Robert Conroy at 9-10 and Direct Testimony of Peter Waldrab at 21-25.

"respective amounts in base rates" that would be used as the baseline for the deferrals, including the estimates/calculations of the vegetation management expense and the actual costs that would be charged (debited) against such a combined storm damage and vegetation manage reserve.[41] In other words, the Companies' filings fail to describe the full scope of their request and fail to even provide the basic information necessary to inform the Commission regarding the request.

Q. Have the Companies demonstrated any need or provided any valid justification for a combined storm damage and vegetation management reserve or a separate standalone vegetation management reserve?

A. No. There is no need or valid justification for any form of vegetation management reserve accounting. Vegetation management expense is a fixed, predictable, and non-volatile expense that does not justify reserve accounting. In fact, reserve accounting may serve as a disincentive for the Companies to control and efficiently manage their vegetation management expense. Reserve accounting simply would allow every dollar spent above the baseline included in base revenues to be deferred to the reserve and then recovered in future rate proceedings, thus circumventing the inherent incentive for the utility to control expenses between rate cases.

Q. Did the Companies provide historic calendar year vegetation management expenses in response to discovery?

A. Yes. The Companies provided the historic actual expenses for distribution and

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[41] *Id.*

transmission vegetation management expenses by FERC O&M expense account in response to AG-KIUC discovery.[42] The vegetation management expenses were between $20 million and $22 million annually each year from 2015 through 2024, except for the additional spend in the years 2018 through 2022 for the Transmission System Improvement Plan and other enhanced distribution vegetation management activities during those years.[43]

Q. Did the Companies finally provide their calculations of vegetation management expense for the test year in response to AG-KIUC discovery?

A. Yes. The Companies initially failed to provide their calculations of vegetation management expense in response to Staff 1-54. The AG and KIUC then specifically requested the Companies' workpapers and calculations in supplemental discovery.[44] Although the Companies provided the workpapers and calculations in response to the supplemental discovery, there was no opportunity for follow-up discovery.

KU included $31.450 million in vegetation management expense in the test year compared to the $21.930 million actual expense in 2024, an increase of $9.520 million, or 43.4%. LG&E included $13.940 million in vegetation management expense in the test year compared to the $7.856 million actual expense in 2024, an increase of $6.084 million, or 77.4%.

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[42] Attachments to responses to AG-KIUC 2-40. I have attached a copy of the responses and attachments as Exhibit LK-10.

[43] Direct Testimony of Peter Waldrab at 21-22.

[44] Responses to AG-KIUC 2-41. I have attached a copy of the responses and attachments as Exhibit LK-11.

In their workpapers provided in response to the AG-KIUC discovery, the Companies started with their distribution and transmission vegetation management "plan" expense, then added additional distribution "target" expense, then added additional transmission "funding" expenses.[45] For KU, the "plan" expense was $21.930 million, the same as the actual expense incurred in 2024. For LG&E, the "plan" expense was $9.160 million, an increase of $1.304 million, or 16.6%, compared to the actual expense incurred in 2024.[46] For KU, the additional distribution "target" expense was $7.345 million and the additional transmission "funding" expense was $2.175 million. For LG&E, the additional distribution "target" expense was $4.055 million and the additional transmission "funding" expense was $0.725 million.

Q. Did the Companies provide any testimony or narrative descriptions of the development of the "plan" expense or the additional "target" and "funding" expenses included in the test year expenses?

A. No. Companies Witness Peter Waldrab addressed the transmission and distribution activities and provided a general description of the Companies' requested reserve accounting for vegetation management expenses. Witness Waldrab also provided a general description of the vegetation management expense included in the test year, but did not describe the specifics or calculations of the amounts included in the per

[45] *Id.*
[46] *Id.*

books "plan" expense or the additional "target" and "incremental" proforma adjustments to increase the "plan" expense for ratemaking purposes.[47]

Q. What is your recommendation?

A. I recommend the Commission approve the Companies' per books "plan" vegetation management expense. I recommend the Commission deny the Companies' additional "target" and "incremental funding" proforma increases in the vegetation management expense. The Companies have the burden to support their requested expense, but did not do so.

In addition, I recommend the Commission deny the Companies' request for vegetation management expense deferral accounting. As I noted previously, there is no need or valid justification for any form of vegetation management reserve accounting.

Q. What are the effects on the Companies' requested increases in these proceedings?

A. The effects are a reduction in the KU vegetation management expense to exclude $8.779 million for the "target" and "incremental funding" proforma increases to the per books "plan" expense in the test year and a reduction in the LG&E vegetation management expense to exclude $4.780 million for the unsupported and unjustified "target" and "incremental funding" proforma increases to the per books "plan" expense in the test year. The effects are a reduction in the KU revenue requirement of $8.816 million and the LG&E revenue requirement of $4.799 million after gross

[47] *Id.* at 23.

up for bad debt expense and Commission fees.

C. Pension, OPEB, And Post-Employment Benefits Expenses Are Overstated

1. Pension Expenses Are Overstated; They Do Not Reflect Prior Commission Orders Disallowing Pension Expense For Participants In Multiple Pension Plans

Q. Describe the Companies' requested pension and 401(k) compensation expenses.

A. The Companies included pension expense for their defined benefit (DB) plan and compensation expense for their 401(k) defined contribution (DC) plans.[48] More specifically, KU included $0.842 million in pension and compensation expense for both the DB and DC plans in the test year compared to negative $3.867 million in the base year and negative $4.783 million in 2024.[49]

LG&E electric included $1.759 million in pension and compensation expense for both the DB and DC plans in the test year compared to negative $1.520 million in the base year and negative $1.466 million in 2024.[50]

LG&E gas included $0.854 million in pension and compensation expense for both the DB and DC plans in the test year compared to negative $0.727 million in the base year and negative $1.005 million in 2024.[51]

Q. Did the Companies reduce their pension and compensation expenses for disallowances previously ordered by the Commission in Cases 2016-00370, 2016-00371, 2018-00294 and 2018-00295 and by the Commission in other cases

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[48] Direct Testimony of Vincent Poplaski at 13-14.
[49] Responses to AG-KIUC 1-70(d). I have attached a copy of the responses as Exhibit LK-12.
[50] *Id.*
[51] *Id.*

for other utilities with employees who participate in multiple pension plans?

A. No. In the Case 2018-00294 and 2018-00295 Orders, the Commission stated "for ratemaking purposes, it is not reasonable to include KU's [LG&E's] contributions to both the Pre-2006 DB [defined benefit] Plan and the Matching Plan [401(k) defined contribution plan]."[52]

The Companies acknowledged they did not reflect the disallowances required by the Commission in those prior cases, but offered no reasons to include the duplicative costs that the Commission has not previously considered in the prior cases and/or in other utility cases.[53]

Q. Have the Companies quantified the required disallowance of pension and compensation expenses for those employees who participate in both plans?

A. Yes. KU quantified a disallowance of $0.933 million and LG&E quantified an electric disallowance of $0.654 million and a gas disallowance of $0.323 million.[54] The amounts shown as adjustments on the table in the Summary section of my testimony are slightly more than the expense reductions due to the gross-up for bad debt expense and Commission fees included in the revenue requirement.

2. Pension Expense For The DB Plan Is Overstated Due To Unreasonable Actuarial Assumptions

Q. Describe how the Companies calculated the forecast DB plan pension expense for the test year.

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[52] Orders at 17.

[53] Responses to AG-KIUC 1-86. I have attached a copy of the responses as my Exhibit___(LK-13).

[54] *Id.*

A. The Companies' actuary calculated the forecast DB plan pension expense for the test year based on direct and specific assumptions provided by the Companies for ratemaking purposes, not for actual accounting purposes. The Companies directed the actuary to use a starting date of February 2025 for the trust fund asset valuation, present value pension liability obligation, prior service obligation, and deferred gains and losses.[55] The Companies' also provided the actuary with other forecast information and assumptions, including forecast participant demographic profiles, forecasts of the timing and amounts of future pay increases, and assumptions for the rate of return on trust fund assets and the discount rate used both to discount the future pension payment obligation and to calculate the interest cost, among others.[56]

The Companies' actuaries started with a valuation date of February 2025 based on actual values for the trust fund assets and the present value of the estimated future pension obligation, as well as the actual values for the prior service costs. The pension cost, before the allocation between expense and capital, was calculated as the return on the trust fund assets at the valuation date, minus the interest on the pension obligation at the valuation date, less the amortization of the prior service cost at the valuation date, minus or plus the amortization of deferred gains and losses at the valuation date.

Q. Are the pension expenses for the DB plan reasonable?

A. No. The pension expenses for the DB plan are overstated. The calculations are

[55] Response to AG-KIUC 1-74.
[56] *Id*.

fundamentally flawed and biased based on the Companies' directions and assumptions provided to the actuary. First, the return on assets credit component of the pension costs is understated because the trust funds at the beginning of the test year are understated. If the pension trust funds are understated, the return on those trust fund assets is understated. The Companies' use of a February 2025 valuation date fails to reflect the subsequent significant increases in equity market valuations, as measured by the Dow Jones Industrial Average, S&P's 500, NASDAQ, and other indices, all of which are at record or near record highs. These valuation increases will be reflected in the actual pension cost calculations by the Companies' actuary for 2026, which will drive the actual pension expense down in 2026 for accounting purposes compared to the forecast calculated expressly and solely for these rate cases.

Second, the return on assets credit component of the pension costs is understated because the Companies reduced the return on the trust fund assets for the estimate calculated expressly and solely for these rate cases. Without explanation in witness testimony or in the MFR schedules and workpapers, the Companies directed the actuary to reduce the return on the trust fund assets from the present assumption of 8.25% through the end of 2025 to 7.25% in the test year specifically for these rate cases.[57] At the same time, the Companies directed the actuary to retain the present assumption of 5.3% for the discount rate applied to the future pension payments to calculate the present value of the pension obligation

[57] *Id.*

specifically for these rate cases.[58] It is highly unusual to reduce the return on the trust fund assets and not reduce the discount rate concurrently due to the direct correlation between both rates, but that is what the Companies directed the actuary to do. As a result, the return on trust fund assets credit (negative) component of the expense calculation was decreased and the calculated pension cost increased, while at the same time, the interest expense component stayed the same, all else equal.

Q. What are the effects of using a June 30, 2025 valuation date for the pension trust fund assets and the pension liability obligations and using the present 8.25% return on trust fund assets instead of the Companies' February 28, 2025 date and a reduction to 7.25% for the return on trust fund assets?

A. The pension expense with these changes in directions and assumptions will be lower than the Companies' request. The Companies were requested to provide the effects through AG-KIUC discovery;[59] however, the Companies did not provide the requested information.[60] I reserve the right to supplement my testimony and potentially modify my recommendations if and when the Companies supplement their responses.

Q. What is your recommendation?

A. I recommend the Commission use the Companies' actual pension expense in the

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[58] *Id.*

[59] Initial responses to AG-KIUC 2-25(d). The Companies provided a supplemental response, but used an April 30, 2025 valuation date, not the June 30, 2025 requested. The Companies provided no explanation for using a different date and one that reflected the temporarily lower stock market valuations in the aftermath of the trade tariff "liberation day" announced in early April, which since have rebounded to record or near record levels. I have attached a copy of the responses as Exhibit LK-14.

[60] *Id.*

calendar year 2024. This recommendation tethers the pension expense to the expense in the most recent actual calendar year and addresses the Companies' biased and overstated estimates reflected in both the base year and the test year.

I also recommend the Commission true-up the allowed pension expense to the actual pension expense incurred in 2026 and subsequent years through deferred regulatory accounting, including debits and credits to regulatory assets or liabilities. It is difficult for the Companies or any other party to accurately estimate this cost in a forecast test year. Pension expense is extremely volatile due to the valuation of the trust fund assets, the return on the trust fund assets and the discount rate. The Companies can bias upward the forecast pension expense based on direction and assumptions provided to their actuary, but the Companies ultimately cannot control the actual returns on trust fund assets or the volatile nature of this expense.

Q. What are the effects of your recommendation?

A. The effects are reductions in the KU requested revenue increase of $5.330 million, LG&E electric requested increase of $3.238 million, and LG&E gas requested increase of $1.866 million.

Q. Are there also problems with the Companies' calculations of OPEBs and other post- employment benefits expenses?

A. Yes. KU included $0.024 million for OPEB expense in the test year compared to negative $0.093 million in the base period and negative $0.060 million in calendar year 2024. KU included $0 for other post-employment benefits expense in the test year compared to negative $0.477 million in the base period and negative $0.477

million in calendar year 2024.[61]

LG&E electric included $1.198 million for OPEB expense in the test year compared to $1.045 million in the base period and $0.813 million in calendar year 2024. LG&E included $0 in other post-employment benefits expense in the test year compared to negative $0.274 million in the base year and negative $0.276 million in 2024.[62]

LG&E gas included $0.549 million for OPEB expense in the test year compared to $0.557 million in the base period and $0.564 million in calendar year 2024. LG&E gas included $0 for other post-employment benefits expense in the test year compared to negative $0.131 million in the base year and negative $0.129 million in 2024.[63]

Q. Why did the Companies forecast post-employment benefits expense in the test year at $0?

A. In response to AG-KIUC discovery on this issue, the Companies stated that "LKE does not budget an amount related to post-employment benefits."[64] That budget anomaly should not deter the Commission from reflecting a reasonable estimate of post-employment benefits expense in the test year.

Q. What is your recommendation?

A As with pension expense, I recommend the Commission use the Companies' actual OPEB and post-employment benefits expenses in 2024. This recommendation

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[61] Response to AG-KIUC 1-70(d). Refer to Exhibit LK-12.
[62] *Id.*
[63] *Id.*
[64] Responses to AG-KIUC 2-27. I have attached a copy of the responses as Exhibit LK-15.

tethers the OPEB and post-employment benefits expense to the most recent actual calendar year and addresses the Companies' biased and overstated estimates for OPEB and post-employment benefits expense reflected in the test year.

I also recommend the Commission true-up the allowed OPEB and post-employment benefits expenses to the actual expenses incurred in 2026 and subsequent years through deferred regulatory accounting, including debits and credits to regulatory assets or liabilities. It is difficult for the Companies or any other party to accurately estimate these costs in a forecast test year. Although not as significant in absolute dollars of expense as pension expense, these expenses also are extremely volatile due to the valuation of the trust fund assets, the return on the trust fund assets, the discount rate, and estimated payouts. The Companies can bias upward the forecast pension expense based on direction and assumptions provided to their actuary, but the Companies ultimately cannot control the actual returns on trust fund assets or the volatile nature of this expense.

Q. What are the effects of your recommendation?

A. The effects are a reduction in the KU increase of $0.532 million, a reduction in the LG&E electric increase of $0.663 million, and a reduction in the LG&E gas increase of $0.113 million.

D. Generating Unit Decommissioning Expense Should Not Be Recovered Until After The Unit Is Retired

Q. Describe the Companies' request to recover generating unit terminal net salvage (decommissioning expense) in the requested depreciation rates and expense.

A. The Companies have included estimates of future decommissioning costs in their requested depreciation rates and expense. Company witness John Spanos describes the use of an estimated $40/kW current dollar cost for decommissioning coal and gas-fired generating units and related facilities.[65] Witness Spanos then escalated the current dollar estimated cost to a future dollar estimated cost at the probable retirement date for each generating unit using a 2.5% annual escalation rate for this purpose. Witness Spanos divided the decommissioning cost by the gross plant remaining after estimated interim retirements and then weighted the terminal and interim net salvage rates to develop a combined net salvage rate. Witness Spanos then multiplied the combined net salvage rate times the gross plant in each account at the study date and added the resulting net negative salvage to the net plant at the study date to calculate the total cost to be recovered over the average remaining service life of each account for each generating unit.

Q. Did the Commission previously deny recovery of decommissioning expense for another utility?

A. Yes. In its Order in Case 2022-00372, shortly after KRS 278.264 was enacted, the Commission disallowed the decommissioning expense for DEK's thermal (coal, gas, and oil fired) generating unit plant accounts, stating: "The Commission also finds that terminal net salvage should be removed from the depreciation rates due to the requirements of KRS 278.264(2) that the Commission 'shall not . . . take any other action which authorizes or allows for the recovery of costs for the retirement

[65] Direct Testimony of John Spanos at 13.

of an electric generating unit…unless the presumption created by this section is rebutted.'"[66] The Commission initially denied recovery of decommissioning expense for the solar generating units as well; however, on rehearing in that case, the Commission allowed recovery of decommissioning expense for the solar generating units, but did so solely on the basis that KRS 278.264 did not apply to the solar generating units. The record in that case was not developed as to other reasons to deny recovery of decommissioning expense on non-thermal generating units until after they were retired.

Q. Has the Commission considered the decommissioning expense issue for the Companies since KRS 278.264 was enacted?

A. No.

Q. Does KRS 278.264 preclude recovery of decommissioning expense prior to seeking and obtaining Commission approval to retire a specific thermal generating unit?

A. Yes. The statute requires a utility to seek and obtain approval to retire a specific thermal generating unit. There are various thresholds the utility must meet before the Commission may approve a requested retirement. The statute also precludes recovery of decommissioning costs until after the Commission approves the retirement.

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[66] Case No. 2022-00372, *Electronic Application of Duke Energy Kentucky, Inc. for 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief* (Ky. PSC Oct. 12, 2023), Order at 14.

KRS 278.264(1) states specifically that, "Prior to retiring an electric generating unit, a utility shall apply to the commission for an order approving the retirement, and shall give the commission thirty (30) days notice of the application." The Company has not filed an Application for any of its generating units, although the Commission approved the retirement of Ghent 2 prior to the enactment of the statute in Case 2022-00402.

KRS 278.264(2) states: "There shall be a rebuttable presumption against the retirement of a fossil fuel-fired electric generating unit. The commission shall not approve the retirement of an electric generating unit, authorize a surcharge for the decommissioning of the unit, or take any other action which authorizes or allows for the recovery of costs for the retirement of an electric generating unit, including any stranded asset recovery, unless the presumption created by this section is rebutted by evidence sufficient for the commission to find that: (a) The utility will replace the retired electric generating unit with new electric generating capacity that: 1.) Is dispatchable by either the utility or the regional transmission organization or independent system operator responsible for balancing load within the utility's service area; 2.) Maintains or improves the reliability and resilience of the electric transmission grid; 3.) Maintains the minimum reserve capacity requirement established by the utility's reliability coordinator; and, 4.) Has the same or higher capacity value and net capability, unless the utility can demonstrate that such capacity value and net capability is not necessary to provide reliable service; (b) The retirement will not harm the utility's ratepayers by causing the utility to incur any net incremental costs to be recovered from ratepayers that

could be avoided by continuing to operate the electric generating unit proposed for retirement in compliance with applicable law; (c) The decision to retire the fossil fuel-fired electric generating unit is not the result of any financial incentives or benefits offered by any federal agency; and, (d) The utility shall not commence retirement or decommissioning of the electric generating unit until the replacement generating capacity meeting the requirements of paragraph (a) of this subsection is fully constructed, permitted, and in operation, unless the utility can demonstrate that it is necessary under the circumstances to commence retirement or decommissioning of the existing unit earlier."

KRS 278.264(3) states that, "The utility shall at a minimum provide the commission with evidence of all known direct and indirect costs of retiring the electric generating unit and demonstrate that cost savings will result to customers as a result of the retirement of the electric generating unit."

Q. Have any of the Companies' witnesses addressed the requirements of KRS 278.264?

A. No. The Companies intentionally and admittedly decided to ignore and not address the effects of this statute in their testimony.[67] Witness Christopher Garrett apparently made this decision and communicated it to Witness Spanos via email,[68] but did not address the effects of the statute in his testimony. Witness Spanos agreed with the Companies, but did not address the effects of the statute in his testimony.[69]

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[67] Refer to responses to AG-KIUC 1-101(b). I have attached a copy only of the KU response and attachment as Exhibit LK-23 due to the volume of the attachment and the fact the attachments are the same.

[68] *Id.*

[69] *Id.*

Despite these decisions by Witness Garrett and Witness Spanos, the Companies had Witness Spanos quantify the effects of excluding the terminal net salvage for the thermal generating units and for all generating units so they had an estimate of the magnitude of the issue.[70]

Q. Even without the statutory prohibition against recovery of terminal net salvage for the thermal generating units that have not been approved for retirement, are there reasons why decommissioning expense should not be recovered prior to the retirement of any of the generating units, regardless of whether they are thermal or non-thermal generating units?

A. Yes. First, the decommissioning cost is inherently not known or measurable. The costs are estimates of costs many years into the future.

Second, recovery of decommissioning costs prior to cash disbursements for such costs after the generating units actually are retired results in a temporary difference for book and tax purposes because the decommissioning expense for book purposes is not deductible for income tax purposes. This temporary difference results in a decommissioning accumulated deferred tax asset (DTA), which is included by the Company in rate base and capitalization because it has to be financed. This is a cost that is unnecessary and can be completely avoided simply by delaying recovery of decommissioning costs until they actually are incurred and deductible for income tax purposes after the generating unit is retired.

Third, delayed recovery of decommissioning expense promotes

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[70] *Id.*

intergenerational equity among customers now and in the future. Generating units are retired when they are no longer economic and are replaced with lower cost generation, that generally is more efficient and has lower fuel and non-fuel operating expenses. The cost of decommissioning is thus a transition cost to the newer, more efficient, and lower cost replacement generation and appropriately recovered from the customers who benefit from the new replacement generation.

Q. What is your recommendation?

A. I recommend the Commission deny recovery of all decommissioning expense, not only for the Companies' thermal generating units, but also for the solar generating, hydro, and wind facilities.

Q. What are the effects of your recommendation?

A. The effects for the KU thermal generating units are a $14.393 million reduction in depreciation expense, a $5.401 million reduction in accumulated depreciation and increase in rate base, net of the ADIT effects, and a $13.911 million reduction in the base revenue requirement and requested base revenue increase.[71]

The effects for the KU solar, wind, and hydro generating units are an additional $0.041 million reduction in depreciation expense, an additional $0.015 million reduction in accumulated depreciation and increase in rate base, net of the ADIT effects, and an additional $0.039 million reduction in the base revenue

[71] The Companies provided revised depreciation rates excluding estimated terminal net salvage in their responses to AG-KIUC 1-102(a). I have provided a copy of the narrative portion of the responses as Exhibit LK-16. I used the revised depreciation rates and the proposed depreciation rates to calculate the difference in the depreciation rates and depreciation expense in the test year. The calculations are included in my electronic workpapers filed contemporaneously with my testimony.

requirement and requested base revenue increase.[72]

The effects for the LG&E thermal generating units are a $5.301 million reduction in depreciation expense, a $1.989 million reduction in accumulated depreciation and increase in rate base, net of the ADIT effects, and a $5.121 million reduction in the base revenue requirement and requested base revenue increase.[73]

The effects for the LG&E solar, wind, and hydro generating units are an additional $0.096 million reduction in depreciation expense, an additional $0.036 million reduction in accumulated depreciation and increase in rate base, net of the ADIT effects, and an additional $0.093 million reduction in the base revenue requirement and requested base revenue increase.[74]

E. Production Plant Account Depreciation Rates And Expense Are Overstated Because Life Spans Are Not Consistent Or Rationalized Or Are Unduly Short

Q. Describe generally the life span parameters used by Witness Spanos to calculate the proposed depreciation rates for the production plant accounts.

A. Witness Spanos relied on forecasts of probable retirement dates and the commercial operation dates to calculate the life span and remaining life span for each of the Companies' generating units. The life spans for similar generating units on the same site and built in the same general time frame differ. The forecast Ghent 1 life span is 60 years, Ghent 2 life span is 57 years, Ghent 3 life span is 56 years, and Ghent 4 life span is 53 years. The forecast Mill Creek 2 life span is 54 years, Mill Creek 3 life span is 61 years, and Mill Creek 4 life span is 57 years.

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[72] *Id.*
[73] *Id.*
[74] *Id.*

The following tables from Witness Spanos' KU and LG&E depreciation studies show these differences, mostly for the coal-fired generating units. The life spans for the gas fired combined cycle and combustion turbine generating units are mostly consistent and rationalized at 40 years, but unnecessarily short, and the life spans for the solar arrays are consistent and rationalized, but unnecessarily short.

Kentucky Utilities Company Proposed Life Spans for Generating Units

Depreciable Group	Major Year in Service	Probable Retirement Year	Life Span
Steam Production Plant			
Brown Unit 1	1956	2019	63
Brown Unit 2	1963	2019	56
Brown Unit 3	1971	2035	64
Ghent Unit 1	1974	2034	60
Ghent Unit 2	1977	2034	57
Ghent Unit 3	1981	2037	56
Ghent Unit 4	1984	2037	53
System Laboratory	1989	2040	51
Trimble County Unit 2	1990, 2011	2066	76, 55
Hydroelectric Production Plant			
Dix Dam	1941	2041	100
Other Production Plant			
Paddy's Run Generator 13	2001	2041	40
Brown Unit 5	2001	2041	40
Brown Unit 6	1999	2039	40
Brown Unit 7	1999	2039	40
Brown Unit 8	1995	2035	40
Brown Unit 9	1994	2034	40
Brown Unit 10	1995	2035	40
Brown Unit 11	1996	2036	40
Trimble County Unit 5	2002	2042	40
Trimble County Unit 6	2002	2042	40
Trimble County Unit 7	2004	2044	40
Trimble County Unit 8	2004	2044	40
Trimble County Unit 9	2004	2044	40
Trimble County Unit 10	2004	2044	40
Haefling Units 1, 2, & 3	1970, 2000	2025	55, 25
Cane Run Unit 7	2015	2055	40
Solar and Wind Producton Plant			
Brown Solar	2016	2041	25
Simpsonville Solar Array 1	2019	2044	25
Simpsonville Solar Array 2	2020	2045	25
Simpsonville Solar Array 3	2021	2046	25
Simpsonville Solar Array 4	2021	2046	25
Brown Wind	2023	2049	25

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Louisville Gas and Electric Company Proposed Life Spans for Generating Units			
Depreciable Group	Major Year in Service	Probable Retirement Year	Life Span
Steam Production Plant			
Mill Creek Unit 1	1972	2024	52
Mill Creek Unit 2	1974	2028	54
Mill Creek Unit 3	1978	2039	61
Mill Creek Unit 4	1982	2039	57
Timble County Unit 1	1990	2045	55
Timble County Unit 2	1990, 2011	2066	76, 55
Hydroelectric Production Plant			
Ohio Falls	1934	2045	111
Other Production Plant			
Cane Run CC 7	2015	2055	40
Paddy's Run Generator 13	2001	2041	40
Brown CT 5	2001	2041	40
Brown CT 6	1999	2039	40
Brown CT 7	1999	2039	40
Trimble County CT 5	2002	2042	40
Trimble County CT 6	2002	2042	40
Trimble County CT 7	2004	2044	40
Trimble County CT 8	2004	2044	40
Trimble County CT 9	2004	2044	40
Trimble County CT 10	2004	2044	40
Solar and Wind Producton Plant			
Brown Solar	2016	2041	25
Simpsonville Solar Array 1	2019	2044	25
Simpsonville Solar Array 2	2020	2045	25
Simpsonville Solar Array 3	2021	2046	25
Simpsonville Solar Array 4	2021	2046	25
Brown Wind	2023	2049	25

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Q. What do you recommend?

A. I recommend the Commission modify the forecast life spans for the coal-fired generating units so they are consistent and rationalized for depreciation rate and expense purposes. These generating units are extremely and increasingly valuable in the PJM capacity markets and in comparison to the costs of new replacement generation. The Companies will continue to operate these generating units until they are uneconomic compared to the costs of new replacement generation. The Commission should recognize this reality in the forecast life spans.

More specifically, I recommend the Commission modify the life spans for the Ghent units so that all four of the units reflect the same life span of 60 years, the forecast life span for Ghent 1 reflected in the requested depreciation rates. This will extend the depreciable life by 3 years for Ghent 2, 4 years for Ghent 3, and 7 years for Ghent 4.

I also recommend the Commission modify the life spans for the Brown Solar and Simpsonville Solar Array 1, Simpsonville Solar Array 2, Simpsonville Solar Array 3, and Simpsonville Solar Array 4 from 25 years to 30 years, the same as the forecast life span for future solar assets recommend by Witness Spanos. This will extend the depreciable life by 5 years for the Brown and Simpsonville Solar Arrays so that all solar resources are depreciated using the same 30-year life span.

In addition, I recommend the Commission modify the life span for all of the existing gas-fired combined cycle and combustion turbine generating units, except for the Haefling units, from 40 years to 45 years, the same as the forecast life span that I recommend for the future combined cycle generating units, namely, Mill

Creek 5, which is presently under construction, and Brown 12 and Mill Creek 6, which have pending requests for CPCNs in Case 2025-00045. The Company's proposed 40 years life span for all gas-fired generating units is unnecessarily and unduly short and results in excessive depreciation rates and expense. The life spans for the existing gas-fired generating units should be reviewed and assessed together with the Companies' proposed life spans for the future generating units to ensure that they are consistent and that the effects of adding the future generating units are reasonable and minimized based on a longer rather than shorter life span. As with the coal-fired generating units, the gas-fired generating units are extremely valuable and the Companies will continue to operate them until they are no longer economic in comparison to new replacement generating units. I address the reasons for the 45-year life spans for the future combined cycle generating units in a subsequent section of my testimony.

Q. What are the effects of your recommendations?

A. The effects of modifying these life spans for the existing generating units so they are consistent and rationalized for depreciation purposes for KU are a $36.697 million reduction in depreciation expense, a $13.771 million reduction in accumulated depreciation and increase in rate base, including the effects of ADIT, and a $35.467 million reduction in the base revenue requirement and the requested base revenue increase.

The effects of modifying these life spans so they are consistent and rationalized for depreciation purposes for LG&E electric are a $2.935 million reduction in depreciation expense, a $1.101 million reduction in accumulated

depreciation and increase in rate base, including the effects of ADIT, and a $2.835 million reduction in the base revenue requirement and the requested base revenue increase.

F. If Allowed, Decommissioning Expense Should Be Recovered As A Separate Standalone Expense, Reflect The AG-KIUC Life Span Recommendations, And Escalated Only Through The End Of The Test Year

Q. If the Commission allows recovery of decommissioning expense for any of the generating units, should it be included as a component of the depreciation rates?

A. No. It should be included as a separate standalone expense. Including the decommissioning in the depreciation rates and expense overstates the decommissioning cost compared to a properly calculated standalone expense.

This occurs because the decommissioning cost is included in the calculation of depreciation rates based on the gross plant at the depreciation study date, in this case, June 30, 2024. Those depreciation rates then are applied to the much greater gross plant in the test year compared to the plant at the study, which necessarily results in a proportionately greater and excessive decommissioning expense compared to the amount included in the depreciation study and depreciation rates.

This problem is eliminated if the expense is included as a standalone expense instead of in the calculation of the depreciation rates and then the depreciation expense in the test year.

Q. If the Commission allows recovery of decommissioning expense for any of the generating units, should it reflect the remaining average service life based on the life spans you recommend?

A. Yes. If the Commission allows recovery of decommissioning expense, then it should reflect the same life spans and other parameters as the depreciation rates and expense, excluding terminal net negative salvage.

Q. If the Commission allows recovery of decommissioning expense for any of the generating units, should it reflect escalation of the decommissioning cost to future dollars beyond the end of the test year?

A. No. The Companies escalated the estimated decommissioning costs from current dollars at the date of the depreciation study to the probable retirement dates for each of the generating units, many years beyond the end of the test year. This creates a significant mismatch between the revenues and other costs included in the test year, which are limited to the test year and don't include growth in revenues due to customer growth beyond the end of the test year or growth in any other expenses beyond the end of the test year. The longer the escalation period, the greater the decommissioning cost and the greater the mismatch with all other revenues and costs in the test year. Also, in contrast to the forecast of gross plant in the test year, which is based on the Company's budget process and reasonably known and certain, the retirement dates for the Company's generating units are not known and certain, nor is the cost in future dollars tied to the retirement dates known and certain.

To illustrate this point more specifically, the Companies included forecast decommissioning costs in 2066 dollars for Trimble County 2, some 40 years after the 2026 test year in this proceeding. The Companies included forecast decommissioning costs in 2055 dollars for Cane Run 7, some 29 years after the

2026 test year in this proceeding.

Q. If the Commission allows decommissioning expense for any of the generating units, what is your recommendation?

A. To reiterate, I do not recommend the Commission allow recovery of decommissioning expense for any of the generating units until after the Commission has expressly authorized the retirement of each thermal generating unit or the actual retirement date of any other non-thermal generating unit.

However, if the Commission allows decommissioning expense for any of the generating units prior to their retirement and prior to actually incurring any costs for this purpose, then I recommend it calculate the expense as a standalone and separate expense to ensure that the expense is not overstated in the test year due to the methodological problem that I described from including the expense in the depreciation rates based on a study date prior to the test year.

I also recommend the Commission reflect the remaining average service lives for each generating unit based on the life span parameters that I recommend for each generating unit in the calculation of the depreciation rates. Both the decommissioning expense and the depreciation expense should reflect the same life span parameters.

Finally, I recommend the Commission limit the escalation of the current dollar decommissioning cost estimates to the end of the test year to ensure that present rates do not reflect forecasts of estimated decommissioning costs in 2055 and 2066 dollars.

Q. If the Commission allows recovery of decommissioning expense for any of the

generating units, what are the effects of your alternative recommendations?

A. The effects for all generating units would be to include the decommissioning expense as a standalone and separate expense offset by the related reductions in the return on rate base. Assuming the terminal net salvage is removed from depreciation expense, for KU, there would be $8.968 million (maximum) in decommissioning expense, a related $0.226 million reduction in accumulated decommissioning and increase in rate base, including the effects of ADIT, and a $8.780 million increase in the base revenue requirement and the requested base revenue increase. For LG&E, there would be $4.418 million (maximum) in decommissioning expense, a related $0.112 million reduction in accumulated decommissioning and increase in rate base, including the effects of ADIT, and a $4.324 million increase in the base revenue requirement and the requested base revenue increase.

G. Requested Depreciation Rates For "Future" Generating Units Are Overstated Due To Unreasonably Short Life Spans, Estimated Interim Retirements, Estimated Interim Net Negative Salvage, And Terminal Net Salvage

Q. Describe the Companies' proposed depreciation rates for "future" generating units.

A. The Companies proposed future depreciation rates for Mill Creek 5, which is presently under construction and expected to be completed in 2027. Witness Spanos provided the proposed depreciation rates by plant account in a footnote to the Section VI Results section of the depreciation study developed for each Company. The entirety of the description of the proposed depreciation rates and their development for Mill Creek 5 provided by Witness Spanos in Direct

Testimony is "There are plans to construct Mill Creek Unit 5 which will be owned by LG&E and KU." That's it. Nor is there any further discussion in the depreciation studies themselves.

Even worse, in the detail he provided for each of the operating generating units, Witness Spanos failed to provide any of the assumptions, parameters, or calculations of the proposed depreciation rates for Mill Creek 5 in the depreciation studies. The entirety of the information provided in support of the proposed depreciation rates for Mill Creek 5 Section VI Results is found in a single footnote contained in each depreciation study as follows:

> NOTE 4: ASSETS PLACED INTO SERVICE ASSOCIATED WITH MILL CREEK UNIT 5 SUBSEQUENT TO JULY 1, 2024 IN THE FOLLOWING ACCOUNTS WILL USE THE ANNUAL ACCRUAL RATE REFLECTED BELOW.
>
> | | |
> |---|---|
> | ACCOUNT 341.00 STRUCTURES AND IMPROVEMENTS | 2.93% |
> | ACCOUNT 342.00 FUEL HOLDERS, PRODUCERS AND ACCESSORIES | 3.10% |
> | ACCOUNT 343.00 PRIME MOVERS | 3.38% |
> | ACCOUNT 344.00 GENERATORS | 2.95% |
> | ACCOUNT 345.00 ACCESSORY ELECTRIC ELECTRIC EQUIPMENT | 2.93% |
> | ACCOUNT 346.00 MISCELLANEOUS POWER PLANT EQUIPMENT | 3.03% |

Q. Did Witness Spanos provide any workpapers with his testimony and exhibits or in response to Staff 1-54, which sought all schedules and workpapers relied on by the Companies in their filing, or in response to AG-KIUC discovery that sought all schedules and workpapers in live Excel format used to calculate the proposed depreciation rates for Mill Creek 5?

A. No. Witness Spanos failed to provide any workpapers in support of his testimony or in response to Staff 1-54 or in response to AG-KIUC discovery that provided any of the assumptions, parameters, or calculations of the proposed depreciation

rates for Mill Creek 5.[75]

Witness Spanos confirmed the Companies failed to provide the underlying calculations or support for the proposed depreciation rates for any future assets, including Mill Creek 5, in response to AG-KIUC discovery.[76] The explanation provided by Witness Spanos for the failure to provide this information for Mill Creek 5 is that "The Companies provided the information for existing assets." That was not an explanation, merely a statement of the information that had been provided, which was not the subject matter of the discovery.

In addition, the Companies were specifically asked the following:[77]

> Provide the source(s) and all support relied on for each assumption/parameter/input used to develop the requested depreciation rates for the [future] assets listed in the notes on these pages, including, but not limited to, estimated service lives and the range of estimated service lives considered, estimated interim retirements, estimated interim net salvage, and estimated terminal net salvage. Also provide all correspondence with KU/LG&E subject matter experts and/or decision makers and all directives from the Companies for these depreciation study assumptions/parameters/inputs."

Witness Spanos responded as follows:

> The requested sources were either professional judgment based on experience performing numerous depreciation studies or consistent with existing assets and/or locations presented in the depreciation studies for KU and/or LGE. There was no additional correspondence.

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[75] Responses to AG-KIUC 1-102, AG-KIUC 2-30, and AG-KIUC 2-33. I have attached a copy of the responses to AG-KIUC 2-30 and AG-KIUC 2-33 as Exhibit LK-17.

[76] Responses to AG-KIUC 2-33. Refer to Exhibit LK-18.

[77] *Id.*

Again, this response failed to provide the specific information necessary to fully review and assess the Companies' requested depreciation rates for Mill Creek 5.

Finally, the Companies were asked once again to provide the information previously requested for the future assets, including Mill Creek 5. The Companies responded: "See attachments being provided in separate files. The files provide the development of the proposed future rates."[78] Although the attachments provide the assumptions and parameters used by Witness Spanos for the proposed Mill Creek 5 depreciation rates, they do not provide the calculations or the basis for the assumptions and parameters, except for the weighted net negative salvage, which Witness Spanos asserts was sourced from the weighted net negative salvage proposed for Cane Run 7. The depreciation rates in the attached Excel file are values; there are no formulas.

There now is no additional opportunity to follow up on the calculations underlying the proposed Mill Creek 5 depreciation rates. Nevertheless, the assumptions and parameters provided indicate that Witness Spanos used a 40-year life span for each of the plant accounts, included *estimated* terminal net salvage, and included *estimated* interim retirements and *estimated* interim net salvage.

In addition, the amounts in each plant account used to calculate the depreciation rates themselves were based on "estimates," although the Companies provided no basis for the "estimates." Yet the plant costs included in each plant

[78] Responses to AG-KIUC 2-33. Refer to Exhibit LK-17.

account have a significant effect on the proposed depreciation rate for each plant account.

Q. Why is this information important for the Commission to review?

A. It is important because it will assist the Commission in its determination of the depreciation rates and the depreciation expense recoverable for Mill Creek 5 when it is completed and enters commercial operation in 2027.

It also is important because it likely will determine the depreciation rates and the depreciation expense for Brown 12 and Mill Creek 6 if those two generating units receive CPCNs in Case 2025-00045 and are completed and enter commercial operation.

The total cost of the three future generating units, including AFUDC, likely will exceed $4 billion. Depreciation expense at a composite depreciation rate of 2.22% for all plant accounts will be $88 million annually, at a composite depreciation rate of 3.0% will be $120 million annually, and at a composite depreciation rate of 4.0% over the relevant plant accounts will be $160 million annually.

Finally, it is important because the depreciation rates will reflect the Commission's decisions on the service life for the three generating units, whether the Companies are allowed to recover *estimated* terminal net negative salvage over their service lives and whether the Companies are allowed to recover *estimated* interim retirements and *estimated* interim net negative salvage in addition to actual interim retirements and actual interim net negative salvage over their service lives.

Q. Do the Companies proposed depreciation rates for Mill Creek 5 include

estimated terminal net salvage, _estimated_ interim retirements, and _estimated_ interim net negative salvage?

A. Yes. The Companies proposed depreciation rates include *estimated* terminal net salvage, *estimated* interim retirements, and *estimated* interim net negative salvage.[79]

Q. How do the Companies' proposed depreciation rates for Mill Creek 5 compare to the present and proposed depreciation rates for Cane Run 7?

A. The present rates and proposed depreciation rates for Cane Run 7 vary significantly between KU and LG&E. The proposed depreciation rates for Mill Creek 5 are the same between KU and LG&E, but are higher than LG&E's proposed depreciation rates for Cane Run 7, except for account 543, which is lower. The following table compares the Companies' proposed depreciation rates for Mill Creek 5 to each Company's present and proposed rates for Cane Run 7.

Comparison of Companies' Proposed Mill Creek 5 and Cane Run 7 Present and Proposed Depreciation Rates

Account	KU Proposed MC 5	KU Present CR 7	KU Proposed CR 7	LG&E Proposed MC 5	LG&E Present CR 7	LG&E Proposed CR 7
341.0	2.93%	2.94%	2.95%	2.93%	2.40%	2.30%
342.0	3.10%	1.53%	1.54%	3.10%	1.20%	1.46%
343.0	3.38%	3.49%	3.76%	3.38%	3.76%	3.93%
433.0	2.95%	2.80%	2.92%	2.95%	2.30%	2.82%
345.0	2.93%	2.87%	2.93%	2.93%	2.30%	2.82%
346.0	3.03%	3.12%	3.18%	3.03%	2.94%	3.05%

[79] Responses to AG-KIUC 2-33(d). Refer to Exhibit LK-17.

Q. Are the proposed depreciation rates for Mill Creek 5 reasonable?

A. No. First, the proposed depreciation rates for Mill Creek 5 by plant account are unreasonable because they are based on estimated plant account balances. These balances will not be known and measurable until the CWIP costs are closed to plant in service and then classified to plant account.

Second, the proposed depreciation rates for Mill Creek 5 using a 40-year life span are unreasonable because the life span is unnecessarily and unduly short, then reduced even further to reflect estimated interim retirements. The Commission should use a longer life span in order to minimize the revenue requirement for each of the future generating units by assuming a longer rather than a shorter life span for this purpose. The life span for depreciation purposes is a matter of judgment for the Commission. The Companies and Witness Spanos have a history of starting with unduly short life spans when generating units enter commercial operation, which they are subsequently forced to lengthen in future years as the generating unit remain economic compared to new replacement generating units.

Third, as previously noted with respect to the operating generating units, KRS 278.264 prohibits the recovery of terminal net salvage until after the Commission approves the retirement of the thermal generating units, which will be decades into the future. In addition, terminal net salvage is inherently not known and measurable today. The costs have not been incurred. When the costs are incurred, they will be known and measurable and will be recoverable at that time. Further, recovery of future *estimated* terminal net salvage results in permanent harm to customers due to the asset ADIT resulting from the inability to deduct

terminal net salvage for income tax purposes until the cost actually is incurred after the generating unit is retired. The asset ADIT is added to rate base and continuously grows throughout the service life of the generating unit until it is fully reversed when the costs actually are incurred.

Fourth, the estimated interim retirements and interim net negative salvage also are unreasonable because there is no history of interim retirements for Mill Creek 5 and there are unlikely to be any *actual* material interim retirements in the early years Mill Creek 5, Brown 12, and Mill Creek 6 are in commercial operation. The estimated interim retirements reduce the Companies proposed 40-year life span to average remaining service lives of 38.38 years for plant account 341, 36.11 years for account 342, 33.13 years for account 343, 37.96 years for account 344, 38.28 years for account 345, and 36.92 years for account 346.[80]

There is no need to estimate future interim retirements and the related interim net negative salvage because the *actual* interim retirements and related interim net salvage always will be reflected as reductions to the accumulated depreciation and always updated and recovered in the periodic depreciation studies and the resulting rates.

In addition, like with the *estimated* terminal net salvage, there are asset ADIT amounts that are added to rate base due to the book tax temporary differences. This unnecessary permanent harm to customers can be avoided simply by using only *actual* interim retirements and *actual* interim net salvage rather than

[80] Response to AG-KIUC 2-33(c). Refer to Exhibit LK-17.

also including *estimated* interim retirements and *estimated* interim net salvage before those costs actually are incurred. Further, the Company's *estimated* interim retirements and estimated interim net salvage are based on *estimated* plant account balances that are not known and measurable, thus compounding the guesstimates embedded into the Companies' methodology.

Finally, the Commission has complete discretion to determine the reasonableness of the assumptions and parameters used to set the depreciation rates. There is no question the Companies will recover their prudent and reasonable costs. Depreciation is a timing issue. The Companies earn a return on rate base, which includes gross plant in service less accumulated depreciation. The recoveries from customers, actual interim retirements, and actual interim net salvage and terminal net salvage are tracked through accumulated depreciation.

Q. What is your recommendation?

A. I recommend a composite depreciation rate of 2.22% for *all* Mill Creek 5 plant accounts. I calculated this depreciation rate as 1 divided by a 45-year life span. This single depreciation rate reflects the fact the costs of Mill Creek 5 by plant account simply are not known at this time. It also excludes *estimated* terminal net salvage, *estimated* interim retirements, and *estimated* interim net negative salvage. The Mill Creek 5 depreciation rate will be adjusted in future depreciation studies to reflect the *actual* plant amounts in each plant account, *actual* interim retirements, and *actual* interim net negative salvage. Again, there is no harm to the Company from excluding *estimated* interim retirements and estimated interim net negative salvage. The Companies always will recover the *actual* amounts to date in each subsequent

depreciation study.

I recommend the 45-year service life because this life span is within the range of estimated and actual service lives for combined cycle and simple cycle combustion turbine generating units. The sheer magnitude of the capital investments in the Mill Creek 5, Brown 12, and Mill Creek 6 generating units demands they be operated for as long as is economically feasible. This should be reflected in the life spans used for the depreciation rates instead of an assumption they will operate only 40 years. I note that although the Companies now propose 40-year service lives for the Cane Run 7 combined cycle, the Mill Creek 5 combined cycle, and all the simple cycle combustion turbines, the Companies actually have operated their gas-fired generating units over longer lives. For example, the Paddy's Run 11 and 12 generating units had 55-year life spans in the Companies' depreciation studies in Cases 2020-00349 and 2020-00350. Similarly, the Companies, and Witness Spanos, historically have proposed shorter life spans initially for new coal-fired generation, then repeatedly revised and extended the life spans over their actual operating lives because they remain economic.

KRS 278.264 proscribes recovery of terminal net salvage unless the utility has filed with the Commission for authorization to retire the thermal generating unit. Obviously, KU and LG&E will not do so until after Mill Creek 5 is no longer economic compared to other generation supply alternatives many decades into the future, likely more than 45 years into the future.

It is unnecessary to include interim retirements and interim net salvage at this time. In every depreciation study after Mill Creek 5 is operational, the

depreciation rates and depreciation expense will reflect *actual* interim retirements and *actual* interim net salvage to date. There is no need to prematurely recover future *estimated* interim retirements and interim net salvage when the actual costs will be recovered and there certainly is no valid argument to impose the cost of an asset ADIT that will grow over the service life of the future generating asset until the decommissioning costs ultimately are incurred after the unit retires. The use of estimated interim retirements and estimated interim net negative salvage results in a permanent harm to customers that can and should be avoided and that can be avoided with no harm whatsoever to the Companies.

Finally, as I already noted, there is no actual plant account information nor is it necessary to develop separate depreciation rates for each Mill Creek 5 plant account at this time. Mill Creek 5 is presently under construction and all construction costs are recorded in account 107 *Construction Work in Progress*. There is no plant in service and, thus, there is no plant account level of detail, necessary to develop separate deprecation rates for each plant account. Nor is any plant account detail necessary if there are no estimated interim retirements, estimated interim net negative salvage, and no estimated terminal net salvage.

Q. Are there any effects from your recommendations for the Mill Creek 5 depreciation rates in these proceedings?

A. No. The depreciation rates for Mill Creek 5, Brown 12, and Mill Creek 6 do not affect the revenue requirements in these proceedings, but will affect the depreciation expense and revenue requirements in future base revenue proceedings and in the proposed Mill Creek 6 rider proceedings.

IV. COST OF CAPITAL ISSUES

A. Effects Of Witness Baudino's Recommendation For Lower Cost Of Long-Term Debt

Q. Have you quantified the effects of Witness Baudino's recommended reduction in the long-term debt rate to reflect a lower coupon rate for the Companies' actual August 2025 new debt issuances?

A. Yes. The effects are a reduction in the KU base revenue requirement of $4.443 million, a reduction in the LG&E electric base revenue requirement of $3.441million, and a reduction in the LG&E gas base revenue requirement of $1.250 million. These reductions reflect the *return on* rate base, not capitalization, and were calculated after all adjustments to rate base recommended by the AG and KIUC.

B. Effects of Witness Baudino's Recommendation For Lower Return On Equity

Q. Have you quantified the effects of Witness Baudino's recommended return on equity of 9.60% compared to the 10.95% return on equity requested by the Companies?

A. Yes. The effects are a reduction in the KU revenue requirement of $54.298 million, a reduction in the LG&E electric revenue requirement of $33.461 million, and a reduction in the LG&E gas revenue requirement of $12.153 million. These reductions reflect the *return on* rate base, not capitalization, and were calculated after all adjustments to rate base recommended by the AG and KIUC.

Q. Have you quantified the effects of a 0.10% change in the return on common equity for each Company?

A. Yes. For KU, each 0.1% return on equity equals $4.022 million in revenue requirements. For LG&E electric, each 0.1% return on equity equals $2.479 million in revenue requirements. For LG&E gas, each 0.1% return on equity equals $0.900 million (gas) in revenue requirements. These reductions reflect the *return on* rate base, not capitalization, and were calculated after all adjustments to rate base recommended by the AG and KIUC.

V. SHARING OF OFF-SYSTEM SALES MARGINS

Q. Describe the origin and operation of the Off-System Sales Adjustment Clause.

A. The OSS margins are reflected in the OSS adjustment clause with a sharing of 75% to customers and 25% to the Companies pursuant to the Commission Orders in Case Nos. 2014-00371 and 2014-00372.[81] Prior to the Commission Orders in those cases, the OSS margins were reflected in the base revenue requirement with a sharing of 100% to customers and 0% to the Companies.

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

A. KU forecasts total OSS margins of $3.487 million in the test year. LG&E forecasts total OSS margins of $5.492 million in the test year.[82]

Q. Do the Companies need an incentive to engage in OSS and maximize OSS margins?

A. No. Such sales and the maximization of the margins are simply another element of the prudent, reasonable, and efficient operation of their systems and the

[81] The OSS adjustment clause provides a credit against other fuel and economy purchased power expenses recoverable through the Companies' FAC riders.

[82] Responses to AG-KIUC 1-73. I have attached a copy of these responses as my Exhibit LK-18.

minimization of fuel and purchased power expenses, 100% of which is recoverable through the FAC, with the limited exceptions for certain adjustments related to forced outages and purchase power capacity costs, which are included in the base revenue requirement.

Q. Do you recommend a change to the sharing of off-system sales margins through the OSS adjustment clause?

A. Yes. I recommend an increase in the allocation to customers to 100% from the present 75%. Customers are allocated 100% of the fixed costs, variable non-fuel expenses, and fuel expenses incurred to generate the energy that is sold off-system to generate the OSS margins. It logically follows that customers should be allocated 100% of the OSS margins. The present allocations to customers of 75% were the result of settlements in prior base rate proceedings and are not justified or reasonable when considered on a standalone basis outside the compromises reflected in those settlements.

As regulated utilities, the Companies have an obligation to operate their systems efficiently and minimize fuel expense in exchange for guaranteed recovery of all prudent and reasonable fuel expenses through the FCA and base revenue requirements.

In addition, there is no evidence that the present allocation to the Companies has incentivized them to make off-system sales that it otherwise could not or would not have made in the normal course of business.

Further, in KPC's most recent rate case the Commission eliminated OSS margin sharing and required that all OSS margins be allocated to ratepayers.

Finally, the Companies are constructing new generation capacity that likely will provide additional energy for off-system sales and increased OSS margins, at least temporarily. These new resources will be recovered from customers in base revenues and through the proposed new Adjustment Clause MC6 *Mill Creek 6 Cost Recovery* at 100%, not at 75%. It is reasonable to match the percentages of OSS margin sharing to customers with the percentages of cost allocation to customers for all generating resources, both existing and future.

VI. RECOVERY OF RPPA COSTS

Q. Briefly describe the Companies' request for a new Renewable Purchase Power Agreement (RPPA) rider to recover the costs of renewable purchased power agreement expense.

A. The Companies propose a new RPPA rider to recover the costs of renewable purchased power agreement expense because the expenses do not qualify for recovery through the FAC as economy purchased power expense. Company witness Andrea Fackler states:[83]

> To date, the Companies have entered into six total solar power purchase agreements. Although, as Mr. Schram testifies, three of the PPAs have been terminated and the other three appear unlikely to proceed on their original terms (if at all), the Companies are proposing a separate adjustment clause to recover the cost of such PPAs and other future renewable energy PPAs later approved by the Commission. The Commission declined to address cost recovery for such PPAs as premature in the Companies' 2022 CPCN proceeding in which the Commission approved four of the six total PPAs.

[83] Direct Testimony of Andrea Fackler at 36-39.

Witness Fackler also describes the mechanics of the proposed RPPA. Among other things, she recommends that the purchased power expense incurred be recovered on a per kWh basis from all customers.

Q. Is it necessary for the Commission to adopt an RPPA in this proceeding?

A. No. The request remains premature, as the Commission found previously in Case 2022-00402. Witness Fackler acknowledges there are no pending RPPAs that require an RPPA at this time. The Companies can seek an RPPA at a later date if there is a need to do so.

Q. Is the Companies' proposal to recover the purchased power expense incurred on a per kWh basis reasonable?

A. No. The costs of solar facilities are all fixed costs. There is no fuel expense. It matters not that the costs are charged or may be charged to the Companies on a per kWh basis. The recovery should reflect the underlying character of the costs, especially for all cost per kWh that exceed the Companies' average FAC rates.

Q. What is your recommendation?

A. I recommend the Commission deny the Companies' request for an RPPA as premature. If an RPPA is adopted, then I recommend the costs be recovered on an allocation basis that reflects the underlying nature of the costs incurred.

VII. STIPULATION AND RECOMMENDATION IN CPCN CASE 2025-00045, INCLUDING PROPOSED NEW EHLF, ADJUSTMENT CLAUSE MC2, AND ADJUSTMENT CLAUSE MC6 TARIFFS

Q. Provide a brief description of the Stipulation and Recommendation entered into by the Companies, the AG, KIUC, and other parties in Case 2025-00045.

A. The Stipulation and Recommendation in Case 2025-00045 represents the settlement of the Companies' requests for CPCNs for Brown 12, Mill Creek 6, and Cane Run BESS and recommendations to the Commission signed by the Companies, the AG, KIUC, and other parties.[84]

The Companies and other signatory parties recommend the Commission approve CPCNs for Brown 12 and Mill Creek 6. The Companies agree to withdraw their request for CPCN for Cane Run BESS. The Companies agree to take necessary actions to delay the retirement of Mill Creek 2 and to continue operating that generating unit at least until 2031 when Mill Creek 6 is scheduled for completion and commercial operation.

The Companies and other signatory parties attached to and referenced in the Stipulation and Recommendation a proposed new Adjustment Clause MC2 *Mill Creek 2 Incremental Stay-Open Cost Recovery* rider to allow LG&E to recover the incremental capital costs and operating expenses incurred after Commission final approval in Case 2025-00045 necessary to continue operating Mill Creek 2 at least through 2031. The proposed Adjustment Clause MC2 provides the formula for incremental cost recovery, including the same Group 1/Group 2 revenue allocation methodology previously adopted by the Commission for the Companies' ECR and Retired Asset Recovery riders (RARs).[85]

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[84] I have attached a copy of the Stipulation and Recommendation in Case 2025-00045 as Exhibit LK-19.

[85] I have attached a copy of the Adjustment Clause Rider MC2 and Exhibit LK-20.

The Companies and other signatory parties attached to and referenced in the Stipulation and Recommendation a proposed new Adjustment Clause MC6 *Mill Creek 6 Cost Recovery* to allow both KU and LG&E to recover all Mill Creek 6 capital costs and operating expenses over the service life of the generating unit. The proposed Adjustment Clause MC6 provide the formula for cost recovery, including the same Group 1/Group 2 revenue allocation methodology previously adopted by the Commission for the Companies' ECR and RAR riders.[86]

Q. Were there any changes to the Companies' proposed EHLF tariff in this proceeding in the Stipulation and Recommendation in the CPCN Case 2025-00045?

A. Yes. The Stipulation and Recommendation in the CPCN Case 2025-00045 modifies the applicability of the proposed new EHLF tariff to new loads. This is necessary to ensure that if an existing load grows and meets the qualifications of the EHLF tariff that it is not required to sign service agreements for 15 years, assume liabilities for minimum contract payments, or provide collateral necessary to ensure performance of the new loads.

Q. Do you agree with the terms of the Stipulation and Settlement in Case 2025-00045, including the modifications to the proposed new EHLF tariff as filed in this proceeding, and recommend the Commission approve the new Adjustment Clause MC2 and Adjustment Clause MC6 riders either in Case 2025-00045 and/or in these rate case proceedings?

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[86] I have attached a copy of the Adjustment Clause Rider MC6 and Exhibit LK-21.

A. Yes. The three tariffs are critical to the Stipulation and Settlement in Case 2025-00045 and ensure a reasonable outcome in that case. The three tariffs are interrelated. The new EHLF tariff provides the Companies with a standardized form of ratemaking recovery for the costs to serve new significant loads with extremely high load factor while ensuring there are necessary safeguards to protect existing customers. The new MC2 tariff is necessary to recover the incremental costs for MC2 to continue operations at least through 2031. The MC6 tariff is necessary provide reasonable recovery of the capital and operating costs for MC6 starting on its in-service date and continuing over its service life, offset initially by the incremental revenues from the proposed new EHLF tariff until those revenues are reflected in the next base rate proceeding after the in-service date of MC6. The MC6 tariff ensures that incremental revenues from the new loads are used to offset the costs of MC6. The MC6 tariff also ensures that customers benefit from the declining cost curve as the rate base is reduced by accumulated depreciation and ADIT.

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
9th day of September 2025.

Notary Public

Jessica K Inman
NOTARY PUBLIC
Cherokee County, GEORGIA
My Commission Expires 07/31/2027

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES, AND APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS	**)**	**CASE NO. 2025-00113**

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, AND APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS	**)**	**CASE NO. 2025-00114**

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE
OFFICE OF THE ATTORNEY GENERAL OF THE COMMONWEALTH OF KENTUCKY AND KENTUCKY INDUSTRIAL UTILITY CUSTOMERS

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

SEPTEMBER 9, 2025

EXHIBIT LK-1

RESUME OF LANE KOLLEN, 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)

Chartered Global Management Accountant (CGMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

Society of Depreciation Professionals

Mr. Kollen has more than forty 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, 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.

RESUME OF LANE KOLLEN, PRESIDENT

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
City of Austin
Georgia Public Service Commission Staff
Florida Office of Public Counsel
Indiana Office of Utility Consumer Counsel
Kentucky Office of Attorney General
Louisiana Public Service Commission
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York City
New York State Energy Office
South Carolina Office of Regulatory Staff
Texas Office of Public Utility Counsel
Utah Office of Consumer Services

RESUME OF LANE KOLLEN, PRESIDENT

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 August 2025

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 Surrebuttal	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 August 2025

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.
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.

Expert Testimony Appearances
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As of August 2025

Date	Case	Jurisdict.	Party	Utility	Subject
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 PUCT	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 PUCT	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX PUCT	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.
5/91	9945	TX PUCT	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.

Expert Testimony Appearances
of
Lane Kollen
As of August 2025

Date	Case	Jurisdict.	Party	Utility	Subject
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 PUCT	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.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.

Expert Testimony Appearances
of
Lane Kollen
As of August 2025

Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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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	U-21485 (Supplemental 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.
12/95	U-21485 (Surrebuttal)				
12/95	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 PUCT	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co., and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.

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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.
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.

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

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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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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 PUCT	The Dallas-Fort Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.
01/00	U-24182 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
04/00	99-1212-EL-ETP 99-1213-EL-ATA 99-1214-EL-AAM	OH	Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.

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Date	Case	Jurisdict.	Party	Utility	Subject
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 PUCT	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 PUCT	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.
10/00	R-00974104 Affidavit	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009	PA	Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.
12/00	U-21453, U-20925, U-22092 (Subdocket C) Surrebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
01/01	U-21453, U-20925, U-22092 (Subdocket B) Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.

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Date	Case	Jurisdict.	Party	Utility	Subject
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	GPU, Inc. FirstEnergy Corp.	Merger, savings, reliability.
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on overall plan structure.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
05/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
07/01	U-21453, U-20925, U-22092 (Subdocket B) Transmission and Distribution Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.
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 PUCT	The Dallas-Fort Worth Hospital Council and the Coalition of Independent Colleges and Universities	TXU Electric	Stipulation. Regulatory assets, securitization financing.

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Date	Case	Jurisdict.	Party	Utility	Subject
02/02	U-25687 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
03/02	14311-U Rebuttal Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards.
03/02	14311-U Rebuttal Panel with Michelle L. Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Revenue requirements. Nuclear life extension, storm damage accruals and reserve, capital structure, O&M expense.
04/02	U-25687 (Suppl. Surrebuttal)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
04/02	U-21453, U-20925 U-22092 (Subdocket C)	LA	Louisiana Public Service Commission	SWEPCO	Business separation plan, T&D Term Sheet, separations methodologies, hold harmless conditions.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
08/02	U-25888	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. and Entergy Louisiana, Inc.	System Agreement, production cost disparities, prudence.
09/02	2002-00224 2002-00225	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Line losses and fuel clause recovery associated with off-system sales.
11/02	2002-00146 2002-00147	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Environmental compliance costs and surcharge recovery.
01/03	2002-00169	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Power Co.	Environmental compliance costs and surcharge recovery.
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.

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06/03	2003-00068	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Environmental cost recovery, correction of base rate error.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Unit power purchases and sale cost-based tariff pursuant to System Agreement.
11/03	ER03-583-000, ER03-583-001, ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, ER03-682-002 ER03-744-000, ER03-744-001 (Consolidated)	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Marketing, L.P, and Entergy Power, Inc.	Unit power purchases and sale agreements, contractual provisions, projected costs, levelized rates, and formula rates.
12/03	U-26527 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
12/03	2003-0334 2003-0335	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Earnings Sharing Mechanism.
12/03	U-27136	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Purchased power contracts between affiliates, terms and conditions.
03/04	U-26527 Supplemental Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
03/04	2003-00433	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	SOAH Docket 473-04-2459 PUC Docket 29206	TX PUCT	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 PUCT	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.

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Date	Case	Jurisdict.	Party	Utility	Subject
08/04	SOAH Docket 473-04-4555 PUC Docket 29526 (Suppl Direct)	TX PUCT	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 PUCT	Houston Council for Health and Education	CenterPoint Energy Houston Electric, LLC	Stranded cost true-up including regulatory Central Co. assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
02/05	18638-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements.
02/05	18638-U Panel with Tony Wackerly	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Comprehensive rate plan, pipeline replacement program surcharge, performance based rate plan.
02/05	18638-U Panel with Michelle Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Energy conservation, economic development, and tariff issues.
03/05	Case Nos. 2004-00426, 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, excess common equity ratio, deferral and amortization of nonrecurring O&M expense.
06/05	2005-00068	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, margins on allowances used for AEP system sales.
06/05	050045-EI	FL	South Florida Hospital and Heallthcare Assoc.	Florida Power & Light Co.	Storm damage expense and reserve, RTO costs, O&M expense projections, return on equity performance incentive, capital structure, selective second phase post-test year rate increase.
08/05	31056	TX PUCT	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.

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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 PUCT	Cities	Texas-New Mexico Power Co.	Stranded cost recovery through competition transition or change.
05/06	31994 Supplemental	TX PUCT	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.
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.

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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 PUCT	Cities	AEP Texas Central Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	PUC Docket 33310	TX PUCT	Cities	AEP Texas North Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Interim rate increase, RUS loan covenants, credit facility requirements, financial condition.
03/07	U-29157	LA	Louisiana Public Service Commission Staff	Cleco Power, LLC	Permanent (Phase II) storm damage cost recovery.
04/07	U-29764 Supplemental and Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
04/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and state income tax effects on equalization remedy receipts.
04/07	ER07-684-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Fuel hedging costs and compliance with FERC USOA.
05/07	ER07-682-000 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.

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10/07	25060-U Direct	GA	Georgia Public Service Commission Public Interest Adversary Staff	Georgia Power Company	Affiliate costs, incentive compensation, consolidated income taxes, §199 deduction.
11/07	06-0033-E-CN Direct	WV	West Virginia Energy Users Group	Appalachian Power Company	IGCC surcharge during construction period and post-in-service date.
11/07	ER07-682-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	ER07-682-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	07-551-EL-AIR Direct	OH	Ohio Energy Group, Inc.	Ohio Edison Company, Cleveland Electric Illuminating Company, Toledo Edison Company	Revenue requirements.
02/08	ER07-956-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.
03/08	ER07-956-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.
04/08	2007-00562, 2007-00563	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas and Electric Co.	Merger surcredit.
04/08	26837 Direct Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Suppl Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.

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06/08	2008-00115	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Environmental surcharge recoveries, including costs recovered in existing rates, TIER.
07/08	27163 Direct	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Revenue requirements, including projected test year rate base and expenses.
07/08	27163 Taylor, Kollen Panel	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Affiliate transactions and division cost allocations, capital structure, cost of debt.
08/08	6680-CE-170 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Nelson Dewey 3 or Colombia 3 fixed financial parameters.
08/08	6680-UR-116 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	CWIP in rate base, labor expenses, pension expense, financing, capital structure, decoupling.
08/08	6680-UR-116 Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Capital structure.
08/08	6690-UR-119 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, incentive compensation, Crane Creek Wind Farm incremental revenue requirement, capital structure.
09/08	6690-UR-119 Surrebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, Section 199 deduction.
09/08	08-935-EL-SSO, 08-918-EL-SSO	OH	Ohio Energy Group, Inc.	First Energy	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	08-917-EL-SSO	OH	Ohio Energy Group, Inc.	AEP	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	2007-00564, 2007-00565, 2008-00251 2008-00252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Company	Revenue forecast, affiliate costs, 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 PUCT	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.

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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	U-21453, U-20925 U-22092 (Sub J) Direct	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	Rebuttal				
04/09	2009-00040 Direct-Interim (Oral)	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Emergency interim rate increase; cash requirements.
04/09	PUC Docket 36530	TX PUCT	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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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03/10	E015/GR-09-1151	MN	Large Power Interveners	Minnesota Power	Revenue requirement issues, cost overruns on environmental retrofit project.
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.
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 PUCT	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.

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10/10	U-23327 Subdocket F Direct	LA	Louisiana Public Service Commission Staff	SWEPCO	AFUDC adjustments in Formula Rate Plan.
11/10	EL10-55 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation rates and expense input effects on System Agreement tariffs.
12/10	ER10-1350 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
01/11	ER10-1350 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
03/11 04/11	ER10-2001 Direct Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Arkansas, Inc.	EAI depreciation rates.
04/11	U-23327 Subdocket E	LA	Louisiana Public Service Commission Staff	SWEPCO	Settlement, incl resolution of S02 allowance expense, var O&M expense, sharing of OSS margins.
04/11 05/11	38306 Direct Suppl Direct	TX PUCT	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.

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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 PUCT	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Investment tax credit, excess deferred income taxes; normalization.
09/11	2011-00161 2011-00162	KY	Kentucky Industrial Utility Consumers, Inc.	Louisville Gas & Electric Company, Kentucky Utilities Company	Environmental requirements and financing.
10/11	11-4571-EL-UNC 11-4572-EL-UNC	OH	Ohio Energy Group	Columbus Southern Power Company, Ohio Power Company	Significantly excessive earnings.
10/11	4220-UR-117 Direct	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.
11/11	4220-UR-117 Surrebuttal	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.
11/11	PUC Docket 39722	TX PUCT	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 PUCT	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 Rebuttal 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.

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06/12	40020	TX PUCT	Cities Served by Oncor	Lone Star Transmission, LLC	Revenue requirements, including ADIT, bonus depreciation and NOL, working capital, self insurance, depreciation rates, federal income tax expense.
07/12	120015-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Revenue requirements, including vegetation management, nuclear outage expense, cash working capital, CWIP in rate base.
07/12	2012-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental retrofits, including environmental surcharge recovery.
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Company	Section 1603 grants, new solar facility, payroll expenses, cost of debt.
10/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Revenue requirements, including off-system sales, outage maintenance, storm damage, injuries and damages, depreciation rates and expense.
10/12	120015-EI Direct	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Settlement issues.
11/12	120015-EI Rebuttal	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Settlement issues.
10/12	40604	TX PUCT	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 PUCT	City of Austin d/b/a Austin Energy	City of Austin d/b/a Austin Energy	Rate case expenses.
12/12	40443	TX PUCT	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 PUCT	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.

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04/13	12-2400-EL-UNC	OH	The Ohio Energy Group	Duke Energy Ohio, Inc.	Capacity charges under state compensation mechanism, deferrals, rider to recover deferrals.
04/13	2012-00578	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Resource plan, including acquisition of interest in Mitchell plant.
05/13	2012-00535	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.
06/13	12-3254-EL-UNC	OH	The Ohio Energy Group, Inc., Office of the Ohio Consumers' Counsel	Ohio Power Company	Energy auctions under CBP, including reserve prices.
07/13	2013-00144	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Biomass renewable energy purchase agreement.
07/13	2013-00221	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Hawesville Smelter market access.
10/13	2013-00199	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.
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	Union Pacific 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	Union Pacific 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.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/14	ER13-1508	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy service agreements and tariffs for affiliate power purchases and sales; return on equity.
10/14	14-0702-E-42T 14-0701-E-D	WV	West Virginia Energy Users Group	First Energy-Monongahela Power, Potomac Edison	Consolidated tax savings; payroll; pension, OPEB, amortization; depreciation; environmental surcharge.
11/14	E-015/CN-12-1163 Surrebuttal	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class allocation.
11/14	05-376-EL-UNC	OH	Ohio Energy Group	Ohio Power Company	Refund of IGCC CWIP financing cost recoveries.
11/14	14AL-0660E	CO	Climax, CF&I Steel	Public Service Company of Colorado	Historic test year v. future test year; AFUDC v. current return; CACJA rider, transmission rider; equivalent availability rider; ADIT; depreciation; royalty income; amortization.
12/14	EL14-026	SD	Black Hills Industrial Intervenors	Black Hills Power Company	Revenue requirement issues, including depreciation expense and affiliate charges.
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.

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04/15	ER2014-0370	MO	Midwest Energy Consumers' Group	Kansas City Power & Light Company	Affiliate transactions, operation and maintenance expense, management audit.
05/15	PUE-2015-00022	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Fuel and purchased power hedge accounting; change in FAC Definitional Framework.
05/15 09/15	EL10-65 Direct, Rebuttal Complaint	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Accounting for AFUDC Debt, related ADIT.
07/15	EL10-65 Direct and Answering Consolidated Bandwidth Dockets	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback ADIT, Bandwidth Formula.
09/15	14-1693-EL-RDR	OH	Public Utilities Commission of Ohio	Ohio Energy Group	PPA rider for charges or credits for physical hedges against market.
12/15	45188	TX PUCT	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.

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05/16	2016-00026 2016-00027	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Need for environmental projects, calculation of environmental surcharge rider.
05/16	16-G-0058 16-G-0059	NY	New York City	Keyspan Gas East Corp., Brooklyn Union Gas Company	Depreciation, including excess reserves, leak prone pipe.
06/16	160088-EI	FL	South Florida Hospital and Healthcare Association	Florida Power and Light Company	Fuel Adjustment Clause Incentive Mechanism re: economy sales and purchases, asset optimization.
07/16	160021-EI	FL	South Florida Hospital and Healthcare Association	Florida Power and Light Company	Revenue requirements, including capital recovery, depreciation, ADIT.
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 PUCT	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 PUCT	Cities of Midland, McAllen, and Colorado City	Sharyland Utilities, LP, Sharyland Distribution & Transmission Services, LLC	Income taxes, depreciation, deferred costs, affiliate expenses.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
08/17	17-0296-E-PC	WV	West Virginia Energy Users Group	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 (Electric)	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 PUCT	Cities Served by Oncor	Oncor Electric Delivery Company	Tax Cuts and Jobs Act; amortization of excess ADIT.
08/18	48401	TX PUCT	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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
12/18	2018-00261	KY	Attorney General	Duke Energy Kentucky (Gas)	Revenues, O&M, regulatory assets, payroll, integrity management, incentive compensation, cash working capital.
01/19	2018-00294 2018-00295	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas & Electric Company	AFUDC v. CWIP in rate base, transmission and distribution plant additions, capitalization, revenues generation outage expense, depreciation rates and expenses, cost of debt.
01/19	2018-00281	KY	Attorney General	Atmos Energy Corp.	AFUDC v. CWIP in rate base, ALG v. ELG depreciation rates, cash working capital, PRP Rider, forecast plant additions, forecast expenses, cost of debt, corporate cost allocation.
02/19 04/19	UD-18-07 Direct Surrebuttal and Cross-Answering	New Orleans	Crescent City Power Users Group	Entergy New Orleans, LLC	Post-test year adjustments, storm reserve fund, NOL ADIT, FIN48 ADIT, cash working capital, depreciation, amortization, capital structure, formula rate plans, purchased power rider.
03/19	2018-00358	KY	Attorney General	Kentucky American Water Company	Capital expenditures, cash working capital, payroll expense, incentive compensation, chemicals expense, electricity expense, water losses, rate case expense, excess deferred income taxes.
03/19	48929	TX PUCT	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Company LLC, Sempra Energy, Sharyland Distribution & Transmission Services, L.L.C.., Sharyland Utilities, L.P.	Sale, transfer, merger transactions, hold harmless and other regulatory conditions.
06/19	49421	TX PUCT	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Prepaid pension asset, accrued OPEB liability, regulatory assets and liabilities, merger savings, storm damage expense, excess deferred income taxes.
07/19	49494	TX PUCT	Cities Served by AEP Texas	AEP Texas, Inc.	Plant in service, prepaid pension asset, O&M, ROW costs, incentive compensation, self-insurance expense, excess deferred income taxes.
08/19	19-G-0309 19-G-0310	NY	New York City	National Grid	Depreciation rates, net negative salvage.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/19	42315	GA	Atlanta Gas Light Company	Public Interest Advocacy Staff	Capital expenditures, O&M expense, prepaid pension asset, incentive compensation, merger savings, affiliate expenses, excess deferred income taxes.
10/19	45253	IN	Duke Energy Indiana	Office of Utility Consumer Counselor	Prepaid pension asset, inventories, regulatory assets and labilities, unbilled revenues, incentive compensation, income tax expense, affiliate charges, ADIT, riders.
12/19	2019-00271	KY	Attorney General	Duke Energy Kentucky	ADIT, EDIT, CWC, payroll expense, incentive compensation expense, depreciation rates, pilot programs
05/20	202000067-EI	FL	Office of Public Counsel	Tampa Electric Company	Storm Protection Plan.
06/20	20190038-EI	FL	Office of Public Counsel	Gulf Power Company	Hurricane Michael costs.
07/20 09/20	PUR-2020-00015 Direct Surrebuttal	VA	Old Dominion Committee for Fair Utility Rates	Appalachian Power Company	Coal Amortization Rider, storm damage, prepaid pension and OPEB assets, return on joint-use assets.
07/20 09/20	2019-226-E Direct Surrebbutal	SC	Office of Regulatory Staff	Dominion Energy South Carolina	Integrated Resource Plan.
10/20	2020-00160	KY	Attorney General	Water Service Corporation of Kentucky	Return on rate base v. operating ratio.
10/20	2020-00174	KY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Rate base v. capitalization, Rockport UPA, prepaid pension and OPEB, cash working capital, incentive compensation, Rockport 2 depreciation expense, EDIT, AMI, grid modernization rider.
11/20 12/20	2020-125-E Direct Surrebuttal	SC	Office of Regulatory Staff	Dominion Energy South Carolina	Summer 2 and 3 cancelled plant and transmission cost recovery; TCJA; regulatory assets.
12/20	2020172-EI	FL	Office of Public Counsel	Florida Power & Light Company	Hurricane Dorian costs.
12/20	29849 (Panel with Philip Hayet, Tom Newsome)	GA	Georgia Public Service Commission Staff	Georgia Power Company	VCM23, Vogtle 3 and 4 rate impact analyses.
02/21 04/21	2019-224-E 2019-225-E Direct Surrebuttal	SC	Office of Regulatory Staff	Duke Energy Carolinas, LLC, Duke Energy Progress, LLC	Integrated Resource Plans.
03/21	51611	TX PUCT	Steering Committee of Cities Served by Oncor	Sharyland Utilities, L.L.C.	ADIT, capital structure, return on equity.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/21	2020-00349 2020-00350	KY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company and Louisville Gas and Electric Company	Rate base v. capitalization, retired plant costs, depreciation, securitization, staffing + payroll, pension + OPEB, AMI, off-system sales margins.
04/21 Direct 07/21	18-857-EL-UNC 19-1338-EL-UNC 20-1034-EL-UNC 20-1476-EL-UNC Supplemental Direct	OH	The Ohio Energy Group	First Energy Ohio Companies	Significantly Excessive Earnings Test; legacy nuclear plant costs.
05/21 06/21	2021-00004 Direct Supplemental Direct	KY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	CPCN for CCR/ELG Projects at Mitchell Plant.
06/21	29849 (Panel with Philip Hayet, Tom Newsome)	GA	Georgia Public Service Commission Staff	Georgia Power Company	VCM24, Vogtle 3 and 4 rate impact analyses.
06/21	2021-00103	KY	Attorney General and Nucor Steel Gallatin	East Kentucky Power Cooperative, Inc.	Revenues, depreciation, interest, TIER, O&M, regulatory asset.
07/21 08/21 10/21	U-35441 Direct Cross-Answering Surrebuttal	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Company	Revenues, O&M expense, depreciation, retirement rider.
09/21	05-21-00007061	TX RRCT	Texas Cities Alliance	CenterPoint, CoServe, Corix, EPCOR, SiEnergy, TGS, UniGas	Securitization; regulatory asset; rates.
09/21	2021-00190	KY	Attorney General	Duke Energy Kentucky	Revenues, O&M expense, depreciation, capital structure, cost of long-term debt, government mandate rider.
09/21	43838	GA	Public Interest Advocacy Staff	Georgia Power Company	Vogtle 3 base rates, NCCR rates; deferrals.
09/21	2021-00214	KY	Attorney General	Atmos Energy Corp.	NOL ADIT, working capital, affiliate expenses, amortization EDIT, capital structure, cost of debt, accelerated replacement Aldyl-A pipe, PRP Rider, Tax Act Adjustment Rider.
12/21	29849 (Panel with Philip Hayet, Tom Newsome)	GA	Georgia Public Service Commission Staff	Georgia Power Company	VCM25, Vogtle 3 and 4 rate impact analyses.
01/22	2021-00358	KY	Attorney General	Jackson Purchase Energy Corporation	Revenues, nonrecurring expenses, normalized expenses, interest expense, TIER.

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Date	Case	Jurisdict.	Party	Utility	Subject
01/22	2021-00421	KY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Proposed Mitchell Plant Operations and Maintenance and Ownership Agreements; sale of Mitchell Plant interest.
02/22	2021-00481	KY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Proposed Liberty Utilities, Inc. acquisition of Kentucky Power Company; harm to customers; conditions to mitigate harm.
03/22	2021-00407	KY	Attorney General	South Kentucky Rural Electric Cooperative Corporation	Revenues, interest income, interest expense, TIER, payroll.
03/22 04/22	U-36190 Direct Cross-Answering	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC	Certification of solar resources.
05/22	20200241-EI 20210078-EI 20210079-EI	FL	Office of Public Counsel	Florida Power & Light Company, Gulf Power Company	Hurricanes Sally, Zeta, Isaias; Tropical Storm Eta, pre-planning, restoration and repair, costs, ratemaking recovery.
05/22	U-36268	LA	Louisiana Public Service Commission Staff	1803 Electric Cooperative, Inc.	Wholesale power contracts, wholesale rate tariffs, wholesale rates.
06/22	20220048-EI 20220049-EI 20220050-EI 20220051-EI	FL	Office of Public Counsel	Tampa Electric Company, Florida Public Utilities Company, Duke Energy Florida, LLC, Florida Power & Light Company	Storm Protection Plans. prudence, reasonableness, cost recovery, including deferred return on CWIP.
06/22	29849 (Panel with Philip Hayet, Tom Newsome)	GA	Georgia Public Service Commission Staff	Georgia Power Company	VCM26, Vogtle 3 and 4 rate impact analyses.
07/22	S-36267	LA	Louisiana Public Service Commission Staff	1803 Electric Cooperative, Inc.	Non-opposition to establish revolving LOC and supporting guarantees by member cooperatives.
08/22	53601	TX PUCT	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Company, LLC	Vendor financing, customer advances, cash working capital, ADFIT and temporary differences, depreciation expense, amortization expense.
09/22	20220010-EI	FL	Office of Public Counsel	Tampa Electric Company, Florida Public Utilities Company, Duke Energy Florida, LLC, Florida Power & Light Company	Storm Protection Plan, Cost Recovery Clause, prudence, reasonableness, deferred return on CWIP.
10/22	5-UR-110	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company	Levelized recovery of retired plan costs, securitization financing.
10/22	2022-00283	KY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Rockport deferrals and recoveries.

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Date	Case	Jurisdict.	Party	Utility	Subject
12/22	2022-00263	KY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Fuel adjustment clause methodology and disallowances.
01/23	29849 (Panel with Philip Hayet, Tom Newsome)	GA	Georgia Public Service Commission Staff	Georgia Power Company	VCM27, Vogtle 3 and 4 rate impact analyses.
1/23 02/23	2022-256-E Direct Surrebuttal	SC	Office of Regulatory Staff	Duke Energy Progress, LLC	Storm response process, costs, deferrals, deferred carrying costs.
03/23	2022-00372	KY	Attorney General	Duke Energy Kentucky, Inc.	Cash working capital, depreciation, decommissioning, regulatory asset amortization, retired generation asset recovery, modifications to existing tariffs, proposed new tariffs.
06/23	20230023-GU	FL	Office of Public Counsel	Peoples Gas System, Inc.	Restructuring, staffing, O&M expenses, storm expense, depreciation expense, amortization of theoretical depreciation surplus.
07/23	2022-00402	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company and Louisville Gas and Electric Company	CPCNs for combined cycle and owned solar resources, acquisition of PPA solar resources, retirement of coal resources.
07/23 08/23	2023-89-E Direct Surrebuttal	SC	Office of Regulatory Staff	Duke Energy Progress, LLC	Securitization financing, quantifiable net benefits, regulatory liability for return on ADIT, financing order and tariff language for calculation of storm recovery charges.
08/23	U-36685	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC	Certification of solar PPAs and related ratemaking.
09/23	6680-UR-124 Direct Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Power and Light Company	Ratemaking alternatives for recovery of retired plant costs, including securitization financing.
09/23	05-UR-110 (Reopener) Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company	Ratemaking alternatives for recovery of retired plant costs, including securitization financing.
10/23	29849	GA	Georgia Public Service Commission Staff	Georgia Power Company	Vogtle 3 and 4 prudence.
10/23	2023-00159	KY	Attorney General Kentucky Industrial Utility Customer, Inc.	Kentucky Power Company	NOL, COR, and other ADIT, incentive comp, regulatory assets, transmission and distribution cost riders, CAMT and other IRA, tax costs rider, securitization.

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Date	Case	Jurisdict.	Party	Utility	Subject
12/23 02/24	2021-00370 Direct Rebuttal	KY	Attorney General Kentucky Industrial Utility Customer, Inc.	Kentucky Power Company	Investigation into adequacy of service and reasonableness of rates.
02/24	2023-00008	KY	Attorney General, Kentucky Industrial Utility Customesr, Inc.	Kentucky Power Company	Fuel adjustment clause; fuel and purchased power expense; peaking unit equivalent methodology.
03/24	05-23-0015513	TX RRCT	Cities Served by CenterPoint Gas	CenterPoint Energy Resources Corp.	Capital structure, Tax Rider, NOL ADIT, CAMT ADIT, annualize revenues, incentive compensation, vendor financing, customer financing, working capital.
05/24	56165	TX PUCT	Cities Served by AEP Texas	AEP Texas, Inc.	Tax Rider, NOL ADIT, CAMT ADIT, annualize revenues, incentive compensation, vendor financing, customer financing, working capital.
05/24 06/24	U-37071 Direct Direct in Support of Settlement	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC	RFP for solar resources; certification of Mondu PPA.
06/24	2024-34-E	SC	Office of Regulatory Staff	Dominion Energy South Carolina, Inc.	Working capital, cash working capital.
06/24	20240026-EI	FL	Office of Public Counsel	Tampa Electric Company	O&M expense, A&G expense, incentive compensation, depreciation rates and expenses, dismantlement expense, tax credits, subsequent year adjustments, tax rider.
06/24	56211	TX PUCT	Gulf Coast Coalition of Cities	Centerpoint Energy Houston Electric, LLC	Tax Rider, CAMT ADIT, vendor financing, customer financing, working capital, prepaid pension, regulatory assets, annualize revenues, Texas margin tax.
08/24 09/24 09/24	5-UR-111 Direct Rebuttal Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company	Recovery of retired plant costs; securitization.
08/24 09/24 09/24	6690-UR-128 Direct Rebuttal Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Public Service Corporation	Recovery of retired plant costs; securitization.
11/24	2024-00243	KY	Attorney General, Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Bright Mountain Solar renewable energy purchase agreement.
12/24	2024-00285	KY	Attorney General	Duke Energy Kentucky, Inc.	Transition from PJM FRR entity to RPM entity; modifications to Rider Profit Sharing Mechanism.
01/25	2024-00276	KY	Attorney General	Atmos Energy Corporation	NOLC DTA, working capital, cash working capital, riders.

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02/25	05-24-00018879	TX (RRCT)	Cities Served by Atmos West Texas	Atmos Energy Corporation	NOLC DTA, other DTAs, DTLs, working capital, riders.
03/25	2024-00354	KY	Attorney General	Duke Energy Kentucky, Inc. (electric)	CAMT, working capital, CWC, unbilled revenues, depreciation, decommissioning, credit card fees, capacity performance insurance, new programs and riders.
05/25 06/25	2025-65-E Direct Surrebuttal	SC	Office of Regulatory Staff	Duke Energy Carolinas	Storm recovery costs, securitization, net benefits, regulatory assets and liabilities.
06/25	57568	TX	Freeport-McMoRan, Inc.	El Paso Electric Company	Revenue annualization, nuclear decommissioning, depreciation rates, long term debt interest payable.
06/25	2025-00045	KY	Attorney General, Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas and Electric Company	CPCN, AFUDC, post in-service deferrals, generation cost recover rider, extremely high factor tariff.
08/25	2025-00113 2025-00114	KY	Attorney General, Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas and Electric Company	Capitalization vs. rate base, CWIP in rate base, storm damage, vegetation management, pension, OPEB, depreciation, sharing OSS margins, extremely high load factor tariff, renewable purchased power agreement, tariff, Mill Creek 2 tariff, Mill Creek 6 tariff.

EXHIBIT LK-2

Kentucky Utilities Company
Case No. 2025-00113
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 12/31/26; Base Period 12ME 8/31/25)

Filing Requirement
Tab 13 - 807 KAR 5:001 Section 16(6)(f)
Sponsoring Witness: Andrea M. Fackler

Description of Filing Requirement:

The utility shall provide a reconciliation of the rate base and capital used to determine its revenue requirements.

Response:

See attached.

KENTUCKY UTILITIES COMPANY

Explanation of Differences between Capitalization and Rate Base

Line No.	Description	13 Month Average Total Company Balance	13 Month Average Kentucky Jurisdictional	13 Month Average Other Jurisdictional
1	Rate Base Percentage (Schedule J-1.1/J-1.2)		93.25%	6.75%
2	Capitalization	$ 8,047,708,246	$ 6,186,741,227	$ 542,933,998
2	Rate Base	7,967,281,242	6,094,469,285	537,623,314
3	**Difference**	$ 80,427,004	$ 92,271,942	$ 5,310,683
4	**Items not included in Rate Base:**			
5	ARO Liabilities	$ (50,581,380)	$ (47,167,137)	$ (3,414,243)
6	ARO Assets		21,397,234	
7	Net Balance Sheet Working Capital	24,317,854	22,676,399	1,641,455
8	Net Regulatory Assets/Liabilities	110,663,665	103,193,867	7,469,797
9	Accumulated Deferred IncomeTaxes	5,090,661	4,747,041	343,620
10	Leases	(485,424)	(452,658)	(32,766)
11	Miscellaneous Deferred Debit	35,192,990	32,817,463	2,375,527
12	Other Property and Investments	287,881		
13	ADIT Proration		(455,171)	(32,948)
14	AMI		992,436	71,839
15	CPCN New Generation		(5,511,579)	(398,962)
16	IT Software Cost Regulatory Asset		1,588,939	115,017
17	EEI Deferred taxes		(301,479)	(21,823)
18	**Items included in rate base:**			
19	Cash Working Capital (Income Statement)	(44,059,243)	(39,263,195)	(4,796,048)
20	Capitalization / Rate Base Allocation Differences	-	(1,990,219)	1,990,219
21	**Total Reconciling Items**	$ 80,427,004	$ 92,271,942	$ 5,310,683

Louisville Gas and Electric Company
Case No. 2025-00114
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 12/31/26; Base Period 12ME 8/31/25)

Filing Requirement
Tab 13 - 807 KAR 5:001 Section 16(6)(f)
Sponsoring Witness: Andrea M. Fackler

Description of Filing Requirement:

The utility shall provide a reconciliation of the rate base and capital used to determine its revenue requirements.

Response:

See attached.

LOUISVILLE GAS AND ELECTRIC COMPANY

Explanation of Differences between Capitalization and Rate Base

Line No.	Description	13 Month Average Total Company Balance	13 Month Average Electric	13 Month Average Gas
1	Rate Base Percentage (Schedule J-1.1/J-1.2)		76.70%	23.30%
2	Capitalization	$ 6,485,683,280	$ 3,732,176,127	$ 1,412,276,202
2	Rate Base	6,437,793,096	3,739,345,032	1,367,652,244
3	**Difference**	$ 47,890,184	$ (7,168,905)	$ 44,623,959
4	**Items not included in Rate Base:**			
5	Net Balance Sheet Working Capital	$ 40,346,657	$ 30,945,886	$ 9,400,771
6	Net Regulatory Assets/Liabilities	133,539,347	102,424,679	31,114,668
7	Accumulated Deferred IncomeTaxes	619,363	475,052	144,312
8	ADIT Proration adjustment		(731,712)	123,313
9	Leases	229,049	175,680	53,368
10	ARO Assets		17,516,343	33,600,471
11	ARO Liabilities	(78,673,329)	(60,342,443)	(18,330,886)
12	Other Property and Investments	868,149	-	-
13	Investment tax credits	(28,159,351)		
14	Retired Asset Recovery Rider		(84,277,508)	
15	IT Software Cost Regulatory Asset		1,479,183	514,874
16	AMI		324,994	266,368
17	CPCN New Gen		(5,483,148)	
18	Bullit County Pipeline Reclass			(1,059,512)
19	Other/Rounding	1		1
20	**Items included in rate base:**			
21	Cash Working Capital (Income Statement)	(20,879,701)	(19,149,630)	(1,730,071)
22	Capitalization / Rate Base Allocation Differences	-	9,473,718	(9,473,718)
23	**Total Reconciling Items**	$ 47,890,184	$ (7,168,905)	$ 44,623,959

EXHIBIT LK-3

KENTUCKY UTILITIES COMPANY

Response to Attorney General and Kentucky Industrial Utility Customers' Initial Request for Information
Dated July 3, 2025

Case No. 2025-00113

Question No. 85

Responding Witness: Andrea M. Fackler / Christopher M. Garrett / Drew T. McCombs

Q-85. Refer to Schedule B-5.2, page 5 of 6, which provides the 13-month average amounts of Additional Sources and Uses of Cash Working Capital in Rate Base for each Company.

a. Provide a detailed schedule of all amounts included in the per books amount of Cash Working Capital in the accounts listed on this schedule by subaccount for each month in 2024, during the base year, for the months September through December 2025, and during the test year. Be sure to provide the subaccount description and amounts for each of the per books sub accounts.

b. Provide a description of the prepaid pension in account 128. Confirm that the amount in this account is simply the excess of the pension trust fund assets over the accumulated pension obligation.

c. Provide all support for the prepaid pension in account 128, including a copy of the actuarial report relied on for this purpose, if any, and the calculation of the test year amount utilizing an annotated version of the actuarial report to the extent relied on for this purpose.

d. Provide a description of the Regulatory Asset – FAS 158 Pension in account 182.

e. Provide all support for the Regulatory Asset – FAS 158 Pension, including a copy of the actuarial report relied on for this purpose, if any, in the calculation of the test year amount utilizing an annotated version of the actuarial report to the extent relied on for this purpose.

f. Provide a description of the accumulated provision for postretirement benefits in account 228.3. Confirm that the amount in this account is simply the excess of the accumulated OPEB obligation over the OPEB trust fund assets.

g. Provide all support for the accumulated provision for postretirement benefits in account 228.3, including a copy of the actuarial report relied on for this purpose, if any, in the calculation of the test year amount utilizing an annotated version of the actuarial report to the extent relied on for this purpose.

h. Provide a description of the Regulatory Liability – Post Retirement in account 254.

i. Provide all support for the Regulatory Liability – Post Retirement, including a copy of the actuarial report relied on for this purpose, if any, in the calculation of the test year amount utilizing an annotated version of the actuarial report to the extent relied on for this purpose.

j. Explain why there is no OPEB clearing account similar to that for pension clearing in account 184.

k. Confirm that it is the Companies' practice not to include regulatory assets in rate base, except for the requested Regulatory Asset – FAS 158 Pension shown on this schedule. If confirmed, then describe the basis for this practice. Cite to Commission orders to the extent relied on for this purpose.

l. Confirm that it is the Companies' practice not to include regulatory liabilities in rate base, except for the requested Regulatory Liability – Post Retirement shown on this schedule. If confirmed, then describe the basis for this practice. Cite to Commission orders to the extent relied on for this purpose.

A-85.

a. See attachment being provided in a separate file.

b. The prepaid pension in account 128 on Schedule B-5.2, page 5 of 6, is the thirteen-month average from December 2025-December 2026 of the forecasted prepaid pension. The balance represents an excess of pension trust fund assets allocated to KU over PBO. The forecast was derived by taking the actual balance of the account as of February 2025 and projecting it forward based upon forecasted pension service cost, interest cost, and estimated return on assets as well as forecasted pension contributions.

c. See page 1 of the attachment being provided in a separate file. Portions of the attachment that are nonresponsive to the request have been redacted.

d. The Regulatory Asset – FAS 158 Pension in account 182 on Schedule B-5.2, page 5 of 6, is the thirteen-month average from December 2025-December 2026 of the forecasted pension regulatory asset. The balance

represents accumulated unamortized prior service costs and net actuarial losses of the plan. The forecast was derived by taking the actual balance of the account as of February 2025 and projecting it forward based upon forecasted amortization of prior service cost and gains and losses as well as quarterly adjustments for regulatory assets allocated from LG&E and KU Services Company (LKS) to KU for KU's portion of the difference in the double corridor and 15-year amortization for LKS.

e. See page 2 of the attachment being provided in a separate file. Portions of the attachment that are nonresponsive to the request have been redacted.

f. The accumulated provision for postretirement benefits in account 228.3 on Schedule B-5.2, page 5 of 6, is the thirteen-month average from December 2025-December 2026 of the forecasted postretirement and post-employment liabilities. The postretirement liability balance represents an excess of projected postretirement obligation over the trust fund assets allocated to KU. The forecast for postretirement was derived by taking the actual balance of the account as of February 2025 and projecting it forward based upon forecasted service cost, interest cost, and estimated return on assets as well as forecasted contributions. The Company does not project changes to the post-employment liability for the forecast. Therefore, the postemployment liability balance in the account as of February 2025 is held constant throughout the forecast period.

g. See page 3 of the attachment being provided in a separate file. Portions of the attachment that are nonresponsive to the request have been redacted.

h. The Regulatory Liability - Postretirement in account 254 on Schedule B-5.2, page 5 of 6, is the thirteen-month average from December 2025-December 2026 of the forecasted postretirement regulatory liability. The balance represents accumulated unamortized prior service costs and net actuarial gains of the plan. The forecast was derived by taking the actual balance of the account as of February 2025 and projecting it forward based upon forecasted amortization of prior service cost and gains and losses.

i. See page 4 of the attachment being provided in a separate file. Portions of the attachment that are nonresponsive to the request have been redacted.

j. The balance shown in account 184 Pension Clearing is the actual balance of the account for burdens for pension, postretirement, and post-employment as of February 2025 and is held constant throughout the forecast period. The forecasted pension expense is reflected as changes in the Prepaid Pension account 182 for service cost, interest cost, and estimated return on assets and in the Regulatory Asset – FAS 158 Pension account for amortizations of prior service cost and actuarial gains and losses. The forecasted postretirement expense is reflected as changes in the

accumulated provision for postretirement benefits account 228.3 for service cost, interest cost, and estimated return on asset and in Regulatory Liability – Postretirement account 254 for amortizations of prior service cost. The Company does not project post-employment expenses in the forecast.

k. Confirmed. This approach is consistent with previous filings.[3] The Companies believe the exclusion of other regulatory assets and liabilities from rate base is supportive of its position to utilize capitalization as its valuation methodology since the Companies' regulatory assets and liabilities are directly related to utility operations. Accordingly, the associated cash outflows or inflows should result in both investors (regulatory assets) and customers (regulatory liabilities) being fairly compensated for the use of those funds.

As it relates to the inclusion of the Regulatory Asset – FAS 158 balance in rate base, the Companies incorporated all balance sheet items associated with pension accounts to reflect the net cash position (funding vs expense). This approach ensures the balance sheet and income statement are appropriately aligned for ratemaking purposes consistent with the settlement agreement reached in Case Nos. 2014-00371 and 2014-00372 whereby the Parties agreed the Commission should approve regulatory-asset treatment for the difference between the Companies' pension expense booked according to its accounting policy on record with the Securities and Exchange Commission and in accordance with Generally Accepted Accounting Principles ("GAAP") and pension expense with actuarial gains and losses amortized over 15 years. Additionally, the Virginia State Corporation Commission approved the inclusion of this regulatory asset in rate base in KU's previous four Virginia base rate cases[4].

l. Confirmed. This approach is consistent with previous filings.[5] The Companies believe the exclusion of other regulatory assets and liabilities from rate base is supportive of its position to utilize capitalization as its valuation methodology since the Companies' regulatory assets and liabilities are directly related to utility operations. Accordingly, the associated cash outflows or inflows should result in both investors (regulatory assets) and customers (regulatory liabilities) being fairly compensated for the use of those funds.

As it relates to the inclusion of the Regulatory Liability – Post Retirement balance in rate base, the Companies incorporated all balance sheet items

[3] Case No. 2018-00295, Order (Ky. PSC Apr. 30, 2019); Case No. 2020-00350, Order (Ky. PSC Jun. 30, 2021).
[4] Case Nos. PUR 2017-00106, PUR 2019-00060, PUR 2021-00171, and PUR-2024-00052.
[5] Case No. 2018-00295, Order (Ky. PSC Apr. 30, 2019); Case No. 2020-00350, Order (Ky. PSC Jun. 30, 2021).

associated with postretirement accounts to reflect the net cash position (funding vs expense).

LG&E does not have a Regulatory Liability – Post Retirement balance; therefore, nothing was included on Schedule B-5.2.

Kentucky Utilities
Monthly detail for account balances found on Sch B-5.2 ($)

	Jan - 2024	Feb - 2024	Mar - 2024	Apr - 2024	May - 2024	Jun - 2024	Jul - 2024	Aug - 2024	Sep - 2024	Oct - 2024	Nov - 2024	Dec - 2024
128.11 - Other special funds - inv other IT asset	50,837,957	50,837,957	50,837,957	50,837,957	50,837,957	51,194,260	51,194,260	51,194,260	51,194,260	51,194,260	51,194,260	46,168,956
128.6 - Other special funds - non-current	22,385,363	20,394,477	21,733,627	21,330,639	21,410,719	20,188,940	19,911,685	19,518,409	19,546,832	17,935,116	17,380,837	15,535,399
182.12 - Other Reg Assets NC Pens	96,091,380	96,091,380	95,754,005	95,754,005	95,754,005	95,689,145	95,352,327	95,002,723	95,495,126	95,145,522	94,795,918	113,479,424
182.33 - Reg Asset - Pension Gain-Loss Amort-15 Year	39,897,098	39,897,098	37,836,095	37,836,095	37,836,095	37,245,881	37,245,881	37,245,881	36,310,820	36,310,820	36,310,820	35,284,981
183.1 - Other Prelim Sur Chg LT	10,142,164	10,142,394	10,138,997	10,142,589	10,251,042	10,146,793	10,146,793	9,993,279	10,064,439	10,144,621	10,179,514	10,336,875
183.2 - Other Prelim Sur Chg Cur	14,806	14,806	-	21,020	21,020	-	21,020	21,020	-	21,020	21,020	(12,785)
184.20 - Clearing Accts (Accr Pens)	-	-	3,202,020	-	-	6,504,990	7,589,154	8,673,320	9,757,485	10,841,650	11,925,815	-
184.8 - Pension Burden Clearing Liab	558,229	1,095,031	-	3,747,070	4,269,626	(0)	(0)	(0)	-	-	-	-
186.2 - Misc deferred debits	85,403	1,314,797	1,229,987	1,219,405	1,226,700	1,159,909	1,161,177	1,112,711	3,218,548	10,789,613	11,229,057	13,840,494
186.6 - Misc Def Debits LTPC	19,549,327	19,995,053	10,435,829	2,558,387	2,907,064	3,511,057	4,185,175	4,882,043	5,484,539	6,063,488	6,671,576	7,035,059
188.1 - Misc Def Debits (Resrch/Dev/Demo Exp)	137,450	0	45,567	-	-	-	-	161	-	-	-	-
228.4 - Accum Prov Inj & Dam (Accr Sal & Ben)	449,709	449,709	437,004	437,004	437,004	420,093	420,093	420,093	434,050	434,050	434,050	459,562
228.5 - Accum Prov Inj & Dam (O/LT Liab)	2,209,310	2,209,310	1,456,727	1,456,727	1,456,727	1,402,153	1,402,153	1,402,153	1,507,914	1,507,914	1,507,914	1,965,025
228.20 - Accum Prov (O/LT Liab)	4,657,284	4,657,284	4,666,467	4,665,127	4,665,127	4,712,806	4,712,806	4,712,806	4,712,806	4,712,806	4,712,806	4,142,906
228.6 - Accum Prov (O/LT Liab FAS 106)	8,228,839	8,198,492	8,322,569	8,250,695	8,221,000	9,579,405	9,393,757	9,363,957	9,382,616	9,091,174	9,061,537	8,410,205
242.0 - Misc current liab	10,638,023	11,428,338	13,350,409	11,006,464	11,776,840	13,121,111	10,578,429	12,003,991	13,626,502	11,229,351	12,978,146	14,273,682
242.1 - Misc Cur & Accr Liab (Accts Payable)	13,542	17,539	10,255	10,693	13,742	10,031	11,727	10,148	19,730	14,798	12,099	15,253
242.2 - Misc Cur & Accr Liab (Accr Sal & Ben)	2,396,052	2,396,052	648,655	648,655	648,655	1,307,379	1,307,379	1,307,379	1,971,836	1,971,836	1,971,836	2,155,068
242.7 - Vested Vacation Unfunded Reserve	5,359,205	5,359,205	6,169,524	6,169,524	6,169,524	6,205,720	6,205,720	6,205,720	6,058,376	6,058,376	6,058,376	5,796,950
242.9 - Medical Expense Unfunded Reserve	1,416,658	1,416,658	1,774,954	1,416,658	1,416,658	1,915,075	1,416,658	1,416,658	1,979,429	1,416,658	1,416,658	1,168,026
253.1 - Other deferred credits - non-current	26,530	26,530	26,533	410	413	416	419	216,722	284,605	338,127	431,380	607,283
253.11 - Other deferred credits - current	822,874	2,431,283	2,100,839	-	28,315	-	40,462	381,164	309	-	442	-
253.2 - Other Def Cr LT Tax Pos	707,702	707,702	732,123	732,123	732,123	757,666	757,666	757,666	783,803	784,022	784,022	803,781
254.11 - Other Reg Liab LT Postretirement	37,206,778	37,206,778	37,143,713	37,143,713	37,143,713	36,527,262	36,486,221	36,445,179	36,404,138	36,363,097	36,322,055	37,404,928

Kentucky Utilities
Monthly detail for account balances found on Sch B-5.2 ($)

	Jan - 2025	Feb - 2025	Mar - 2025	Apr - 2025	May - 2025	Jun - 2025	Jul - 2025	Aug - 2025	Sep - 2025	Oct - 2025	Nov - 2025	Dec - 2025
128.11 - Other special funds - inv other IT asset	46,168,956	46,168,956	47,272,836	48,376,715	49,480,595	50,584,474	51,688,354	52,792,234	53,896,113	54,999,993	56,103,872	57,207,752
128.6 - Other special funds - non-current	14,814,065	14,824,375	13,376,582	12,166,774	10,331,278	7,749,503	6,381,525	6,148,568	5,587,719	5,336,333	5,137,150	2,690,858
182.12 - Other Reg Assets NC Pens	113,026,670	112,573,915	111,980,075	111,527,321	111,074,566	110,480,726	110,027,971	109,575,217	108,981,376	108,528,622	108,075,868	107,482,027
182.33 - Reg Asset - Pension Gain-Loss Amort-15 Year	35,284,981	35,284,981	35,105,840	35,105,840	35,105,840	34,926,698	34,926,698	34,926,698	34,747,557	34,747,557	34,747,557	34,568,415
183.1 - Other Prelim Sur Chg LT	35,487,170	35,949,140	10,090,574	10,090,574	10,090,574	10,090,574	10,090,574	10,090,574	10,090,574	10,090,574	10,090,574	10,090,574
183.2 - Other Prelim Sur Chg Cur	8,235	8,235	8,235	8,235	8,235	8,235	8,235	8,235	8,235	8,235	8,235	8,235
184.20 - Clearing Accts (Accr Pens)	1,103,880	2,207,761	2,207,761	2,207,761	2,207,761	2,207,761	2,207,761	2,207,761	2,207,761	2,207,761	2,207,761	2,207,761
184.8 - Pension Burden Clearing Liab	(0)	0	0	0	0	0	0	0	0	0	0	0
186.2 - Misc deferred debits	14,041,688	13,172,314	12,590,271	12,242,389	10,940,427	10,638,804	10,714,588	10,790,372	10,538,748	10,639,532	10,740,316	10,841,100
186.6 - Misc Def Debits LTPC	8,046,948	8,675,741	9,273,483	9,881,659	10,466,459	11,069,679	11,688,611	12,311,852	12,906,976	13,517,552	14,139,332	14,740,967
188.1 - Misc Def Debits (Resrch/Dev/Demo Exp)	-	-	-	-	-	-	-	-	-	-	-	-
228.4 - Accum Prov Inj & Dam (Accr Sal & Ben)	459,562	459,562	459,562	459,562	459,562	459,562	459,562	459,562	459,562	459,562	459,562	459,562
228.5 - Accum Prov Inj & Dam (O/LT Liab)	1,965,025	1,965,025	1,965,025	1,965,025	1,965,025	1,965,025	1,965,025	1,965,025	1,965,025	1,965,025	1,965,025	1,965,025
228.20 - Accum Prov (O/LT Liab)	4,142,906	4,142,906	4,142,906	4,142,906	4,142,906	4,142,906	4,142,906	4,142,906	4,142,906	4,142,906	4,142,906	4,142,906
228.6 - Accum Prov (O/LT Liab FAS 106)	8,388,114	8,358,687	8,376,966	8,378,170	8,396,449	8,414,729	8,415,932	8,434,212	8,452,492	8,453,695	8,471,975	8,490,255
242.0 - Misc current liab	10,799,968	11,896,972	11,861,956	11,826,941	11,791,925	11,756,909	11,721,893	11,686,877	11,651,862	11,616,846	11,581,830	11,546,814
242.1 - Misc Cur & Accr Liab (Accts Payable)	19,073	18,273	18,273	18,273	18,273	18,273	18,273	18,273	18,273	18,273	18,273	18,273
242.2 - Misc Cur & Accr Liab (Accr Sal & Ben)	1,393,333	642,288	(1,904,017)	(1,665,751)	(1,442,464)	(1,221,720)	(988,095)	(759,335)	(524,413)	(274,512)	(87,675)	116,552
242.7 - Vested Vacation Unfunded Reserve	5,796,950	5,796,950	5,796,950	5,796,950	5,796,950	5,796,950	5,796,950	5,796,950	5,796,950	5,796,950	5,796,950	5,796,950
242.9 - Medical Expense Unfunded Reserve	1,168,026	1,168,026	1,168,026	1,168,026	1,168,026	1,168,026	1,168,026	1,168,026	1,168,026	1,168,026	1,168,026	1,168,026
253.1 - Other deferred credits - non-current	676,749	736,213	736,213	736,213	736,213	736,213	736,213	736,213	736,213	736,213	736,213	736,213
253.11 - Other deferred credits - current	1,204	10,007	10,007	10,007	10,007	10,007	10,007	10,007	10,007	10,007	10,007	10,007
253.2 - Other Def Cr LT Tax Pos	803,781	803,781	803,781	803,781	803,781	803,781	803,781	803,781	803,781	803,781	803,781	803,781
254.11 - Other Reg Liab LT Postretirement	37,373,415	37,341,902	37,310,388	37,278,875	37,247,362	37,215,849	37,184,336	37,152,823	37,121,309	37,089,796	37,058,283	37,026,770

Kentucky Utilities
Monthly detail for account balances found on Sch B-5.2 ($)

	Jan - 2026	Feb - 2026	Mar - 2026	Apr - 2026	May - 2026	Jun - 2026	Jul - 2026	Aug - 2026	Sep - 2026	Oct - 2026	Nov - 2026	Dec - 2026
128.11 - Other special funds - inv other IT asset	58,038,590	58,869,429	59,700,268	60,531,106	61,361,945	62,192,783	63,023,622	63,854,461	64,685,299	65,516,138	66,346,976	67,177,815
128.6 - Other special funds - non-current	2,690,858	2,690,858	2,690,858	2,690,858	2,690,858	2,690,858	2,690,858	2,690,858	2,690,858	2,690,858	2,690,858	2,690,858
182.12 - Other Reg Assets NC Pens	106,968,631	106,455,234	105,525,097	105,011,700	104,498,304	103,568,167	103,054,770	102,541,373	101,611,236	101,097,840	100,584,443	99,654,306
182.33 - Reg Asset - Pension Gain-Loss Amort-15 Year	34,568,415	34,568,415	34,659,837	34,659,837	34,659,837	34,751,259	34,751,259	34,751,259	34,842,681	34,842,681	34,842,681	34,934,103
183.1 - Other Prelim Sur Chg LT	10,090,574	10,090,574	10,090,574	10,090,574	10,090,574	10,090,574	10,090,574	10,090,574	10,090,574	10,090,574	10,090,574	10,090,574
183.2 - Other Prelim Sur Chg Cur	8,235	8,235	8,235	8,235	8,235	8,235	8,235	8,235	8,235	8,235	8,235	8,235
184.20 - Clearing Accts (Accr Pens)	2,207,761	2,207,761	2,207,761	2,207,761	2,207,761	2,207,761	2,207,761	2,207,761	2,207,761	2,207,761	2,207,761	2,207,761
184.8 - Pension Burden Clearing Liab	0	0	0	0	0	0	0	0	0	0	0	0
186.2 - Misc deferred debits	10,944,202	11,047,304	11,099,174	10,267,619	10,370,721	10,473,822	10,576,924	10,680,026	10,783,128	10,886,230	10,989,332	11,092,434
186.6 - Misc Def Debits LTPC	15,654,558	16,235,246	16,832,150	9,388,699	10,019,968	10,627,189	11,263,919	11,899,878	12,507,706	13,130,423	13,751,816	14,364,494
188.1 - Misc Def Debits (Resrch/Dev/Demo Exp)	-	-	-	-	-	-	-	-	-	-	-	-
228.4 - Accum Prov Inj & Dam (Accr Sal & Ben)	459,562	459,562	459,562	459,562	459,562	459,562	459,562	459,562	459,562	459,562	459,562	459,562
228.5 - Accum Prov Inj & Dam (O/LT Liab)	1,965,025	1,965,025	1,965,025	1,965,025	1,965,025	1,965,025	1,965,025	1,965,025	1,965,025	1,965,025	1,965,025	1,965,025
228.20 - Accum Prov (O/LT Liab)	4,142,906	4,142,906	4,142,906	4,142,906	4,142,906	4,142,906	4,142,906	4,142,906	4,142,906	4,142,906	4,142,906	4,142,906
228.6 - Accum Prov (O/LT Liab FAS 106)	8,521,817	8,569,468	8,617,120	8,648,682	8,696,334	8,743,985	8,775,547	8,823,199	8,870,850	8,902,413	8,950,064	8,997,716
242.0 - Misc current liab	11,546,814	11,546,814	11,546,814	11,546,814	11,546,814	11,546,814	11,546,814	11,546,814	11,546,814	11,546,814	11,546,814	11,546,814
242.1 - Misc Cur & Accr Liab (Accts Payable)	18,273	18,273	18,273	18,273	18,273	18,273	18,273	18,273	18,273	18,273	18,273	18,273
242.2 - Misc Cur & Accr Liab (Accr Sal & Ben)	361,435	599,825	(1,855,689)	(1,601,609)	(1,377,567)	(1,128,742)	(880,031)	(636,135)	(371,201)	(118,770)	90,367	307,239
242.7 - Vested Vacation Unfunded Reserve	5,796,950	5,796,950	5,796,950	5,796,950	5,796,950	5,796,950	5,796,950	5,796,950	5,796,950	5,796,950	5,796,950	5,796,950
242.9 - Medical Expense Unfunded Reserve	1,168,026	1,168,026	1,168,026	1,168,026	1,168,026	1,168,026	1,168,026	1,168,026	1,168,026	1,168,026	1,168,026	1,168,026
253.1 - Other deferred credits - non-current	736,213	736,213	736,213	736,213	736,213	736,213	736,213	736,213	736,213	736,213	736,213	736,213
253.11 - Other deferred credits - current	10,007	10,007	10,007	10,007	10,007	10,007	10,007	10,007	10,007	10,007	10,007	10,007
253.2 - Other Def Cr LT Tax Pos	803,781	803,781	803,781	803,781	803,781	803,781	803,781	803,781	803,781	803,781	803,781	803,781
254.11 - Other Reg Liab LT Postretirement	36,999,160	36,971,551	36,943,941	36,916,332	36,888,722	36,861,113	36,833,503	36,805,894	36,778,284	36,750,675	36,723,065	36,695,456

Kentucky Utilities

	(a) Feb - 2025	Mar - 2025	Apr - 2025	May - 2025	Jun - 2025	Jul - 2025	Aug - 2025	Sep - 2025	Oct - 2025	Nov - 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	OCT 2026	NOV 2026	DEC 2026	**13 Month AVG DEC-26**
!8.6 - Other special funds - non-current (**Restricted Cash Drawdown**)											2,691	2,691	2,691	2,691	2,691	2,691	2,691	2,691	2,691	2,691	2,691	2,691	2,691	
128.1 - Other spec funds - investments	46,169	47,273	48,377	49,481	50,584	51,688	52,792	53,896	55,000	56,104	57,208	58,039	58,869	59,700	60,531	61,362	62,193	63,024	63,854	64,685	65,516	66,347	67,178	64,884
Change in forecasted balance from prior month		1,104	1,104	1,104	1,104	1,104	1,104	1,104	1,104	1,104	1,104	831	831	831	831	831	831	831	831	831	831	831	831	Schedule B-5.2

Components of change in balance from prior month:

Monthly Service Cost, Interest Cost & EROA		1,104	1,104	1,104	1,104	1,104	1,104	1,104	1,104	1,104	1,104	831	831	831	831	831	831	831	831	831	831	831	831	
Annual Estimated Contribution																								
		1,104	1,104	1,104	1,104	1,104	1,104	1,104	1,104	1,104	1,104	831	831	831	831	831	831	831	831	831	831	831	831	

Components of account balance Feb 2025:

Actuary Report	46,169	p.5 (a)
	46,169	p.5 (b)

Components of Monthly Service Cost, Interest Cost & EROA:	p.6 (a) 2025	p.6 (c) 2026
Service Cost	2,644	2,382
Interest Cost	13,214	12,732
Estimated Return on Assets	(29,105)	(25,084)
Annual Total	(13,247)	(9,970)
Monthly Total	(1,104)	(831)

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Kentucky Utilities

	(a) Feb - 2025	Mar - 2025	Apr - 2025	May - 2025	Jun - 2025	Jul - 2025	Aug - 2025	Sep - 2025	Oct - 2025	Nov - 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	OCT 2026	NOV 2026	DEC 2026	**13 Month AVG DEC-26**
Regulatory Assets																								
182 - Regulatory assets Pension & Postretirement	147,859	147,086	146,633	146,180	145,407	144,955	144,502	143,729	143,276	142,823	142,050	141,537	141,024	140,185	139,672	139,158	138,319	137,806	137,293	136,454	135,941	135,427	134,588	138,420
Change in forecasted balance from prior month		(773)	(453)	(453)	(773)	(453)	(453)	(773)	(453)	(453)	(773)	(513)	(513)	(839)	(513)	(513)	(839)	(513)	(513)	(839)	(513)	(513)	(839)	Schedule B-5.2
Components of change in balance from prior month:																								
Monthly Amortization of Prior Service Cost and Gains/Losses		(453)	(453)	(453)	(453)	(453)	(453)	(453)	(453)	(453)	(453)	(513)	(513)	(513)	(513)	(513)	(513)	(513)	(513)	(513)	(513)	(513)	(513)	
LKS to KU Regulatory Asset Adjustment (Qtrly)		(362)			(362)			(362)			(362)			(368)			(368)			(325)			(368)	
		(815)	(453)	(453)	(815)	(453)	(453)	(815)	(453)	(453)	(815)	(513)	(513)	(881)	(513)	(513)	(881)	(513)	(513)	(839)	(513)	(513)	(881)	

Components of account balance Feb 2025:

Actuary Report	148,764	p.5 (c)
YTD Amortization	(906)	p.5 (d)
	147,859	p.5 (e)

Components of Amortization:	p.6 (b) 2025	p.6 (d) 2026
Amortization of Prior Service Cost	66	66
Amortization of Gains and Losses	5,367	6,094
Annual Total	5,433	6,161
Monthly Total	453	513

LKS to KU Reg Adjustment Allocation (Annual)	p.9 (a)	1,448	p.9 (b)	1,471
LKS to KU Regulatory Asset Adjustment (Qtrly)		362		368

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Kentucky Utilities

	(a) Feb - 2025	Mar - 2025	Apr - 2025	May - 2025	Jun - 2025	Jul - 2025	Aug - 2025	Sep - 2025	Oct - 2025	Nov - 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	OCT 2026	NOV 2026	DEC 2026	**13 Month AVG DEC-26**
Accumulated Provision for Post Retirement Benefits	12,502	12,520	12,521	12,539	12,558	12,559	12,577	12,595	12,597	12,615	12,633	12,665	12,712	12,760	12,792	12,839	12,887	12,918	12,966	13,014	13,045	13,093	13,141	12,882
Change in forecasted balance from prior month		18	1	18	18	1	18	18	1	18	18	32	48	48	32	48	48	32	48	48	32	48	48	Schedule B-5.2
Components of change in balance from prior month:																								
Monthly Service Cost, Interest Cost & EROA		18	18	18	18	18	18	18	18	18	18	48	48	48	48	48	48	48	48	48	48	48	48	
Quarterly Estimated VEBA Contribution			(323)			(323)			(323)			(322)			(322)			(322)			(322)				
Quarterly Estimated Employee Contributions			306			306			306			306			306			306			306				
		18	1	18	18	1	18	18	1	18	18	32	48	48	32	48	48	32	48	48	32	48	48	

Components of account balance Feb 2025:

Actuary Report	(8,410)	p.5 (f)
VEBA Contribution	(165)	p.5 (g)
Payments	216	p.5 (h)
RDS payment	(4,143)	p.5 (i)
	(12,502)	p.5 (j)

Components of Monthly Service Cost, Interest Cost & EROA:

	p.7 (a)	2025	p.7 (c)	2026
Service Cost		630		646
Interest Cost		2,334		2,255
Estimated Return on Assets		(2,744)		(2,329)
Annual Total		219		572
Monthly Total		18		48

		2025		2026
Funding	p. 8 (a)	4,639	p. 8 (b)	4,442
Quarterly funding		1,160		1,110
Less: Employee Contributions	p.10 (a)	306	p.10 (b)	306
Net Benefit Payments		854		804
% of Benefit Payment Eligible for Reimbursement	p.11 (a)	0.98	p.11 (a)	0.98
401(h) Reimbursement Eligible Benefit Payments		837		788
Net VEBA Contribution		323		322

Kentucky Utilities

	(a) Feb - 2025	Mar - 2025	Apr - 2025	May - 2025	Jun - 2025	Jul - 2025	Aug - 2025	Sep - 2025	Oct - 2025	Nov - 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	OCT 2026	NOV 2026	DEC 2026	13 Month AVG DEC
254 - Reg Liabilities Postretirement	37,342	37,310	37,279	37,247	37,216	37,184	37,153	37,121	37,090	37,058	37,027	36,999	36,972	36,944	36,916	36,889	36,861	36,834	36,806	36,778	36,751	36,723	36,695	36,861
Change in forecasted balance from prior month		(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	Schedule B-5.2

Components of change in balance from prior month:

Monthly Amortization of Prior Service Cost and Gains/Losses		(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	
		(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	

Components of account balance Feb 2025:

Actuary Report	37,405	p.5 (k)
YTD Amortization	(63)	p.5 (l)
	37,342	p.5 (m)

Components of Amortization:	2025	2026
Amortization of Prior Service Cost	p.7 (b) 424	p.7 (d) 424
Amortization of Gains and Losses	(803)	(756)
Annual Total	(378)	(331)
Monthly Total	(32)	(28)

KENTUCKY UTILITIES COMPANY (0110)
ACCUMULATED PROVISION FOR PENSIONS AND POSTRETIREMENT

Prepared By: KEC 3/10/2025

Reviewed By: GRS 3/21/2025

Risk Level: Medium - Due 14th work day of the month following quarter end or last day of month following non-quarter end months.

Balances are tied out at year-end to Actuary's Disclosures

				01/01/25											2/28/2025	
	GAAP Balances			BEGINNING			Remeasurement	Remeasurement	Remeasurement		Payments				ENDING	
	Pensions			BALANCE	NPPC	Reclasses	OCI	Funded Status	Settlement	Contributions	Utilization	PPLS Transfers	Settlement		BALANCE	
128023	Prepaid Pension		p.12 (a)	(a) 46,168,956	-	-	-	-	-	-	-		-		(b) 46,168,956.00	
182313	Reg Asset - Pension Gain-Loss Amortization-15 Year		p.15 (a)	35,284,981	-	-	-	-	-	-	-		-		35,284,981.17	
182315	Regulatory Asset - Pension	148,764,406 (c)	p.13 (a)	113,479,424	(d) (905,509)	-	-	-	-	-	-		-		112,573,915.48	147,858,897 (e)
	Postretirement															
228301	FASB 106 Postretirement Benefit Liability	p.14 (a) (8,410,205) (f)		(9,068,305)	(0)	-	-	-	-	(g) (164,831.53)	(h) 216,349.99		-		(9,016,786.54)	
228307	FASB106 Medicare Subsidy			658,100	-	-	-	-	-	-	-		-		658,100.00	
254010	Regulatory Liability - OPEB		p.14 (b)	(k) (37,404,928)	(l) 63,026	-	-	-	-	-	-		-		(m) (37,341,901.55)	
	FAS 112															
228305	POST EMPLOYMENT BENEFIT PAYABLE	(4,142,906) (i)	p.16 (a)	(4,238,679)	-	-	-		-	-	-		-		(4,238,679.06)	
228325	FASB 112 - POST EMPLOY MEDICARE SUBSIDY		p.16 (b)	95,773	-	-	-		-	-	-		-		95,772.62	
															(j) (12,501,592.98)	

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LG&E & KU Energy LLC
Estimated Net Periodic Pension Cost ("NPPC") Reflecting 15-year (Gain)/Loss Amortization Method For LG&E and KU Pension Plan
2025 Fiscal Year

	Reg-15 LG&E		Reg-15 KU	
Service cost	2,675,583		(a)	2,644,472
Interest cost	16,536,924			13,213,991
Expected return on assets	(33,978,630)			(29,105,018)
Amortizations:				
Prior service cost	1,203,159		(b)	66,291
(Gain)/loss	10,052,320			5,366,761
ASC 715 NPBC	(3,510,644)			(7,813,503)

LG&E & KU Energy LLC
Estimated Net Periodic Pension Cost ("NPPC") Reflecting 15-year (Gain)/Loss Amortization Method For LG&E and KU Pension Plan
2026 Fiscal Year

	Reg-15 LG&E		Reg-15 KU	
Service cost	2,627,098		(c)	2,382,068
Interest cost	15,864,517			12,731,507
Expected return on assets	(28,988,663)			(25,083,638)
Amortizations:				
Prior service cost	872,007		(d)	66,291
(Gain)/loss	10,989,410			6,094,468
ASC 715 NPBC	1,364,369			(3,809,304)

Notes

1. Discount rate: 5.30% beginning on December 31, 2024 and throughout the forecast period (based on economic conditions as of August 21, 2024).
2. Expected return on assets assumption for calculating annual NPPC: 8.25% in 2025 and 7.25% throughout the rest of the forecast period.
3. Projected asset return assumption: The fair value of assets are based on actual return through August 21, 2024 (as provided by PPL), 8.25% per annum return for the remainder of 2024 and 2025, and 7.25% return in subsequent years. Additionally, estimated administrative expenses of $2.5 million in 2024 and all subsequent years are assumed to be paid from the trust and are allocated based on actual administrative expenses in 2023 ($1.0 million for LG&E, $0.7 million for KU and $0.8 million for Servco in 2024 and all subsequent years).
4. Population projection assumes the experience of the current population aligns with the accounting valuation assumptions.
5. Expected effect of collective bargaining as of December 31, 2026 is consistent with the actual impact of a three-year increase in the Flat Rate Multipliers reflected at December 31, 2023 and adjusted based on the expected population at the time of the future plan changes.
6. Actual contributions for 2024 and assumed contributions for 2025-2029 are detailed in the table at the end of this exhibit. Disclosure of significant risks related to the plan is required under ASOP No. 51. The analysis provided herein provides future pension contributions based on specific economic outcomes. It is beyond the scope of this analysis to analyze the potential range of future pension contributions due to different economic outcomes or demographic or legislative changes, but we can do so upon request. See Appendix C in our valuation report dated September 2023 for disclosures required under ASOP No. 51 of significant risks related to the plan.
7. These accounting projections are based on the 15-year amortization method valuation results provided on May 31, 2024. Except where noted above, the description of the data, assumptions, methods, models, plan provisions, and limitations as set forth in the accounting valuation results cover letter provided on May 31, 2024 should be considered part of these results. Please see the attached letter for a description of all other assumptions, methods, and models used in this analysis.

LG&E & KU Energy LLC
2025 Estimated ASC 715 Net Periodic Benefit Cost ("NPBC") For Postretirement Benefit Plan

	LG&E	KU	[redacted]
Service cost	840,390	(a) 629,834	
Interest cost	2,449,170	2,333,568	
Expected return on assets	-	(2,744,046)	
Amortizations:			
Prior service cost	538,003	(b) 424,373	
(Gain)/loss	(838,361)	(802,531)	
ASC 715 NPBC	2,989,202	(158,802)	

LG&E & KU Energy LLC
2026 Estimated ASC 715 Net Periodic Benefit Cost ("NPBC") For Postretirement Benefit Plan

	LG&E	KU	[redacted]
Service cost	877,723	(c) 645,556	
Interest cost	2,394,432	2,254,830	
Expected return on assets	-	(2,328,568)	
Amortizations:			
Prior service cost	538,003	(d) 424,373	
(Gain)/loss	(798,431)	(755,687)	
ASC 715 NPBC	3,011,727	240,504	

Notes

1. Discount rate: 5.30% beginning on December 31, 2024 and throughout the forecast period (based on economic conditions as of August 21, 2024).
2. Expected return on assets assumption for calculating annual NPBC: 8.25% for 2025 and 7.25% annually throughout the remainder of the forecast period (applied only to 401(h) amounts; Non-union and Union VEBA amounts are assumed to remain level over the projection period (i.e., contributions equal disbursements and a 0.00% expected return on assets)).
3. Projected asset return assumption: 401(h) amounts are based on actual return through August 21, 2024, 8.25% for the remainder of 2024 and 2025, then 7.25% in subsequent years. Contributions to the 401(h) account are assumed to be equal to the maximum deductible amount and are expected to be contributed at June 30th of the following fiscal year (projected to be $0 in all years). Benefit payments are assumed to be paid from the 401(h) account to the extent allowable. Non-union and Union VEBA amounts are assumed to remain level over the projection period (i.e., contributions equal disbursements and a 0.00% actual return on assets).
4. Population projection assumes the experience of the current population aligns with the accounting valuation assumptions.
5. It is assumed that no plan changes occur throughout the projection period.
6. These accounting projections are based on the January 1, 2024 valuation results provided on May 31, 2024. Except where noted above, the descriptions of the data, assumptions, methods, models, plan provisions, and limitations as set forth in the accounting valuation results cover letter provided on May 31, 2024 should be considered part of these results. Please see the attached letter for a description of all other assumptions, methods, and models used in this analysis.

LG&E & KU Energy LLC
Estimated Benefit Payments For Postretirement Benefit Plan

Fiscal Year	LG&E	KU	[redacted]
2024	4,520,427	4,715,318	
2025	4,409,735 (a)	4,639,007	
2026	4,231,657 (b)	4,441,609	
[redacted]			

Estimated Contributions to 401(h) Account

Fiscal Year	401(h) Account
2024	-
2025	-
2026	-
2027	-
2028	-
2029	-

Notes

1. Discount rate: 5.30% beginning on December 31, 2024 and throughout the forecast period (based on economic conditions as of August 21, 2024).
2. Expected return on assets assumption for calculating annual NPBC: 8.25% for 2025 and 7.25% annually throughout the remainder of the forecast period (applied only to 401(h) amounts; Non-union and Union VEBA amounts are assumed to remain level over the projection period (i.e., contributions equal disbursements and a 0.00% expected return on assets)).
3. Projected asset return assumption: 401(h) amounts are based on actual return through August 21, 2024, 8.25% for the remainder of 2024 and 2025, then 7.25% in subsequent years. Contributions to the 401(h) account are assumed to be equal to the maximum deductible amount and are expected to be contributed at June 30th of the following fiscal year (projected to be $0 in all years). Benefit payments are assumed to be paid from the 401(h) account to the extent allowable. Non-union and Union VEBA amounts are assumed to remain level over the projection period (i.e., contributions equal disbursements and a 0.00% actual return on assets).
4. Population projection assumes the experience of the current population aligns with the accounting valuation assumptions.
5. It is assumed that no plan changes occur throughout the projection period.
6. These accounting projections are based on the January 1, 2024 valuation results provided on May 31, 2024. Except where noted above, the descriptions of the data, assumptions, methods, models, plan provisions, and limitations as set forth in the accounting valuation results cover letter provided on May 31, 2024 should be considered part of these results. Please see the attached letter for a description of all other assumptions, methods, and models used in this analysis.

Pension Expense "Gross Up" for Jurisdictions/Entities not permitted 15 Year Amortization of Gain/Loss

Financial Planning

	2025			2026		
	LGE	KU	[redacted]	LGE	KU	[redacted]
Double Corridor	10,616,665	2,989,084		12,656,372	4,385,036	
15 Year Amort	10,052,320	5,366,761		10,989,410	6,094,468	
Difference	564,345	(2,377,677)		1,666,962	(1,709,432)	
DC Calulation for $ Allocated to PPLS:						
Difference						
Allocation Factor - Transferred Emp.						
PPLS DC Adjustment						
Adjusted Difference - KY Regulated						
Double Corridor Adjustments - KY Regulated						
Adjust for Labor to LKC:						
Labor % Allocated to LKC						
DC Adj - $ Allocated to LKC						
Regulatory Asset Adjustments[2]:						
	LGE	KU		LGE	KU	
Amortization Difference	564,345	(2,377,677)		1,666,962	(1,709,432)	
DC Adjustment	-	-		-	-	
Subtotal Before LKS Allocation	564,345	(2,377,677)		1,666,962	(1,709,432)	
LKS Allocation (Net of LKC %)	46.772%	52.859%		46.772%	52.859%	
LKS Reg Adjustment Allocation	(1,280,911)	(1,447,610)		(1,301,274)	(1,470,623)	
		(a)			(b)	

Forecasted Employee Contributions for VEBA Reimbursements

	Actual Contributions	
2014	4,201,000.82	
2015	4,211,730.10	0.26%
2016	4,397,073.33	4.40%
2017	4,743,831.99	7.89%
2018	4,842,285.39	2.08%
2019	4,492,825.04	-7.22%
2020	5,558,617.18	23.72%
2021	5,069,375.06	-8.80%
2022	3,025,903.31	-40.31%
2023	3,074,781.68	1.62%

		Average	
	Q3-2024 VEBA Allocations	**20.54%**	**39.80%**

	Projected Contributions	LG&E	KU
2022	3,025,903.31	621,520.54	1,204,309.52
2023	3,074,781.68	631,560.16	1,223,763.11
2024	3,074,781.68	631,560.16	1,223,763.11
2025	3,074,781.68	631,560.16	1,223,763.11
2026	3,074,781.68	631,560.16	1,223,763.11

For UI Input

2024	157,890.04		305,940.78
2025	157,890.04	(a)	305,940.78
2026	157,890.04	(b)	305,940.78

Note: 2022-2024 are trending around $3.1M/year of employee contributions so hold flat in budget.

LG&E and KU Energy LLC
Retiree Medical Continuation Plan
Allocation of Benefit Payments - 2024

	LG&E Non-Union		KU Non-Union		Non-Union Total	
Expected Benefit Payments - Total	1,430,533		3,906,524		8,099,459	
Expected Benefit Payments - 401(h)	1,429,293		3,905,285		7,926,577	
Actual Medco Payments			1,134,554			
Allocation - VEBA [non-Medco]	**20.5%**		**39.8%**		100.00%	
Allocation - 401(h) [non-Medco]	**21.0%**		**40.8%**		97.9%	

(a)

wtw

LG&E and KU Energy LLC Retirement Programs Qualified - Double Corridor Plan Name Disclosure for Fiscal Year Ending 31-Dec-24 under US GAAP	[redacted]	Regulatory LG&E USD	[redacted]	Regulatory KU USD	[redacted]
Disclosed Benefit Cost		31-Dec-24		31-Dec-24	
A Disclosed Benefit Cost					
1 Employer service cost		2,646,971		2,866,890	
2 Interest cost		17,753,703		14,007,370	
3 Expected return on plan assets		(35,404,345)		(29,884,240)	
4 Subtotal		(15,003,671)		(13,009,980)	
5 Net prior service cost/(credit) amortization		1,974,608		66,291	
6 Net loss/(gain) amortization		6,701,485		0	
7 Subtotal		8,676,093		66,291	
8 Net periodic benefit cost/(income)		(6,327,578)		(12,943,689)	
9 Curtailment (gain)/loss		0		0	
10 Settlement (gain)/loss		0		0	
11 Special/contractual termination benefits		0		0	
12 Disclosed net benefit cost		(6,327,578)		(12,943,689)	
B Presentation of Benefit Cost Pursuant to ASC 715-20					
1 Employer service cost		2,646,971		2,866,890	
2 Other components of net periodic benefit cost		(8,974,549)		(15,810,579)	
3 Other adjustments to net benefit cost		0		0	
4 Disclosed net benefit cost		(6,327,578)		(12,943,689)	
C Assumptions Used to Determine Benefit Cost					
1 Discount rate		5.53%		5.53%	
2 Expected long-term rate of return on plan assets		8.25%		8.25%	
3 Rate of compensation increase		3.25%		3.25%	
Balance Sheet Asset/(Liability)					
A Development of Balance Sheet Asset/(Liability)					
1 Projected benefit obligation (PBO)		(317,021,697)		(253,217,305)	
2 Fair value of plan assets, excluding receivable contributions		345,775,296		299,386,261	
3 Net balance sheet asset/(liability)		28,753,599		46,168,956	
				(a)	
B Current and Noncurrent Classification					
1 Noncurrent asset		28,753,599		46,168,956	
2 Current liability		0		0	
3 Noncurrent liability		0		0	
4 Net balance sheet asset/(liability)		28,753,599		46,168,956	
C Reconciliation of Net Balance Sheet Asset/(Liability)					
1 Net balance sheet asset/(liability) at end of prior fiscal year		33,561,846		50,837,957	
2 Employer service cost		(2,646,971)		(2,866,890)	
3 Interest cost		(17,753,703)		(14,007,370)	
4 Expected return on plan assets		35,404,345		29,884,240	
5 Plan amendments		0		0	
6 Actuarial gain/(loss)		(19,811,918)		(17,678,981)	
7 Employer contributions		0		0	
8 Benefits paid directly by the Company		0		0	
9 Transfer payments		0		0	
10 Acquisitions/divestitures		0		0	
11 Curtailments		0		0	
12 Settlements (if settled using corporate cash)		0		0	
13 Special/contractual termination benefits		0		0	
14 Net balance sheet asset /(liability) at end of current fiscal year		28,753,599		46,168,956	
D Assumptions and Dates Used for Disclosure					
1 Discount rate		5.92%		5.92%	
2 Rate of compensation increase		3.25%		3.25%	
5 Census date		1-Jan-24		1-Jan-24	

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LG&E and KU Energy LLC Retirement Programs Qualified - Double Corridor Plan Name Disclosure for Fiscal Year Ending 31-Dec-24 under US GAAP	Regulatory LG&E USD	Regulatory KU USD
Accumulated Other Comprehensive (Income)/Loss		
A Accumulated Other Comprehensive (Income)/Loss		
1 Net prior service cost/(credit)	4,637,395	367,451
2 Net loss/(gain)	176,046,131	113,159,172
3 Accumulated other comprehensive (income)/loss [Before adjustment for tax effects]	180,683,526	113,526,623
B Development of Accumulated Other Comprehensive (Income)/Loss (AOCI)		(a)
1 AOCI at prior fiscal year end	169,547,701	95,913,933
2 Amounts amortized during the year		
a. Net prior service (cost)/credit	(1,974,608)	(66,291)
b. Net (loss)/gain	(6,701,485)	0
3 Occurring during the year		
a. Net prior service cost/(credit)	0	0
b. Net loss/(gain)	19,811,918	17,678,981
4 Amounts recognized due to curtailment/settlement		
a. Net prior service (cost)/credit	0	0
b. Net (loss)/gain	0	0
5 AOCI at current fiscal year end	180,683,526	113,526,623
Additional Disclosure Information		
A Accumulated Benefit Obligation (ABO)		
1 ABO at current fiscal year end	(306,983,377)	(243,784,703)
B Expected Future Benefit Payments		
1 During fiscal year ending December 31, 2025	33,079,462	26,141,342
2 During fiscal year ending December 31, 2026	31,448,158	24,159,685
3 During fiscal year ending December 31, 2027	29,973,347	24,009,764
4 During fiscal year ending December 31, 2028	28,599,904	23,712,056
5 During fiscal year ending December 31, 2029	27,411,573	23,273,232
6 During fiscal years ending December 31, 2030 through December 31, 2034	128,287,145	102,116,293
C Actuarial Gain/(Loss)		
1 Gain/(loss) due to demographic experience	(195,103)	(1,089,394)
2 Gain/(loss) due to financial assumption changes	12,531,471	10,122,582
3 Gain/(loss) due to demographic assumption changes	(661,680)	(575,826)
4 Gain/(loss) due to investment return different from that assumed	(31,486,606)	(26,136,343)
5 Total	(19,811,918)	(17,678,981)
Changes in Disclosed Plan Obligations and Assets		
A Change in Projected Benefit Obligation (PBO)		
1 PBO at prior fiscal year end	342,815,917	267,777,173
2 Employer service cost	2,646,971	2,866,890
3 Interest cost	17,753,703	14,007,370
4 Actuarial loss/(gain)	(11,674,688)	(8,457,362)
5 Plan participants' contributions	0	0
6 Benefits paid from plan assets	(34,520,206)	(22,976,766)
7 Benefits paid from Company assets	0	0
8 Transfers from (to) other plans	0	0
9 Administrative expenses paid	0	0
10 Plan amendments	0	0
11 Acquisitions/(divestitures)	0	0
12 Curtailments	0	0
13 Settlements	0	0
14 Special/contractual termination benefits	0	0
15 PBO at current fiscal year end	317,021,697	253,217,305
B Change in Plan Assets		
1 Fair value of plan assets at prior fiscal year end	376,377,763	318,615,130
2 Actual return on plan assets	3,917,739	3,747,897
3 Employer contributions	0	0
4 Plan participants' contributions	0	0
5 Benefits paid	(34,520,206)	(22,976,766)
6 Transfer payments	0	0
7 Administrative expenses paid	0	0
8 Acquisitions/(divestitures)	0	0
9 Settlements	0	0
10 Fair value of plan assets at current fiscal year end	345,775,296	299,386,261

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LG&E and KU Energy LLC Retirement Programs PRW Plan Name Disclosure for Fiscal Year Ending 31-Dec-24 under US GAAP		LG&E USD		KU USD
Disclosed Benefit Cost		31-Dec-24		31-Dec-24
A Disclosed Benefit Cost				
1 Employer service cost		769,524		627,318
2 Interest cost		2,572,359		2,476,553
3 Expected return on plan assets		(184,814)		(2,819,344)
4 Subtotal		3,157,069		284,527
5 Net prior service cost/(credit) amortization		538,003		424,373
6 Net loss/(gain) amortization		(948,650)		(916,869)
7 Subtotal		(410,647)		(492,496)
8 Net periodic postretirement benefit cost/(income)		2,746,422		(207,969)
9 Curtailment (gain)/loss		0		0
10 Settlement (gain)/loss		0		0
11 Special/contractual termination benefits		0		0
12 Other adjustments		0		0
13 Disclosed net benefit cost		2,746,422		(207,969)
B Presentation of Benefit Cost Pursuant to ASC 715-20				
1 Employer service cost		769,524		627,318
2 Other components of net periodic benefit cost		1,976,898		(835,287)
3 Other adjustments to net benefit cost		0		0
4 Disclosed net benefit cost		2,746,422		(207,969)
C Assumptions Used to Determine Benefit Cost				
1 Discount rate		5.56%		5.56%
2 Expected long-term rate of return on plan assets		8.25%		8.25%
3 Current health care cost trend rate		6.25%		6.25%
4 Ultimate health care cost trend rate		5.00%		5.00%
5 Year of ultimate trend rate		2029		2029
Balance Sheet Asset/(Liability)				
A Development of Balance Sheet Asset/(Liability)				
1 Accumulated postretirement benefit obligation (APBO)		(46,993,544)		(42,523,384)
2 Fair value of plan assets, excluding receivable contributions		2,908,033		34,113,179
3 Net balance sheet asset/(liability)		(44,085,511)		(8,410,205)
B Current and Noncurrent Classification				(a)
1 Noncurrent asset		0		0
2 Current liability		(1,440,836)		0
3 Noncurrent liability		(42,644,675)		(8,410,205)
4 Net balance sheet asset/(liability)		(44,085,511)		(8,410,205)
C Reconciliation of Net Balance Sheet Asset/(Liability)				
1 Net balance sheet asset/(liability) at end of prior fiscal year		(43,896,514)		(9,009,451)
2 Employer service cost		(769,524)		(627,318)
3 Interest cost		(2,572,359)		(2,476,553)
4 Expected return on plan assets		184,814		2,819,344
5 Plan amendments		0		0
6 Actuarial gain/(loss)		2,735,277		690,646
7 Employer contributions		(196,146)		137,757
8 Benefits paid directly by the Company, net of retiree contributions		428,941		163,654
9 Medicare Part D subsidy on benefits paid during the year		0		(108,284)
10 Acquisitions/divestitures		0		0
11 Curtailments		0		0
12 Settlements (if settled using corporate cash)		0		0
13 Special/contractual termination benefits		0		0
14 Other adjustments		0		0
15 Net balance sheet asset /(liability) at end of current fiscal year		(44,085,511)		(8,410,205)
D Assumptions and Dates Used for Disclosure				
1 Discount rate		5.92%		5.92%
2 Current health care cost trend rate		7.00%		7.00%
3 Ultimate health care cost trend rate		5.00%		5.00%
4 Year of ultimate trend rate		2033		2033
5 Census date		1-Jan-24		1-Jan-24
Accumulated Other Comprehensive (Income)/Loss				
A Accumulated Other Comprehensive (Income)/Loss				
1 Net prior service cost/(credit)		3,312,832		2,348,854
2 Net loss/(gain)		(22,236,500)		(39,753,782)
3 Accumulated other comprehensive (income)/loss [Before adjustment for tax effects]		(18,923,668)		(37,404,928)
B Development of Accumulated Other Comprehensive (Income)/Loss (AOCI)				(b)
1 AOCI at prior fiscal year end		(16,599,038)		(37,206,778)
2 Amounts amortized during the year				
a. Net prior service (cost)/credit		(538,003)		(424,373)
b. Net (loss)/gain		948,650		916,869
3 Occurring during the year				
a. Net prior service cost/(credit)		0		0
b. Net loss/(gain)		(2,735,277)		(690,646)
4 Amounts recognized due to curtailment/settlement				
a. Net prior service (cost)/credit		0		0
b. Net (loss)/gain		0		0
5 Other adjustments		0		0
5 AOCI at current fiscal year end		(18,923,668)		(37,404,928)

Reg Asset/AOCI & PAA Allocation Reconciliation

[redacted]

	LG&E Reg. Asset-182313	KU Reg. Asset-182313
2015 LKS Reg Allocations	1,067,162	1,180,412
2015 LKS FIN Allocations		
2015 LGE New Reg. Asset/Allocations	4,752,518	662,358
2015 KU New Reg. Asset		2,994,962
2015 - Non-KPSC Amortization - LGE	(71,899)	
2015 - Non-KPSC Amortization - KU		(293,266)
2015 PAA Gross-up		
Allocation at 12/31/15	5,747,781	4,544,466
2016 LKS Reg Allocations	998,775	1,010,510
2016 LKS FIN Allocations		
2016 LGE New Reg. Asset/Allocations	4,212,477	675,889
2016 KU New Reg. Asset		2,900,438
2016 - Non-KPSC Amortization - LGE	(73,791)	
2016 - Non-KPSC Amortization - KU		(285,490)
2016 PAA Gross-up		
Allocation at 12/31/16	10,885,242	8,845,813
2017 LKS Reg Allocations	1,797,606	1,830,660
2017 LKS FIN Allocations		
2017 LGE New Reg. Asset/Allocations	6,006,352	874,279
2017 KU New Reg. Asset		3,132,976
2017 - Non-KPSC Amortization - LGE	(94,033)	
2017 - Non-KPSC Amortization - KU		(304,243)
2017 PAA Gross-up		
Allocation at 12/31/17	18,595,167	14,379,485
2018 LKS Reg Allocations	2,184,301	2,220,774
2018 LKS FIN Allocations		
2018 LGE New Reg. Asset/Allocations	4,444,541	675,626
2018 KU New Reg. Asset		2,992,406
2018 - Non-KPSC Amortization - LGE	(72,021)	
2018 - Non-KPSC Amortization - KU		(288,259)
2018 PAA Gross-up		
Allocation at 12/31/18	25,151,988	19,980,032
2019 LKS Reg Allocations	563,850	592,088
2019 LKS FIN Allocations		
2019 LGE New Reg. Asset/Allocations	3,576,929	623,028
2019 KU New Reg. Asset		902,875
2019 - Non-KPSC Amortization - LGE	(39,683)	
2019 - Non-KPSC Amortization - KU		(54,064)
2019 PAA Gross-up		
Allocation at 12/31/19	29,253,084	22,043,959
2020 LKS Reg Allocations	1,975,396	1,970,036
2020 LKS FIN Allocations		
2020 LGE New Reg. Asset/Allocations	4,170,695	745,980
2020 - Non-KPSC Amortization - LGE	(46,882)	
2020 KU New Reg. Asset		3,072,974
2020 - Non-KPSC Amortization - KU		(181,705)
2020 PAA Gross-up		
2020 Settlement Charge	9,065,539	7,375,741
Allocation at 12/31/2020	44,417,832	35,026,985
2021 LKS Reg Allocations	1,084,452	1,100,739
2021 LKS FIN Allocations		
2021 LGE New Reg. Asset/Allocations	(342,147)	(59,356)
2021 - Non-KPSC Amortization - LGE	4,274	
2021 KU New Reg. Asset		440,782
2021 - Non-KPSC Amortization - KU		(25,565)
2021 PAA Gross-up		
2021 Settlement Charge	8,753,869	7,871,694
Allocation at 12/31/2021	53,918,280	44,355,279
2022 LKS Reg Allocations	(3,147,667)	(3,333,669)
2022 LKS FIN Allocations		
2022 LGE New Reg. Asset/Allocations	(5,874,184)	(1,003,468)
2022 - Non-KPSC Amortization - LGE	68,853	
2022 KU New Reg. Asset		(3,231,650)
2022 - Non-KPSC Amortization - KU		186,078
Recon: 2022 - Non-KPSC Amortization - KU		12,787
2022 PAA Gross-up		
2022 Settlement Charge	11,615,769	12,632,999
Allocation at 12/31/2022	56,581,051	49,618,356
2023 LKS Reg Allocations	(3,375,174)	(3,862,360)
2023 LKS FIN Allocations		
2023 LGE New Reg. Asset/Allocations	(7,558,223)	(1,275,457)
2023 - Non-KPSC Amortization - LGE	85,381.00	
Recon: 2023 - Non-KPSC Amortization - LGE	7,342.85	
2023 KU New Reg. Asset		(4,462,186)
2023 - Non-KPSC Amortization - KU		259,206
2023 PAA Gross-up		
2023 PPLS I/C Receivable		
2023 Overstatement LKS credit allocation to KU		(380,463)
Allocation at 12/31/2023	**45,740,378**	**39,897,098**
2024 LKS Reg Allocations	(704,205)	(825,555)
2024 LKS Non-KPSC Cumulative Amortization - LKC		
Reclass: PPLS Fin-15yr Adjustment to 219014 AOCI		
Reclass: 2023 LKS FIN Allocations		
Reclass: 2023 Pension PAA Gross-up		
2024 LGE New Reg. Asset/Allocations	(1,532,921)	(261,365)
2024 - Non-KPSC Amortization - LGE	15,899	
2024 KU New Reg. Asset		(4,128,954)
2024 - Non-KPSC Amortization - KU		223,294
Straight Line Pension PAA Adjustment		
2023 Overstatement LKS credit allocation to KU		380,463
Recon: PPLS Allocation Adjustment (2024)		
Other Recon Item (2024)		
IM	(68)	2
Allocation at 12/31/2024	**43,519,082**	**35,284,981**

(a)

Purpose: The purpose of this worksheet is to reconcile the new regulatory assets and AOCI's allocation which is recorded under the 15 yr Vintage amortization method where the difference between the 15 yr method and the double corridor method is allocated to the utilities PPL and LKC.

Treasury %	4.576%	Want the closer number to treasury %
0.25%	4.530%	0.05%
-0.25%	4.030%	0.55%

ESTIMATE

ASC 712 obligation as of December 31, 2024 — **Discount Rate** **4.28%**

Division	Liability Prior to Retiree Drug Subsidy Offset	Retiree Drug Subsidy Offset	Liability With Retiree Drug Subsidy Offset	Total Count (including LTDs, dependents, and Surviving spouses)
LG&E	$ 2,370,000	$ 59,000	$ 2,311,000	16
Kentucky Utilities	4,293,000	97,000	4,196,000	27

Change per 0.25% bp — **Discount Rate** 4.53%

ASC 712 obligation as of December 31, 2024 — New liability for all ben $ **7,725,000**

Change per -.25 BP $ (99,000)

Percent change -1.27%

Division	Liability Prior to Retiree Drug Subsidy Offset	Retiree Drug Subsidy Offset	Liability With Retiree Drug Subsidy Offset	Total Count (including LTDs, dependents, and Surviving spouses)
LG&E	$ 2,340,012	58,253	$ 2,281,758	16
Kentucky Utilities	(a) 4,238,679	(b) 95,773	4,142,906	27

Change per -0.25% bp — **Discount Rate** 4.03%

ASC 712 obligation as of December 31, 2024 — New liability for all ben $ **7,926,000**

Change per -.25 BP $ 102,000

Percent change 1.30%

Division	Liability Prior to Retiree Drug Subsidy Offset	Retiree Drug Subsidy Offset	Liability With Retiree Drug Subsidy Offset	Total Count (including LTDs, dependents, and Surviving spouses)
LG&E	$ 2,400,897	$ 59,769	$ 2,341,128	16
Kentucky Utilities	4,348,967	98,265	4,250,702	27

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LG&E and KU Energy LLC

Estimated as of December 31, 2024 ASC 712 Obligations - Long Term Disability Benefits

Division	Liability Prior to Retiree Drug Subsidy Offset	Retiree Drug Subsidy Offset	Liability With Retiree Drug Subsidy Offset	Headcount*
LG&E	$2,370,000	$59,000	$2,311,000	16
KU	$4,293,000	$97,000	$4,196,000	27

Assumptions:				
Discount Rate	4.28%			
LTD Recovery Rate	Group Long Term Disability (GLTD) table for disabled participants, based on the Society of Actuaries' 2019 GLTD Experience Study Preliminary Report			
Mortality Assumption (used for Life Insurance benefit)	Pri-2012 Disabled Retiree table without collar adjustments projected generationally using scale MP-2020			

**Headcount totals have been updated to reflect the primary participant/survivor only as of August 1, 2024. There were 56 primary participants/survivors included in the December 31, 2023 valuation.*

Liability Adjustment Examples:

If the discount rate increases 25 basis points as of December 31, 2024

New liability for all benefits = $7,725,000

If the discount rate decreases 25 basis points as of December 31, 2024

New liability for all benefits = $7,926,000

Census data as of August 1, 2024; liability rolled forward to December 31, 2024.

Medical per capita claims costs have been updated to reflect the most recently available data.

Discount rate for the valuation is equal to the 10-year Treasury as of the last business day for the year. As of October 31, 2024 the 10-year Treasury is 4.28%.

The results above are based on the data, assumptions, methods and plan provisions outlined in the December 31, 2023 actuarial valuation report issued on January 3, 2024, with the exception of specific items noted above. The descriptions of the data, assumptions, methods, models, plan provisions and limitations of the valuation reports and their use should be considered part of these results. The forthcoming December 31, 2024 valuation report will contain additional details on the data, assumptions, methods, models and provisions used in this valuation.

https://wtwonline.sharepoint.com/sites/ctclient_604575_2024RETANN/Data Privacy/PPL LTD Results_FAS112_10_31_2024 Estimate.xlsx
12/11/2024

EXHIBIT LK-4

KENTUCKY UTILITIES COMPANY

Response to the Joint Supplemental Data Requests of the Attorney General and Kentucky Industrial Utility Customers'
Dated July 31, 2025

Case No. 2025-00113

Question No. 19

Responding Witness: Christopher M. Garrett / Drew T. McCombs

Q-19. Refer to the response to AG-KIUC 1-85 (b) and (c).

a. Provide the workpapers in Excel live format with all formulas intact used to forecast the prepaid pension amounts in account 128.

b. Confirm the Company assumed no contributions to the pension plan in 2025 and 2026. If this is not correct, then provide a corrected statement and provide the actual and estimated contributions by month from January 2025 through December 2026.

c. Confirm that the pension funding recorded in account 128 is the net of the cumulative Company contributions to the pension trust funds, realized earnings/losses and realized and unrealized gains and losses on trust fund assets, and interest on the present value pension obligation,

d. Refer to page 5 of 16 of the response to AG-KIUC 1-85(c). Indicate whether the positive $35.285 million regulatory asset for account 182313 is a deferred gain or a deferred loss.

e. Refer to Notes 1-3 on page 6 of 15 of the response to AG-KIUC 1-85(c), which state:

1. Discount rate: 5.30% beginning on December 31, 2024 and throughout the forecast period (based on economic conditions as of August 21, 2024).

2. Expected return on assets assumption for calculating annual NPPC: 8.25% in 2025 and 7.25% throughout the rest of the forecast period.

3. Projected asset return assumption: The fair value of assets are based on actual return through August 21, 2024 (as provided by PPL), 8.25% per annum return for the remainder of 2024 and 2025, and 7.25% return in subsequent years.

i. Provide all support, including copies and all source documents and/or other references for the reduction in the expected return on assets assumption and explain why the Companies assumed a reduction of 1.0% in this return, but no reduction in the discount rate when both rates are typically considered correlated and subject to the same micro and macro economic conditions.

ii. Confirm that the higher the discount rate, the lesser the PBO and therefore, the greater the forecast amount in account 128, all else equal.

iii. Confirm that the higher the return on assets, the greater the trust fund valuation and therefore, the lesser the forecast amount in account 128, all else equal.

A-19.

a. See attachment being provided in a separate file.

b. Confirmed.

c. Confirmed.

d. This is a deferred loss. This represents the difference in actuarial gains/losses calculated under the double-corridor approach and the approved regulatory approach of 15-year amortization.

e.

i. The Expected Return on Asset (EROA) Assumption and the Discount Rate (DR) assumption are set in different ways, as required by the accounting standards. The discount rate is calculated using the AA bond universe as of a specific measurement date, while the EROA is a long-term expectation of return on the trust assets. The approaches for setting these assumptions are different, and as such the assumptions are not expected to move in tandem.

The Companies' annual assumption setting process is intended to assess the various economic and actuarial assumptions to account for changing market conditions, expectations for future economic outlook and demographic experience, amongst other data points.

For the mid-year forecast incorporated into the 2025 Business Plan, we considered the following to develop the DR:

- Consistent with former practice, we used our actuary's bond matching model as of April 30, 2025. See attachment being provided in a separate file.
- The bond matching model matches the plan's cash flows to coupons and expected maturity values of individually selected bonds. Individual bonds are theoretically purchased to settle the plan's expected future benefit payments (bonds that match the timing of the plan's cash flows). The discount rate is the single rate that provides the same present value of discounted cashflows.
- This approach reflects approximation of the process of settlement of obligations as required by the Financial Accounting Standards Board.

For the mid-year forecast incorporated into the 2025 Business Plan, we updated EROA based on management's assessment of evolving market conditions and expectations for future economic outlook as provided by our investment consultant. The capital market projections at that time indicated the expectation of lower future asset returns, stating the global economy faced downside risks and US growth was expected to trend downward toward 1% by the end of 2025. See attachment being provided in a separate file. The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

ii. Not confirmed. If a discount rate change is viewed in isolation, a higher discount rate would result in a lower PBO. However, a higher discount rate may not always result in lower expense because the discount rate impacts the components of total expense differently.

iii. Confirmed, a higher EROA percentage, all else held constant, would result in lower total benefit cost.

Kentucky Utilities

	(a) Feb - 2025	Mar - 2025	Apr - 2025	May - 2025	Jun - 2025	Jul - 2025	Aug - 2025	Sep - 2025	Oct - 2025	Nov - 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	OCT 2026	NOV 2026	DEC 2026	13 Month AVG DEC-26
128.6 - Other special funds - non-current (**Restricted Cash Drawdown**)											2,691	2,691	2,691	2,691	2,691	2,691	2,691	2,691	2,691	2,691	2,691	2,691	2,691	
128.1 - Other spec funds - investments	46,169	47,273	48,377	49,481	50,584	51,688	52,792	53,896	55,000	56,104	57,208	58,039	58,869	59,700	60,531	61,362	62,193	63,024	63,854	64,685	65,516	66,347	67,178	64,884
Change in forecasted balance from prior month		1,104	1,104	1,104	1,104	1,104	1,104	1,104	1,104	1,104	1,104	831	831	831	831	831	831	831	831	831	831	831	831	Schedule B-5.2
Components of change in balance from prior month:																								
Monthly Service Cost, Interest Cost & EROA		1,104	1,104	1,104	1,104	1,104	1,104	1,104	1,104	1,104	1,104	831	831	831	831	831	831	831	831	831	831	831	831	
Annual Estimated Contribution																								
		1,104	1,104	1,104	1,104	1,104	1,104	1,104	1,104	1,104	1,104	831	831	831	831	831	831	831	831	831	831	831	831	
Components of account balance Feb 2025:																								
Actuary Report	46,169	p.5 (a)																						
	46,169	p.5 (b)																						

Components of Monthly Service Cost, Interest Cost & EROA:	p.6 (a) 2025	p.6 (c) 2026
Service Cost	2,644	2,382
Interest Cost	13,214	12,732
Estimated Return on Assets	(29,105)	(25,084)
Annual Total	(13,247)	(9,970)
Monthly Total	(1,104)	(831)

Exhibit 1
Page 1

wtw

LG&E & KU Energy LLC
Estimated Net Periodic Pension Cost ("NPPC") Reflecting 15-year (Gain)/Loss Amortization Method For LG&E and KU Pension Plan
2025 Fiscal Year

	Reg-15 LG&E		Reg-15 KU	
Service cost	2,675,583		(a)	2,644,472
Interest cost	16,536,924			13,213,991
Expected return on assets	(33,978,630)			(29,105,018)
Amortizations:			(b)	

LKE
LG&E and KU Pension Plan
Purpose and Actuarial Statement

This report documents the results of discount rate analysis for the LG&E and KU Pension Plan. The primary purpose of this analysis is to support the discount rate selection as of April 30, 2025 as required under FASB Accounting Standards Codification Topic 715-20-50 (ASC 715).

Except for the discount rate mentioned above, the results presented in this report are based on the participant data, assumptions, methods, models, and plan provisions used to develop the January 1, 2025 actuarial valuation results delivered on May 30, 2025. Therefore, such information and the reliances and limitations of those results and its use should be considered part of this report.

Further, the results are based on the BOND:Link model methodology described in WTW's U.S. BOND:Link Methodology Description. The results are also based on the RATE:Link curve methodology described in WTW's Global RATE:Link Methodology Description. These documents should also be considered part of this report.

The undersigned are members of the Society of Actuaries and meet the "Qualification Standards for Actuaries Issuing Statements of Actuarial Opinion in the United States" related to pension and other postretirement benefit plans.

Our objectivity is not impaired by any relationship between LKE and our employer, Willis Towers Watson US LLC ("WTW").



Kristin A. May, FSA, EA
Senior Director, Retirement



Will DeGothseir, FSA, EA
Director, Retirement

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			Total	<=30 Years
Measurement date	30 Apr 2025			
Region	US			
Effective settlement				
Year of final matched payment	30			
Discount later payments to	Final matched payment			
Limit on cash that can be carried forward to next	1.00	years' benefit payments		
Final matched payment can be funded over	6	years		
Interest rates				
For discounting payments longer than final matched payment	US 10%-90%			
For carrying forward surplus	US 10%-90%			
Bonds eligible for selection				
Bonds in universe			856	831
Exclusions (not additive; bonds can be excluded for more than one reason)				
Collateralized bonds	Do not exclude		0	0
Bonds priced less expensively than threshold percentile equal to	97.5%		21	17
BVAL score less than	4		218	216
Specific bonds (identified by TRUE in column K of sheet "All bonds")	FALSE		0	0
Total exclusions			229	225
Bonds eligible for selection			627	606
Maximum purchase amounts				
Limits on individual bonds				
Percent of obligation	10.0%			
Percent of bond issue	100.0%			
Aggregate limit on bonds with lower BVAL scores (a threshold of 1 or a limit of 100% will disable this)				
Limit applies to bonds with scores below threshold equal to	6			
Maximum percent of portfolio for such bonds	100.0%			

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LKE
LG&E and KU Pension Plan
Settlement Portfolio

Number of bonds	20
Market value	956,029,414
Discount rate	5.78%

									Portfolio Allocation			
Number	ID	Issuer	Coupon Rate	Maturity	Amount Outstanding	Annualized Yield	Market Value	BVAL Score	Market Value	Fraction of Issue	Fraction of Portfolio	Universe
1	BBG00001RML5	Colgate-Palmolive Co	7.600%	19 May 2025	130,000,000	7.463%	134,428,350	9	95,602,943	71.1%	10.0%	Corporate
2	BBG009T67NM3	University of Chicago/The	3.622%	1 Oct 2027	9,125,000	4.681%	8,943,721	5	8,943,721	100.0%	0.9%	Corporate
3	BBG00KHTW070	ASB Bank Ltd	3.940%	1 Mar 2028	150,000,000	4.869%	147,535,452	6	45,170,230	30.6%	4.7%	Corporate
4	BBG00699HD64	Northwest Florida Timber Finance LLC	4.750%	4 Mar 2029	180,000,000	5.188%	179,008,447	6	61,574,420	34.4%	6.4%	Corporate
5	BBG01JR70MT2	CommonSpirit Health	3.347%	1 Oct 2029	2,000,000	5.387%	1,852,028	4	1,852,028	100.0%	0.2%	Corporate
6	BBG000009QJ1	AARP	7.500%	1 May 2031	125,000,000	5.632%	141,928,537	6	95,602,943	67.4%	10.0%	Corporate
7	BBG00006PL65	Massachusetts Mutual Life Insurance Co	5.625%	15 May 2033	193,184,000	5.653%	198,777,976	8	95,602,943	48.1%	10.0%	Corporate
8	BBG0000BD107	HSBC Bank USA NA/New York NY	5.625%	15 Aug 2035	383,353,000	5.617%	390,339,763	10	95,602,943	24.5%	10.0%	Corporate
9	BBG00008D8Q1	Bank of America NA	6.000%	15 Oct 2036	1,250,000,000	5.657%	1,297,200,381	10	57,112,299	4.4%	6.0%	Corporate
10	BBG0000LGD51	Wells Fargo Bank NA	6.600%	15 Jan 2038	1,413,633,000	5.644%	1,572,454,513	8	4,922,563	0.3%	0.5%	Corporate
11	BBG0000Q6DM2	HSBC Bank USA NA	7.000%	15 Jan 2039	700,000,000	5.679%	807,059,341	8	95,602,943	11.8%	10.0%	Corporate
12	BBG00008Z832	Northwestern Mutual Life Insurance Co/The	6.063%	30 Mar 2040	1,224,250,000	5.665%	1,288,819,833	9	3,808,440	0.3%	0.4%	Corporate
13	BBG00FQMZ108	Baptist Health South Florida Inc	4.342%	15 Nov 2041	250,000,000	5.757%	219,492,583	8	21,229,976	9.7%	2.2%	Corporate
14	BBG00395HQR7	Shell International Finance BV	3.625%	21 Aug 2042	500,000,000	5.801%	389,356,623	9	50,867,830	13.1%	5.3%	Corporate
15	BBG00748FJG7	Teachers Insurance & Annuity Association of America	4.900%	15 Sep 2044	1,650,000,000	5.946%	1,477,968,639	9	65,847,076	4.5%	6.9%	Corporate
16	BBG00DRL06K9	Shell International Finance BV	3.750%	12 Sep 2046	245,620,000	5.842%	186,622,846	9	16,743,252	9.0%	1.8%	Corporate
17	BBG00000ZJV4	Northern Pacific Railway Co	3.000%	1 Jan 2047	29,689,700	5.898%	19,621,302	7	19,621,302	100.0%	2.1%	Corporate
18	BBG00N8CV7D0	Nature Conservancy/The	4.496%	1 Feb 2049	40,000,000	5.842%	33,946,397	4	11,635,337	34.3%	1.2%	Corporate
19	BBG00T5JC6D8	Massachusetts Mutual Life Insurance Co	3.375%	15 Apr 2050	700,000,000	5.909%	476,863,567	9	95,602,943	20.0%	10.0%	Corporate
20	BBG00RN56H18	Montefiore Obligated Group	3.787%	1 Sep 2050	50,000,000	5.906%	36,918,960	6	13,083,282	35.4%	1.4%	Corporate

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LKE
LG&E and KU Pension Plan
Bond Payments

Year	1	2	3	4	5	6	7	8	9	10	11
Total	145,455,452	47,081,884	84,528,861	100,112,886	65,294,831	84,063,237	79,343,300	77,954,824	81,931,227	49,214,906	103,421,114
Payment From Bond											
1	99,106,313	0	0	0	0	0	0	0	0	0	0
2	327,977	1,060,722	8,557,509	0	0	0	0	0	0	0	0
3	1,802,172	1,802,172	31,752,361	15,988,941	0	0	0	0	0	0	0
4	2,927,205	2,927,205	2,927,205	42,672,275	22,195,815	0	0	0	0	0	0
5	66,353	66,353	66,353	226,239	1,873,585	0	0	0	0	0	0
6	6,401,717	6,401,717	6,401,717	6,401,717	6,401,717	49,239,523	44,519,585	0	0	0	0
7	5,287,043	5,287,043	5,287,043	5,287,043	5,287,043	5,287,043	5,287,043	48,418,152	52,394,555	0	0
8	5,269,890	5,269,890	5,269,890	5,269,890	5,269,890	5,269,890	5,269,890	5,269,890	5,269,890	24,948,124	76,854,199
9	3,264,723	3,264,723	3,264,723	3,264,723	3,264,723	3,264,723	3,264,723	3,264,723	3,264,723	3,264,723	5,564,856
10	292,771	292,771	292,771	292,771	292,771	292,771	292,771	292,771	292,771	292,771	292,771
11	5,818,391	5,818,391	5,818,391	5,818,391	5,818,391	5,818,391	5,818,391	5,818,391	5,818,391	5,818,391	5,818,391
12	217,353	217,353	217,353	217,353	217,353	217,353	217,353	217,353	217,353	217,353	217,353
13	1,062,346	1,062,346	1,062,346	1,062,346	1,062,346	1,062,346	1,062,346	1,062,346	1,062,346	1,062,346	1,062,346
14	2,360,415	2,360,415	2,360,415	2,360,415	2,360,415	2,360,415	2,360,415	2,360,415	2,360,415	2,360,415	2,360,415
15	3,576,523	3,576,523	3,576,523	3,576,523	3,576,523	3,576,523	3,576,523	3,576,523	3,576,523	3,576,523	3,576,523
16	820,988	820,988	820,988	820,988	820,988	820,988	820,988	820,988	820,988	820,988	820,988
17	888,539	888,539	888,539	888,539	888,539	888,539	888,539	888,539	888,539	888,539	888,539
18	616,378	616,378	616,378	616,378	616,378	616,378	616,378	616,378	616,378	616,378	616,378
19	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578
20	667,777	667,777	667,777	667,777	667,777	667,777	667,777	667,777	667,777	667,777	667,777

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LKE
LG&E and KU Pension Plan
Bond Payments

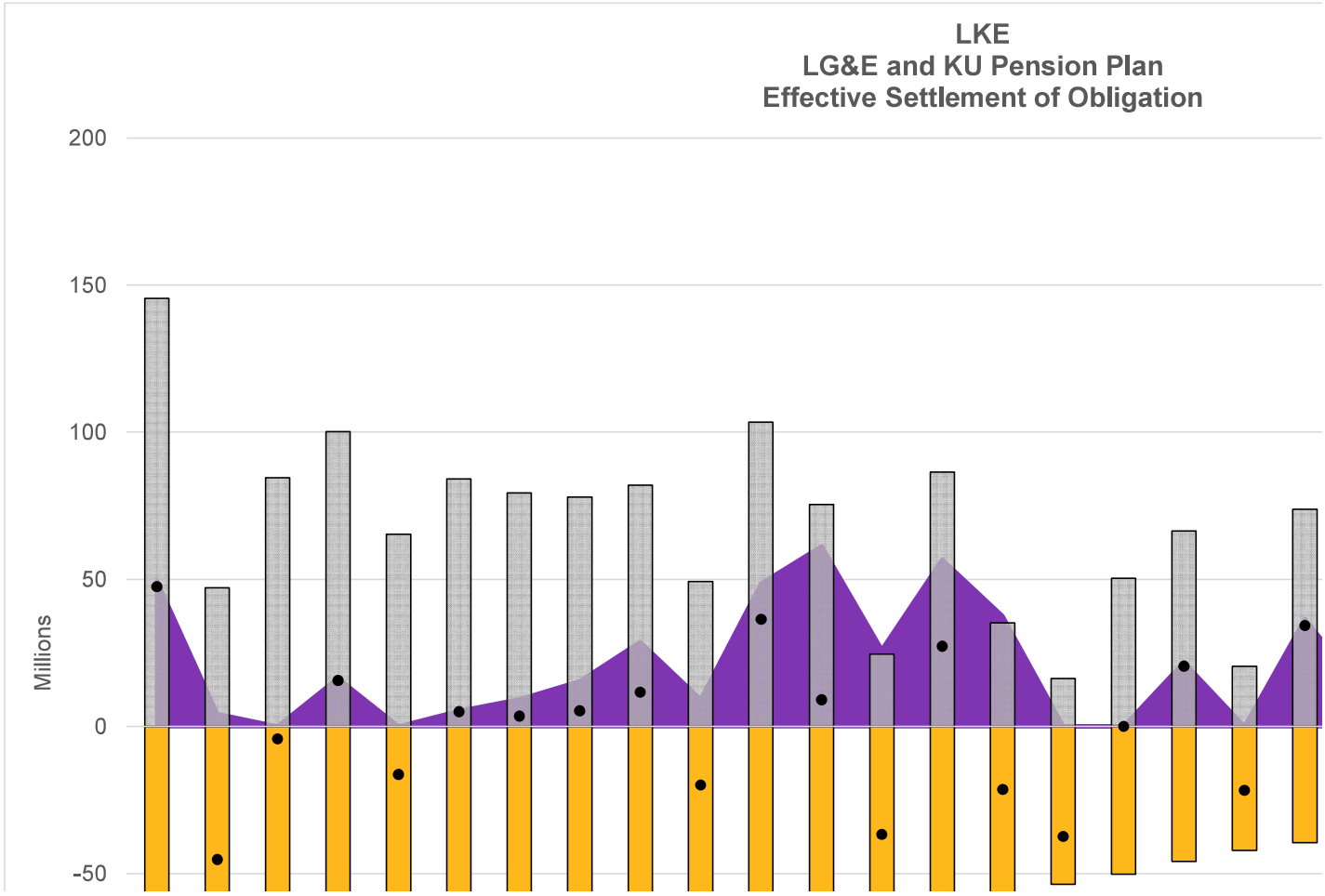
Year	12	13	14	15	16	17	18	19	20	21	22
Total	75,387,143	24,455,906	86,363,697	35,205,835	16,251,586	50,256,609	66,356,593	20,428,688	73,808,876	10,594,394	50,667,223
Payment From Bond											
1	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0
9	54,385,084	0	0	0	0	0	0	0	0	0	0
10	292,771	3,746,618	973,187	0	0	0	0	0	0	0	0
11	5,818,391	5,818,391	70,499,613	18,272,852	0	0	0	0	0	0	0
12	217,353	217,353	217,353	2,259,438	1,578,041	0	0	0	0	0	0
13	1,062,346	1,062,346	1,062,346	1,062,346	1,062,346	24,187,066	1,057,248	0	0	0	0
14	2,360,415	2,360,415	2,360,415	2,360,415	2,360,415	14,818,760	54,048,562	0	0	0	0
15	3,576,523	3,576,523	3,576,523	3,576,523	3,576,523	3,576,523	3,576,523	12,754,428	66,134,616	0	0
16	820,988	820,988	820,988	820,988	820,988	820,988	820,988	820,988	820,988	3,741,122	19,529,349
17	888,539	888,539	888,539	888,539	888,539	888,539	888,539	888,539	888,539	888,539	25,173,142
18	616,378	616,378	616,378	616,378	616,378	616,378	616,378	616,378	616,378	616,378	616,378
19	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578
20	667,777	667,777	667,777	667,777	667,777	667,777	667,777	667,777	667,777	667,777	667,777

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LG&E and KU Pension Plan
Bond Payments

Year	23	24	25	26	27	28	29	30
Total	11,154,597	16,060,303	85,830,601	81,590,709	0	0	0	0
Payment From Bond								
1	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0
16	0	0	0	0	0	0	0	0
17	5,189,865	0	0	0	0	0	0	0
18	616,378	10,711,948	3,619,068	0	0	0	0	0
19	4,680,578	4,680,578	78,655,354	66,424,683	0	0	0	0
20	667,777	667,777	3,556,179	15,166,026	0	0	0	0

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Reconciliation

	Cash Available				Excess for year			
Year	Bond Payments For Year	Carried From Prior Years	Total	Benefit Payments	Excess	Limit to Carry	Interest Rate	Discarded
1	145,455,452	0	145,455,452	97,982,195	47,473,257	88,796,453	4.03%	0
2	47,081,884	49,386,774	96,468,658	92,375,595	4,093,063	85,191,210	4.23%	0
3	84,528,861	4,266,213	88,795,073	88,795,073	0	80,787,032	4.63%	0
4	100,112,886	0	100,112,886	84,531,494	15,581,392	77,775,314	4.99%	0
5	65,294,831	16,358,260	81,653,091	81,653,091	0	75,106,787	5.30%	0
6	84,063,237	0	84,063,237	79,089,916	4,973,321	71,864,947	5.60%	0
7	79,343,300	5,251,971	84,595,270	75,891,458	8,703,813	68,680,582	5.87%	0
8	77,954,824	9,215,011	87,169,834	72,714,373	14,455,462	66,311,163	6.10%	0
9	81,931,227	15,336,620	97,267,847	70,353,281	26,914,566	65,081,815	6.26%	0
10	49,214,906	28,598,285	77,813,190	69,153,195	8,659,995	63,080,934	6.35%	0
11	103,421,114	9,210,154	112,631,268	67,088,387	45,542,881	62,366,327	6.40%	0
12	75,387,143	48,457,673	123,844,816	66,357,838	57,486,978	57,486,978	6.42%	0
13	24,455,906	61,175,375	85,631,282	61,175,375	24,455,906	55,586,537	6.42%	0
14	86,363,697	26,025,071	112,388,768	59,153,137	53,235,631	53,235,631	6.41%	0
15	35,205,835	56,649,163	91,854,998	56,649,163	35,205,835	50,478,368	6.41%	0
16	16,251,586	37,462,721	53,714,306	53,714,306	0	47,227,192	6.41%	0
17	50,256,609	0	50,256,609	50,256,609	0	43,118,714	6.42%	0
18	66,356,593	0	66,356,593	45,889,062	20,467,531	39,659,878	6.44%	0
19	20,428,688	21,786,019	42,214,707	42,214,707	0	37,180,328	6.47%	0
20	73,808,876	0	73,808,876	39,584,140	34,224,735	34,224,735	6.49%	0
21	10,594,394	36,447,603	47,041,997	36,447,603	10,594,394	31,346,609	6.53%	0
22	50,667,223	11,286,235	61,953,459	33,393,622	28,559,837	28,559,837	6.57%	0
23	11,154,597	30,436,381	41,590,979	30,436,381	11,154,597	26,218,415	6.62%	0
24	16,060,303	11,892,484	27,952,788	27,952,788	0	N/A	6.66%	0
25	85,830,601	0	85,830,601	25,835,233	59,995,368	N/A	6.71%	0
26	81,590,709	64,023,329	145,614,039	23,411,749	122,202,290	N/A	6.77%	0
27	0	130,470,862	130,470,862	21,316,078	109,154,784	N/A	6.82%	0
28	0	116,598,757	116,598,757	19,364,344	97,234,413	N/A	6.87%	0
29	0	103,917,416	103,917,416	17,527,431	86,389,984	N/A	6.93%	0
30	0	92,372,894	92,372,894	92,372,894	0	0	6.98%	0

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LKE
LG&E and KU Pension Plan
Discount Rate

Benefit obligation	
Matching portfolio	956,029,414
PV of payments discounted separately	0
Total	956,029,414
Discount rate	5.78%
PV of benefit payments	956,029,423
Macaulay duration	8.56
Modified duration	8.09

Year	Maturity	Payment	PV at 5.78%
1	0.5	97,982,195	95,265,987
2	1.5	92,375,595	84,904,240
3	2.5	88,795,073	77,151,153
4	3.5	84,531,494	69,431,015
5	4.5	81,653,091	63,399,965
6	5.5	79,089,916	58,052,232
7	6.5	75,891,458	52,658,942
8	7.5	72,714,373	47,695,885
9	8.5	70,353,281	43,624,095
10	9.5	69,153,195	40,535,520
11	10.5	67,088,387	37,175,110
12	11.5	66,357,838	34,759,903
13	12.5	61,175,375	30,293,147
14	13.5	59,153,137	27,690,255
15	14.5	56,649,163	25,068,254
16	15.5	53,714,306	22,469,944
17	16.5	50,256,609	19,874,061
18	17.5	45,889,062	17,154,736
19	18.5	42,214,707	14,918,325
20	19.5	39,584,140	13,223,880
21	20.5	36,447,603	11,510,338
22	21.5	33,393,622	9,969,286
23	22.5	30,436,381	8,589,640
24	23.5	27,952,788	7,457,418
25	24.5	25,835,233	6,515,642
26	25.5	23,411,749	5,581,618
27	26.5	21,316,078	4,804,132
28	27.5	19,364,344	4,125,645
29	28.5	17,527,431	3,530,114
30	29.5	15,811,658	3,010,435
31	30.5	14,220,353	2,559,433
32	31.5	12,753,585	2,169,936
33	32.5	11,408,932	1,835,021
34	33.5	10,181,835	1,548,117
35	34.5	9,066,519	1,303,165
36	35.5	8,055,510	1,094,545
37	36.5	7,140,911	917,224
38	37.5	6,314,433	766,721
39	38.5	5,568,091	639,133
40	39.5	4,894,273	531,073
41	40.5	4,285,965	439,639
42	41.5	3,736,892	362,359
43	42.5	3,241,597	297,146
44	43.5	2,795,385	242,233
45	44.5	2,394,316	196,135
46	45.5	2,035,094	157,594
47	46.5	1,714,934	125,540
48	47.5	1,431,513	99,063
49	48.5	1,182,647	77,367
50	49.5	966,151	59,748
51	50.5	779,859	45,591
52	51.5	621,477	34,345
53	52.5	488,618	25,527
54	53.5	378,748	18,705
55	54.5	289,241	13,504
56	55.5	217,450	9,597
57	56.5	160,819	6,709
58	57.5	116,916	4,611

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LKE
LG&E and KU Pension Plan
Discount Rate

Benefit obligation	
Matching portfolio	956,029,414
PV of payments discounted separately	0
Total	956,029,414
Discount rate	5.78%
PV of benefit payments	956,029,423
Macaulay duration	8.56
Modified duration	8.09

Year	Maturity	Payment	PV at 5.78%
59	58.5	83,499	3,113
60	59.5	58,553	2,064
61	60.5	40,297	1,343
62	61.5	27,213	857
63	62.5	18,031	537
64	63.5	11,726	330
65	64.5	7,488	199
66	65.5	4,703	118
67	66.5	2,911	69
68	67.5	1,781	40
69	68.5	1,080	23
70	69.5	653	13
71	70.5	394	7
72	71.5	239	4
73	72.5	146	2
74	73.5	90	1
75	74.5	55	1
76	75.5	34	0
77	76.5	20	0
78	77.5	12	0
79	78.5	7	0
80	79.5	4	0
81	80.5	0	0
82	81.5	0	0
83	82.5	0	0
84	83.5	0	0
85	84.5	0	0
86	85.5	0	0
87	86.5	0	0
88	87.5	0	0
89	88.5	0	0
90	89.5	0	0
91	90.5	0	0
92	91.5	0	0
93	92.5	0	0
94	93.5	0	0
95	94.5	0	0
96	95.5	0	0
97	96.5	0	0
98	97.5	0	0
99	98.5	0	0
100	99.5	0	0

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LOUISVILLE GAS AND ELECTRIC COMPANY

Response to the Joint Supplemental Data Requests of the Attorney General and Kentucky Industrial Utility Customers'
Dated July 31, 2025

Case No. 2025-00114

Question No. 19

Responding Witness: Christopher M. Garrett / Drew T. McCombs

Q-19. Refer to the response to AG-KIUC 1-85 (b) and (c).

a. Provide the workpapers in Excel live format with all formulas intact used to forecast the prepaid pension amounts in account 128.

b. Confirm the Company assumed no contributions to the pension plan in 2025 and 2026. If this is not correct, then provide a corrected statement and provide the actual and estimated contributions by month from January 2025 through December 2026.

c. Confirm that the pension funding recorded in account 128 is the net of the cumulative Company contributions to the pension trust funds, realized earnings/losses and realized and unrealized gains and losses on trust fund assets, and interest on the present value pension obligation,

d. Refer to page 5 of 16 of the response to AG-KIUC 1-85(c). Indicate whether the positive $35.285 million regulatory asset for account 182313 is a deferred gain or a deferred loss.

e. Refer to Notes 1-3 on page 6 of 15 of the response to AG-KIUC 1-85(c), which state:

1. Discount rate: 5.30% beginning on December 31, 2024 and throughout the forecast period (based on economic conditions as of August 21, 2024).

2. Expected return on assets assumption for calculating annual NPPC: 8.25% in 2025 and 7.25% throughout the rest of the forecast period.

3. Projected asset return assumption: The fair value of assets are based on actual return through August 21, 2024 (as provided by PPL), 8.25% per annum return for the remainder of 2024 and 2025, and 7.25% return in subsequent years.

i. Provide all support, including copies and all source documents and/or other references for the reduction in the expected return on assets assumption and explain why the Companies assumed a reduction of 1.0% in this return, but no reduction in the discount rate when both rates are typically considered correlated and subject to the same micro and macro economic conditions.

ii. Confirm that the higher the discount rate, the lesser the PBO and therefore, the greater the forecast amount in account 128, all else equal.

iii. Confirm that the higher the return on assets, the greater the trust fund valuation and therefore, the lesser the forecast amount in account 128, all else equal.

A-19.

a. See attachment being provided in a separate file.

b. Confirmed.

c. Confirmed.

d. This is a deferred loss. This represents the difference in actuarial gains/losses calculated under the double-corridor approach and the approved regulatory approach of 15-year amortization.

e.

i. The Expected Return on Asset (EROA) Assumption and the Discount Rate (DR) assumption are set in different ways, as required by the accounting standards. The discount rate is calculated using the AA bond universe as of a specific measurement date, while the EROA is a long-term expectation of return on the trust assets. The approaches for setting these assumptions are different, and as such the assumptions are not expected to move in tandem.

The Companies' annual assumption setting process is intended to assess the various economic and actuarial assumptions to account for changing market conditions, expectations for future economic outlook and demographic experience, amongst other data points.

For the mid-year forecast incorporated into the 2025 Business Plan, we considered the following to develop the DR:

- Consistent with former practice, we used our actuary's bond matching model as of April 30, 2025. See attachment being provided in a separate file.
- The bond matching model matches the plan's cash flows to coupons and expected maturity values of individually selected bonds. Individual bonds are theoretically purchased to settle the plan's expected future benefit payments (bonds that match the timing of the plan's cash flows). The discount rate is the single rate that provides the same present value of discounted cashflows.
- This approach reflects approximation of the process of settlement of obligations as required by the Financial Accounting Standards Board.

For the mid-year forecast incorporated into the 2025 Business Plan, we updated EROA based on management's assessment of evolving market conditions and expectations for future economic outlook as provided by our investment consultant. The capital market projections at that time indicated the expectation of lower future asset returns, stating the global economy faced downside risks and US growth was expected to trend downward toward 1% by the end of 2025. See attachment being provided in a separate file. The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

ii. Not confirmed. If a discount rate change is viewed in isolation, a higher discount rate would result in a lower PBO. However, a higher discount rate may not always result in lower expense because the discount rate impacts the components of total expense differently.

iii. Confirmed, a higher EROA percentage, all else held constant, would result in lower total benefit cost.

Louisville Gas & Electric

	(a) Feb - 2025	Mar - 2025	Apr - 2025	May - 2025	Jun - 2025	Jul - 2025	Aug - 2025	Sep - 2025	Oct - 2025	Nov - 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	OCT 2026	NOV 2026	DEC 2026	**13 Month AVG DEC-26**	
128.6 - Other special funds - non-current- Electric (**Restricted Cash Drawdown**)	181	162	147	123	89	70	66	58	54	50	17	17	17	17	17	17	17	17	17	17	17	17	17		
128.6 - Other special funds - non-current-Gas (**Restricted Cash Drawdown**)	14,830	13,280	11,985	10,021	7,258	5,720	5,396	4,722	4,379	4,091	1,399	1,399	1,399	1,399	1,399	1,399	1,399	1,399	1,399	1,399	1,399	1,399	1,399		
128.11 - Other special funds - investment other It asset-Electric	19,078	19,893	20,709	21,526	22,342	23,159	23,975	24,792	25,608	26,424	27,241	27,821	28,402	28,982	29,562	30,143	30,723	31,304	31,884	32,464	33,045	33,625	34,206	30,740	Electric
128.11 - Other special funds - investment other It asset-Gas	9,676	10,089	10,503	10,917	11,331	11,745	12,159	12,573	12,987	13,401	13,815	14,110	14,404	14,699	14,993	15,287	15,582	15,876	16,170	16,465	16,759	17,053	17,348	16,981	Gas
128 Prepaid Pension + Restricted Cash Drawdown	43,765	43,424	43,344	42,586	41,020	40,694	41,597	42,145	43,028	43,967	42,473	43,347	44,222	45,097	45,972	46,846	47,721	48,596	49,471	50,345	51,220	52,095	52,970	61,048	
128 Balance w/o 128.6 Restricted Cash Drawdown	28,754	29,982	31,212	32,443	33,673	34,904	36,134	37,365	38,595	39,826	41,056	41,931	42,806	43,681	44,555	45,430	46,305	47,180	48,054	48,929	49,804	50,679	51,553	Schedule B-5.2	
Change in forecasted balance from prior month		1,228	1,231	1,231	1,231	1,231	1,231	1,231	1,231	1,231	1,231	875	875	875	875	875	875	875	875	875	875	875	875		
Components of change in balance from prior month:																									
Monthly Service Cost, Interest Cost & EROA		1,231	1,231	1,231	1,231	1,231	1,231	1,231	1,231	1,231	1,231	875	875	875	875	875	875	875	875	875	875	875	875		
Restitution Payment		(2)																							
		1,228	1,231	1,231	1,231	1,231	1,231	1,231	1,231	1,231	1,231	875	875	875	875	875	875	875	875	875	875	875	875		
Components of account balance Feb 2025:																									
Actuary Report	28,754	p.5 (a)																							
	2,904,113	p.5 (b)																							

Components of Monthly Service Cost, Interest Cost & EROA:	p.6 (a) 2025	p.6 (c) 2026
Service Cost	2,676	2,627
Interest Cost	16,537	15,865
Estimated Return on Assets	(33,979)	(28,989)
Annual Total	(14,766)	(10,497)
Monthly Total	(1,231)	(875)

Exhibit 1
Page 1

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LG&E & KU Energy LLC
Estimated Net Periodic Pension Cost ("NPPC") Reflecting 15-year (Gain)/Loss Amortization Method For LG&E and KU Pension Plan
2025 Fiscal Year

	Reg-15 LG&E		Reg-15 KU
Service cost	2,675,563	(a)	2,644,472
Interest cost	16,536,924		13,213,991

LKE
LG&E and KU Pension Plan
Purpose and Actuarial Statement

This report documents the results of discount rate analysis for the LG&E and KU Pension Plan. The primary purpose of this analysis is to support the discount rate selection as of April 30, 2025 as required under FASB Accounting Standards Codification Topic 715-20-50 (ASC 715).

Except for the discount rate mentioned above, the results presented in this report are based on the participant data, assumptions, methods, models, and plan provisions used to develop the January 1, 2025 actuarial valuation results delivered on May 30, 2025. Therefore, such information and the reliances and limitations of those results and its use should be considered part of this report.

Further, the results are based on the BOND:Link model methodology described in WTW's U.S. BOND:Link Methodology Description. The results are also based on the RATE:Link curve methodology described in WTW's Global RATE:Link Methodology Description. These documents should also be considered part of this report.

The undersigned are members of the Society of Actuaries and meet the "Qualification Standards for Actuaries Issuing Statements of Actuarial Opinion in the United States" related to pension and other postretirement benefit plans.

Our objectivity is not impaired by any relationship between LKE and our employer, Willis Towers Watson US LLC ("WTW").



Kristin A. May, FSA, EA
Senior Director, Retirement



Will DeGothseir, FSA, EA
Director, Retirement

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			Total	<=30 Years
Measurement date	30 Apr 2025			
Region	US			
Effective settlement				
Year of final matched payment	30			
Discount later payments to	Final matched payment			
Limit on cash that can be carried forward to next	1.00	years' benefit payments		
Final matched payment can be funded over	6	years		
Interest rates				
For discounting payments longer than final matched payment	US 10%-90%			
For carrying forward surplus	US 10%-90%			
Bonds eligible for selection				
Bonds in universe			856	831
Exclusions (not additive; bonds can be excluded for more than one reason)				
Collateralized bonds	Do not exclude		0	0
Bonds priced less expensively than threshold percentile equal to	97.5%		21	17
BVAL score less than	4		218	216
Specific bonds (identified by TRUE in column K of sheet "All bonds")	FALSE		0	0
Total exclusions			229	225
Bonds eligible for selection			627	606
Maximum purchase amounts				
Limits on individual bonds				
Percent of obligation	10.0%			
Percent of bond issue	100.0%			
Aggregate limit on bonds with lower BVAL scores (a threshold of 1 or a limit of 100% will disable this)				
Limit applies to bonds with scores below threshold equal to	6			
Maximum percent of portfolio for such bonds	100.0%			

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LKE
LG&E and KU Pension Plan
Settlement Portfolio

Number of bonds	20
Market value	956,029,414
Discount rate	5.78%

									Portfolio Allocation			
Number	ID	Issuer	Coupon Rate	Maturity	Amount Outstanding	Annualized Yield	Market Value	BVAL Score	Market Value	Fraction of Issue	Fraction of Portfolio	Universe
1	BBG00001RML5	Colgate-Palmolive Co	7.600%	19 May 2025	130,000,000	7.463%	134,428,350	9	95,602,943	71.1%	10.0%	Corporate
2	BBG009T67NM3	University of Chicago/The	3.622%	1 Oct 2027	9,125,000	4.681%	8,943,721	5	8,943,721	100.0%	0.9%	Corporate
3	BBG00KHTW070	ASB Bank Ltd	3.940%	1 Mar 2028	150,000,000	4.869%	147,535,452	6	45,170,230	30.6%	4.7%	Corporate
4	BBG00699HD64	Northwest Florida Timber Finance LLC	4.750%	4 Mar 2029	180,000,000	5.188%	179,008,447	6	61,574,420	34.4%	6.4%	Corporate
5	BBG01JR70MT2	CommonSpirit Health	3.347%	1 Oct 2029	2,000,000	5.387%	1,852,028	4	1,852,028	100.0%	0.2%	Corporate
6	BBG000009QJ1	AARP	7.500%	1 May 2031	125,000,000	5.632%	141,928,537	6	95,602,943	67.4%	10.0%	Corporate
7	BBG00006PL65	Massachusetts Mutual Life Insurance Co	5.625%	15 May 2033	193,184,000	5.653%	198,777,976	8	95,602,943	48.1%	10.0%	Corporate
8	BBG0000BD107	HSBC Bank USA NA/New York NY	5.625%	15 Aug 2035	383,353,000	5.617%	390,339,763	10	95,602,943	24.5%	10.0%	Corporate
9	BBG00008D8Q1	Bank of America NA	6.000%	15 Oct 2036	1,250,000,000	5.657%	1,297,200,381	10	57,112,299	4.4%	6.0%	Corporate
10	BBG0000LGD51	Wells Fargo Bank NA	6.600%	15 Jan 2038	1,413,633,000	5.644%	1,572,454,513	8	4,922,563	0.3%	0.5%	Corporate
11	BBG0000Q6DM2	HSBC Bank USA NA	7.000%	15 Jan 2039	700,000,000	5.679%	807,059,341	8	95,602,943	11.8%	10.0%	Corporate
12	BBG00008Z832	Northwestern Mutual Life Insurance Co/The	6.063%	30 Mar 2040	1,224,250,000	5.665%	1,288,819,833	9	3,808,440	0.3%	0.4%	Corporate
13	BBG00FQMZ108	Baptist Health South Florida Inc	4.342%	15 Nov 2041	250,000,000	5.757%	219,492,583	8	21,229,976	9.7%	2.2%	Corporate
14	BBG00395HQR7	Shell International Finance BV	3.625%	21 Aug 2042	500,000,000	5.801%	389,356,623	9	50,867,830	13.1%	5.3%	Corporate
15	BBG00748FJG7	Teachers Insurance & Annuity Association of America	4.900%	15 Sep 2044	1,650,000,000	5.946%	1,477,968,639	9	65,847,076	4.5%	6.9%	Corporate
16	BBG00DRL06K9	Shell International Finance BV	3.750%	12 Sep 2046	245,620,000	5.842%	186,622,846	9	16,743,252	9.0%	1.8%	Corporate
17	BBG00000ZJV4	Northern Pacific Railway Co	3.000%	1 Jan 2047	29,689,700	5.898%	19,621,302	7	19,621,302	100.0%	2.1%	Corporate
18	BBG00N8CV7D0	Nature Conservancy/The	4.496%	1 Feb 2049	40,000,000	5.842%	33,946,397	4	11,635,337	34.3%	1.2%	Corporate
19	BBG00T5JC6D8	Massachusetts Mutual Life Insurance Co	3.375%	15 Apr 2050	700,000,000	5.909%	476,863,567	9	95,602,943	20.0%	10.0%	Corporate
20	BBG00RN56H18	Montefiore Obligated Group	3.787%	1 Sep 2050	50,000,000	5.906%	36,918,960	6	13,083,282	35.4%	1.4%	Corporate

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LKE
LG&E and KU Pension Plan
Bond Payments

Year	1	2	3	4	5	6	7	8	9	10	11
Total	145,455,452	47,081,884	84,528,861	100,112,886	65,294,831	84,063,237	79,343,300	77,954,824	81,931,227	49,214,906	103,421,114
Payment From Bond											
1	99,106,313	0	0	0	0	0	0	0	0	0	0
2	327,977	1,060,722	8,557,509	0	0	0	0	0	0	0	0
3	1,802,172	1,802,172	31,752,361	15,988,941	0	0	0	0	0	0	0
4	2,927,205	2,927,205	2,927,205	42,672,275	22,195,815	0	0	0	0	0	0
5	66,353	66,353	66,353	226,239	1,873,585	0	0	0	0	0	0
6	6,401,717	6,401,717	6,401,717	6,401,717	6,401,717	49,239,523	44,519,585	0	0	0	0
7	5,287,043	5,287,043	5,287,043	5,287,043	5,287,043	5,287,043	5,287,043	48,418,152	52,394,555	0	0
8	5,269,890	5,269,890	5,269,890	5,269,890	5,269,890	5,269,890	5,269,890	5,269,890	5,269,890	24,948,124	76,854,199
9	3,264,723	3,264,723	3,264,723	3,264,723	3,264,723	3,264,723	3,264,723	3,264,723	3,264,723	3,264,723	5,564,856
10	292,771	292,771	292,771	292,771	292,771	292,771	292,771	292,771	292,771	292,771	292,771
11	5,818,391	5,818,391	5,818,391	5,818,391	5,818,391	5,818,391	5,818,391	5,818,391	5,818,391	5,818,391	5,818,391
12	217,353	217,353	217,353	217,353	217,353	217,353	217,353	217,353	217,353	217,353	217,353
13	1,062,346	1,062,346	1,062,346	1,062,346	1,062,346	1,062,346	1,062,346	1,062,346	1,062,346	1,062,346	1,062,346
14	2,360,415	2,360,415	2,360,415	2,360,415	2,360,415	2,360,415	2,360,415	2,360,415	2,360,415	2,360,415	2,360,415
15	3,576,523	3,576,523	3,576,523	3,576,523	3,576,523	3,576,523	3,576,523	3,576,523	3,576,523	3,576,523	3,576,523
16	820,988	820,988	820,988	820,988	820,988	820,988	820,988	820,988	820,988	820,988	820,988
17	888,539	888,539	888,539	888,539	888,539	888,539	888,539	888,539	888,539	888,539	888,539
18	616,378	616,378	616,378	616,378	616,378	616,378	616,378	616,378	616,378	616,378	616,378
19	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578
20	667,777	667,777	667,777	667,777	667,777	667,777	667,777	667,777	667,777	667,777	667,777

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LKE
LG&E and KU Pension Plan
Bond Payments

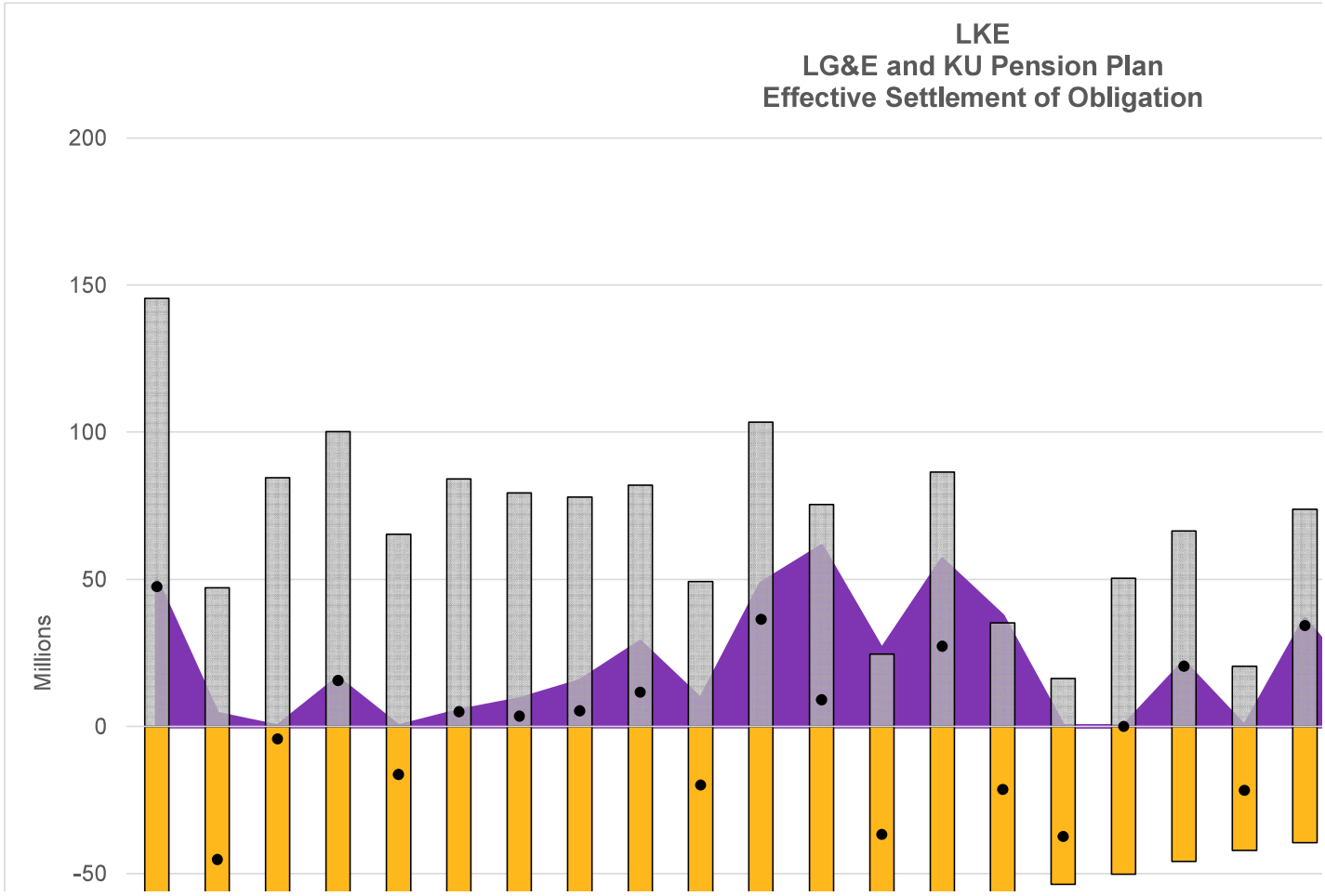
Year	12	13	14	15	16	17	18	19	20	21	22
Total	75,387,143	24,455,906	86,363,697	35,205,835	16,251,586	50,256,609	66,356,593	20,428,688	73,808,876	10,594,394	50,667,223
Payment From Bond											
1	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0
9	54,385,084	0	0	0	0	0	0	0	0	0	0
10	292,771	3,746,618	973,187	0	0	0	0	0	0	0	0
11	5,818,391	5,818,391	70,499,613	18,272,852	0	0	0	0	0	0	0
12	217,353	217,353	217,353	2,259,438	1,578,041	0	0	0	0	0	0
13	1,062,346	1,062,346	1,062,346	1,062,346	1,062,346	24,187,066	1,057,248	0	0	0	0
14	2,360,415	2,360,415	2,360,415	2,360,415	2,360,415	14,818,760	54,048,562	0	0	0	0
15	3,576,523	3,576,523	3,576,523	3,576,523	3,576,523	3,576,523	3,576,523	12,754,428	66,134,616	0	0
16	820,988	820,988	820,988	820,988	820,988	820,988	820,988	820,988	820,988	3,741,122	19,529,349
17	888,539	888,539	888,539	888,539	888,539	888,539	888,539	888,539	888,539	888,539	25,173,142
18	616,378	616,378	616,378	616,378	616,378	616,378	616,378	616,378	616,378	616,378	616,378
19	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578	4,680,578
20	667,777	667,777	667,777	667,777	667,777	667,777	667,777	667,777	667,777	667,777	667,777

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LKE
LG&E and KU Pension Plan
Bond Payments

Year	23	24	25	26	27	28	29	30
Total	11,154,597	16,060,303	85,830,601	81,590,709	0	0	0	0
Payment From Bond								
1	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0
16	0	0	0	0	0	0	0	0
17	5,189,865	0	0	0	0	0	0	0
18	616,378	10,711,948	3,619,068	0	0	0	0	0
19	4,680,578	4,680,578	78,655,354	66,424,683	0	0	0	0
20	667,777	667,777	3,556,179	15,166,026	0	0	0	0

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LKE
LG&E and KU Pension Plan
Reconciliation

	Cash Available				Excess for year			
Year	Bond Payments For Year	Carried From Prior Years	Total	Benefit Payments	Excess	Limit to Carry	Interest Rate	Discarded
1	145,455,452	0	145,455,452	97,982,195	47,473,257	88,796,453	4.03%	0
2	47,081,884	49,386,774	96,468,658	92,375,595	4,093,063	85,191,210	4.23%	0
3	84,528,861	4,266,213	88,795,073	88,795,073	0	80,787,032	4.63%	0
4	100,112,886	0	100,112,886	84,531,494	15,581,392	77,775,314	4.99%	0
5	65,294,831	16,358,260	81,653,091	81,653,091	0	75,106,787	5.30%	0
6	84,063,237	0	84,063,237	79,089,916	4,973,321	71,864,947	5.60%	0
7	79,343,300	5,251,971	84,595,270	75,891,458	8,703,813	68,680,582	5.87%	0
8	77,954,824	9,215,011	87,169,834	72,714,373	14,455,462	66,311,163	6.10%	0
9	81,931,227	15,336,620	97,267,847	70,353,281	26,914,566	65,081,815	6.26%	0
10	49,214,906	28,598,285	77,813,190	69,153,195	8,659,995	63,080,934	6.35%	0
11	103,421,114	9,210,154	112,631,268	67,088,387	45,542,881	62,366,327	6.40%	0
12	75,387,143	48,457,673	123,844,816	66,357,838	57,486,978	57,486,978	6.42%	0
13	24,455,906	61,175,375	85,631,282	61,175,375	24,455,906	55,586,537	6.42%	0
14	86,363,697	26,025,071	112,388,768	59,153,137	53,235,631	53,235,631	6.41%	0
15	35,205,835	56,649,163	91,854,998	56,649,163	35,205,835	50,478,368	6.41%	0
16	16,251,586	37,462,721	53,714,306	53,714,306	0	47,227,192	6.41%	0
17	50,256,609	0	50,256,609	50,256,609	0	43,118,714	6.42%	0
18	66,356,593	0	66,356,593	45,889,062	20,467,531	39,659,878	6.44%	0
19	20,428,688	21,786,019	42,214,707	42,214,707	0	37,180,328	6.47%	0
20	73,808,876	0	73,808,876	39,584,140	34,224,735	34,224,735	6.49%	0
21	10,594,394	36,447,603	47,041,997	36,447,603	10,594,394	31,346,609	6.53%	0
22	50,667,223	11,286,235	61,953,459	33,393,622	28,559,837	28,559,837	6.57%	0
23	11,154,597	30,436,381	41,590,979	30,436,381	11,154,597	26,218,415	6.62%	0
24	16,060,303	11,892,484	27,952,788	27,952,788	0	N/A	6.66%	0
25	85,830,601	0	85,830,601	25,835,233	59,995,368	N/A	6.71%	0
26	81,590,709	64,023,329	145,614,039	23,411,749	122,202,290	N/A	6.77%	0
27	0	130,470,862	130,470,862	21,316,078	109,154,784	N/A	6.82%	0
28	0	116,598,757	116,598,757	19,364,344	97,234,413	N/A	6.87%	0
29	0	103,917,416	103,917,416	17,527,431	86,389,984	N/A	6.93%	0
30	0	92,372,894	92,372,894	92,372,894	0	0	6.98%	0

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LKE
LG&E and KU Pension Plan
Discount Rate

Benefit obligation	
Matching portfolio	956,029,414
PV of payments discounted separately	0
Total	956,029,414
Discount rate	5.78%
PV of benefit payments	956,029,423
Macaulay duration	8.56
Modified duration	8.09

Year	Maturity	Payment	PV at 5.78%
1	0.5	97,982,195	95,265,987
2	1.5	92,375,595	84,904,240
3	2.5	88,795,073	77,151,153
4	3.5	84,531,494	69,431,015
5	4.5	81,653,091	63,399,965
6	5.5	79,089,916	58,052,232
7	6.5	75,891,458	52,658,942
8	7.5	72,714,373	47,695,885
9	8.5	70,353,281	43,624,095
10	9.5	69,153,195	40,535,520
11	10.5	67,088,387	37,175,110
12	11.5	66,357,838	34,759,903
13	12.5	61,175,375	30,293,147
14	13.5	59,153,137	27,690,255
15	14.5	56,649,163	25,068,254
16	15.5	53,714,306	22,469,944
17	16.5	50,256,609	19,874,061
18	17.5	45,889,062	17,154,736
19	18.5	42,214,707	14,918,325
20	19.5	39,584,140	13,223,880
21	20.5	36,447,603	11,510,338
22	21.5	33,393,622	9,969,286
23	22.5	30,436,381	8,589,640
24	23.5	27,952,788	7,457,418
25	24.5	25,835,233	6,515,642
26	25.5	23,411,749	5,581,618
27	26.5	21,316,078	4,804,132
28	27.5	19,364,344	4,125,645
29	28.5	17,527,431	3,530,114
30	29.5	15,811,658	3,010,435
31	30.5	14,220,353	2,559,433
32	31.5	12,753,585	2,169,936
33	32.5	11,408,932	1,835,021
34	33.5	10,181,835	1,548,117
35	34.5	9,066,519	1,303,165
36	35.5	8,055,510	1,094,545
37	36.5	7,140,911	917,224
38	37.5	6,314,433	766,721
39	38.5	5,568,091	639,133
40	39.5	4,894,273	531,073
41	40.5	4,285,965	439,639
42	41.5	3,736,892	362,359
43	42.5	3,241,597	297,146
44	43.5	2,795,385	242,233
45	44.5	2,394,316	196,135
46	45.5	2,035,094	157,594
47	46.5	1,714,934	125,540
48	47.5	1,431,513	99,063
49	48.5	1,182,647	77,367
50	49.5	966,151	59,748
51	50.5	779,859	45,591
52	51.5	621,477	34,345
53	52.5	488,618	25,527
54	53.5	378,748	18,705
55	54.5	289,241	13,504
56	55.5	217,450	9,597
57	56.5	160,819	6,709
58	57.5	116,916	4,611

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LKE
LG&E and KU Pension Plan
Discount Rate

Benefit obligation	
Matching portfolio	956,029,414
PV of payments discounted separately	0
Total	956,029,414
Discount rate	5.78%
PV of benefit payments	956,029,423
Macaulay duration	8.56
Modified duration	8.09

Year	Maturity	Payment	PV at 5.78%
59	58.5	83,499	3,113
60	59.5	58,553	2,064
61	60.5	40,297	1,343
62	61.5	27,213	857
63	62.5	18,031	537
64	63.5	11,726	330
65	64.5	7,488	199
66	65.5	4,703	118
67	66.5	2,911	69
68	67.5	1,781	40
69	68.5	1,080	23
70	69.5	653	13
71	70.5	394	7
72	71.5	239	4
73	72.5	146	2
74	73.5	90	1
75	74.5	55	1
76	75.5	34	0
77	76.5	20	0
78	77.5	12	0
79	78.5	7	0
80	79.5	4	0
81	80.5	0	0
82	81.5	0	0
83	82.5	0	0
84	83.5	0	0
85	84.5	0	0
86	85.5	0	0
87	86.5	0	0
88	87.5	0	0
89	88.5	0	0
90	89.5	0	0
91	90.5	0	0
92	91.5	0	0
93	92.5	0	0
94	93.5	0	0
95	94.5	0	0
96	95.5	0	0
97	96.5	0	0
98	97.5	0	0
99	98.5	0	0
100	99.5	0	0

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EXHIBIT LK-5

KENTUCKY UTILITIES COMPANY

Response to the Joint Supplemental Data Requests of the Attorney General and Kentucky Industrial Utility Customers'
Dated July 31, 2025

Case No. 2025-00113

Question No. 20

Responding Witness: Christopher M. Garrett / Drew T. McCombs

Q-20. Refer to the response to AG-KIUC 1-85(d) re: the Regulatory Asset – FAS 158 Pension in account 182 and the statement the account "represents accumulated unamortized prior service costs and net actuarial losses of the plan." Describe in detail how the Companies actually financed these amounts, including when the Companies paid the unamortized prior service costs and how they financed those costs and when the Companies paid the net actuarial losses of the plan and how the Companies financed those costs.

A-20. The amounts recognized in account 182 as a result of the implementation of FAS 158 represents prior service costs and actuarial losses which have not yet been included in net periodic pension cost. These amounts are not financed by the Companies with the exception discussed below but are included in both rate base and capitalization as the corresponding prepaid pension asset and post-retirement liability are also included in rate base and capitalization.

The Companies agreed to amortize actuarial losses over a period of 15 years as a result of the stipulation agreement reached in the 2014 rate cases[2] which reduced the amount of pension expense being recovered from customers in rates and thus a portion of this balance is being financed by the Companies.

Exclusion of this account from rate base and capitalization would result in asymmetrical rate treatment.

[2] Case No. 2014-00371, *Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*. (Ky. PSC Jun. 30, 2015), Order at 5.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to the Joint Supplemental Data Requests of the Attorney General and Kentucky Industrial Utility Customers'
Dated July 31, 2025

Case No. 2025-00114

Question No. 20

Responding Witness: Christopher M. Garrett / Drew T. McCombs

Q-20. Refer to the response to AG-KIUC 1-85(d) re: the Regulatory Asset – FAS 158 Pension in account 182 and the statement the account "represents accumulated unamortized prior service costs and net actuarial losses of the plan." Describe in detail how the Companies actually financed these amounts, including when the Companies paid the unamortized prior service costs and how they financed those costs and when the Companies paid the net actuarial losses of the plan and how the Companies financed those costs.

A-20. The amounts recognized in account 182 as a result of the implementation of FAS 158 represents prior service costs and actuarial losses which have not yet been included in net periodic pension cost. These amounts are not financed by the Companies with the exception discussed below but are included in both rate base and capitalization as the corresponding prepaid pension asset and post-retirement liability are also included in rate base and capitalization.

The Companies agreed to amortize actuarial losses over a period of 15 years as a result of the stipulation agreement reached in the 2014 rate cases[2] which reduced the amount of pension expense being recovered from customers in rates and thus a portion of this balance is being financed by the Companies.

Exclusion of this account from rate base and capitalization would result in asymmetrical rate treatment.

[2] Case No. 2014-00371, *Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*. (Ky. PSC Jun. 30, 2015), Order at 5.

EXHIBIT LK-6

KENTUCKY UTILITIES COMPANY

Response to Joint Supplemental Data Requests of the Attorney General and KIUC
Dated February 5, 2021

Case No. 2020-00349

Question No. 14

Responding Witness: Christopher M. Garrett

Q-14. Refer to the Company's response to AG-KIUC 1-54(d) related to the pension regulatory asset recorded as "Regulatory Asset – FAS 158 Pension" in account 182 shown on Schedule B-5.2, page 5 of 6.

a. Confirm that the unamortized prior service costs are the portion of the pension liability that has not yet been recorded in pension cost." Confirm that the pension cost calculation includes no return or interest on the prior service cost, but it does include interest on the entire pension liability. If either of these statements are incorrect, then provide corrected statements and all support for the corrected statements.

b. Confirm that the net actuarial losses of the plan are reflected in the trust fund assets used to determine the net funding of the pension plan. Confirm that the pension cost calculation includes a return on the trust fund assets and that if there have been losses they are reflected in a lower return on the trust fund assets and thus, a higher pension cost. If either of these statements is incorrect, then provide corrected statements and all support for the corrected statements.

A-14. The Company follows Accounting Standards Codification ("ASC") 715-20 for the calculation of all components of pension cost.

a. Unamortized prior service cost is the unamortized portion of the increase or decrease in a pension plan's projected benefit obligation due to a plan amendment and is therefore included as a portion of the pension liability. Since unamortized prior service cost is a component of the entire pension liability, the calculation of the pension cost does include interest on the unamortized prior service cost. Unamortized prior service cost is not part of the asset balance on which the Expected Return on Assets (EROA) is calculated.

b. Net actuarial gains or losses arise either from 1) plan experience that is different from what was assumed or 2) changes in plan assumptions. Both types impact the funded status of the plan, but not all of them impact the trust

fund assets. The plan experience variances can be the result of investment performance varying from the assumed EROA or from demographic variances such as actual death rates or retirement dates varying from those assumed. Only those actuarial gains and losses arising from investment performance impact the trust funds assets. All other forms of actuarial gains and losses, most notably those actuarial gains and losses resulting from changes in discount rates, impact the calculation of the plan's liability.

One component of the calculation of pension cost is an expected return on plan assets. The expected return on plan assets is determined based on a market-related value of plan assets, which is calculated by rolling forward the prior year market-related value with contributions, disbursements and long-term expected return on investments. One-fifth of the difference between the actual value and the expected value is added (or subtracted if negative) to the expected value to determine the new market-related value. Therefore, it is confirmed that actuarial gains reduce future pension cost and actuarial losses increase future pension cost. In effect, the actuarial gains and losses serve as a mechanism to adjust future expense to reflect previously unrecognized expense as well as expected changes in the future liability.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Supplemental Data Requests of the Attorney General and KIUC
Dated February 5, 2021

Case No. 2020-00350

Question No. 14

Responding Witness: Christopher M. Garrett

Q-14. Refer to the Company's response to AG-KIUC 1-54(d) related to the pension regulatory asset recorded as "Regulatory Asset – FAS 158 Pension" in account 182 shown on Schedule B-5.2, page 5 of 6.

a. Confirm that the unamortized prior service costs are the portion of the pension liability that has not yet been recorded in pension cost." Confirm that the pension cost calculation includes no return or interest on the prior service cost, but it does include interest on the entire pension liability. If either of these statements are incorrect, then provide corrected statements and all support for the corrected statements.

b. Confirm that the net actuarial losses of the plan are reflected in the trust fund assets used to determine the net funding of the pension plan. Confirm that the pension cost calculation includes a return on the trust fund assets and that if there have been losses they are reflected in a lower return on the trust fund assets and thus, a higher pension cost. If either of these statements is incorrect, then provide corrected statements and all support for the corrected statements.

A-14. The Company follows Accounting Standards Codification ("ASC") 715-20 for the calculation of all components of pension cost.

a. Unamortized prior service cost is the unamortized portion of the increase or decrease in a pension plan's projected benefit obligation due to a plan amendment and is therefore included as a portion of the pension liability. Since unamortized prior service cost is a component of the entire pension liability, the calculation of the pension cost does include interest on the unamortized prior service cost. Unamortized prior service cost is not part of the asset balance on which the Expected Return on Assets (EROA) is calculated.

b. Net actuarial gains or losses arise either from 1) plan experience that is different from what was assumed or 2) changes in plan assumptions. Both types impact the funded status of the plan, but not all of them impact the trust

fund assets. The plan experience variances can be the result of investment performance varying from the assumed EROA or from demographic variances such as actual death rates or retirement dates varying from those assumed. Only those actuarial gains and losses arising from investment performance impact the trust funds assets. All other forms of actuarial gains and losses, most notably those actuarial gains and losses resulting from changes in discount rates, impact the calculation of the plan's liability.

One component of the calculation of pension cost is an expected return on plan assets. The expected return on plan assets is determined based on a market-related value of plan assets, which is calculated by rolling forward the prior year market-related value with contributions, disbursements and long-term expected return on investments. One-fifth of the difference between the actual value and the expected value is added (or subtracted if negative) to the expected value to determine the new market-related value. Therefore, it is confirmed that actuarial gains reduce future pension cost and actuarial losses increase future pension cost. In effect, the actuarial gains and losses serve as a mechanism to adjust future expense to reflect previously unrecognized expense as well as expected changes in the future liability.

EXHIBIT LK-7

KENTUCKY UTILITIES COMPANY

Response to Joint Supplemental Data Requests of the Attorney General and KIUC
Dated February 5, 2021

Case No. 2020-00349

Question No. 11

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

Q-11. Refer to the Commission's Order in Case No. 2020-00174 at 10-11 wherein it addresses an adjustment to increase Kentucky Power Company's pension and OPEB expense by $3.7 million based on a calculation performed by KPCo witness Ms. Whitney addressed in her rebuttal testimony and detailed in her Exhibit_HMW-R3 in that proceeding.

a. Provide a calculation for the adjustment to pension expense using the KPCo methodology for the Company, including allocations/charges from LKE, for the test year in this proceeding. Provide all assumptions, data, and workpapers in live Excel format with all formulas intact.

b. Provide a calculation for the adjustment to OPEB expense using the KPCo methodology for the Company, including allocations/charges from LKE, for the test year in this proceeding. Provide all assumptions, data, and workpapers in live Excel format with all formulas intact.

c. Confirm that a portion of the Company's pension and OPEB costs is charged to expense and a portion is charged to capital.

A-11.

a. See attachment being provided in Excel format. The first section of the "Summary" tab in the excel workbook provides the revenue requirement decrease associated with the removal of the prepaid pension asset from capitalization / rate base. The second section of the "Summary" tab provides the revenue requirement increase associated with the corresponding expense adjustments necessitated by the removal of the prepaid pension asset.

The Company does not agree with the use of this methodology in this proceeding and further notes that the difference is small once all relevant adjustments, including variable rate PBGC premiums and ADIT, are considered. The prepaid pension asset reduces the pension plan's variable rate PBGC premiums. Therefore, the calculation on tab 1 of the file reflects the impact of the EROA being applied to the avoided variable rate premium. As it relates to ADIT, the Company has included both the impact of removing

the ADIT liability associated with the prepaid pension asset currently included in capitalization / rate base as well as the excess ADIT amortization currently being returned to customers via the Economic Relief Surcredit. The Company further notes that it is utilizing capitalization and not rate base as its valuation methodology in these proceedings for good reason.

b. The calculation is not applicable to the OPEB expense as the plan's allocation to KU is a liability.

c. KU confirms that a portion of the Company's pension and OPEB costs is charged to expense and a portion is charged to capital. The calculation in the attachment includes the allocation to capital.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Supplemental Data Requests of the Attorney General and KIUC
Dated February 5, 2021

Case No. 2020-00350

Question No. 11

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

Q-11. Refer to the Commission's Order in Case No. 2020-00174 at 10-11 wherein it addresses an adjustment to increase Kentucky Power Company's pension and OPEB expense by $3.7 million based on a calculation performed by KPCo witness Ms. Whitney addressed in her rebuttal testimony and detailed in her Exhibit_HMW-R3 in that proceeding.

a. Provide a calculation for the adjustment to pension expense using the KPCo methodology for the Company, including allocations/charges from LKE, for the test year in this proceeding. Provide all assumptions, data, and workpapers in live Excel format with all formulas intact.

b. Provide a calculation for the adjustment to OPEB expense using the KPCo methodology for the Company, including allocations/charges from LKE, for the test year in this proceeding. Provide all assumptions, data, and workpapers in live Excel format with all formulas intact.

c. Confirm that a portion of the Company's pension and OPEB costs is charged to expense and a portion is charged to capital.

A-11.

a. See attachment being provided in Excel format. The first section of the "Summary" tab in the excel workbook provides the revenue requirement decrease associated with the removal of the prepaid pension asset from capitalization / rate base. The second section of the "Summary" tab provides the revenue requirement increase associated with the corresponding expense adjustments necessitated by the removal of the prepaid pension asset.

The Company does not agree with the use of this methodology in this proceeding and further notes that the difference is small once all relevant adjustments, including variable rate PBGC premiums and ADIT, are considered. The prepaid pension asset reduces the pension plan's variable rate PBGC premiums. Therefore, the calculation on tab 1 of the file reflects the impact of the EROA being applied to the avoided variable rate premium.

As it relates to ADIT, the Company has included both the impact of removing the ADIT liability associated with the prepaid pension asset currently included in capitalization / rate base as well as the excess ADIT amortization currently being returned to customers via the Economic Relief Surcredit. The Company further notes that it is utilizing capitalization and not rate base as its valuation methodology in these proceedings for good reason.

b. The calculation is not applicable to the OPEB expense as the plan's allocation to LG&E is a liability.

c. LG&E confirms that a portion of the Company's pension and OPEB costs is charged to expense and a portion is charged to capital. The calculation in the attachment includes the allocation to capital.

EXHIBIT LK-8

KENTUCKY UTILITIES COMPANY

Response to the Joint Supplemental Data Requests of the Attorney General and Kentucky Industrial Utility Customers'
Dated July 31, 2025

Case No. 2025-00113

Question No. 35

Responding Witness: Drew T. McCombs

Q-35. Provide an annual history from 2015 through 2024 of routine storm expense by FERC O&M expense account, i.e., unnamed storm expense the Companies did not defer pursuant to an accounting order from the Commission. Identify each such storm and provide a brief description.

A-35. See attachment being provided in a separate file for KU total storm expense by FERC O&M expense accounts for minor storms. The Companies do not compile descriptions of minor storms.

Minor Storms Expense

FERC	FERC Account Name	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
408	Taxes other than income taxes, utility operating income	-	-	-	-	-	-	-	-	49,976	57,034
562	Station expenses	5,322	-	-	-	-	-	-	-	-	-
571	Maintenance of overhead lines	588,286	307,552	176,143	291,656	319,209	344,416	266,349	353,777	205,128	228,260
580	Operation supervision and engineering	67,853	113,958	50,273	74,094	69,404	115,992	179,959	434,119	204,404	303,397
583	Overhead line expenses	99,383	148,861	38,146	129,017	141,833	98,039	101,654	118,224	44,174	116,513
584	Underground line expenses	880	-	-	-	-	-	-	-	-	-
588	Miscellaneous distribution expenses	-	948	-	266	15,398	3,959	16,851	5,465	49,212	7,864
590	Maintenance supervision and engineering	-	-	10,840	-	-	-	-	837	2,739	-
591	Maintenance of structures	-	-	-	-	-	-	-	424	-	-
593	Maintenance of overhead lines	1,247,301	1,588,622	1,444,787	1,014,621	1,416,867	1,573,958	1,925,018	2,784,473	2,118,038	2,387,491
594	Maintenance of underground lines	2,482	1,193	-	-	-	-	-	-	-	-
595	Maintenance of line transformers	14,437	8,841	33,209	6,088	14,489	-	9,609	3,957	21,222	16,340
598	Maintenance of miscellaneous distribution plant	6,731	22,308	10,963	4,608	11,893	9,698	9,637	13,511	6,593	54,523
909	Informational and instructional advertising expenses	-	-	-	850	-	-	-	-	-	-
925	Injuries and damages	-	2,287	-	-	-	-	-	-	1,024	831
926	Employee pensions and benefits	-	-	-	-	-	-	-	-	45,749	58,270
Total Minor Storms Expense		**2,032,675**	**2,194,570**	**1,764,360**	**1,521,200**	**1,989,093**	**2,146,063**	**2,509,078**	**3,714,787**	**2,748,257**	**3,230,523**

KENTUCKY UTILITIES COMPANY

Response to the Joint Supplemental Data Requests of the Attorney General and Kentucky Industrial Utility Customers'
Dated July 31, 2025

Case No. 2025-00113

Question No. 36

Responding Witness: Drew T. McCombs

Q-36. Provide an annual history from 2015 through 2024 by FERC O&M expense account for named storms the Companies deferred to a regulatory asset pursuant to an accounting order from the Commission.

A-36. See attachment being provided in a separate file for KU total storm expense by FERC O&M expense accounts for storms that were deferred to a regulatory asset.

Regulatory Asset Storms Expense

FERC	FERC Account Name	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
408	Taxes other than income taxes, utility operating income	-	-	-	-	-	-	-	-	108,337	220,987
570	Maintenance of station equipment	-	-	-	-	-	-	-	-	-	13,031
571	Maintenance of overhead lines	-	-	-	43,186	-	-	-	-	971,893	855,920
580	Operation supervision and engineering	-	-	-	545,569	2,547	-	-	-	2,069,346	1,690,601
583	Overhead line expenses	-	-	-	204,565	-	-	-	-	50,091	191,190
590	Maintenance supervision and engineering	-	-	-	11,465	-	-	-	-	32,034	83,036
593	Maintenance of overhead lines	-	-	-	3,983,487	281	-	-	-	7,333,315	11,448,927
594	Maintenance of underground lines	-	-	-	264	-	-	-	-	960	5,642
595	Maintenance of line transformers	-	-	-	8,903	-	-	-	-	171,037	283,099
598	Maintenance of miscellaneous distribution plant	-	-	-	110,952	-	-	-	-	550,775	1,193,420
909	Informational and instructional advertising expenses	-	-	-	600	-	-	-	-	210,442	172,728
920	Administrative and general salaries	-	-	-	8,335	-	-	-	-	264	16,574
925	Injuries and damages	-	-	-	3,623	-	-	-	-	98,220	287,537
926	Employee pensions and benefits	-	-	-	-	-	-	-	-	71,673	88,119
Total Regulatory Asset Storms Expense		**-**	**-**	**-**	**4,920,948**	**2,828**	**-**	**-**	**-**	**11,668,387**	**16,550,811**

Note:

2023 costs of $11,668,387 are offset by a regulatory asset recorded at a Corporate cost center of $11,016,643. The regulatory asset excludes costs associated with normal operations and Virginia costs.

2024 costs of $16,550,811 are offset by regulatory assets recorded at a Corporate cost center of $15,606,568. The regulatory assets exclude costs associated with normal operations and Virginia costs.

KENTUCKY UTILITIES COMPANY

Response to the Joint Supplemental Data Requests of the Attorney General and Kentucky Industrial Utility Customers'
Dated July 31, 2025

Case No. 2025-00113

Question No. 37

Responding Witness: Drew T. McCombs

Q-37. Provide an annual history from 2015 through 2024 by FERC O&M expense account for named storms the Companies did not defer.

A-37. See attachment being provided in a separate file for KU total storm expense by FERC O&M expense accounts for major storms that the Companies did not defer.

Major Storms Expense (excludes Regulatory Asset Storms)

FERC	FERC Account Name	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
408	Taxes other than income taxes, utility operating income	-	-	-	-	-	-	-	-	76,562	21,000
571	Maintenance of overhead lines	-	-	-	-	-	-	1,368,340	-	-	-
580	Operation supervision and engineering	149,332	129,346	103,494	246,364	33,879	71,287	745,056	686,958	404,658	164,901
583	Overhead line expenses	93,501	26,540	34,942	35,108	12,771	6,332	430,226	731,844	172,059	19,432
588	Miscellaneous distribution expenses	-	-	-	-	-	-	7,890	473	-	-
590	Maintenance supervision and engineering	138,520	15,784	53,347	18,980	2,012	11,840	111,332	39,778	11,759	16,075
593	Maintenance of overhead lines	1,625,805	762,575	699,343	1,163,020	265,919	312,514	3,677,843	4,061,340	4,025,723	646,162
594	Maintenance of underground lines	5,568	-	5,189	612	105	-	-	11,093	1,490	-
595	Maintenance of line transformers	33,767	4,266	19,690	33,372	3,250	-	763	20,081	47,079	16,004
598	Maintenance of miscellaneous distribution plant	98,153	15,378	25,457	42,037	18,691	12,481	206,016	246,352	327,485	50,893
909	Informational and instructional advertising expenses	-	-	-	17,922	13,654	-	53,462	1,687	-	45,252
920	Administrative and general salaries	-	-	-	-	-	2,595	-	-	426	460
925	Injuries and damages	15,024	300	2,925	-	-	-	-	700	6,244	1,628
926	Employee pensions and benefits	-	-	-	-	-	-	-	-	47,060	16,470
930	General advertising expenses	2,270	-	-	-	-	-	-	-	-	-
Total Major Storms Expense		**2,161,940**	**954,188**	**944,387**	**1,557,416**	**350,281**	**417,048**	**6,600,928**	**5,800,306**	**5,120,545**	**998,278**

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to the Joint Supplemental Data Requests of the Attorney General and Kentucky Industrial Utility Customers'
Dated July 31, 2025

Case No. 2025-00114

Question No. 35

Responding Witness: Drew T. McCombs

Q-35. Provide an annual history from 2015 through 2024 of routine storm expense by FERC O&M expense account, i.e., unnamed storm expense the Companies did not defer pursuant to an accounting order from the Commission. Identify each such storm and provide a brief description.

A-35. See attachment being provided in a separate file for storm expense by FERC O&M expense accounts for minor storms. The Companies do not compile descriptions of minor storms.

Minor Storms Expense

FERC	FERC Account Name	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
408	Taxes other than income taxes, utility operating income	-	-	-	-	-	-	-	-	30,204	63,772
571	Maintenance of overhead lines	143,193	83,641	99,240	54,068	107,782	17,538	53,610	46,927	37,658	76,043
580	Operation supervision and engineering	475,214	177,619	211,775	265,745	110,219	138,063	115,545	90,658	183,131	188,692
583	Overhead line expenses	512,601	228,904	238,270	373,629	366,433	301,187	586,366	328,181	277,238	685,086
588	Miscellaneous distribution expenses	-	-	-	-	2,128	3,620	3,845	2,206	22,101	-
590	Maintenance supervision and engineering	55,311	4,112	49,716	27,307	6,910	8,318	1,291	10,461	4,115	24,880
593	Maintenance of overhead lines	2,232,069	1,160,901	1,226,047	1,568,886	1,586,905	1,244,752	1,332,764	727,679	1,004,948	1,445,306
594	Maintenance of underground lines	137,857	63,518	29,509	88,368	78,152	19,457	32,343	19,427	17,317	37,730
595	Maintenance of line transformers	1	-	-	-	-	-	-	-	-	-
598	Maintenance of miscellaneous distribution plant	114,717	12,450	7,998	10,476	6,203	6,569	8,250	4,663	7,081	18,132
880	Other expenses	-	-	-	8,129	-	-	-	-	-	-
909	Informational and instructional advertising expenses	-	-	-	18,690	-	-	-	-	-	-
925	Injuries and damages	-	-	-	-	-	-	-	-	693	1,425
926	Employee pensions and benefits	-	-	-	-	-	-	-	-	29,121	59,142
930	General advertising expenses	12,500	-	-	-	-	-	-	-	-	-
Total Minor Storms Expense		**3,683,461**	**1,731,145**	**1,862,556**	**2,415,299**	**2,264,733**	**1,739,504**	**2,134,015**	**1,230,201**	**1,613,606**	**2,600,206**

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to the Joint Supplemental Data Requests of the Attorney General and Kentucky Industrial Utility Customers'
Dated July 31, 2025

Case No. 2025-00114

Question No. 36

Responding Witness: Drew T. McCombs

Q-36. Provide an annual history from 2015 through 2024 by FERC O&M expense account for named storms the Companies deferred to a regulatory asset pursuant to an accounting order from the Commission.

A-36. See attachment being provided in a separate file for total storm expense by FERC O&M expense accounts for storms that were deferred to a regulatory asset.

Regulatory Asset Storms Expense

FERC	FERC Account Name	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
408	Taxes other than income taxes, utility operating income	-	-	-	-	-	-	-	-	79,817	90,263
571	Maintenance of overhead lines	-	-	-	40,468	-	-	-	-	152,164	98,143
580	Operation supervision and engineering	-	-	-	1,586,936	34,839	-	-	-	2,147,048	1,049,874
583	Overhead line expenses	-	-	-	240,817	235,219	-	-	-	425,009	327,775
590	Maintenance supervision and engineering	-	-	-	15,222	675	-	-	-	19,563	12,395
593	Maintenance of overhead lines	-	-	-	6,677,336	(110,862)	-	-	-	5,359,136	4,145,108
594	Maintenance of underground lines	-	-	-	47,272	5,038	-	-	-	5,016	22,165
595	Maintenance of line transformers	-	-	-	5,056	-	-	-	-	1,410	641
598	Maintenance of miscellaneous distribution plant	-	-	-	266,235	43,892	-	-	-	468,836	343,075
909	Informational and instructional advertising expenses	-	-	-	63,954	-	-	-	-	186,237	108,298
920	Administrative and general salaries	-	-	-	2,075	-	-	-	-	379	-
925	Injuries and damages	-	-	-	-	-	-	-	-	16,283	530
926	Employee pensions and benefits	-	-	-	-	-	-	-	-	55,247	58,609
Total Regulatory Asset Storms Expense		**-**	**-**	**-**	**8,945,370**	**208,800**	**-**	**-**	**-**	**8,916,145**	**6,256,875**

Note:

2023 costs of $8,916,145 are offset by a regulatory asset recorded at a Corporate cost center of $8,360,948. The regulatory asset excludes costs associated with normal operations.

2024 costs of $6,256,875 are offset by regulatory assets recorded at a Corporate cost center of $5,911,960. The regulatory assets exclude costs associated with normal operations.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to the Joint Supplemental Data Requests of the Attorney General and Kentucky Industrial Utility Customers'
Dated July 31, 2025

Case No. 2025-00114

Question No. 37

Responding Witness: Drew T. McCombs

Q-37. Provide an annual history from 2015 through 2024 by FERC O&M expense account for named storms the Companies did not defer.

A-37. See attachment being provided in a separate file for storm expense by FERC O&M expense accounts for major storms that the Companies did not defer.

Major Storms Expense (excludes Regulatory Asset Storms)

FERC	FERC Account Name	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
408	Taxes other than income taxes, utility operating income	-	-	-	-	-	-	-	-	135,649	42,616
571	Maintenance of overhead lines	-	-	-	-	-	-	135,851	-	-	-
580	Operation supervision and engineering	151,474	96,781	80,490	645,671	488,830	74,905	225,830	600,769	1,421,045	243,713
583	Overhead line expenses	57,781	36,324	45,492	308,885	216,411	158,474	99,100	3,556,459	1,210,829	220,919
590	Maintenance supervision and engineering	8,247	4,677	13,607	9,745	29,821	8,251	4,332	24,596	12,349	9,874
593	Maintenance of overhead lines	1,035,072	508,205	354,201	2,360,291	2,294,762	785,624	811,091	3,615,880	6,958,548	1,844,488
594	Maintenance of underground lines	6,275	1,025	6,514	18,707	458	8,945	669	73,974	28,286	26,543
595	Maintenance of line transformers	22,910	2,089	534	13,019	1,237	910	61	-	5,874	1,138
598	Maintenance of miscellaneous distribution plant	22,187	7,004	3,020	53,185	80,529	17,019	8,274	181,902	215,833	87,974
909	Informational and instructional advertising expenses	-	-	-	3,104	26,579	-	49,673	27,339	6,631	29,323
920	Administrative and general salaries	-	-	-	-	562	-	4,508	-	-	-
925	Injuries and damages	-	895	-	-	-	-	-	-	35,613	19,411
926	Employee pensions and benefits	-	-	-	-	-	-	-	-	119,253	34,558
Total Major Storms Expense		**1,303,946**	**656,999**	**503,858**	**3,412,608**	**3,139,189**	**1,054,128**	**1,339,387**	**8,080,918**	**10,149,910**	**2,560,556**

EXHIBIT LK-9

KENTUCKY UTILITIES COMPANY

Response to the Joint Supplemental Data Requests of the Attorney General and Kentucky Industrial Utility Customers'
Dated July 31, 2025

Case No. 2025-00113

Question No. 39

Responding Witness: Drew T. McCombs / Heather D. Metts

Q-39. Provide the total storm expense by FERC O&M expense account in the base period and test year, along with all support relied on to estimate these expenses in an Excel workbook in live format and with all formulas intact. Identify where the expenses were included in the filings.

A-39. Total storm expense by FERC O&M expense account for total KU in the base period and test year are below. See attachments being provided in separate files for the support relied on to estimate the storm expenses. The storm expenses are embedded in Schedule C (Filing Requirement Tab 56 - 807 KAR 5:001 Section 16(8)(c) in the FERC O&M expense accounts provided below).

FERC	FERC Account Name	Base Period	Test Year
408	Taxes other than income taxes, utility operating income	237,862	-
566	Miscellaneous transmission expenses	358	-
570	Maintenance of station equipment	27,327	-
571	Maintenance of overhead lines	1,715,816	623,235
580	Operation supervision and engineering	2,155,541	631,919
583	Overhead line expenses	306,677	205,962
588	Miscellaneous distribution expenses	13,247	21,708
590	Maintenance supervision and engineering	88,564	32,827
592	Maintenance of station equipment	61	100
593	Maintenance of overhead lines	17,424,324	4,714,693
594	Maintenance of underground lines	16,169	2,658
595	Maintenance of line transformers	136,688	24,878
598	Maintenance of miscellaneous distribution plant	1,464,904	156,122
909	Informational and instructional advertising expenses	129,829	25,302
920	Administrative and general salaries	8,280	-
925	Injuries and damages	288,499	-
926	Employee pensions and benefits	119,106	-
Total		**24,133,253**	**6,439,406**

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to the Joint Supplemental Data Requests of the Attorney General and Kentucky Industrial Utility Customers'
Dated July 31, 2025

Case No. 2025-00114

Question No. 39

Responding Witness: Drew T. McCombs / Heather D. Metts

Q-39. Provide the total storm expense by FERC O&M expense account in the base period and test year, along with all support relied on to estimate these expenses in an Excel workbook in live format and with all formulas intact. Identify where the expenses were included in the filings.

A-39. Total storm expense by FERC O&M expense account in the base period and test year are below. See attachments being provided in a separate files for the support relied on to estimate the storm expenses. The storm expenses are embedded in Schedule C (Filing Requirement Tab 56 - 807 KAR 5:001 Section 16(8)(c) in the FERC O&M expense accounts provided below).

FERC	FERC Account Name	Base Period	Test Year
408	Taxes other than income taxes, utility operating income	88,063	-
566	Miscellaneous transmission expenses	193	-
571	Maintenance of overhead lines	201,759	86,053
580	Operation supervision and engineering	1,628,214	829,723
583	Overhead line expenses	1,243,687	1,028,547
588	Miscellaneous distribution expenses	5,586	7,620
590	Maintenance supervision and engineering	36,300	28,825
593	Maintenance of overhead lines	6,095,472	4,724,957
594	Maintenance of underground lines	189,516	58,903
595	Maintenance of line transformers	51,381	1,884
598	Maintenance of miscellaneous distribution plant	179,755	101,037
909	Informational and instructional advertising expenses	93,895	67,094
925	Injuries and damages	8,811	-
926	Employee pensions and benefits	59,699	-
Total		**9,882,331**	**6,934,643**

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to the Joint Supplemental Data Requests of the Attorney General and Kentucky Industrial Utility Customers'
Dated July 31, 2025

Case No. 2025-00114

Question No. 40

Responding Witness: Drew T. McCombs

Q-40. Provide an annual history from 2015 through 2024 of vegetation management expense by FERC O&M expense account.

A-40. See attachment being provided in a separate file.

								2024	2025	2026	2027	2028	2029
Major	(All)				CPI Inflation source: IHS Economics			2.7%	2.0%	2.4%	2.4%	2.2%	2.2%
Including Reg Asset amounts													
Sum of Amount	**Column Labels**					Average - Incl	Average Excl Reg						
Row Labels	**2019**	**2020**	**2021**	**2022**	**2023**	Reg Asset	Asset						
0100	107,782	17,538	189,461	46,927	190,437	110,429	80,272						
0110	319,209	344,416	1,634,689	353,777	1,183,024	767,023	581,360						
Grand Total	**426,991**	**361,954**	**1,824,150**	**400,704**	**1,373,461**	877,452	661,633						
Regulatory Assets													
LG&E					150,783		150,783						
KU					928,312		928,312						
					1,079,095								
						Average Excl							
Costs Excluding Reg Asset						Reg Asset		2024	**2025**	**2026**	**2027**	**2028**	**2029**
0100	107,782	17,538	189,461	46,927	39,655	80,272		82,420	84,061	86,054	88,125	90,105	92,092
0110	319,209	344,416	1,634,689	353,777	254,711	581,360		596,914	608,801	623,234	638,231	652,569	666,958
Grand Total	**426,991**	**361,954**	**1,824,150**	**400,704**	**294,366**	661,633		679,334	692,862	709,288	726,356	742,673	759,050

Major	Yes

Sum of Amount	**Column Labels**	
Row Labels	**2021**	**2022**
0100	142,255	(4,943)
0110	1,470,822	4,920
Grand Total	**1,613,077**	**(23)**

Major	No	
Year	(Multiple Items)	2017-2021

Sum of Amount	**Column Labels**												
Row Labels	**01**	**02**	**03**	**04**	**05**	**06**	**07**	**08**	**09**	**10**	**11**	**12**	**Grand Total**
OUTSIDE SERVICES LABOR	51,352	289,293	170,208	56,686	72,902	166,192	180,633	219,280	107,722	72,803	126,279	121,483	1,634,832
OUTSIDE SERVICES MATERIAL	9,566	2,758	12,445	7,587	9,366	8,220	10,716	10,443	192	82	9,394	(651)	80,118
LABOR	3,482	11,514	5,426	1,771	6,162	5,508	6,748	3,553	6,585	3,902	2,333	937	57,921
TRANSPORTATION EQUIP	943	3,025	1,473	255	2,089	1,662	2,328	1,363	2,636	1,399	653	876	18,703
PURCHASED MATERIAL	2,075	911	350	1,382	1,900	3,379	2,246	2,830	(42)	711	1,808	175	17,726
OVERHEADS COMPANY LABOR	458	1,850	1,084	519	1,291	713	813	386	974	690	550	343	9,672
WAREHOUSE MATERIAL		462	1,453		815	424	409	686	77	488	242	1,049	6,104
MEALS	39	76	150	173	84	147	69	131	242	10	472	55	1,648
RIGHTS OF WAY		850				550							1,400
CORPORATE DEFAULT								1,176					1,176
WAREHOUSE OVERHEADS	22	98	55	48	51	90	49	44	12	38	17	33	557
TRAVEL		13	254										268
Grand Total	**67,937**	**310,850**	**192,899**	**68,420**	**94,659**	**186,887**	**204,013**	**239,891**	**118,398**	**80,120**	**141,748**	**124,300**	**1,830,123**

Major	No

Sum of Amount	Column Labels												
Row Labels	**01**	**02**	**03**	**04**	**05**	**06**	**07**	**08**	**09**	**10**	**11**	**12**	**Grand Total**
0100	**1,825**	**13,560**	**67,521**	**3,183**	**9,904**	**42,073**	**24,241**	**50,099**	**16,843**	**34,134**	**42,291**	**13,259**	**318,933**
2018	(3,717)	6,703	3,745		9,215	7,776	4,061	16,309	6,865	1,234	40,396	1,949	94,537
2019	-	4,508	32,045	(1,614)	(821)	19,685	3,451	28,331	9,693	1,195		11,310	107,782
2020	5,543	124					6,126	5,458	286				17,538
2021		2,224	9,214	372		1,798	-			31,705	1,894		47,206
2022			22,517	4,426	1,510	12,815	10,603						51,870
0110	**66,112**	**297,290**	**125,378**	**65,237**	**84,756**	**144,814**	**179,772**	**189,792**	**101,555**	**45,987**	**99,458**	**111,041**	**1,511,190**
2018	20,991	7,498	24,427	2,956	11,403	54,223	95,553	11,455	-	17,040	70,209	19,087	334,842
2019	19,884	65,320	52,068	31,155	(1,147)	13,266	45,734	11,113	20,255	18	12,961	48,582	319,209
2020	22,373	24,073	12,363	4,629	60,040	33,917	9,863	86,807	64,365	18,841	5,867	1,278	344,416
2021	277	9,383	6,978	5,875	13,573	18,758	5,220	46,594	20,779	2,194	4,822	29,413	163,867
2022	2,587	191,016	29,542	20,622	887	24,649	23,401	33,823	(3,844)	7,893	5,598	12,682	348,857
Grand Total	**67,937**	**310,850**	**192,899**	**68,420**	**94,659**	**186,887**	**204,013**	**239,891**	**118,398**	**80,120**	**141,748**	**124,300**	**1,830,123**

Combined	4%	17%	11%	4%	5%	10%	11%	13%	6%	4%	8%	7%	
LG&E	1%	4%	21%	1%	3%	13%	8%	16%	5%	11%	13%	4%	
KU	4%	20%	8%	4%	6%	10%	12%	13%	7%	3%	7%	7%	
LG&E													Totals Check
2025	3,121	14,278	8,860	3,143	4,348	8,584	9,371	11,019	5,438	3,680	6,511	5,709	84,061
2026	3,194	14,616	9,070	3,217	4,451	8,788	9,593	11,280	5,567	3,767	6,665	5,845	86,054
2027	3,271	14,968	9,289	3,295	4,558	8,999	9,824	11,551	5,701	3,858	6,826	5,985	88,125
2028	3,345	15,304	9,497	3,369	4,660	9,201	10,044	11,811	5,829	3,945	6,979	6,120	90,105
2029	3,419	15,642	9,707	3,443	4,763	9,404	10,266	12,071	5,958	4,032	7,133	6,255	92,092
KU													
2025	22,600	103,406	64,169	22,760	31,489	62,169	67,866	79,801	39,386	26,653	47,153	41,349	608,801
2026	23,136	105,858	65,690	23,300	32,236	63,643	69,475	81,693	40,320	27,284	48,271	42,329	623,234
2027	23,692	108,405	67,271	23,861	33,011	65,174	71,147	83,659	41,290	27,941	49,433	43,348	638,231
2028	24,224	110,840	68,782	24,397	33,753	66,638	72,745	85,538	42,217	28,569	50,543	44,322	652,569
2029	24,759	113,284	70,299	24,935	34,497	68,108	74,349	87,424	43,148	29,199	51,658	45,299	666,958
Combined													
2025	25,720	117,684	73,029	25,903	35,837	70,753	77,237	90,820	44,824	30,333	53,664	47,059	692,862
2026	26,330	120,474	74,760	26,517	36,687	72,430	79,068	92,973	45,887	31,052	54,936	48,174	709,288
2027	26,964	123,373	76,559	27,155	37,569	74,173	80,970	95,210	46,991	31,799	56,258	49,333	726,356
2028	27,569	126,145	78,279	27,765	38,413	75,840	82,789	97,349	48,047	32,513	57,522	50,442	742,673
2029	28,177	128,926	80,005	28,377	39,260	77,512	84,615	99,496	49,106	33,230	58,791	51,554	759,050

Business Use

EXHIBIT LK-10

KENTUCKY UTILITIES COMPANY

Response to the Joint Supplemental Data Requests of the Attorney General and Kentucky Industrial Utility Customers'
Dated July 31, 2025

Case No. 2025-00113

Question No. 40

Responding Witness: Drew T. McCombs

Q-40. Provide an annual history from 2015 through 2024 of vegetation management expense by FERC O&M expense account.

A-40. See attachment being provided in a separate file.

KU Vegetation Management cost by FERC
2015-2024

FERC	FERC Account Description	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
408	Taxes other than income taxes, utility operating income	-	-	-	-	-	-	-	-	54,561	65,900
571	Maintenance of overhead lines	5,329,874	5,286,815	7,985,349	10,866,181	9,729,780	7,969,097	11,094,673	15,221,693	6,950,168	8,128,162
588	Miscellaneous distribution expenses	257	300	116	-	-	-	-	27,430	-	29,747
593	Maintenance of overhead lines	14,345,827	14,921,309	13,829,922	16,319,983	17,789,441	17,090,177	17,612,627	23,326,867	12,314,916	13,511,652
921	Office supplies and expenses	-	-	-	-	-	31	-	-	-	5,289
925	Injuries and Damages	-	-	-	-	-	-	-	-	2,838	2,546
926	Employee Pension and Benefits	-	-	-	-	-	-	-	-	189,621	217,513
Grand Total		**19,675,958**	**20,208,424**	**21,815,387**	**27,186,164**	**27,519,221**	**25,059,305**	**28,707,300**	**38,575,990**	**19,512,105**	**21,960,809**

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to the Joint Supplemental Data Requests of the Attorney General and Kentucky Industrial Utility Customers'
Dated July 31, 2025

Case No. 2025-00114

Question No. 40

Responding Witness: Drew T. McCombs

Q-40. Provide an annual history from 2015 through 2024 of vegetation management expense by FERC O&M expense account.

A-40. See attachment being provided in a separate file.

LGE Vegetation Management cost by FERC
2015-2024

FERC	FERC Account Description	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
408	Taxes other than income taxes, utility operating income	-	-	-	-	-	-	-	-	28,168	25,486
426	Other Deductions	-	-	-	-	-	-	1,180	820	-	-
571	Maintenance of overhead lines	793,879	1,773,847	2,374,307	3,556,088	5,657,314	5,805,840	5,690,622	5,644,486	1,831,587	1,374,279
588	Miscellaneous distribution expenses	-	-	-	-	-	-	-	21,552	-	23,372
593	Maintenance of overhead lines	9,522,917	8,654,392	7,841,253	8,155,981	7,988,331	8,200,760	9,103,796	9,453,363	6,602,246	6,346,353
830	Maintenance Supervision and Engineering	-	-	-	-	-	45	-	-	-	-
921	Office supplies and expenses	-	-	-	-	-	144	800	1,685	1,324	4,891
925	Injuries and Damages	-	-	-	-	-	-	-	-	1,266	1,161
926	Employee Pension and Benefits	-	-	-	-	-	-	-	-	88,372	80,772
Grand Total		**10,316,795**	**10,428,239**	**10,215,560**	**11,712,069**	**13,645,646**	**14,006,788**	**14,796,398**	**15,121,906**	**8,552,963**	**7,856,314**

EXHIBIT LK-11

KENTUCKY UTILITIES COMPANY

Response to the Joint Supplemental Data Requests of the Attorney General and Kentucky Industrial Utility Customers'
Dated July 31, 2025

Case No. 2025-00113

Question No. 41

Responding Witness: Drew T. McCombs / Heather D. Metts

Q-41. Provide the vegetation management expense by FERC O&M expense account in the base period and test year, along with all support relied on to estimate these expenses in an Excel workbook in live format and with all formulas intact. Identify where the expenses were included in the filing.

A-41. The vegetation management expense by FERC O&M expense account for total KU in the base year and test year are below. For the support, see attachment being provided in a separate file. The vegetation management expenses are embedded in Schedule C (Filing Requirement Tab 56 - 807 KAR 5:001 Section 16(8)(c) in the FERC O&M expense accounts provided below).

FERC	FERC Account Name	Base Year	Test Year
408	Taxes other than income taxes, utility operating income	34,446	-
570	Maintenance of substation equipment	-	-
571	Maintenance of overhead lines	6,698,116	10,425,051
588	Miscellaneous distribution expenses	18,816	-
593	Maintenance of overhead lines	14,590,486	21,021,287
921	Office supplies and expenses	1,540	3,207
925	Workers Comp expense	1,401	-
926	Group Life Insurance expense	108,742	-
Total		**21,453,548**	**31,449,544**

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to the Joint Supplemental Data Requests of the Attorney General and Kentucky Industrial Utility Customers'
Dated July 31, 2025

Case No. 2025-00114

Question No. 41

Responding Witness: Drew T. McCombs / Heather D. Metts

Q-41. Provide the vegetation management expense by FERC O&M expense account in the base period and test year, along with all support relied on to estimate these expenses in an Excel workbook in live format and with all formulas intact. Identify where the expenses were included in the filing.

A-41. The vegetation management expense by FERC O&M expense account in the base year and test year are below. For the support, see attachment being provided in a separate file. The vegetation management expenses are embedded in Schedule C (Filing Requirement Tab 56 - 807 KAR 5:001 Section 16(8)(c) in the FERC O&M expense accounts provided below).

FERC	FERC Account Name	Base Year	Test Year
408	Taxes other than income taxes, utility operating income	14,235	-
570	Maintenance of substation equipment	683	1,366
571	Maintenance of overhead lines	1,208,159	2,174,052
588	Miscellaneous distribution expenses	14,784	-
593	Maintenance of overhead lines	7,914,364	11,762,386
921	Office supplies and expenses	2,091	2,519
925	Workers Comp expense	945	-
926	Group Life Insurance expense	45,378	-
Total		**9,200,639**	**13,940,324**

Vegetation Management
2026 Test year

	Test year	Pro Forma	Total Test Year
LGE			
T&D Veg	9,051,192	4,780,318	13,831,510
Supervision Of Veg	108,824	-	108,824
Miscellaneous Veg	(10)	-	(10)
Total LGE	9,160,006	4,780,318	13,940,324
KU			
T&D Veg	21,751,906	9,519,682	31,271,588
Supervision Of Veg	177,555	-	177,555
Miscellaneous Veg	401	-	401
Total KU	21,929,862	9,519,682	31,449,544

Maintenance Recovery Circuits Proforma Spend						
Op Center	**Count of Circuit**	**Sum of Mileage**		**Cost/Mile**		**Incremental Budget**
Danville	3	41.34	$	8,298.16	$	343,044
Earlington	28	388.11	$	3,367.14	$	1,306,807
Etown	6	98.20	$	7,166.40	$	703,738
London	1	30.37	$	10,677.41	$	324,273
Maysville	6	173.15	$	8,240.87	$	1,426,871
Midway	9	95.76	$	11,489.81	$	1,100,308
Pineville	4	57.79	$	5,719.29	$	330,512
Richmond	5	61.39	$	9,366.82	$	575,069
Shelbyville	3	49.18	$	5,884.06	$	289,378
Grand Total	**65**	**995.29**			**$**	**6,400,000**

Hazard Tree Proforma Spend					
Op Center	**Targeted Trees**		**Cost/Tree**		**Incremental Budget**
Louisville	1,500	$	2,703.58	$	4,055,370
Lexington	500	$	1,889.26	$	944,630
Grand Total	**2,000**	**$**	**2,296.42**	**$**	**5,000,000**

Maintenance Circuits				
Op Center	**Count of Circuit**	**Sum of Mileage**	**Cost/Mile**	**Incremental Budget**
Danville	31	224.42	$4,419.25	$991,768.09
Earlington	33	346.75	$3,768.42	$1,306,709.64
Etown	17	108.93	$4,847.10	$527,994.60
Lexington	44	381.31	$9,043.02	$3,448,193.96
London	7	75.58	$4,720.63	$356,785.22
Louisville	183	1137.93	$6,702.08	$7,626,496.00
Maysville	9	207.58	$4,904.44	$1,018,063.66
Midway	14	350.67	$7,109.77	$2,493,183.05
Norton	19	231.31	$4,228.77	$978,156.79
Pineville	10	119.41	$3,330.61	$397,708.14
Richmond	14	131.09	$4,858.99	$636,965.00
Shelbyville	20	172.14	$5,113.16	$880,179.36
Grand Total	**401**	**3487.12**	**$**	**20,662,203**

Hazard Tree			
Op Center	**Targeted Trees**	**Cost/Tree**	**Incremental Budget**
Danville	80	$1,015.65	$81,252
Earlington	133	$588.48	$78,268
Etown	55	$775.80	$42,669
Lexington			
London	23	$2,083.60	$47,923
Louisville			
Maysville	24	$2,125.98	$51,024
Midway	75	$811.75	$60,881
Norton	44	$820.75	$36,113
Pineville	37	$1,379.13	$51,028
Richmond	22	$1,569.10	$34,520
Shelbyville	64	$845.58	$54,117
Grand Total	**557**	**$**	**537,795**

2026	Project / Task	Feb	March	April	May	June
LG&E	TLROW/ROUTINE	$43,938	$43,938	$87,872	$87,872	$87,872
KU	TKROW/ROUTINE	$131,814	$131,814	$263,616	$263,616	$263,616
	Totals	$175,752	$175,752	$351,488	$351,488	$351,488
	Split KU by 3 for regions	$43,938	$43,938	$87,872	$87,872	$87,872

July	August	September	October	Total
$87,872	$87,872	$87,872	$109,840	$724,948
$263,616	$263,616	$263,616	$329,728	$2,175,052
$351,488	$351,488	$351,488	$439,568	$2,900,000
$87,872	$87,872	$87,872	$109,909	

EXHIBIT LK-12

KENTUCKY UTILITIES COMPANY

Response to Attorney General and Kentucky Industrial Utility Customers' Initial Request for Information
Dated July 3, 2025

Case No. 2025-00113

Question No. 70

Responding Witness: Drew T. McCombs / Heather D. Metts / Vincent Poplaski

Q-70. Refer to the Payroll Analysis Attachment, page 2 of 2, to Filing Requirement Tab 60 of 807 KAR5:001 Section 16(8)(g) for KU. Refer further to the employee benefits amount in total and the O&M portion of those amounts for the base year and the test year on lines 29-31. Refer also to the increase in the ratio of O&M labor dollars data included on lines 18-19.

a. Explain all known reasons why the employee benefits costs for KU are expected to increase by $9,512,140, or 19.65%, from the base year to the test year.

b. Explain all known reasons why the employee benefits expenses for KU are expected to increase by $6,398,750, or 20.18%, from the base year to the test year.

c. Provide the total benefits cost by type for KU for each of the years 2021 through 2024, 2025 to date, the base year and the test year.

d. Provide the total benefits expense by type for KU for each of the years 2021 through 2024, 2025 to date, the base year and the test year.

e. Explain why the ratio of O&M labor dollars to total labor dollars for this category of costs is expected to increase from 59.76% to 63.98% for KU from the base year to the test year.

f. Provide the ratio of O&M labor dollars to total labor dollars for each of the years 2021 through 2024, 2025 to date, the base year and the test year.

A-70. **Original Response:**

a. Pension, post-retirement and post-employment plans make up the majority of this increase. There were no substantial changes to benefits offered. The pension plan has been closed since 1/1/2006 and the post-retirement benefit plans were closed between 1/1/2024 and 1/1/2025

- For the pension and postretirement plans, the increase is primarily due to a lower Expected Return on Asset (EROA) projected value, which is calculated using an EROA percentage return assumption and the plans' market-related value of assets.
- Per accounting standards, management is required to review all pension assumptions on at least an annual basis. This annual process is intended to assess the various economic and actuarial assumptions to account for changing market conditions, expectations for future economic outlook and demographic experience, amongst other data points. As part of this assessment process that includes discussions with the Companies' investment consultants and actuaries, the EROA assumption was updated for the 2025 Business Plan. The update resulted in a different EROA assumption for the base year and the test year, declining by 1%.
- In addition, changes in the plans' asset base will be updated during the forecasting process. As an example, the plans' actual investment return for 2024 was 1.35% vs. the Expected Return of 8.25%. The actual return on assets lowers the asset base and lowers projected EROA amounts in dollars, which in turn results in higher cost, since there is less investment income to offset the ongoing cost of the pension benefit.
- For the post-employment benefit plan, which provides medical, dental and life insurance benefits to disabled employees, the base year reflects an actual credit recorded due to a decrease in the number of employees on disability and an increase in the discount rate for the year based on year-end bond rates required to measure the obligation. For the test year, and consistent with annual budgeting, there is no amount included resulting in what would be considered an increase. However, there is no budget or projection for post-employment benefits as the obligation and activity is not material to KU's balance sheet or income statement in total. Post-employment benefits are only measured annually at December 31st and dependent on employees who either become disabled during the year or recover and are removed from the obligation, which is based on bond rates used to develop the obligation as of December 31st, due to the combined significant uncertainty and based on materiality, amounts are not forecast.

b. Pension, post-retirement and post-employment plans make up the majority of this increase. See the response to (a).

c. See attachment being provided in a separate file.

d. See attachment being provided in a separate file.

e. These percentages will change based on the amount of labor charged to capital projects. The level of capital spending fluctuates from year to year, and the ratios for the test year are well within the ranges the Companies expect and have previously experienced.

f. The ratios of O&M labor dollars to total labor dollars for the time periods requested are as follows:

Year	Ratio of O&M Labor Dollars to Total Labor Dollars
2021	66.99%
2022	66.57%
2023	63.38%
2024	58.71%
2025	58.18%
Base Period	59.76%
Test Period	63.98%

August 15, 2025 Supplemental Response:

d. Following the submission of this initial request for information, the Company identified an error in the base period labor formulas. The revisions provided include reclassifications between employee groups in actuals. See attachment being provided in a separate file.

f. The ratios of O&M labor dollars to total labor dollars for the time periods requested are as follows:

Year	Ratio of O&M Labor Dollars to Total Labor Dollars
2021	66.99%
2022	66.57%
2023	63.37%
2024	58.71%
2025	58.18%
Base Period	59.76%
Test Period	63.98%

Kentucky Utilities Company
Case No. 2025-00113
Total Benefits Costs by Type
Historical Calendar Years 2021 through May 2025, Base Period for the 12 months ending August 31, 2025, & Test Period for the 12 months ending December 31, 2026

Employee Benefits*	2021	2022	2023	2024	YTD 2025 as of May 31	Base Period	Test Period
Company Contribution to the Savings Plan	10,628,769	10,605,521	11,259,434	10,667,064	3,999,986	10,515,355	11,463,602
Dental	680,954	654,439	626,586	573,605	216,746	606,768	713,113
Life Insurance	799,282	424,276	401,885	465,077	143,750	508,642	476,934
Long Term Disability	840,781	582,368	535,013	446,209	140,248	392,181	448,834
Medical	20,852,207	20,752,358	19,308,515	18,628,616	5,904,578	19,942,096	20,200,858
Other Benefits	1,367,146	4,199,388	663,498	188,021	439,978	963,259	1,017,068
Pension	2,871,894	227,831	(3,737,075)	(8,830,734)	(3,420,424)	(8,375,851)	259,445
Post-Employment	(1,126,922)	1,324,555	(76,967)	(808,576)	1,477	(807,505)	-
Post-Retirement	(1,044,555)	(2,154,603)	313,832	(190,011)	(91,696)	(253,000)	48,449
PPLS Benefits**	-	1,512,253	6,339,082	5,773,810	-	1,905,169	4,462,957
PPLS Medical/Other	-	-	-	1,892,301	1,994,384	2,386,045	-
Short Term Incentive	17,441,624	15,624,274	18,075,300	20,237,355	5,768,019	18,793,291	17,735,750
Tuition Reimbursement	316,800	211,348	222,331	174,903	54,543	167,031	199,755
Workers Compensation	403,173	618,352	605,972	593,659	1,138,995	1,667,382	896,240
Total	**54,031,154**	**54,582,358**	**54,537,405**	**49,811,299**	**16,290,583**	**48,410,864**	**57,923,004**

*Allocated benefit components from PPLS that are separately identifiable are included in the respective categories shown above.
**PPLS Benefits includes Medical, Dental, Life, Long Term Disability, 401k, Retirement Income and Other

Kentucky Utilities Company
Case No. 2025-00113
Total Benefits Expense by Type
Historical Calendar Years 2021 through May 2025, Base Period for the 12 months ending August 31, 2025, & Test Period for the 12 months ending December 31, 2026

Employee Benefits*	2021	2022	2023	2024	YTD 2025 as of May 31	Base Period	Test Period
Company Contribution to the Savings Plan	7,197,473	6,985,143	7,155,924	6,442,124	2,615,546	6,315,235	7,065,175
Dental	463,565	431,373	403,198	351,479	130,863	369,638	438,584
Life Insurance	542,135	282,677	255,586	280,499	86,912	304,227	293,514
Long Term Disability	570,538	387,317	340,297	269,904	84,761	234,390	276,885
Medical	14,115,184	13,618,199	12,245,885	11,342,379	3,569,139	12,095,003	12,429,037
Other Benefits	923,912	3,866,575	454,212	142,694	313,355	1,011,856	603,780
Pension	2,110,613	565,631	(1,379,065)	(4,782,877)	(1,830,568)	(3,867,300)	841,898
Post-Employment	(700,288)	830,306	(84,313)	(477,283)	161	(477,486)	-
Post-Retirement	(682,521)	(1,366,701)	223,072	(60,206)	(89,469)	(92,537)	23,959
PPLS Benefits**	-	1,411,710	5,319,938	4,827,162	-	1,675,988	3,669,423
PPLS Medical/Other	-	-	-	1,567,210	1,399,379	1,861,641	-
Short Term Incentive	11,771,786	10,451,896	11,514,712	12,399,222	3,585,450	11,157,165	11,713,931
Tuition Reimbursement	309,259	205,711	216,896	171,935	52,875	165,618	199,755
Workers Compensation	260,327	376,283	383,938	363,826	610,159	950,718	546,963
Total	**36,881,983**	**38,046,119**	**37,050,279**	**32,838,068**	**10,528,563**	**31,704,155**	**38,102,905**

*Allocated benefit components from PPLS that are separately identifiable are included in the respective categories shown above.
**PPLS Benefits includes Medical, Dental, Life, Long Term Disability, 401k, Retirement Income and Other

Case No. 2025-00113
Attachment to Supplemental Response to AG-KIUC-1 Question No. 70(d)
Page 1 of 1
McCombs/Metts/Poplaski

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General and the Kentucky Industrial Utility Customers' Initial Request for Information
Dated July 3, 2025

Case No. 2025-00114

Question No. 70

Responding Witness: Drew T. McCombs / Heather D. Metts / Vincent Poplaski

Q-70. Refer to the Payroll Analysis Attachment, page 2 of 2, to Filing Requirement Tab 60 of 807 KAR5:001 Section 16(8)(g) for LG&E. Refer further to the employee benefits amount in total and the O&M portion for the base year and the test year on lines 35-37. Refer also to the increase in the ratio of O&M labor dollars data included on lines 18-19.

a. Explain all known reasons why the employee benefits costs for LG&E are expected to increase by $10,076,617, or 19.81%, from the base year to the test year.

b. Explain all known reasons why the employee benefits expenses for LG&E are expected to increase by $7,858,916, or 23.92%, from the base year to the test year.

c. Provide the total benefits cost by type for LGE for each of the years 2021 through 2024, 2025 to date, the base year and the test year.

d. Provide the total benefits expense by type and by division for LGE for each of the years 2021 through 2024, 2025 to date, the base year and the test year.

e. Explain why the ratio of O&M labor dollars to total labor dollars for this category of costs is expected to increase from 63.81% to 66.24% for LG&E from the base year to the test year.

f. Provide the ratio of O&M labor dollars to total labor dollars for each of the years 2021 through 2024, 2025 to date, the base year and the test year. provide in total and by division.

A-70. **Original Response:**

a. Pension, post-retirement and post-employment plans make up the majority of this increase. There were no substantial changes to benefits offered. The pension plan has been closed since 1/1/2006 and the post-retirement benefit plan were closed between 1/1/2024 and 1/1/2025

- For the pension and postretirement plans, the increase is primarily due to a lower Expected Return on Asset (EROA) projected value, which is calculated using an EROA percentage return assumption and the plans' market-related value of assets.
- Per accounting standards, management is required to review all pension assumptions on at least an annual basis. This annual process is intended to assess the various economic and actuarial assumptions to account for changing market conditions, expectations for future economic outlook and demographic experience, amongst other data points. As part of this assessment process that includes discussions with the Companies' investment consultants and actuaries, the EROA assumption was updated for the 2025 Business Plan. The update resulted in a different EROA assumption for the base year and the test year, declining by 1%.
- In addition, changes in the plans' asset base will be updated during the forecasting process. As an example, the plans' actual investment return for 2024 was 1.35% vs. the Expected Return of 8.25%. The actual return on assets lowers the asset base and lower projected EROA amounts in dollars, which in turn results in higher cost, since there is less investment income to offset the ongoing cost of the pension benefit.
- For the post-employment benefit plan, which provides medical, dental and life insurance benefits to disabled employees, the base year reflects an actual credit recorded due to a decrease in the number of employees on disability and an increase in the discount rate for the year based on year-end bond rates required to measure the obligation. For the test year, and consistent with annual budgeting, there is no amount included resulting in what would be considered an increase. However, there is no budget or projection for post-employment benefits as the obligation and activity is not material to KU's balance sheet or income statement in total. Post-employment benefits are only measured annually at December 31st and dependent on employees who either become disabled during the year or recover and are removed from the obligation, which is based on bond rates used to develop the obligation as of December 31st, due to the combined significant uncertainty and based on materiality, amounts are not forecasted.

b. Pension, post-retirement and post-employment plans make up the majority of this increase. See the response to (a).

c. See attachment being provided in a separate file.

d. See attachment being provided in a separate file.

e. These percentages will change based on the amount of labor charged to capital projects. The level of capital spending fluctuates from year to year, and the ratios for the test year are well within the ranges the Companies expect and have previously experienced.

f. The ratios of O&M labor dollars to total labor dollars for the time periods requested are as follows:

Year	Ratio of O&M Labor Dollars to Total Labor Dollars		
	Total	Electric	Gas
2021	67.29%	66.72%	68.67%
2022	67.87%	67.16%	69.54%
2023	66.29%	65.80%	67.41%
2024	64.03%	62.99%	66.46%
2025	64.16%	64.26%	63.94%
Base Period	63.66%	62.20%	66.99%
Test Period	66.24%	64.42%	70.18%

August 15, 2025 Supplemental Response:

d. Following the submission of this initial request for information, the Company identified an error in the base period labor formulas. The revisions provided include reclassifications between employee groups in actuals. See attachment being provided in a separate file.

f. The ratios of O&M labor dollars to total labor dollars for the time periods requested are as follows:

Year	Ratio of O&M Labor Dollars to Total Labor Dollars		
	Total	Electric	Gas
2021	67.29%	66.72%	68.67%
2022	67.87%	67.16%	69.54%
2023	66.53%	65.80%	68.23%
2024	64.30%	63.00%	67.36%
2025	64.34%	64.26%	64.52%

Base Period	63.81%	62.20%	67.47%
Test Period	66.24%	64.42%	70.18%

Louisville Gas & Electric Company
Case No. 2025-00114
Total Benefits Costs by Type
Historical Calendar Years 2021 through May 2025, Base Period for the 12 months ending August 31, 2025, & Test Period for the 12 months ending December 31, 2026

Employee Benefits*	2021	2022	2023	2024	YTD 2025 as of May 31	Base Period	Test Period
Company Contribution to the Savings Plan	9,851,953	9,949,201	10,095,045	9,625,912	4,729,067	10,417,283	11,111,500
Dental	629,221	563,975	514,042	499,733	244,084	557,837	658,028
Life Insurance	689,645	368,442	334,805	369,381	164,157	427,474	446,957
Long Term Disability	672,908	462,027	417,758	352,398	165,589	335,673	436,548
Medical	17,863,122	17,444,330	15,977,717	15,836,258	6,647,719	17,880,090	18,644,591
Other Benefits	1,169,624	4,508,910	627,637	75,977	360,202	1,050,085	763,500
Pension	4,891,072	3,930,286	1,975,681	(3,692,090)	(1,349,769)	(3,527,244)	4,120,038
Post-Employment	(73,427)	265,515	(603,203)	(619,010)	1,393	(619,967)	-
Post-Retirement	1,428,183	524,887	2,313,832	2,138,996	982,345	2,496,576	2,621,989
PPLS Benefits**	-	1,457,673	6,208,991	5,754,850	-	1,800,832	4,222,079
PPLS Medical/Other	-	-	-	1,668,609	2,003,655	2,140,687	-
Short Term Incentive	16,388,060	14,248,945	16,568,696	17,945,413	6,732,137	16,925,320	16,979,726
Tuition Reimbursement	366,388	248,626	253,235	197,874	105,669	197,665	193,810
Workers Compensation	346,996	250,438	585,639	856,969	306,366	779,165	739,326
Total	**54,223,746**	**54,223,255**	**55,269,876**	**51,011,271**	**21,092,616**	**50,861,475**	**60,938,092**

*Allocated benefit components from PPLS that are separately identifiable are included in the respective categories shown above.
**PPLS Benefits includes Medical, Dental, Life, Long Term Disability, 401k, Retirement Income and Other

Louisville Gas & Electric Company
Case No. 2025-00114
Total Benefits Expense by Type
Historical Calendar Years 2021 through May 2025, Base Period for the 12 months ending August 31, 2025, & Test Period for the 12 months ending December 31, 2026

Electric

Employee Benefits*	2021	2022	2023	2024	YTD 2025 as of May 31	Base Period	Test Period
Company Contribution to the Savings Plan	4,745,120	4,752,657	4,695,746	4,290,722	2,267,296	4,290,924	4,606,941
Dental	310,232	275,347	248,333	229,177	108,791	238,523	276,819
Life Insurance	338,589	178,204	158,796	168,396	72,783	180,805	187,151
Long Term Disability	339,470	227,451	200,513	161,451	73,165	138,196	181,194
Medical	8,755,549	8,464,260	7,514,235	7,186,672	2,958,350	7,633,850	7,846,483
Other Benefits	578,332	3,091,283	307,427	19,211	163,020	764,232	337,121
Pension	2,945,230	2,445,457	1,413,002	(1,465,751)	(541,102)	(1,519,677)	1,758,984
Post-Employment	(11,100)	156,090	(279,331)	(275,901)	1,647	(274,369)	-
Post-Retirement	496,382	80,877	923,408	813,362	384,618	1,044,931	1,197,910
PPLS Benefits**	-	1,007,128	3,915,619	3,583,750	-	1,222,650	2,624,040
PPLS Medical/Other	-	-	-	1,039,855	1,031,226	1,261,348	-
Short Term Incentive	7,816,726	6,799,983	7,685,248	8,103,406	3,042,501	6,884,484	7,843,571
Tuition Reimbursement	290,365	202,306	198,383	146,471	81,403	148,491	156,069
Workers Compensation	158,695	103,031	250,137	355,356	128,312	205,710	306,368
Total	**26,763,591**	**27,784,076**	**27,231,514**	**24,356,178**	**9,772,011**	**22,220,099**	**27,322,650**

Gas

Employee Benefits*	2021	2022	2023	2024	YTD 2025 as of May 31	Base Period	Test Period
Company Contribution to the Savings Plan	1,992,475	2,067,672	2,118,006	2,004,018	1,040,050	2,252,165	2,537,427
Dental	124,278	111,638	100,541	99,074	50,677	112,925	147,378
Life Insurance	136,311	74,542	68,664	74,008	34,365	89,219	100,740
Long Term Disability	128,747	91,232	83,733	70,185	34,990	70,335	99,475
Medical	3,546,142	3,528,135	3,279,300	3,184,533	1,381,708	3,676,531	4,176,415
Other Benefits	232,163	1,128,824	137,423	19,353	74,269	296,260	187,165
Pension	691,231	502,905	40,027	(1,004,825)	(378,403)	(727,273)	854,086
Post-Employment	(24,668)	41,760	(131,075)	(128,501)	(64)	(130,876)	-
Post-Retirement	388,135	208,165	600,168	564,319	265,112	556,538	548,732
PPLS Benefits**	-	351,149	1,350,769	1,279,129	-	419,770	901,075
PPLS Medical/Other	-	-	-	377,411	445,196	459,925	-
Short Term Incentive	3,265,768	2,943,528	3,376,870	3,609,407	1,376,565	3,331,589	3,615,692
Tuition Reimbursement	67,630	40,262	48,901	48,093	22,320	47,622	37,741
Workers Compensation	79,304	57,854	146,261	208,241	70,374	183,590	188,759
Total	**10,627,516**	**11,147,666**	**11,219,587**	**10,404,444**	**4,417,159**	**10,638,320**	**13,394,685**

*Allocated benefit components from PPLS that are separately identifiable are included in the respective categories shown above.
**PPLS Benefits includes Medical, Dental, Life, Long Term Disability, 401k, Retirement Income and Other

EXHIBIT LK-13

KENTUCKY UTILITIES COMPANY

Response to Attorney General and Kentucky Industrial Utility Customers' Initial Request for Information
Dated July 3, 2025

Case No. 2025-00113

Question No. 86

Responding Witness: Christopher M. Garrett / Vincent Poplaski

Q-86. 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, provide the total and jurisdictional amount of matching contributions made on behalf of employees who also participate in any 401-K retirement savings account for each Company if the Commission applied the same methodology for a similar disallowance in the instant proceeding. If the Companies made adjustments to remove portions of expenses in the filings, cite to the amounts and locations removed.

A-86. After the Orders referenced in this question were issued, the Companies filed their 2020 rate cases (Case Nos. 2020-00349 and 2020-00350). In those cases, their filed position on this issue was that no disallowance of 401k contribution costs should be made for those employees also participating in a defined pension benefit plan. A Stipulation and Recommendation was reached in those cases and it included specific compromised amounts leading to the stipulated and recommended revenue requirements. A disallowance of the 401k costs referenced in this question was not one of those compromised amounts. The Commission approved the Stipulation and Recommendation with modifications by Order of June 30, 2021, but without making any disallowance for the subject 401k costs. The Companies' filed position in this case is the same as it was in the 2020 cases that these 401k costs should not be disallowed. For the amounts requested in this question, see the attachment being provided in a separate file.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General and the Kentucky Industrial Utility Customers' Initial Request for Information
Dated July 3, 2025

Case No. 2025-00114

Question No. 86

Responding Witness: Christopher M. Garrett / Vincent Poplaski

Q-86. 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, provide the total and jurisdictional amount of matching contributions made on behalf of employees who also participate in any 401-K retirement savings account for each Company if the Commission applied the same methodology for a similar disallowance in the instant proceeding. If the Companies made adjustments to remove portions of expenses in the filings, cite to the amounts and locations removed.

A-86. After the Orders referenced in this question were issued, the Companies filed their 2020 rate cases (Case Nos. 2020-00349 and 2020-00350). In those cases, their filed position on this issue was that no disallowance of 401k contribution costs should be made for those employees also participating in a defined pension benefit plan. A Stipulation and Recommendation was reached in those cases and it included specific compromised amounts leading to the stipulated and recommended revenue requirements. A disallowance of the 401k costs referenced in this question was not one of those compromised amounts. The Commission approved the Stipulation and Recommendation with modifications by Order of June 30, 2021, but without making any disallowance for the subject 401k costs. The Companies' filed position in this case is the same as it was in the 2020 cases that these 401k costs should not be disallowed. For the amounts requested in this question, see the attachment being provided in a separate file.

EXHIBIT LK-14

KENTUCKY UTILITIES COMPANY

Response to the Joint Supplemental Data Requests of the Attorney General and Kentucky Industrial Utility Customers'
Dated July 31, 2025

Case No. 2025-00113

Question No. 25

Responding Witness: Christopher M. Garrett / Drew T. McCombs

Q-25. Refer to the response to AG-KIUC 1-74, which requested a copy of the Companies' actuarial reports for the most recent historic calendar year, base year, and test year. They were not provided.

a. Provide the actuarial reports requested in AG-KIUC 1-74.

b. Provide all communications between the Companies and the actuarial firm regarding assumptions in the base year and test year, including the date(s) used for the trust fund asset valuations and the present value of the pension obligations for the base year and test year, and the rate of return on the trust fund assets and the discount rate used for the pension obligations for the base year and test year.

c. Provide the pension cost and expense calculations for the base year and test year using the actual trust fund asset valuation and the pension obligation as of June 30, 2025 and the Companies' assumptions for the rate of return on the trust fund assets and the discount rate used for the pension obligations for the base year and test year. Provide all calculations in an Excel workbook in live format with all formulas intact.

d. Provide the pension cost and expense calculations for the base year and test year using the actual trust fund asset valuation and the pension obligation as of June 30, 2025 and the rate of return on the trust fund assets at 8.25% and the Companies' assumptions for the discount rate used for the pension obligations for the base year and test year. Provide all calculations in an Excel workbook in live format with all formulas intact.

A-25.

a. See attachment being provided in a separate file. The file contains the 2024 yearend disclosures from Willis Towers Watson ("WTW"). Page 2 of the attachment to AG-KIUC 1-74 contains the information from WTW used to develop the pension expense for the base and test years.

b. See attachment being provided in a separate file.

c. See attachment being provided in a separate file. The file contains the reconciliation between pension expense calculation in the test year and actuarial reports based on asset valuations and discount rate as of April 30, 2025.

d. The Companies have requested WTW to provide updated net periodic pension cost projections with an EROA assumption of 8.25% and will provide updated expense calculations when the information becomes available.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to the Joint Supplemental Data Requests of the Attorney General and Kentucky Industrial Utility Customers'
Dated July 31, 2025

Case No. 2025-00114

Question No. 25

Responding Witness: Christopher M. Garrett / Drew T. McCombs

Q-25. Refer to the response to AG-KIUC 1-74, which requested a copy of the Companies' actuarial reports for the most recent historic calendar year, base year, and test year. They were not provided.

a. Provide the actuarial reports requested in AG-KIUC 1-74.

b. Provide all communications between the Companies and the actuarial firm regarding assumptions in the base year and test year, including the date(s) used for the trust fund asset valuations and the present value of the pension obligations for the base year and test year, and the rate of return on the trust fund assets and the discount rate used for the pension obligations for the base year and test year.

c. Provide the pension cost and expense calculations for the base year and test year using the actual trust fund asset valuation and the pension obligation as of June 30, 2025 and the Companies' assumptions for the rate of return on the trust fund assets and the discount rate used for the pension obligations for the base year and test year. Provide all calculations in an Excel workbook in live format with all formulas intact.

d. Provide the pension cost and expense calculations for the base year and test year using the actual trust fund asset valuation and the pension obligation as of June 30, 2025 and the rate of return on the trust fund assets at 8.25% and the Companies' assumptions for the discount rate used for the pension obligations for the base year and test year. Provide all calculations in an Excel workbook in live format with all formulas intact.

A-25.

a. See attachment being provided in a separate file. The file contains the 2024 yearend disclosures from Willis Towers Watson ("WTW"). Page 2 of the attachment to AG-KIUC 1-74 contains the information form WTW used to develop the pension expense for the base and test years.

b. See attachment being provided as a separate file.

c. See attachment being provided in a separate file. The file contains the reconciliation between pension expense calculation in the test year and actuarial reports based on asset valuation and discount rate as of April 30, 2025.

d. The Companies have requested WTW to provide updated net periodic pension cost projections with an EROA assumption of 8.25% and will provide an updated expense calculation when the information becomes available.

EXHIBIT LK-15

KENTUCKY UTILITIES COMPANY

Response to the Joint Supplemental Data Requests of the Attorney General and Kentucky Industrial Utility Customers'
Dated July 31, 2025

Case No. 2025-00113

Question No. 27

Responding Witness: Drew T. McCombs / Heather D. Metts / Vincent Poplaski

Q-27. Refer to the attachment to the response to AG-KIUC 1-70(d), which provides a history of employment benefits expense by type. Explain for KU why the post-employment benefits are $0 in the test year compared to negative $0.477 million in 2024 and negative $0.477 million in the base period. Provide all support for the calculations in 2024, base period, and test year in live Excel format and with all formulas intact.

A-27. LKE does not budget an amount related to post-employment benefits, which primarily consists of continued medical benefits and life insurance for long-term disability participants and their dependents. The amount is subject to fluctuation over time, which has not been significant and is subject to multiple variables including the number of long-term disability participants at year end, variances in medical costs and usage by those participants, and the year-end discount rate used to calculate the present value of the obligation. The annual expense is primarily representative of the change in the long-term disability liability over the year. See attachment being provided in a separate file. The file provides support for the 2024 actuarial determined long-term disability liability. Additionally, Willis Towers Watson performs these calculations and the Companies are mindful of the expense associated with performing the calculations.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to the Joint Supplemental Data Requests of the Attorney General and Kentucky Industrial Utility Customers'
Dated July 31, 2025

Case No. 2025-00114

Question No. 27

Responding Witness: Drew T. McCombs / Heather D. Metts / Vincent Poplaski

Q-27. Refer to the attachment to the response to AG-KIUC 1-70(d), which provides a history of employment benefits expense by type.

a. Explain for LG&E electric why the post-employment benefits are $0 in the test year compared to negative $0.276 million in 2024 and negative $0.274 million in the base period. Provide all support for the calculations in 2024, base period, and test year in live Excel format and with all formulas intact.

b. Explain for LG&E gas why the post-employment benefits are $0 in the test year compared to negative $0.129 million in 2024 and negative $0.131 million in the base period. Provide all support for the calculations in 2024, base period, and test year in live Excel format and with all formulas intact.

A-27.

a. LKE does not budget an amount related to post-employment benefits, which primarily consists of continued medical benefits and life insurance for long-term disability participants and their dependents. The amount is subject to fluctuation over time, which has not been significant and is subject to multiple variables including the number of long-term disability participants at year end, variances in medical costs and usage by those participants, and the year-end discount rate used to calculate the present value of the obligation. The annual expense is primarily representative of the change in the long-term disability liability over the year. See attachment being provided in a separate file. The file provides support for the 2024 actuarial determined long-term disability liability. Additionally, Willis Towers Watson performs these calculations and the Companies are mindful of the expense associated with performing the calculations.

b. See the response to part (a).

EXHIBIT LK-16

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General and the Kentucky Industrial Utility Customers' Initial Request for Information
Dated July 3, 2025

Case No. 2025-00114

Question No. 102

Responding Witness: John J. Spanos

Q-102. Refer to Exhibit JJS-KU-1 at VI-4 through VI-11 and to Exhibit JJS-LG&E-1 (provided in 25-2025_PSC_DR1_LGE_Attach_to_Q32_-_LGE_Depreciation_Study) at pages VI-4 through VI-14.

a. Provide a version of these schedules without terminal net salvage on the production plant accounts. Provide these schedules in an Excel workbook in live format and with all formulas intact.

b. Provide a version of these schedules without interim retirements and without net salvage on all plant accounts. Provide these schedules in an Excel workbook in live format and with all formulas intact.

A-102.

a. See attachments being provided in separate files. The files set forth summarized depreciation rates and expense with terminal net salvage for production plant accounts removed. The second table for each Company represents the revised weighted net salvage calculation that is used in the calculation of the depreciation rates and expense.

b. There are no interim retirements for mass property accounts and excluding the net salvage that has occurred or are anticipated to occur is not consistent with proper depreciation accounting. Removing interim retirements and net salvage would be not produce any depreciation rate for mass property assets.

EXHIBIT LK-17

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to the Joint Supplemental Data Requests of the Attorney General and Kentucky Industrial Utility Customers'
Dated July 31, 2025

Case No. 2025-00114

Question No. 30

Responding Witness: John J. Spanos

Q-30. Provide all of Witness Spanos' schedules and workpapers in Excel live format with all formulas intact, including, but not limited to, the calculations of estimated decommissioning costs for the production plant by site location and/or generating unit, the escalation of current dollar estimated decommissioning costs to future dollars, and the calculation of the weighted terminal net salvage, weighted interim net salvage, and the sum of terminal and interim net salvage.

A-30. Table 2 reflecting the calculation of weighted net salvage in Excel format for both Kentucky Utilities and Louisville Gas and Electric was provided in response to PSC 1-54. The attachments reflecting the escalation of decommissioning costs and weighted interim net salvage were provided in response to AG-KIUC 1-43.

KENTUCKY UTILITIES COMPANY

Response to the Joint Supplemental Data Requests of the Attorney General and Kentucky Industrial Utility Customers'
Dated July 31, 2025

Case No. 2025-00113

Question No. 33

Responding Witness: John J. Spanos

Q-33. Refer to the Direct Testimony of John Spanos at 20 wherein he discusses developing depreciation rates for future assets, including additional assets at Simpsonville Solar, new assets at Marion and Mercer, Mill Creek 5, and Brown BESS assets. Refer also to the notes on pages VI-10 and VI-11 of JJS-1 for KU and on pages VI-9 and VI-10 for LG&E electric related to the requested depreciation rates for Brown BESS, AMI, Paddy's Run CT pipeline, Simpsonville Solar Arrays 3, 4, 5, Mercer Solar, Marion Solar, and Mill Creek 5.

a. Confirm the Companies did not provide the underlying calculations or support for the proposed depreciation rates for the future assets. If confirmed, explain why they were not provided either with the filing or in response to Staff 1-54.

b. Provide the source(s) and all support relied on for each assumption/parameter/input used to develop the requested depreciation rates for the assets listed in the notes on these pages, including, but not limited to, estimated service lives and the range of estimated service lives considered, estimated interim retirements, estimated interim net salvage, and estimated terminal net salvage. Also provide all correspondence with KU/LG&E subject matter experts and/or decision makers and all directives from the Companies for these depreciation study assumptions/parameters/inputs.

c. Provide the schedules and workpapers in live Excel format and with all formulas intact relied on for the requested depreciation rates for the future assets listed in the notes on the referenced pages. Provide the schedules and workpapers for the future assets in the same level of detail and with the same information shown for each of the existing assets on the schedules in Section IV of each of the depreciation studies.

d. Refer to the response to AG-KIUC 1-102 (a) and (b).

    i. Confirm the response did not provide the requested information for any of the future assets and the proposed depreciation rates described and provided in the notes.

ii. Provide the information requested in AG-KIUC 1-102 (a) and (b) in the same format and in the same level of detail for the future assets as was provided in the response for the existing assets starting with the detailed schedules and workpapers provided in response to part (c) of this question used to calculate the proposed depreciation rates listed in the notes for the future assets so that there is the same sequence of proposed depreciation rates for the future assets as for the existing assets, i.e., support for proposed depreciation rates, modifications to exclude terminal net salvage from production and BESS plant accounts, further modifications to exclude interim retirements and interim net salvage in addition to excluding terminal net salvage from all production and BESS plant accounts.

A-33.

a. Confirmed. The Companies provided the information for existing assets.

b. The requested sources were either professional judgment based on experience performing numerous depreciation studies or consistent with existing assets and/or locations presented in the depreciation studies for KU and/or LGE. There was no additional correspondence.

c. See attachments being provided in separate files. The depreciation calculation reflected in the attachment reflects estimated original cost of future assets, not actual original cost.

d.

i. Confirmed.

ii. See attachments being provided in separate files. The files provide the development of the proposed future rates with no terminal net salvage component. The weighted net salvage calculation for Simpsonville Solar and Mill Creek Unit 5 (used Cane Run CC 7 calculation) were previously provided in response to AG-KIUC 1-102(a).

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to the Joint Supplemental Data Requests of the Attorney General and Kentucky Industrial Utility Customers'
Dated July 31, 2025

Case No. 2025-00114

Question No. 33

Responding Witness: John J. Spanos

Q-33. Refer to the Direct Testimony of John Spanos at 20 wherein he discusses developing depreciation rates for future assets, including additional assets at Simpsonville Solar, new assets at Marion and Mercer, Mill Creek 5, and Brown BESS assets. Refer also to the notes on pages VI-10 and VI-11 of JJS-1 for KU and on pages VI-9 and VI-10 for LG&E electric related to the requested depreciation rates for Brown BESS, AMI, Paddy's Run CT pipeline, Simpsonville Solar Arrays 3, 4, 5, Mercer Solar, Marion Solar, and Mill Creek 5.

a. Confirm the Companies did not provide the underlying calculations or support for the proposed depreciation rates for the future assets. If confirmed, explain why they were not provided either with the filing or in response to Staff 1-54.

b. Provide the source(s) and all support relied on for each assumption/parameter/input used to develop the requested depreciation rates for the assets listed in the notes on these pages, including, but not limited to, estimated service lives and the range of estimated service lives considered, estimated interim retirements, estimated interim net salvage, and estimated terminal net salvage. Also provide all correspondence with KU/LG&E subject matter experts and/or decision makers and all directives from the Companies for these depreciation study assumptions/parameters/inputs.

c. Provide the schedules and workpapers in live Excel format and with all formulas intact relied on for the requested depreciation rates for the future assets listed in the notes on the referenced pages. Provide the schedules and workpapers for the future assets in the same level of detail and with the same information shown for each of the existing assets on the schedules in Section IV of each of the depreciation studies.

d. Refer to the response to AG-KIUC 1-102 (a) and (b).

    i. Confirm the response did not provide the requested information for any of the future assets and the proposed depreciation rates described and provided in the notes.

ii. Provide the information requested in AG-KIUC 1-102 (a) and (b) in the same format and in the same level of detail for the future assets as was provided in the response for the existing assets starting with the detailed schedules and workpapers provided in response to part (c) of this question used to calculate the proposed depreciation rates listed in the notes for the future assets so that there is the same sequence of proposed depreciation rates for the future assets as for the existing assets, i.e., support for proposed depreciation rates, modifications to exclude terminal net salvage from production and BESS plant accounts, further modifications to exclude interim retirements and interim net salvage in addition to excluding terminal net salvage from all production and BESS plant accounts.

A-33.

a. Confirmed. The Companies provided the information for existing assets.

b. The requested sources were either professional judgment based on experience performing numerous depreciation studies or consistent with existing assets and/or locations presented in the depreciation studies for KU and/or LGE. There was no additional correspondence.

c. See attachments being provided in separate files. The depreciation calculation reflected in the attachment reflects estimated original cost of future assets, not actual original cost.

d.

i. Confirmed

ii. See attachments being provided in separate files. The files provide the development of the proposed future rates with no terminal net salvage component. The weighted net salvage calculation for Simpsonville Solar and Mill Creek Unit 5 (used Cane Run CC 7 calculation) were previously in response to AG-KIUC 1-102(a).

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 303.00 MISCELLANEOUS INTANGIBLE PLANT - 5-YEAR

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE NET SALVAGE PERCENT.. 0						
2024	10,000.00			10,000	5.00	2,000
	10,000.00			10,000		2,000
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					5.0	20.00

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 303.00 MISCELLANEOUS INTANGIBLE PLANT - 10-YEAR

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE NET SALVAGE PERCENT.. 0						
2024	10,000.00			10,000	10.00	1,000
	10,000.00			10,000		1,000
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					10.0	10.00

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 303.00 MISCELLANEOUS INTANGIBLE PLANT - 15-YEAR

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE NET SALVAGE PERCENT.. 0						
2024	10,000.00			10,000	15.00	667
	10,000.00			10,000		667

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 15.0 6.67

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 303.00 MISCELLANEOUS INTANGIBLE PLANT - AMI

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE NET SALVAGE PERCENT.. 0						
2024	10,000.00			10,000	15.00	667
	10,000.00			10,000		667

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 15.0 6.67

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 341.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 5						
INTERIM SURVIVOR CURVE.. IOWA 55-R3						
PROBABLE RETIREMENT YEAR.. 6-2064						
NET SALVAGE PERCENT.. -12						
2024	70,000,000.00			78,400,000	38.28	2,048,067
	70,000,000.00			78,400,000		2,048,067

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.3 2.93

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 341.60 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SIMPSONVILLE SOLAR ARRAY 3 INTERIM SURVIVOR CURVE.. IOWA 40-S3 PROBABLE RETIREMENT YEAR.. 6-2046 NET SALVAGE PERCENT.. -4						
2024	10,000.00			10,400	21.90	475
	10,000.00			10,400		475
SIMPSONVILLE SOLAR ARRAY 4 INTERIM SURVIVOR CURVE.. IOWA 40-S3 PROBABLE RETIREMENT YEAR.. 6-2046 NET SALVAGE PERCENT.. -4						
2024	10,000.00			10,400	21.90	475
	10,000.00			10,400		475
SIMPSONVILLE SOLAR ARRAY 5 INTERIM SURVIVOR CURVE.. IOWA 40-S3 PROBABLE RETIREMENT YEAR.. 6-2049 NET SALVAGE PERCENT.. -4						
2024	10,000.00			10,400	24.76	420
	10,000.00			10,400		420
MARION/MERCER SOLAR INTERIM SURVIVOR CURVE.. IOWA 40-S3 PROBABLE RETIREMENT YEAR.. 6-2054 NET SALVAGE PERCENT.. -5						
2024	10,000,000.00			10,500,000	29.23	359,220
	10,000,000.00			10,500,000		359,220
	10,030,000.00			10,531,200		360,590
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					29.2	3.60

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 342.00 FUEL HOLDERS, PRODUCERS AND ACCESSORIES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 5						
INTERIM SURVIVOR CURVE.. IOWA 45-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2064						
NET SALVAGE PERCENT.. -12						
2024	8,000,000.00			8,960,000	36.11	248,131
	8,000,000.00			8,960,000		248,131
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					36.1	3.10

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 342.30 FUEL HOLDERS, PRODUCERS AND ACCESSORIES - LINE INSPECTIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PADDY'S RUN CT PIPELINE						
SURVIVOR CURVE.. IOWA 8-S4						
NET SALVAGE PERCENT.. 0						
2024	10,000.00			10,000	8.00	1,250
	10,000.00			10,000		1,250

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.0 12.50

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 343.00 PRIME MOVERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 5						
INTERIM SURVIVOR CURVE.. IOWA 40-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2064						
NET SALVAGE PERCENT.. -12						
2024	385,000,000.00			431,200,000	33.13	13,015,394
	385,000,000.00			431,200,000		13,015,394

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 33.1 3.38

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 344.00 GENERATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 5						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2064						
NET SALVAGE PERCENT.. -12						
2024	80,000,000.00			89,600,000	37.96	2,360,379
	80,000,000.00			89,600,000		2,360,379
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					38.0	2.95

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 344.60 GENERATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SIMPSONVILLE SOLAR ARRAY 5						
INTERIM SURVIVOR CURVE.. IOWA 25-S2.5						
PROBABLE RETIREMENT YEAR.. 6-2049						
NET SALVAGE PERCENT.. -4						
2024	10,000.00			10,400	22.18	469
	10,000.00			10,400		469
MARION/MERCER SOLAR						
INTERIM SURVIVOR CURVE.. IOWA 25-S2.5						
PROBABLE RETIREMENT YEAR.. 6-2054						
NET SALVAGE PERCENT.. -5						
2024	145,000,000.00			152,250,000	24.02	6,338,468
	145,000,000.00			152,250,000		6,338,468
	145,010,000.00			152,260,400		6,338,937
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					24.0	4.37

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 345.00 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 5						
INTERIM SURVIVOR CURVE.. IOWA 55-R3						
PROBABLE RETIREMENT YEAR.. 6-2064						
NET SALVAGE PERCENT.. -12						
2024	30,000,000.00			33,600,000	38.28	877,743
	30,000,000.00			33,600,000		877,743
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					38.3	2.93

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 345.60 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SIMPSONVILLE SOLAR ARRAY 3 INTERIM SURVIVOR CURVE.. IOWA 45-R2.5 PROBABLE RETIREMENT YEAR.. 6-2046 NET SALVAGE PERCENT.. -4						
2024	10,000.00			10,400	21.39	486
	10,000.00			10,400		486
SIMPSONVILLE SOLAR ARRAY 4 INTERIM SURVIVOR CURVE.. IOWA 45-R2.5 PROBABLE RETIREMENT YEAR.. 6-2046 NET SALVAGE PERCENT.. -4						
2024	10,000.00			10,400	21.39	486
	10,000.00			10,400		486
SIMPSONVILLE SOLAR ARRAY 5 INTERIM SURVIVOR CURVE.. IOWA 45-R2.5 PROBABLE RETIREMENT YEAR.. 6-2049 NET SALVAGE PERCENT.. -4						
2024	10,000.00			10,400	24.11	431
	10,000.00			10,400		431
MARION/MERCER SOLAR INTERIM SURVIVOR CURVE.. IOWA 45-R2.5 PROBABLE RETIREMENT YEAR.. 6-2054 NET SALVAGE PERCENT.. -5						
2024	15,000,000.00			15,750,000	28.47	553,214
	15,000,000.00			15,750,000		553,214
	15,030,000.00			15,781,200		554,617
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					28.5	3.69

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 346.00 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 5 INTERIM SURVIVOR CURVE.. IOWA 45-R3 PROBABLE RETIREMENT YEAR.. 6-2064 NET SALVAGE PERCENT.. -12						
2024	5,000,000.00			5,600,000	36.92	151,679
	5,000,000.00			5,600,000		151,679
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					36.9	3.03

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 346.60 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SIMPSONVILLE SOLAR ARRAY 3 INTERIM SURVIVOR CURVE.. IOWA 40-R2.5 PROBABLE RETIREMENT YEAR.. 6-2046 NET SALVAGE PERCENT.. -4						
2024	10,000.00			10,400	21.24	490
	10,000.00			10,400		490
SIMPSONVILLE SOLAR ARRAY 4 INTERIM SURVIVOR CURVE.. IOWA 40-R2.5 PROBABLE RETIREMENT YEAR.. 6-2046 NET SALVAGE PERCENT.. -4						
2024	10,000.00			10,400	21.24	490
	10,000.00			10,400		490
SIMPSONVILLE SOLAR ARRAY 5 INTERIM SURVIVOR CURVE.. IOWA 40-R2.5 PROBABLE RETIREMENT YEAR.. 6-2049 NET SALVAGE PERCENT.. -4						
2024	10,000.00			10,400	23.88	436
	10,000.00			10,400		436
MARION/MERCER SOLAR INTERIM SURVIVOR CURVE.. IOWA 40-R2.5 PROBABLE RETIREMENT YEAR.. 6-2054 NET SALVAGE PERCENT.. -5						
2024	50,000.00			52,500	28.03	1,873
	50,000.00			52,500		1,873
	80,000.00			83,700		3,289

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 25.4 4.11

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 348.00 ENERGY STORAGE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 15-S3						
NET SALVAGE PERCENT.. -5						
2024	10,000.00			10,500	15.00	700
	10,000.00			10,500		700
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					15.0	7.00

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 397.00 COMMUNICATION EQUIPMENT - AMI

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE NET SALVAGE PERCENT.. 0						
2024	10,000.00			10,000	15.00	667
	10,000.00			10,000		667

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 15.0 6.67

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

TABLE 2. CALCULATION OF WEIGHTED NET SALVAGE PERCENT FOR GENERATION PLANT AS OF JUNE 30, 2024

ACCOUNT		TERMINAL RETIREMENTS RETIREMENTS ($)	TERMINAL RETIREMENTS NET SALVAGE (%)	TERMINAL RETIREMENTS NET SALVAGE ($)	INTERIM RETIREMENTS RETIREMENTS ($)	INTERIM RETIREMENTS NET SALVAGE (%)	INTERIM RETIREMENTS NET SALVAGE ($)	TOTAL NET SALVAGE ($)	TOTAL RETIREMENT	ESTIMATED WEIGHTED NET SALVAGE (%)
(1)		(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)=(4)+(7)	(9)=(2)+(5)	(10)=(8)/(9)
OTHER PRODUCTION PLANT - SOLAR										
	MERCER/MARION SOLAR									
341.60	STRUCTURES AND IMPROVEMENTS	8,521,023	(4)	(340,841)	1,478,977	(5)	(73,949)	(414,790)	10,000,000	*(4)*
344.60	GENERATORS	38,624,027	(4)	(1,544,961)	106,375,973	(5)	(5,318,799)	(6,863,760)	145,000,000	*(5)*
345.60	ACCESSORY ELECTRIC EQUIPMENT	12,739,117	(4)	(509,565)	2,260,883	0	-	(509,565)	15,000,000	*(3)*
346.60	MISCELLANEOUS POWER PLANT EQUIPMENT	39,913	(4)	(1,597)	10,087	(3)	(303)	(1,900)	50,000	*(4)*
	TOTAL MERCER/MARION SOLAR	***59,924,079***		***(2,396,964)***	***110,125,921***		***(5,393,050)***	***(7,790,014)***	***170,050,000***	***(5)***
TOTAL OTHER PRODUCTION PLANT - SOLAR		59,924,079		(2,396,964)	110,125,921		(5,393,050)	(7,790,014)	170,050,000	

Remaining Support

1. Simpsonville Solar future asset locations uses the same interim survivor curve estimate by Account and weighted net salvage estimate as the existing solar assets. This weighted net salvage calculation was provided as "2025 PSC DR1 KU Attach to Q54 - Att 2 Exhibit JJS-KU-1 - 2024 - Table 2.xlsx" in response to PSC-1-54.
2. Mill Creek Unit 5 future asset location uses the same interim survivor curve estimate by Account and weighted net salvage estimate as the existing Cane Run CC 7. This weighted net salvage calculation was provided as "2025 PSC DR1 KU Attach to Q54 - Att 2 Exhibit JJS-KU-1 - 2024 - Table 2.xlsx" in response to PSC-1-54.

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 341.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 5						
INTERIM SURVIVOR CURVE.. IOWA 55-R3						
PROBABLE RETIREMENT YEAR.. 6-2064						
NET SALVAGE PERCENT.. -6						
2024	70,000,000.00			74,200,000	38.28	1,938,349
	70,000,000.00			74,200,000		1,938,349

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.3 2.77

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 341.60 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SIMPSONVILLE SOLAR ARRAY 3						
INTERIM SURVIVOR CURVE.. IOWA 40-S3						
PROBABLE RETIREMENT YEAR.. 6-2046						
NET SALVAGE PERCENT.. -2						
2024	10,000.00			10,200	21.90	466
	10,000.00			10,200		466
SIMPSONVILLE SOLAR ARRAY 4						
INTERIM SURVIVOR CURVE.. IOWA 40-S3						
PROBABLE RETIREMENT YEAR.. 6-2046						
NET SALVAGE PERCENT.. -2						
2024	10,000.00			10,200	21.90	466
	10,000.00			10,200		466
SIMPSONVILLE SOLAR ARRAY 5						
INTERIM SURVIVOR CURVE.. IOWA 40-S3						
PROBABLE RETIREMENT YEAR.. 6-2049						
NET SALVAGE PERCENT.. -2						
2024	10,000.00			10,200	24.76	412
	10,000.00			10,200		412
MARION/MERCER SOLAR						
INTERIM SURVIVOR CURVE.. IOWA 40-S3						
PROBABLE RETIREMENT YEAR.. 6-2054						
NET SALVAGE PERCENT.. -3						
2024	10,000,000.00			10,300,000	29.23	352,378
	10,000,000.00			10,300,000		352,378
	10,030,000.00			10,330,600		353,722
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					29.2	3.53

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 342.00 FUEL HOLDERS, PRODUCERS AND ACCESSORIES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 5						
INTERIM SURVIVOR CURVE.. IOWA 45-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2064						
NET SALVAGE PERCENT.. -6						
2024	8,000,000.00			8,480,000	36.11	234,838
	8,000,000.00			8,480,000		234,838

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 36.1 2.94

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 343.00 PRIME MOVERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 5						
INTERIM SURVIVOR CURVE.. IOWA 40-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2064						
NET SALVAGE PERCENT.. -6						
2024	385,000,000.00			408,100,000	33.13	12,318,141
	385,000,000.00			408,100,000		12,318,141
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					33.1	3.20

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 344.00 GENERATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 5						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2064						
NET SALVAGE PERCENT.. -6						
2024	80,000,000.00			84,800,000	37.96	2,233,930
	80,000,000.00			84,800,000		2,233,930
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					38.0	2.79

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 344.60 GENERATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SIMPSONVILLE SOLAR ARRAY 5 INTERIM SURVIVOR CURVE.. IOWA 25-S2.5 PROBABLE RETIREMENT YEAR.. 6-2049 NET SALVAGE PERCENT.. -2						
2024	10,000.00			10,200	22.18	460
	10,000.00			10,200		460
MARION/MERCER SOLAR INTERIM SURVIVOR CURVE.. IOWA 25-S2.5 PROBABLE RETIREMENT YEAR.. 6-2054 NET SALVAGE PERCENT.. -3						
2024	145,000,000.00			149,350,000	24.02	6,217,735
	145,000,000.00			149,350,000		6,217,735
	145,010,000.00			149,360,200		6,218,195
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					24.0	4.29

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 345.00 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 5						
INTERIM SURVIVOR CURVE.. IOWA 55-R3						
PROBABLE RETIREMENT YEAR.. 6-2064						
NET SALVAGE PERCENT.. -6						
2024	30,000,000.00			31,800,000	38.28	830,721
	30,000,000.00			31,800,000		830,721
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					38.3	2.77

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 345.60 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SIMPSONVILLE SOLAR ARRAY 3 INTERIM SURVIVOR CURVE.. IOWA 45-R2.5 PROBABLE RETIREMENT YEAR.. 6-2046 NET SALVAGE PERCENT.. -2						
2024	10,000.00			10,200	21.39	477
	10,000.00			10,200		477
SIMPSONVILLE SOLAR ARRAY 4 INTERIM SURVIVOR CURVE.. IOWA 45-R2.5 PROBABLE RETIREMENT YEAR.. 6-2046 NET SALVAGE PERCENT.. -2						
2024	10,000.00			10,200	21.39	477
	10,000.00			10,200		477
SIMPSONVILLE SOLAR ARRAY 5 INTERIM SURVIVOR CURVE.. IOWA 45-R2.5 PROBABLE RETIREMENT YEAR.. 6-2049 NET SALVAGE PERCENT.. -2						
2024	10,000.00			10,200	24.11	423
	10,000.00			10,200		423
MARION/MERCER SOLAR INTERIM SURVIVOR CURVE.. IOWA 45-R2.5 PROBABLE RETIREMENT YEAR.. 6-2054 NET SALVAGE PERCENT.. -3						
2024	15,000,000.00			15,450,000	28.47	542,677
	15,000,000.00			15,450,000		542,677
	15,030,000.00			15,480,600		544,054
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					28.5	3.62

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 346.00 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 5						
INTERIM SURVIVOR CURVE.. IOWA 45-R3						
PROBABLE RETIREMENT YEAR.. 6-2064						
NET SALVAGE PERCENT.. -6						
2024	5,000,000.00			5,300,000	36.92	143,554
	5,000,000.00			5,300,000		143,554

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 36.9 2.87

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 346.60 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SIMPSONVILLE SOLAR ARRAY 3 INTERIM SURVIVOR CURVE.. IOWA 40-R2.5 PROBABLE RETIREMENT YEAR.. 6-2046 NET SALVAGE PERCENT.. -2						
2024	10,000.00			10,200	21.24	480
	10,000.00			10,200		480
SIMPSONVILLE SOLAR ARRAY 4 INTERIM SURVIVOR CURVE.. IOWA 40-R2.5 PROBABLE RETIREMENT YEAR.. 6-2046 NET SALVAGE PERCENT.. -2						
2024	10,000.00			10,200	21.24	480
	10,000.00			10,200		480
SIMPSONVILLE SOLAR ARRAY 5 INTERIM SURVIVOR CURVE.. IOWA 40-R2.5 PROBABLE RETIREMENT YEAR.. 6-2049 NET SALVAGE PERCENT.. -2						
2024	10,000.00			10,200	23.88	427
	10,000.00			10,200		427
MARION/MERCER SOLAR INTERIM SURVIVOR CURVE.. IOWA 40-R2.5 PROBABLE RETIREMENT YEAR.. 6-2054 NET SALVAGE PERCENT.. -3						
2024	50,000.00			51,500	28.03	1,837
	50,000.00			51,500		1,837
	80,000.00			82,100		3,224

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 25.5 4.03

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

TABLE 2. CALCULATION OF WEIGHTED NET SALVAGE PERCENT FOR GENERATION PLANT AS OF JUNE 30, 2024

ACCOUNT		TERMINAL RETIREMENTS RETIREMENTS ($)	TERMINAL RETIREMENTS NET SALVAGE (%)	TERMINAL RETIREMENTS NET SALVAGE ($)	INTERIM RETIREMENTS RETIREMENTS ($)	INTERIM RETIREMENTS NET SALVAGE (%)	INTERIM RETIREMENTS NET SALVAGE ($)	TOTAL NET SALVAGE ($)	TOTAL RETIREMENT	ESTIMATED WEIGHTED NET SALVAGE (%)
(1)		(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)=(4)+(7)	(9)=(2)+(5)	(10)=(8)/(9)
OTHER PRODUCTION PLANT - SOLAR										
	MERCER/MARION SOLAR									
341.60	STRUCTURES AND IMPROVEMENTS	8,521,023	0	0	1,478,977	(5)	(73,949)	(73,949)	10,000,000	*(1)*
344.60	GENERATORS	38,624,027	0	0	106,375,973	(5)	(5,318,799)	(5,318,799)	145,000,000	*(4)*
345.60	ACCESSORY ELECTRIC EQUIPMENT	12,739,117	0	0	2,260,883	0	-	-	15,000,000	*0*
346.60	MISCELLANEOUS POWER PLANT EQUIPMENT	39,913	0	0	10,087	(3)	(303)	(303)	50,000	*(1)*
	TOTAL MERCER/MARION SOLAR	***59,924,079***		-	***110,125,921***		***(5,393,050)***	***(5,393,050)***	***170,050,000***	***(3)***
TOTAL OTHER PRODUCTION PLANT - SOLAR		59,924,079		-	110,125,921		(5,393,050)	(5,393,050)	170,050,000	

EXHIBIT LK-18

KENTUCKY UTILITIES COMPANY

Response to Attorney General and Kentucky Industrial Utility Customers' Initial Request for Information
Dated July 3, 2025

Case No. 2025-00113

Question No. 73

Responding Witness: Drew T. McCombs / Heather D. Metts

Q-73. For both Companies, provide a schedule showing by month from January 2022 through the end of the test year, including the months between the end of the base year and the beginning of the test year, the (a) total off-system sales revenues and the (b) net margins. In addition, (c) provide the amount of the net margins reflected in the base revenue requirement in the base year and in the test year annotated and/or reconciled to the schedule provided in this response. Further, (d) separate the monthly net margins to reflect the sharing allocation between the Companies and customers and show the calculation of this allocation.

A-73. See attachment being provided in a separate file.

KENTUCKY UTILITIES COMPANY
Case No. 2025-00113

Electric Off-System Sales Revenues and Margins
For January 2022 through December 2026

Month	Total Electric Off-System Sales Revenues (a)	Total Electric Off-System Sales Net Margins (b)	Net Margin Reflected in Base Revenue Requirement [1] (c)	Customer's Share of Net Margin (75%) (d)	Company's Share of Net Margin (25%) (d)
January 2022	$ 1,990,850	$ 636,428	-	$ 477,321	$ 159,107
February 2022	642,484	157,449	-	118,087	39,362
March 2022	528,399	48	-	36	12
April 2022	1,058,057	16,351	-	12,263	4,088
May 2022 [2]	8,797,003	4,413,028	-	3,309,771	1,103,257
June 2022 [3]	149,589	34,062	-	25,547	8,515
July 2022	2,775,094	1,371,062	-	1,028,297	342,766
August 2022	4,710,840	2,662,009	-	1,996,507	665,502
September 2022 [3]	1,795,295	817,694	-	613,271	204,423
October 2022	1,400,379	723,498	-	542,623	180,874
November 2022	2,151,404	802,004	-	601,503	200,501
December 2022	6,079,450	1,662,183	-	1,246,637	415,546
January 2023	$ 219,903	$ (2,009)	-	$ (1,507)	$ (502)
February 2023	82,518	30,325	-	22,744	7,581
March 2023	38,271	(277)	-	(207)	(69)
April 2023	66,312	61,255	-	45,942	15,314
May 2023	184,101	131,832	-	98,874	32,958
June 2023	179,520	74,959	-	56,219	18,740
July 2023	1,951,046	653,772	-	490,329	163,443
August 2023	1,117,962	372,659	-	279,494	93,165
September 2023	901,242	229,656	-	172,242	57,414
October 2023	716,391	158,957	-	119,218	39,739
November 2023	248,806	70,466	-	52,850	17,617
December 2023	61,516	2,316	-	1,737	579
January 2024	$ 1,035,513	$ 132,106	-	$ 99,079	$ 33,026
February 2024	19,747	1,585	-	1,189	396
March 2024	30,693	(58,988)	-	(44,241)	(14,747)
April 2024	265,415	61,660	-	46,245	15,415
May 2024	653,843	271,718	-	203,788	67,929
June 2024	1,096,002	363,495	-	272,621	90,874
July 2024	2,340,192	853,206	-	639,904	213,301
August 2024	1,744,833	719,000	-	539,250	179,750
September 2024	919,675	288,098	-	216,073	72,024
October 2024	291,635	55,792	-	41,844	13,948
November 2024	4,583	578	-	434	145
December 2024	222,754	51,839	-	38,879	12,960

KENTUCKY UTILITIES COMPANY
Case No. 2025-00113

Electric Off-System Sales Revenues and Margins
For January 2022 through December 2026

Month	Total Electric Off-System Sales Revenues (a)	Total Electric Off-System Sales Net Margins (b)	Net Margin Reflected in Base Revenue Requirement [1] (c)	Customer's Share of Net Margin (75%) (d)	Company's Share of Net Margin (25%) (d)
January 2025	$ 7,904,426	$ 3,929,547	-	$ 2,947,161	$ 982,387
February 2025	3,706,077	1,308,663	-	981,497	327,166
March 2025	451,472	55,275	-	41,456	13,819
April 2025	1,967,554	303,479	-	227,609	75,870
May 2025	1,364,663	177,342	-	133,007	44,336
June 2025	1,566,229	320,248	-	240,186	80,062
July 2025	987,008	225,625	-	169,219	56,406
August 2025	739,835	163,183	-	122,387	40,796
September 2025	2,118,004	474,941		356,206	118,735
October 2025	2,472,979	361,102		270,826	90,275
November 2025	1,272,758	124,220		93,165	31,055
December 2025	1,142,462	37,440		28,080	9,360
January 2026	$ 1,592,170	$ 183,274	-	$ 137,455	$ 45,818
February 2026	1,005,227	63,185	-	47,389	15,796
March 2026	193,727	4,254	-	3,191	1,064
April 2026	216,217	22,220	-	16,665	5,555
May 2026	1,478,158	406,923	-	305,192	101,731
June 2026	2,655,676	885,157	-	663,868	221,289
July 2026	1,056,230	317,289		237,966	79,322
August 2026	895,878	275,015		206,261	68,754
September 2026	1,955,772	645,645	-	484,234	161,411
October 2026	1,790,141	356,416		267,312	89,104
November 2026	995,376	213,082		159,812	53,271
December 2026	1,414,917	115,750	-	86,812	28,937

(1) There are no off-system sales revenues or expenses reflected in the base revenue requirement. Effective July 1, 2015, all revenues and expenses flow through the Off-System Sales Clause, per PSC Order 2014-00372.

(2) Other Consumables recorded in May 2022 were incorrect and subsequently corrected in June 2022. OSS filings in May and June were filed with correct Other Consumables.

(3) A reserve for Big Rivers was recorded in June but was subsequently reversed in September. The June and September OSS filings did not include the reserve and reversal.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General and the Kentucky Industrial Utility Customers' Initial Request for Information Dated July 3, 2025

Case No. 2025-00114

Question No. 73

Responding Witness: Drew T. McCombs / Heather D. Metts

Q-73. For both Companies, provide a schedule showing by month from January 2022 through the end of the test year, including the months between the end of the base year and the beginning of the test year, the (a) total off-system sales revenues and the (b) net margins. In addition, (c) provide the amount of the net margins reflected in the base revenue requirement in the base year and in the test year annotated and/or reconciled to the schedule provided in this response. Further, (d) separate the monthly net margins to reflect the sharing allocation between the Companies and customers and show the calculation of this allocation.

A-73. See attachment being provided in a separate file.

Louisville Gas and Electric Company
Case No. 2025-00114

Electric Off-System Sales Revenues and Margins
For January 2022 through December 2026

Month	Total Electric Off-System Sales Revenues (a)	Total Electric Off-System Sales Net Margins (b)	Net Margin Reflected in Base Revenue Requirement [1] (c)	Customer's Share of Net Margin (75%) (d)	Company's Share of Net Margin (25%) (d)
January 2022	$ 3,058,904	$ 1,548,191	-	$ 1,161,143	$ 387,048
February 2022	1,076,517	444,885	-	333,663	111,221
March 2022	1,696,076	814,548	-	610,911	203,637
April 2022	4,365,498	2,217,720	-	1,663,290	554,430
May 2022 [2]	3,968,438	1,867,728	-	1,400,796	466,932
June 2022 [3]	42,072	3,423	-	2,567	856
July 2022	730,218	428,007	-	321,005	107,002
August 2022	1,549,615	1,092,857	-	819,643	273,214
September 2022 [3]	904,849	634,553	-	475,915	158,638
October 2022	253,023	40,751	-	30,563	10,188
November 2022	3,045,323	1,034,168	-	775,626	258,542
December 2022	10,740,697	4,698,702	-	3,524,027	1,174,676
January 2023	$ 640,269	$ 233,202	-	$ 174,901	$ 58,300
February 2023	217,807	99,129	-	74,346	24,782
March 2023	293,265	89,813	-	67,360	22,453
April 2023	99,750	15,672	-	11,754	3,918
May 2023	160,933	29,907	-	22,430	7,477
June 2023	178,292	83,667	-	62,750	20,917
July 2023	597,395	220,475	-	165,356	55,119
August 2023	429,203	144,821	-	108,616	36,205
September 2023	336,533	64,781	-	48,586	16,195
October 2023	788,230	273,342	-	205,006	68,335
November 2023	1,203,923	352,385	-	264,289	88,096
December 2023	641,480	188,884	-	141,663	47,221
January 2024	$ 3,398,679	$ 1,353,277	-	$ 1,014,958	$ 338,319
February 2024	430,558	159,697	-	119,773	39,924
March 2024	164,092	49,374	-	37,030	12,343
April 2024	155,403	(22,577)	-	(16,933)	(5,644)
May 2024	394,575	81,073	-	60,805	20,268
June 2024	440,018	32,663	-	24,497	8,166
July 2024	782,971	48,818	-	36,613	12,204
August 2024	321,742	5,898	-	4,423	1,474
September 2024	436,785	59,438	-	44,579	14,860
October 2024	1,181,431	334,956	-	251,217	83,739
November 2024	93,048	5,919	-	4,439	1,480
December 2024	1,203,040	256,742	-	192,557	64,186

Louisville Gas and Electric Company
Case No. 2025-00114

Electric Off-System Sales Revenues and Margins
For January 2022 through December 2026

Month	Total Electric Off-System Sales Revenues (a)	Total Electric Off-System Sales Net Margins (b)	Net Margin Reflected in Base Revenue Requirement [1] (c)	Customer's Share of Net Margin (75%) (d)	Company's Share of Net Margin (25%) (d)
January 2025	$ 9,213,564	$ 4,537,987	-	$ 3,403,490	$ 1,134,497
February 2025	3,781,532	1,228,697	-	921,523	307,174
March 2025	314,785	54,124	-	40,593	13,531
April 2025	1,540,159	290,035	-	217,526	72,509
May 2025	2,354,968	581,943	-	436,458	145,486
June 2025	2,107,690	668,599	-	501,449	167,150
July 2025	709,425	200,183	-	150,138	50,046
August 2025	416,606	117,445	-	88,084	29,361
September 2025	1,954,563	631,570		473,677	157,892
October 2025	1,268,141	272,363		204,272	68,091
November 2025	1,906,946	483,132		362,349	120,783
December 2025	2,885,687	732,066		549,049	183,016
January 2026	$ 3,136,645	$ 749,544	-	$ 562,158	$ 187,386
February 2026	2,495,240	565,289	-	423,966	141,322
March 2026	404,559	83,975	-	62,981	20,994
April 2026	282,039	51,766	-	38,824	12,941
May 2026	1,604,933	267,885	-	200,914	66,971
June 2026	1,769,144	428,042	-	321,031	107,010
July 2026	865,281	211,519		158,639	52,880
August 2026	378,714	49,761		37,321	12,440
September 2026	2,656,655	710,210	-	532,658	177,553
October 2026	3,011,576	637,163		477,872	159,291
November 2026	3,224,903	786,692		590,019	196,673
December 2026	3,646,311	949,069	-	711,802	237,267

(1) There are no off-system sales revenues or expenses reflected in the base revenue requirement. Effective July 1, 2015, all revenues and expenses flow through the Off-System Sales Clause, per PSC Order 2014-00372.

(2) Other Consumables recorded in May 2022 were incorrect and subsequently corrected in June 2022. OSS filings in May and June were filed with correct Other Consumables.

(3) A reserve for Big Rivers was recorded in June but was subsequently reversed in September. The June and September OSS filings did not include the reserve and reversal.

EXHIBIT LK-19

STIPULATION AND RECOMMENDATION

This Stipulation and Recommendation ("Stipulation") is entered into this 29th day of July 2025 by and among Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, "the Utilities"); Attorney General of the Commonwealth of Kentucky, by and through the Office of Rate Intervention ("AG"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); Southern Renewable Energy Association ("SREA"); and Kentucky Coal Association, Inc. ("KCA"). (Collectively, the Utilities, AG, KIUC, SREA, and KCA are the "Parties.")

W I T N E S S E T H:

WHEREAS, on February 28, 2025, KU and LG&E filed with the Kentucky Public Service Commission ("Commission") its Joint Application *In the Matter of: Electronic Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates* ("Joint Application"), and the Commission has established Case No. 2025-00045 to review KU's and LG&E's Joint Application;

WHEREAS, on April 30, 2025, KU filed with the Commission its Application *In the Matter of: Electronic Application of Kentucky Utilities Company for Approval of Its 2025 Compliance Plan for Recovery by Environmental Surcharge Plan* ("Case No. 2025-00105"), and the Commission consolidated Case No. 2025-00105 into Case No. 2025-00045 by Orders dated May 14, 2025, in the records of both cases (for expediency, "this proceeding" or "this case" as used herein refers to the consolidated proceeding);

WHEREAS, the AG; KIUC; Lexington-Fayette Urban County Government ("LFUCG"); Louisville/Jefferson County Metro Government ("Louisville Metro"); Kentuckians for the Commonwealth ("KFTC"), Kentucky Solar Energy Society ("KYSES"), Metropolitan Housing

Coalition ("MHC"), and Mountain Association ("MA") (collectively, the "Joint Intervenors"); SREA, Sierra Club, and KCA have participated as full intervenors in Case No. 2025-00045;

WHEREAS, an in-person informal conference for the purpose of discussing settlement and the text of this Stipulation, attended by representatives of the Parties, Louisville Metro, LFUCG, Joint Intervenors, Sierra Club, and the Commission Staff, took place on July 22 and 23, 2025, during which a number of procedural and substantive issues were discussed, including potential settlement of all issues pending before the Commission in this case;

WHEREAS, the Parties hereto desire to settle all the issues pending before the Commission in this case;

WHEREAS, Louisville Metro and LFUCG take no position on the Stipulation and Recommendation and will not oppose it at the hearing;

WHEREAS, the Joint Intervenors and Sierra Club elected not to join this Stipulation and Recommendation;

WHEREAS, it is understood by all Parties hereto that this Stipulation is subject to the approval of the Commission insofar as it constitutes an agreement by the Parties for settlement, and, absent express agreement stated herein, does not represent agreement on any specific claim, methodology, or theory supporting the appropriateness of any proposed or recommended relief, matters, or issues addressed herein;

WHEREAS, all of the Parties, who represent diverse interests and divergent viewpoints, agree that this Stipulation, viewed in its entirety, is a fair, just, and reasonable resolution of their issues resolved in this Stipulation; and

WHEREAS, the Parties believe sufficient and adequate data and information in the record of this proceeding supports this Stipulation, and further believe the Commission should approve it without modifications or conditions;

NOW, THEREFORE, for and in consideration of the promises and conditions set forth herein, the Parties hereby stipulate and agree as follows:

ARTICLE I. CPCN APPROVALS, SITE COMPATABILITY CERTIFICATES, RELATED FINANCIAL MATTERS, AND REPORTING COMMITMENT

1.1. CPCN and Site Compatibility Certificate Approvals. The Parties agree the Commission should issue an order granting the Utilities Certificates of Public Convenience and Necessity ("CPCNs") and site compatibility certificates pursuant to KRS 278.216 as requested in the Utilities' application in Case No. 2025-00045, i.e., without condition or modification, for the following:

(A) An approximately 645 MW net summer rating natural gas combined cycle combustion turbine at KU's E.W. Brown Generating Station ("Brown 12"), including related gas and electric transmission construction at the station;

(B) An approximately 645 MW net summer rating natural gas combined cycle combustion turbine at LG&E's Mill Creek Generating Station ("Mill Creek 6"), including related gas and electric transmission construction at the station; and

(C) A selective catalytic reduction system at KU's Ghent Generating Station for Ghent 2 ("Ghent 2 SCR").

1.2. Withdrawal of Cane Run Battery Energy Storage System ("BESS") CPCN Request. The Utilities will withdraw their request for the Cane Run BESS without prejudice in this case, but they may re-file a CPCN Application for Cane Run BESS, or a substitute for it, at any time, which would be supported by a competitive procurement process.

1.3. Cost Recovery Review Metrics for Mill Creek 6. The Parties agree that one sufficient Mill Creek 6 cost recovery review metric (not a precondition) is having a total of at least 500 MW of executed electric service agreements under the Utilities' proposed Rate EHLF (Extremely High Load Factor) entered into by the in-service date for Mill Creek 6 in 2031. Support for Mill Creek 6 cost recovery could also be shown in other ways, including, but not limited to, non-Rate EHLF load growth, an increase in off-system sales, the acquisition of municipal or other load, replacing lost capacity if the Ohio Valley Electric Corporation's coal plants close, selling to other utilities or data centers in Kentucky, or selling part of Mill Creek 6 capacity.

1.4. Potential long-term power agreement with another Kentucky utility that is related to Kentucky data center(s) not located in the Utilities' service territories. The Utilities agree to seek Commission approval for any long-term (i.e., longer than one year) sale of capacity, energy, or both to another Kentucky utility for the purpose of serving one or more Kentucky data centers not in the Utilities' service territories. This could include, but not be limited to, joining an application to the Commission by the data-center serving utility for approval of a power purchase agreement under KRS 278.300. Issues that could be addressed in any such proceeding would include: (1) the extent to which the data center serving utility would pay for any direct and indirect incremental costs to provide electric service outside of the Utilities' service territories to the extent consistent with the Utilities' Open Access Transmission Tariff and all other applicable regulatory requirements; (2) the rates, terms and conditions of such an agreement and their relationship to the Utilities' proposed Rate EHLF; and (3) any sharing of revenues above the proposed Rate EHLF until the effective date of new base rates.

1.5. Deferral Accounting Requests. The Parties agree the Commission should approve the following deferral accounting treatment for the Utilities:

(A) As requested in the Utilities' application in Case No. 2025-00045 and without condition or modification, the Utilities will establish regulatory asset(s) for the difference between allowance for funds used during construction ("AFUDC") accrued at the Utilities' weighted average cost of capital and AFUDC accrued using the methodology approved by the Federal Energy Regulatory Commission during the construction periods of Brown 12 and Mill Creek 6.

(B) The Utilities will withdraw their request for a regulatory asset for post-in-service carrying costs ("PISCC"), operating and maintenance expense, property taxes, investment tax credit amortization, and depreciation expense as requested in their Application.

1.6. Reporting Commitment. The Utilities will provide semi-annual in-person construction, economic development, and load forecast updates to the Commission beginning in the second quarter of 2026 and ending in the second quarter of 2032. All Case No. 2025-00045 intervenors may attend such update meetings.

ARTICLE II. MILL CREEK 6 COST RECOVERY MECHANISM

2.1. Mill Creek 6 Cost Recovery Mechanism. The Parties agree the Commission should authorize LG&E to recover all non-fuel costs of Mill Creek 6 through a new Adjustment Clause MC6 (Mill Creek 6 Cost Recovery; attached hereto as Stipulation Exhibit 1).

(A) Costs recovered through Adjustment Clause MC6 will be all non-fuel costs of Mill Creek 6 from its in-service date through its retirement date, including without limitation depreciation, a weighted average cost of capital carrying cost using the most recently approved base rate return on equity appropriately grossed up for income taxes, and all Mill Creek 6 non-fuel operating expenses (including without limitation property taxes). Property taxes for the first year shall be based on the CWIP balance at the first of the year, not the in-service cost. Depreciation

shall be based on the same service life and treatment of interim retirements, interim net salvage, and terminal net salvage approved by the Commission for Brown 12 in a comprehensive base rate proceeding. During each expense month, the weighted average cost of capital will apply to the undepreciated capital cost of Mill Creek 6 (including any future plant additions) and regulatory asset balance for AFUDC, adjusted for accumulated deferred income taxes without any reduction for asset net operating loss accumulated deferred income taxes.

(B) The first expense month for Mill Creek 6 cost recovery through Adjustment Clause MC6 will be the month in which Mill Creek 6 goes in service, and the last expense month will be the month in which Mill Creek 6 retires. Cost recovery for any expense month will be billed in the second month thereafter (the billing month), e.g., for a January expense month, the following March will be the billing month.

(C) Temporary Offset to Cost Recovery through Adjustment Clause MC6. Cost recovery through Adjustment Clause MC6 will be partially and temporarily offset by certain revenues LG&E collects beginning with the in-service date of Mill Creek 6 and ending with the first date on which new electric base rates take effect for LG&E following the in-service date of Mill Creek 6. Such offsetting revenues will consist only of Maximum Load Charge revenues (i.e., all demand charge revenues, including all base, intermediate, and peak demand charge revenues for rate schedules that include such demand charge components) incremental to those then embedded in base rates from (1) customers taking service under Rate EHLF and (2) all Eligible Data Center customers as defined in Section 2.2 (all such revenues are "Offsetting Revenues"). As with cost recovery under Adjustment Clause MC6, Offsetting Revenues collected in an expense month will be credited against costs to be recovered under Adjustment Clause MC6 in the corresponding Billing Month.

(D) The Parties agree the Commission should approve all necessary regulatory deferral accounting required for the operation of Adjustment Clause MC6, including all regulatory asset and liability accounting required to address the delay between each expense month and billing month.

(E) Adjustment Clause MC6 will use the Group 1 and Group 2 methodology for revenue allocation used in LG&E's Environmental Cost Recovery Surcharge.

2.2. Eligible Data Center. For purposes of **ARTICLE II** of this Stipulation and Recommendation only, an "Eligible Data Center" is:

(A) Any centralized facility that is used primarily or exclusively for electronic information services such as the management, storage, processing, and dissemination of electronic data and information (including mining of cryptocurrency) through the use of computer systems, servers, networking equipment, and related components (each, an "Eligible Data Center") where such Eligible Data Center meets the following requirements:

(i) The expected or actual peak of the real-time energy demand of the Eligible Data Center is between 50 MVA and 100 MVA; and

(ii) The expected or actual monthly load factor for the Eligible Data Center is seventy-five percent (75%) or greater.

ARTICLE III. RATE EHLF COMMITMENTS

3.1. Rate EHLF Commitments. Regarding Rate EHLF, which the Utilities proposed in their pending rate proceedings in Case Nos. 2025-00113 and 2025-00114, the Parties agree to the following:

(A) In Case Nos. 2025-00113 and 2025-00114, the Utilities will seek approval to apply Rate EHLF only to new customers, and all Parties will support that proposal; and

(B) The Utilities will file all Rate EHLF electric service agreements with the Commission.

ARTICLE IV. MILL CREEK 2 LIFE EXTENSION

4.1. Environmental Approvals. The Utilities will seek necessary environmental approvals to allow Mill Creek 2 to continue to operate until Mill Creek 6 goes in service.

4.2. Existing Mill Creek 2 Retirement Authority Suffices. The Parties agree, and ask and recommend the Commission's final order in this proceeding to explicitly state, that the Utilities' existing authority to retire Mill Creek 2 suffices for a later retirement. For avoidance of doubt, the Utilities are not withdrawing their existing Mill Creek 2 retirement authority.

4.3. Mill Creek 2 Life Extension. The Parties agree that if the Utilities receive the necessary environmental approvals and the Commission's final order in this case affirms the Utilities' existing authority to delay Mill Creek 2's retirement until Mill Creek 6's in-service date, the Utilities will extend Mill Creek 2's life and continue to seek to maximize its value to customers as it does today, for instance, through economic dispatch and off-system sales.

4.4. Adjustment Clause MC2. The Parties agree the Commission should approve Adjustment Clause MC2 (attached hereto as Stipulation Exhibit 2), which is similar to LG&E's Adjustment Clause ECR (Environmental Cost Recovery Surcharge) and will provide recovery of the incremental Mill Creek 2 stay-open costs LG&E incurs that are not recovered through base rates, including incremental capital expenditures and other costs incurred specifically for this purpose after the date of this Stipulation. The Parties agree the Commission should approve all necessary regulatory deferral accounting required for the operation of Adjustment Clause MC2, including all regulatory asset and liability accounting required to address the delay between each expense month and billing month.

4.5. Analysis of Continued Operations of Mill Creek 2. As part of their 2027 Integrated Resource Plan filing, the Utilities will provide an analysis of the continued operation of Mill Creek 2 beyond 2031. If the analysis determines continued operation of Mill Creek 2 is economical, the Utilities will take the necessary steps to obtain the required approvals to allow Mill Creek 2 to operate beyond 2031. One of the required approvals would be obtaining Commission affirmation that the Utilities' existing Mill Creek 2 retirement authority would extend beyond the in-service date of Mill Creek 6. If such additional life extension would be economical and the Utilities were able to obtain all required approvals, all such life extension costs would be recovered through Adjustment Clause MC2.

4.6. LMAPCD Jurisdiction. Notwithstanding anything contained herein to the contrary, the Parties agree that the Stipulation and Recommendation does not impair, limit, or otherwise interfere with the jurisdiction of the Louisville Metro Air Pollution Control District ("LMAPCD").

ARTICLE V. OTHER COMMITMENTS

5.1. Renewable RFP Commitment. The Utilities commit to issue a request for proposals ("RFP") for renewable energy and energy storage by mid-2026 seeking to procure energy and capacity of utility scale solar, wind, storage, and/or hybrid resources.

5.2. Stakeholder Feedback. Prior to issuing the RFP, the Utilities agree to give intervenors to this proceeding the opportunity to provide feedback on the RFP.

5.3. Contracting Resources. For any cost-effective resources or those needed to serve customer requests (for instance, Green Tariff Option 3) identified in the RFP responses, the Utilities will complete contracting (with appropriate regulatory-out provisions) by mid-2028, and

apply for Commission approval by December 31, 2028, seeking approval for cost-effective resources.

ARTICLE VI. SEEM REPORTING COMMITMENT

6.1. SEEM Reporting Commitment. Beginning in the first quarter of 2026 and ending in the first quarter of 2031, the Utilities will file annual reports on their participation in the Southeast Energy Exchange Market ("SEEM"), including company-specific cost and benefit assessments and underlying data.

ARTICLE VII. ALL OTHER RELIEF TO BE GRANTED AS REQUESTED IN THE UTILITIES' APPLICATIONS

7.1. All Other Relief Requested by Utilities to Be Approved as Filed. The Parties recommend to the Commission that, except as modified in this Stipulation and the exhibits attached hereto, all other relief requested in the Utilities' filings in Case Nos. 2025-00045 and 2025-00105 should be approved as filed.

ARTICLE VIII. MISCELLANEOUS PROVISIONS

8.1. Except as specifically stated otherwise in this Stipulation, entering into this Stipulation shall not be deemed in any respect to constitute an admission by any of the Parties that any computation, formula, allegation, assertion or contention made by any other party in this case is true or valid.

8.2. The Parties agree that the foregoing Stipulation represents a fair, just, and reasonable resolution of the issues addressed herein and request that the Commission approve the Stipulation.

8.3. Following the execution of this Stipulation, the Parties shall cause the Stipulation to be filed with the Commission on July 29, 2025, together with a request to the Commission for consideration and approval of this Stipulation.

8.4. This Stipulation is subject to the acceptance of, and approval by, the Commission. The Parties agree to act in good faith and to use their best efforts to recommend to the Commission that this Stipulation be accepted and approved. The Parties commit to notify immediately any other Party of any perceived violation of this provision so the Party may have an opportunity to cure any perceived violation, and all Parties commit to work in good faith to address and remedy promptly any such perceived violation. In all events, counsel for all Parties will represent to the Commission that the Stipulation is a fair, just, and reasonable means of resolving all issues in this proceeding, and all Parties will clearly and definitively ask the Commission to accept and approve the Stipulation as such.

8.5. If the Commission issues an order adopting this Stipulation in its entirety and without additional conditions, each of the Parties agrees that it shall file neither an application for rehearing with the Commission nor an appeal to the Franklin Circuit Court with respect to such order.

8.6. If the Commission does not accept and approve this Stipulation in its entirety, then any adversely affected Party may withdraw from the Stipulation within the statutory periods provided for rehearing and appeal of the Commission's order by (1) giving notice of withdrawal to all other Parties and (2) timely filing for rehearing or appeal. If any Party timely seeks rehearing of or appeals the Commission's order, all Parties will continue to have the right to withdraw until the conclusion of all rehearings and appeals. Upon the latter of (1) the expiration of the statutory periods provided for rehearing and appeal of the Commission's order and (2) the conclusion of all rehearings and appeals, all Parties that have not withdrawn will continue to be bound by the terms of the Stipulation as modified by the Commission's order.

8.7. If the Stipulation is voided or vacated for any reason after the Commission has approved the Stipulation, none of the Parties will be bound by the Stipulation.

8.8. The Stipulation shall in no way be deemed to affect or diminish the jurisdiction of the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

8.9. The Stipulation shall inure to the benefit of and be binding upon the Parties hereto and their successors and assigns.

8.10. The Stipulation constitutes the complete agreement and understanding among the Parties, and any and all oral statements, representations, or agreements made prior hereto or contemporaneously herewith shall be null and void and shall be deemed to have been merged into the Stipulation.

8.11. The Parties agree that, for the purpose of the Stipulation only, the terms are based upon the independent analysis of the Parties to reflect a fair, just, and reasonable resolution of the issues herein and are the product of compromise and negotiation.

8.12. The Parties agree that neither the Stipulation nor any of its terms shall be admissible in any court or commission except insofar as such court or commission is addressing litigation arising out of the implementation of the terms herein, the approval of this Stipulation, or a Party's compliance with this Stipulation. This Stipulation shall not have any precedential value in this or any other jurisdiction.

8.13. The signatories hereto warrant that they have appropriately informed, advised, and consulted their respective Parties in regard to the contents and significance of this Stipulation and based upon the foregoing are authorized to execute this Stipulation on behalf of their respective Parties.

8.14. The Parties agree that this Stipulation is a product of negotiation among all Parties hereto, and no provision of this Stipulation shall be strictly construed in favor of or against any Party. Notwithstanding anything contained in the Stipulation, the Parties recognize and agree that the effects, if any, of any future events upon the operating income of the Utilities are unknown and this Stipulation shall be implemented as written.

8.15. The Parties agree that this Stipulation may be executed in multiple counterparts.

[Signature Pages Follow]

APPENDIX A: LIST OF STIPULATION EXHIBITS

Stipulation Exhibit 1:	Adjustment Clause MC6 (Mill Creek 6 Cost Recovery)
Stipulation Exhibit 2:	Adjustment Clause MC2 (Mill Creek 2 Incremental Stay-Open Cost Recovery)

IN WITNESS WHEREOF, the Parties have hereunto affixed their signatures.

Kentucky Utilities Company and
Louisville Gas and Electric Company

HAVE SEEN AND AGREED:

By: Allyson K. Sturgeon

Allyson K. Sturgeon

Attorney General for the Commonwealth of Kentucky, by and through the Office of Rate Intervention

HAVE SEEN AND AGREED:

By: _____

J. Michael West
T. Toland Lacy
Angela M. Goad
Lawrence W. Cook
John G. Horne II

Kentucky Industrial Utility Customers, Inc.

HAVE SEEN AND AGREED:

By: _____

Michael L. Kurtz
Jody Kyler Cohn

Lexington-Fayette Urban County Government

HAVE SEEN AND TAKE NO POSITION ON THE STIPULATION AND RECOMMENDATION AND WILL NOT OPPOSE IT AT HEARING:

By: M. Todd Osterloh

James W. Gardner
M. Todd Osterloh
Rebecca Price

Louisville/Jefferson County Metro Government

HAVE SEEN AND TAKE NO POSITION ON THE STIPULATION AND RECOMMENDATION AND WILL NOT OPPOSE IT AT HEARING:

By: _____

James W. Gardner
M. Todd Osterloh
Rebecca Price

Southern Renewable Energy Association

HAVE SEEN AND AGREED:

By: _____

Randal A. Strobo
David E. Spenard

Kentucky Coal Association, Inc.

HAVE SEEN AND AGREED:

By: /s/ Matthew R. Malone (with permission)
Matthew R. Malone
William H. May, III

EXHIBIT LK-20

Louisville Gas and Electric Company

P.S.C. Electric No. 14, Original Sheet No. XX

Adjustment Clause **MC2**

Mill Creek 2 Incremental Stay-Open Cost Recovery

APPLICABLE

In all territory served.

AVAILABILITY

This schedule is mandatory to Standard Rate Schedules listed in Section 1 of the General Index except Rate PSA and Special Charges, all Pilot Programs listed in Section 3 of the General Index, and Adjustment Clauses (Fuel Adjustment Clause (including Off-System Sales Adjustment Clause), Environmental Cost Recovery Surcharge, Demand-Side Management Cost Recovery Mechanism, and Retired Asset Recovery). Rate schedules subject to Adjustment Clause MC2 are divided into Group 1 or Group 2 as follows:

Group 1: Rates RS; RTOD-Energy; RTOD-Demand; VFD; AES; LS; RLS; LE; and TE.
Group 2: Rates GS; GTOD-Energy; GTOD-Demand; PS; TODS; TODP; RTS; EHLF; FLS; EVSE; EVC-L2; EVC-FAST; and OSL.

RATE

The monthly billing amount under each of the schedules to which this mechanism is applicable shall be increased or decreased by a percentage factor calculated in accordance with the following formula.

$$\text{Group MC2 Billing Factor} = \text{Group E(m)} / \text{Group R(m)}$$

As set forth below, Group E(m) is E(m) for the current expense month allocated to each of Group 1 and Group 2. Group R(m) for Group 1 is the twelve (12) month average revenue ending with the current expense month and for Group 2 is the twelve (12) month average non-fuel revenue ending with the current expense month.

DEFINITIONS

1. $E(m) = [(RB/12)\ (ROR + (ROR - DR)\ (TR / (1 - TR))] + OE$
   a. RB is the Mill Creek 2 Incremental Stay-Open Rate Base.
   b. ROR is the Company's overall rate of return (cost of short-term debt, long-term debt, preferred stock, and common equity) as approved by the Kentucky Public Service Commission in the Company's most recent base rate case.
   c. DR is the Debt Rate (cost of short-term debt and long-term debt).
   d. TR is the Composite Federal and State Income Tax Rate.
   e. OE is Incremental Stay-Open Operating Expenses of Mill Creek 2 not otherwise recovered through base rates or other cost-recovery mechanisms.

DATE OF ISSUE: XXXX XX, 2025

DATE EFFECTIVE: With Service Rendered
On and After XXXX XX, 2025

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2025-00045 dated XXXX

Louisville Gas and Electric Company

P.S.C. Electric No. 14, Original Sheet No. XX

Adjustment Clause **MC2**

Mill Creek 2 Incremental Stay-Open Cost Recovery

DEFINITIONS (continued)

2. E(m) is adjusted for any (Over)/Under collection or prior period adjustment to arrive at Adjusted Net E(m). Adjusted Net E(m) is allocated to Group 1 and Group 2 on the basis of Revenue as a Percentage of Total Revenue for the twelve (12) months ending with the Current Month to arrive at Group 1 E(m) and Group 2 E(m).

3. The Group 1 R(m) is the average of total Group 1 monthly base revenue for the twelve (12) months ending with the current expense month. Base revenue includes customer, energy, and lighting charges for each rate schedule included in Group 1 to which this mechanism is applicable and automatic adjustment clause revenues for the Fuel Adjustment Clause, Off-System Sales Adjustment Clause, Environmental Cost Recovery Surcharge, Retired Asset Recovery, and the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule in Group 1.

4. The Group 2 R(m) is the average of total Group 2 monthly base non-fuel revenue for the twelve (12) months ending with the current expense month. Base non-fuel revenue includes customer, non-fuel energy, and demand charges for each rate schedule included in Group 2 to which this mechanism is applicable and automatic adjustment clause revenues for the Environmental Cost Recovery Surcharge, Retired Asset Recovery, and the Demand-Side Management Cost Recovery Mechanism, as applicable for each rate schedule in Group 2. Non-fuel energy is equal to the tariff energy rate for each rate schedule included in Group 2 less the base fuel factor as defined on Sheet No. 85.1, Paragraph 6.

5. Current expense month (m) shall be the second month preceding the month in which Adjustment Clause MC2 is billed.

DATE OF ISSUE: XXXX XX, 2025

DATE EFFECTIVE: With Service Rendered
On and After XXXX XX, 2025

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2025-00045 dated XXXX

EXHIBIT LK-21

Louisville Gas and Electric Company

P.S.C. Electric No. 14, Original Sheet No. XX

Adjustment Clause **MC6**

Mill Creek 6 Cost Recovery

APPLICABLE

In all territory served.

AVAILABILITY

This schedule is mandatory to Standard Rate Schedules listed in Section 1 of the General Index except Rate PSA and Special Charges, all Pilot Programs listed in Section 3 of the General Index, and Adjustment Clauses (Fuel Adjustment Clause (including Off-System Sales Adjustment Clause), Environmental Cost Recovery Surcharge, Demand-Side Management Cost Recovery Mechanism, and Retired Asset Recovery). Rate schedules subject to Adjustment Clause MC6 are divided into Group 1 or Group 2 as follows:

Group 1: Rates RS; RTOD-Energy; RTOD-Demand; VFD; AES; LS; RLS; LE; and TE.
Group 2: Rates GS; GTOD-Energy; GTOD-Demand; PS; TODS; TODP; RTS; EHLF; FLS; EVSE; EVC-L2; EVC-FAST; and OSL.

RATE

The monthly billing amount under each of the schedules to which this mechanism is applicable shall be increased or decreased by a percentage factor calculated in accordance with the following formula.

$$\text{Group MC6 Billing Factor} = \text{Group E(m)} / \text{Group R(m)}$$

As set forth below, Group E(m) is E(m) for the current expense month allocated to each of Group 1 and Group 2. Group R(m) for Group 1 is the twelve (12) month average revenue ending with the current expense month and for Group 2 is the twelve (12) month average non-fuel revenue ending with the current expense month.

DEFINITIONS

1. $E(m) = [(RB/12)\,(ROR + (ROR - DR)\,(TR / (1 - TR))] + OE - OR$
   a. RB is the Mill Creek 6 Rate Base.
   b. ROR is the Company's overall rate of return (cost of short-term debt, long-term debt, preferred stock, and common equity) as approved by the Kentucky Public Service Commission in the Company's most recent base rate case.
   c. DR is the Debt Rate (cost of short-term debt and long-term debt).
   d. TR is the Composite Federal and State Income Tax Rate.
   e. OE is all Operating Expenses of Mill Creek 6.
   f. OR is all Offsetting Revenues as defined below.

DATE OF ISSUE: XXXX XX, 2025

DATE EFFECTIVE: With Service Rendered
On and After XXXX XX, 2025

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2025-00045 dated XXXX

Louisville Gas and Electric Company

P.S.C. Electric No. 14, Original Sheet No. XX

Adjustment Clause **MC6**
Mill Creek 6 Cost Recovery

DEFINITIONS (continued)

2. E(m) is adjusted for any (Over)/Under collection or prior period adjustment to arrive at Adjusted Net E(m). Adjusted Net E(m) is allocated to Group 1 and Group 2 on the basis of Revenue as a Percentage of Total Revenue for the twelve (12) months ending with the Current Month to arrive at Group 1 E(m) and Group 2 E(m).

3. The Group 1 R(m) is the average of total Group 1 monthly base revenue for the twelve (12) months ending with the current expense month. Base revenue includes customer, energy, and lighting charges for each rate schedule included in Group 1 to which this mechanism is applicable and automatic adjustment clause revenues for the Fuel Adjustment Clause, Off-System Sales Adjustment Clause, Environmental Cost Recovery Surcharge, Retired Asset Recovery, and the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule in Group 1.

4. The Group 2 R(m) is the average of total Group 2 monthly base non-fuel revenue for the twelve (12) months ending with the current expense month. Base non-fuel revenue includes customer, non-fuel energy, and demand charges for each rate schedule included in Group 2 to which this mechanism is applicable and automatic adjustment clause revenues for the Environmental Cost Recovery Surcharge, Retired Asset Recovery, and the Demand-Side Management Cost Recovery Mechanism, as applicable for each rate schedule in Group 2. Non-fuel energy is equal to the tariff energy rate for each rate schedule included in Group 2 less the base fuel factor as defined on Sheet No. 85.1, Paragraph 6.

5. Current expense month (m) shall be the second month preceding the month in which Adjustment Clause MC6 is billed.

6. Offsetting Revenues.

    a. Beginning with the in-service date of Mill Creek 6 and ending on the date on which new electric base rates first go into effect resulting from Company's first base rate case after Mill Creek 6 goes in service, Offsetting Revenues are actual Maximum Load Charge revenues (i.e., all demand charge revenues, including all base, intermediate, and peak demand charge revenues for rate schedules that include such demand charge components) incremental to those then embedded in base rates from (1) customers taking service under Rate EHLF and (2) all Eligible Data Center customers.

DATE OF ISSUE: XXXX XX, 2025

DATE EFFECTIVE: With Service Rendered
On and After XXXX XX, 2025

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2025-00045 dated XXXX

Louisville Gas and Electric Company

P.S.C. Electric No. 14, Original Sheet No. XX

Adjustment Clause **MC6**
Mill Creek 6 Cost Recovery

DEFINITIONS (continued)

b. An "Eligible Data Center" is any centralized facility used primarily or exclusively for electronic information services such as the management, storage, processing, and dissemination of electronic data and information (including mining of cryptocurrency) through the use of computer systems, servers, networking equipment, and related components with (a) an expected or actual peak of real-time energy demand between 50 MVA and 100 MVA and (b) an expected or actual monthly load factor of seventy-five percent (75%) or greater.

c. For clarity, any revenues Company receives prior to the in-service date of Mill Creek 6 are not Offsetting Revenues, and any revenues Company receives on and after the date on which new electric base rates first go into effect resulting from Company's first base rate case after Mill Creek 6 goes in service are not Offsetting Revenues. Therefore, Offsetting Revenues will be zero beginning with the expense month following the month in which new electric base rates first go into effect resulting from Company's first base rate case after Mill Creek 6 goes in service.

DATE OF ISSUE: XXXX XX, 2025

DATE EFFECTIVE: With Service Rendered
On and After XXXX XX, 2025

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2025-00045 dated XXXX

EXHIBIT LK-22

KENTUCKY UTILITIES COMPANY

Response to Attorney General and Kentucky Industrial Utility Customers' Initial Request for Information
Dated July 3, 2025

Case No. 2025-00113

Question No. 101

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

Q-101. Refer to the Direct Testimony of Christopher Garrett at 18 wherein he describes the Company's decision to reject the depreciation rates recommended by Witness Spanos for Brown 3 and Mill Creek 2.

a. Provide a copy of all communications with Witness Spanos in which the Company directed that certain assumptions or parameters be used and/or in which the Company proposed modifications to the depreciation rates developed by Witness Spanos.

b. Provide a copy of all communications with Witness Spanos that addressed whether the thermal production plant accounts depreciation rates should include terminal net salvage.

c. Indicate whether the Company or Witness Spanos decided to include terminal net salvage in the thermal production plant accounts depreciation rates. If Witness Spanos made this decision, then describe the Company's review and agreement with this decision.

d. Provide a copy of all communications with Witness Spanos that addressed whether the thermal production plant accounts depreciation rates should include interim retirements and interim net salvage.

e. Indicate whether the Company or Witness Spanos decided to include interim retirements and interim net salvage in the thermal production plant accounts depreciation rates. If Witness Spanos made this decision, then describe the Company's review and agreement with this decision.

A-101.

a. See attachment being provided in a separate file for email correspondence.

b. See the response to part (a).

c. The Company discussed the inclusion of terminal net salvage for thermal production plant accounts with Mr. Spanos given the Commission's stance

on this issue. Ultimately, both parties collectively agreed that terminal net salvage should be included in depreciation rates as evidenced by the email from Mr. Garrett to Mr. Spanos dated November 25, 2024 and included in the attachment referenced in part (a).

d. See the response to part (a).

e. Mr. Spanos recommended maintaining the weighted net salvage percentage approach which was consistent with previous studies and the Company was in agreement with his recommendation. There was no discussion as to whether interim retirements and interim net salvage was to be included in thermal production plant. The concept in the email was whether interim retirements and interim net salvage should be applied to all plant investment to replace the concept of terminal net salvage. Therefore, Mr. Spanos proposed inclusion of interim retirements and interim net salvage for all investment for thermal production plant accounts in order to replace the terminal net salvage component.

From: [redacted]
To: [redacted]
Cc: [redacted]
Subject: LGE and KU Depreciation Study
Date: Monday, September 9, 2024 3:34:53 PM

John,

We have the following items we would like to discuss with you.

1. Chris Garrett has asked if we can have rates based on historical by mid-October?
2. IT Software: Can we better align with PPL? They currently have:
    a. $5M and under – 5 years
    b. Above $5M to $10M – 10 years
    c. Above $10M – 15 years
3. On the IT Software, can we get your thoughts no later than 9/20/2024 on this as to whether making this change is appropriate/feasible with this study. Our legal department is asking in preparation of the next rate case.
4. Tower Coatings-LKE is utilizing the same materials as those utilized by PG&E with the expectation that the coatings will extend the useful lives of LKE's assets in a substantial manner, 20-25 years, consistent with PG&E's findings. Currently we are tracking this in accounts E354/E355 and will be shown as a separate retirement unit within PowerPlan. Should we split and have a separate depreciation rate based on this life assumption?
5. LGE/KU would like to auto-retire communication equipment and any other accounts included in our small tools policy. We would like to discuss the timing of this to include in the next rate case.
6. With the implementation of the AMI meters do we need to discuss a rate change for this account as a result? This is related to the high retirements shown in account E370 for both LGE and KU.
7. Site Visits – can we discuss when/if you will be visiting, and which sites you would like to go to as soon as possible to reserve the time on the appropriate calendars? We realize you may need to finish reviewing our responses before giving us this information.

Also, you will be receiving a file through our secure email server with the following files:

1. KU Data Questions – 2024.docx
2. LGE – 2024 – Data Questions.docx
3. Corrections to 2020 data.xlsx
4. FERC Order AI20-3-000 – Pipeline Testing costs.PDF
5. LGE – Attachment for Question 1.PDF
6. lge salvage & cor thru 06-2024 – corrected.xlsx
7. 20240826_Unit Ratings.xlsx (note – this is from Fred's request of 9/5/2024)

Please let us know when if you receive the files and/or if you have any issues downloading them.

Thank you!

Karen Daly
Senior Accounting Analyst | Asset Accounting | LG&E and KU

220 West Main Street, Louisville, KY 40202
[redacted]

Confidential

From: [redacted]
To: [redacted]
Cc: [redacted]
Subject: RE: LGE and KU Depreciation Study
Date: Tuesday, October 22, 2024 2:00:29 PM
Attachments: image001.png

John,
We should have clarified the criteria. The determination would be based on a combination of factors that would include contract term and cost, with contract term being the most important factor.

Currently, we do not have a significant amount of cloud software. None of it is beyond 5 years. However, we are requesting the additional categories to align with PPL and we expect to have hosted software with longer contracts and higher dollar amounts in the future, especially as we work to implement joint systems with PPL.

Thanks,
Heather

From: Spanos, John J. [redacted]>
Sent: Saturday, October 19, 2024 11:13 AM
To: Daly, Karen [redacted]; Johnston Jr., Frederick B. [redacted]
Cc: DiEnno, Heather [redacted]; Neiderer, Mackenzie P. [redacted]>
Subject: RE: LGE and KU Depreciation Study

EXTERNAL email. STOP and THINK before responding, clicking on links, or opening attachments.

Karen and Heather:

I am a little concerned about you determination of software. It should not be solely by cost.

Generally, the higher cost applications do have longer lives but the bigger factor is how long the software will be used and useful.

John

Business Use

From: Daly, Karen [redacted]
Sent: Wednesday, October 16, 2024 4:09 PM
To: Johnston Jr., Frederick B. <[redacted]
Cc: DiEnno, Heather [redacted]; Spanos, John J. [redacted]; Neiderer, Mackenzie P. <[redacted]
Subject: RE: LGE and KU Depreciation Study

[EXTERNAL EMAIL]: This email originated from outside the organization. Do not click links or open attachments unless you recognize the sender and know the content is safe.

Fred,

Please see our answers below in RED.

If you have additional questions, please let us know.

Thanks!

Karen Daly
Senior Accounting Analyst | Asset Accounting | LG&E and KU
220 West Main Street, Louisville, KY 40202
[redacted]

Business Use

Business Use

From: Johnston Jr., Frederick B. <[redacted]
Sent: Tuesday, October 15, 2024 1:41 PM
To: Daly, Karen [redacted]; DiEnno, Heather <[redacted]>
Cc: Spanos, John J. <[redacted]; Neiderer, Mackenzie P. <[redacted]
Subject: LGE and KU Depreciation Study

EXTERNAL email. STOP and THINK before responding, clicking on links, or opening attachments.

Karen and Heather,

We wanted to follow up with you related to a few items as we continue to move forward with the subject line Depreciation Studies. The items are listed below.

1. If LGE/KU is still planning for a future test year depreciation calculation, LGE/KU will need to provide forecasted activity for LGE and KU through December 31, 2025 to be used to develop a Future Test Year calculation? We will forward this as soon as it is available.
2. LGE/KU to provided updated surviving age distributions related to assets reflected in Account 303 reflecting the realignment of assets based on amortization periods and the amortization periods to be utilized for each subaccount. We would like to align the lives to be in line with our parent company PPL, mainly given that we will be spending significate IT dollars in the future.

   So, the splits we would like for all software are:
   a. $5M and under – 5 years
   b. Above $5M to $10M – 10 years
   c. Above $10M – 15 years
   (PPL Schedule below)

PPL ELECTRIC UTILITIES CORPORATION

TABLE 2. SUMMARY OF ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2021

	DEPRECIABLE GROUP (1)	SURVIVOR CURVE (2)	ORIGINAL COST AS OF DECEMBER 31, 2021 (3)	BOOK DEPRECIATION RESERVE (4)	FUTURE ACCRUALS (5)	CALCULATED ACCRUAL AMOUNT (6)
DEPRECIABLE PLANT						
	INTANGIBLE PLANT					
303.2	MISCELLANEOUS INTANGIBLE PLANT - SOFTWARE					
	5-YEAR ASSETS	5-SQ	116,404,518.57	70,529,136	45,875,383	13,640,726
	10-YEAR ASSETS	10-SQ	23,582,057.32	6,026,421	17,555,636	2,276,253
	15-YEAR ASSETS	15-SQ	26,794,473.25	991,431	25,803,042	1,779,520
	TOTAL ACCOUNT 303.2		166,781,049.14	77,546,988	89,234,061	17,696,499
303.6	RF MESH AMR SOFTWARE					
	5-YEAR ASSETS	5-SQ	3,535,866.34	3,430,057	105,809	74,686
303.8	CLOUD SOFTWARE					
	5-YEAR ASSETS	5-SQ	20,440,979.53	7,158,678	13,282,302	3,287,633
	10-YEAR ASSETS	10-SQ	16,143,924.80	2,719,204	13,424,721	1,486,048
	15-YEAR ASSETS	15-SQ	15,656,966.78	2,664,496	12,992,471	962,405
	TOTAL ACCOUNT 303.8		52,241,871.11	12,542,378	39,699,494	5,736,086

The splits we would consider reclassing are minimal. As of 6/30/2024 – all our cloud software was under $5M, however it will be higher in the future. For regular software in 303, the amounts to move are:

Asset	LGE	KU	Total	
Enterprise GIS Phase 2	$11,706,893.71		$ 11,706,893.71	To over $10M Group
Oracle Financial Upgrade	9,532,579.87	$ 10,981,428.66	$ 20,514,008.53	To over $10M Group
	$ 21,239,473.58	$ 10,981,428.66	$ 32,220,902.24	
Geographic Information System	$ 4,001,842.65	$ 5,093,223.60	$ 9,095,066.25	To over $5M Group
Siemens EnergyIP	$ 3,077,018.01	$ 3,760,809.96	$ 6,837,827.97	To over $5M Group

		$
$ 7,078,860.66	$ 8,854,033.56	15,932,894.22

The balance in the 303 accounts would remain in the under $5m group.

3. LGE and KU responses to Data Questions follow up.
   a. Several of the data questions we asked for both LGE and KU related to "young retirements". The response we received included text indicating that the retirements should have been made to older vintages and "We continue to educate asset accounting staff and refine our process". Is there a plan for the LGE and KU team to revisit/correct these past retirement or is the plan to address the issue going forward? This issue will be addressed going forward. We do not plan to "change" any of the numbers provided previously.
   b. Regarding LGE Electric Distribution Accounts: We asked why there was no Gross Salvage recorded in 2023 or 2024 for the following Accounts (364, 365, 366, 367 and 373.1). The response indicated that there has not been a change in practice regarding Gross Salvage, but did not explain why no Gross Salvage was being recorded for these Accounts. Please explain why no Gross Salvage was recorded for these Accounts during this period. We don't always know when or if we will receive salvage proceeds. When they are received, we will record to these accounts.

Thanks.

Fred

Frederick B. Johnston, Jr. | Assistant Project Manager
Gannett Fleming Valuation and Rate Consultants, LLC | 207 Senate Avenue, Camp Hill, PA 17011-2378
t [redacted]
Excellence Delivered As Promised
gannettfleming.com | Stay connected: *LinkedIn* | *Facebook* | *Twitter*

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From: [redacted]
To:
Cc:
Subject: RE: Follow-up
Date: Tuesday, November 19, 2024 12:20:21 PM

EXTERNAL email. STOP and THINK before responding, clicking on links, or opening attachments.

Heather:

We will work to create the new version you requested below. For our purposes, we will identify as Version 7.
We will add the footnoted rate for AMI

As for reserve adjustments, once we confirm which option is the preferred plan, then we can identify the actual reserve adjustments as they could be different depending on the version we go with. And based on our discussions, I am not sure any of these versions are guaranteed to be the one we file.

John

Business Use

From: DiEnno, Heather <[redacted]>
Sent: Tuesday, November 19, 2024 12:07 PM
To: Spanos, John J. [redacted]
Cc: Daly, Karen [redacted]
Subject: Follow-up

[EXTERNAL EMAIL]: This email originated from outside the organization. Do not click links or open attachments unless you recognize the sender and know the content is safe.

Hi John,
Chris Garret reviewed the files and had a couple of notes:

- The ruling regarding terminal net salvage applied to fossil production, and not hydro, solar, and wind. Can we get an updated version 6 with the terminal net salvage added back for non-fossil production?
- Regarding the AMI meters that will go in service next year, will you add a note for their rate (as you planned to for the new IT categories?)

Also, will we be able to get the Mill Creek reserve transfers by December 4?

Thank you,
Heather

Heather L. DiEnno CPA, CIA, CFE
Manager | Asset Accounting | LG&E and KU
220 West Main Street, Louisville, KY 40202
[redacted]
lge-ku.com

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From: [redacted]
To: [redacted]
Cc: [redacted]
Subject: RE: Follow-up
Date: Monday, November 25, 2024 9:26:31 AM

Agree with John. We believe it is inappropriate to remove terminal net salvage from steam and other production depreciation rates and do not plan to file using this scenario. This scenario was needed for analytical purposes to determine the magnitude of terminal net salvage included in our steam and other production depreciation rates.

Chris

Business Use

Business Use

From: DiEnno, Heather <[redacted]>
Sent: Monday, November 25, 2024 7:39 AM
To: Spanos, John J. [redacted]; McCombs, Drew T [redacted]>; Garrett, Christopher <[redacted]>
Cc: Daly, Karen Lorraine [redacted]>; Johnston Jr., Frederick B. [redacted]
Subject: RE: Follow-up

+Drew and Chris….please see John's comment below regarding Version 7.

Business Use

From: Spanos, John J. [redacted]
Sent: Friday, November 22, 2024 8:43 AM
To: DiEnno, Heather <[redacted]>
Cc: Daly, Karen <[redacted]>; Johnston Jr., Frederick B. [redacted]
Subject: RE: Follow-up

EXTERNAL email. STOP and THINK before responding, clicking on links, or opening attachments.

Heather:

I do not think it is appropriate to present version 7 in our case. Conceptionally terminal net salvage should be included for all production and picking and choosing takes away the validity of the approach and the definition of depreciation. I think it

would be appropriate to include terminal net salvage for steam assets and let the Commission deny it. If you do not like that option, then I suggest just applying an interim net salvage percent to all assets, however, that will create a higher depreciation expense than including terminal net salvage

John

Business Use

From: DiEnno, Heather <[redacted]>
Sent: Thursday, November 21, 2024 5:38 PM
To: Spanos, John J. <[redacted]
Cc: Daly, Karen [redacted]; Johnston Jr., Frederick B. <f[redacted]>
Subject: RE: Follow-up

[EXTERNAL EMAIL]: This email originated from outside the organization. Do not click links or open attachments unless you recognize the sender and know the content is safe.

Hi John,
I spoke with Chris and Drew today and they would like to proceed with Version 7. Please let me know if you have what you need from us or if you have additional questions.

As a reminder, we would like to have the adjustments for MC1 by early December 4 if possible.

Thank you,
Heather

Business Use

From: Spanos, John J. [redacted]>
Sent: Tuesday, November 19, 2024 4:16 PM
To: DiEnno, Heather <[redacted]>
Cc: Daly, Karen [redacted]>; Johnston Jr., Frederick B. [redacted]>
Subject: RE: Follow-up

EXTERNAL email. STOP and THINK before responding, clicking on links, or opening attachments.

Heather:

We have put together a version 7 which includes terminal net salvage for generation

assets accept fossil production.

Also, there is not a need for an AMI footnoted rate since we have assets in place with a comparable rate to what we would project. we added footnotes for software for the accounts that did not have a rate to work with already. That is why LGE common is included.

Just to be clear, these schedules are not my recommended position for a study as we are providing the options you requested for doing revenue requirement work.

John

Business Use

From: DiEnno, Heather [redacted]>
Sent: Tuesday, November 19, 2024 12:07 PM
To: Spanos, John J. [redacted]>
Cc: Daly, Karen [redacted]
Subject: Follow-up

[EXTERNAL EMAIL]: This email originated from outside the organization. Do not click links or open attachments unless you recognize the sender and know the content is safe.

Hi John,
Chris Garret reviewed the files and had a couple of notes:

- The ruling regarding terminal net salvage applied to fossil production, and not hydro, solar, and wind. Can we get an updated version 6 with the terminal net salvage added back for non-fossil production?
- Regarding the AMI meters that will go in service next year, will you add a note for their rate (as you planned to for the new IT categories?)

Also, will we be able to get the Mill Creek reserve transfers by December 4?

Thank you,
Heather

Heather L. DiEnno CPA, CIA, CFE
Manager | Asset Accounting | LG&E and KU
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From: [redacted]
To: [redacted]
Cc: [redacted]
Subject: RE: Rates
Date: Tuesday, November 5, 2024 6:07:26 AM
Attachments: KU - 062024 -Table 1 - v1.xlsx
KU - 062024 -Table 1 - v2.xlsx
KU - 062024 -Table 1 - v3.xlsx

EXTERNAL email. STOP and THINK before responding, clicking on links, or opening attachments.

Heather,

Please find attached the KU summary schedules for Versions 1, 2 and 3 updated to reflect the 2035 life associated with Brown Unit 3.

Fred

Frederick B. Johnston, Jr. | Assistant Project Manager
Gannett Fleming Valuation and Rate Consultants, LLC | 207 Senate Avenue, Camp Hill, PA 17011-2378
t [redacted]
Excellence Delivered As Promised
gannettfleming.com | Stay connected: *LinkedIn* | *Facebook* | *Twitter*

Business Use

From: DiEnno, Heather [redacted]>
Sent: Friday, November 1, 2024 12:00 PM
To: Spanos, John J. [redacted]>
Cc: Johnston Jr., Frederick B. [redacted]>
Subject: RE: Rates

[EXTERNAL EMAIL]: This email originated from outside the organization. Do not click links or open attachments unless you recognize the sender and know the content is safe.

Hi John,
Chris Garrett asked that I reach out to you and ask that you change the Brown 3 life back to 2035.

Thank you,
Heather

Business Use

From: Spanos, John J. [redacted]
Sent: Wednesday, October 30, 2024 10:09 AM
To: DiEnno, Heather <[redacted]>
Cc: Johnston Jr., Frederick B. <[redacted]>
Subject: RE: Rates

EXTERNAL email. STOP and THINK before responding, clicking on links, or opening attachments.

Heather:

Attached are our depreciation scenarios for both KU and LGE. There are a total of 11 files. Three versions of KU, 3 versions of LGE electric and common and two versions for LGE Gas. There are a lot of open issues to resolve.

Version 1 in all cases relates to depreciation parameters with life parameters that produce slightly higher depreciation expense.
Version 2 in all cases relates to depreciation parameters with life parameters that produce slightly lower depreciation expense.
Version 3 where applicable uses version 1 parameters but makes some possible reserve adjustments where necessary.

There are a few accounts that still require some discussion. These are highlighted. We also need to further discuss presentation of some accounts/locations.

Please review and we can set up a call when we all are available to resolve any issues in order to come up with the most appropriate scenario.

Thanks
John

Business Use

From: DiEnno, Heather <[redacted]>
Sent: Tuesday, October 22, 2024 3:01 PM
To: Spanos, John J. [redacted]>
Cc: Johnston Jr., Frederick B. [redacted]>
Subject: RE: Rates

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Thanks for the update.

Business Use

From: Spanos, John J. [redacted]>
Sent: Tuesday, October 22, 2024 2:59 PM
To: DiEnno, Heather <[redacted]>
Cc: Johnston Jr., Frederick B. [redacted]>
Subject: RE: Rates

EXTERNAL email. STOP and THINK before responding, clicking on links, or opening attachments.

Heather:

We are a little behind where we wanted to be based on not moving forward with our calculations as we tried to resolve the Acct 303 issues.

We will do our best to get you numbers within the week but I expect that will be the best we can do as we will be providing a few scenarios/versions based on how were need to address the fact that you will not be revising the retirement issues we mentioned in our emails

Thanks
John

Business Use

From: DiEnno, Heather [redacted]>
Sent: Tuesday, October 22, 2024 2:09 PM
To: Spanos, John J. [redacted]>
Subject: Rates

[EXTERNAL EMAIL]: This email originated from outside the organization. Do not click links or open attachments unless you recognize the sender and know the content is safe.

Hi John,
I just spoke Drew and he was wondering when we would be able to get the rates based on actuals. I know you all are still working through the IT assets, but he was wondering if we could go ahead and get the rates for the other assets. Our Budget group is working on their 2025 plan and need the

rates to complete it.

Thanks,
Heather

Heather L. DiEnno CPA, CIA, CFE
Manager | Asset Accounting | LG&E and KU
220 West Main Street, Louisville, KY 40202
O: 502.627.4626 | **M**: 502.541.8460| **F**: 502.217.2728
lge-ku.com

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From: [redacted]
To: [redacted]
Cc: [redacted]
Subject: RE: Rates Follow-Up Questions
Date: Wednesday, December 18, 2024 11:36:53 AM

EXTERNAL email. STOP and THINK before responding, clicking on links, or opening attachments.

We are working on the draft reports that will include the rates. did not know you already assumed a 30 year life for Mercer and Marion as that may change what we have planned.

Should have the draft reports to you prior which includes all the rates before the holiday

Business Use

From: DiEnno, Heather [redacted]>
Sent: Wednesday, December 18, 2024 11:34 AM
To: Spanos, John J. <[redacted]
Cc: Daly, Karen [redacted]; Johnston Jr., Frederick B. [redacted]>
Subject: RE: Rates Follow-Up Questions

[EXTERNAL EMAIL]: This email originated from outside the organization. Do not click links or open attachments unless you recognize the sender and know the content is safe.

Hi John,
I just wanted to check in on timing for getting the rates discussed below? Budget needs them to finalize their files, so would appreciate if we could get them in the first week of January.

I did learn that Mercer and Marion assumed a 30 year life in the CPCN analysis, so I wanted to pass that along.

Thanks,
Heather

Business Use

From: DiEnno, Heather

Sent: Friday, December 13, 2024 2:30 PM
To: Spanos, John J. <[redacted]
Cc: Daly, Karen <[redacted]>; Johnston Jr., Frederick B. <[redacted]>
Subject: RE: Rates Follow-Up Questions

Hi John, please see our response in green below:

From: DiEnno, Heather [redacted]>
Sent: Thursday, December 12, 2024 12:44 PM
To: Spanos, John J. <[redacted]>
Cc: Daly, Karen [redacted]
Subject: Rates Follow-Up Questions

[EXTERNAL EMAIL]: This email originated from outside the organization. Do not click links or open attachments unless you recognize the sender and know the content is safe.

Hi John,
Thank you for sending the rate splits.

I had a few follow-up questions for you:

1. Could you please provides rates for Marion and Mercer solar, which are not yet in service? Yes, we can. are they similar to other solar farms? Would it be appropriate to use rates for an existing facility, such as Brown solar? The parameters may be the same but the rates for new solar farms may not be the same as Brown. I suggest having footnoted rates in the table. Are both LGE or KU? Mercer is LGE and KU. Marion is KU. This will be most similar to Simpsonville Solar
2. For Simpsonville Solar 5 Panels, would it be appropriate to use the Simpsonville Solar 4 Panels rates? should have footnoted rate as most appropriate response. I assume you are referring to Acct 344.6 Yes, 344.6
3. For Simpsonville Solar A3, A4, and A5 Access Elec, would it be appropriate to use the rate for Simpsonville Solar A2? Same question for these units for Misc Power Equipment same response as above. Most appropriate is to have footnoted rates for new assets. These are accounts 345.6 and 346.6
4. Can you please provide a rate for Paddy's Run CT ILI? Are you referring to line inspections? Are they similar guidelines to Cane Run and Trimble County? Yes, in line inspections. Similar to Cane Run and Trimble.
5. For DMS equipment, would it be appropriate to use the old rate for the new DSM assets that will be placed in service? A new rate would be appropriate Can you please provide a new rate? Assets will go in service this year and we will use an old rate until the new rate is approved.
6. For AMI communication equipment and software will you be adding a note that we will be using the FERC mandated rate of 15 years? We have a rate for Acct 370.11 AMI meters. If you are putting assets into another account and want it identified then we will need to know

which account to determine if the 15 year life is appropriate for those assets. We are referring to AMI software in 303 and AMI Communication Equipment in 397.

Thank you,
Heather

Heather L. DiEnno CPA, CIA, CFE
Manager | Asset Accounting | LG&E and KU
220 West Main Street, Louisville, KY 40202
O: [redacted]
lge-ku.com

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From: [redacted]
To: [redacted]
Cc: [redacted]
Subject: KU DRAFT Depreciation Study Report as of June 30, 2024
Date: Monday, December 23, 2024 2:07:09 PM
Attachments: DRAFT KU 2024.pdf

EXTERNAL email. STOP and THINK before responding, clicking on links, or opening attachments.

Heather,

Please find attached a draft of the KU depreciation study report as of June 30, 2024 for your review. Please share with the members of your team as appropriate.

One specific item of note for which we are awaiting clarification is related to the footnoted rates for the Marion and Mercer Solar Generating Plants. The footnoted rates are based on a 25-year overall life and will need to be updated if the Companies are planning for an overall life other than 25 years.

We look forward to hearing from you with any feedback related to the attached draft reports.

Thanks.

Fred

Frederick B. Johnston, Jr. | Assistant Project Manager
Gannett Fleming Valuation and Rate Consultants, LLC | 207 Senate Avenue, Camp Hill, PA 17011-2378
t [redacted]
Excellence Delivered As Promised
gannettfleming.com | Stay connected: *LinkedIn* | *Facebook* | *Twitter*

From: [redacted]
To: [redacted]
Cc: [redacted]
Subject: RE: Chris KU Depreciation Study Comments
Date: Thursday, January 9, 2025 2:54:57 PM
Attachments: image001.png

EXTERNAL email. STOP and THINK before responding, clicking on links, or opening attachments.

Heather:

Just following up on this email since we have not heard back from you and cannot finalize the reports.

If we need to include Mill Creek Unit 5 in our footnoted rates then we need to know what type of unit, when it will be built etc.

Also, just confirming the solar life span issue. I believe we explained why we think 25 years should be continued to be used however, we did not have confirmation that you were okay with our position

John

Confidential

From: Spanos, John J.
Sent: Sunday, January 5, 2025 3:39 PM
To: DiEnno, Heather [redacted]; Johnston Jr., Frederick B. [redacted]>
Cc: Daly, Karen [redacted]
Subject: RE: Chris KU Depreciation Study Comments

I have commented on the areas that requested a response.

If you need something for Mill Creek 5 you will need to give some information

---

From: DiEnno, Heather [redacted]
Sent: Friday, January 3, 2025 5:09 PM
To: Spanos, John J. <[redacted]; Johnston Jr., Frederick B. [redacted]>
Cc: Daly, Karen <[redacted]
Subject: FW: Chris KU Depreciation Study Comments

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safe.

Confidential

From: McCombs, Drew [PPL] <[redacted]>
Sent: Thursday, January 02, 2025 4:30 PM
To: DiEnno, Heather <[redacted]; Daly, Karen <[redacted]>
Subject: Chris KU Depreciation Study Comments

Chris KU depreciation study comments.

Drew

Drew McCombs | Director, Regulatory Accounting
Controller | phone: [redacted]

PPL
220 W Main Street
9th Floor
Louisville, KY, 40202

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From: [redacted]
To: [redacted]
Cc: [redacted]
Subject: RE: Chris KU Depreciation Study Comments
Date: Wednesday, January 15, 2025 12:09:54 PM
Attachments: image001.png

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Heather

I am currently at hearings and have hearings next week as well.

Given my updated flight plans, I suggest trying to get a call for tomorrow somewhere between 10:00 – 3:00.

Based on your discussions, I think these three topics need to be on the table. Some of them we had addressed but this request changes some of the thinking on some we thought were resolved.

Terminal net salvage(decommissioning costs) for Mill Creek 1 and possibly others at Mill Creek
Life span for solar. More than just the new facilities
The footnoted rates for Mill Creek Unit 5. Should that be for both LGE and KU

Thanks
John

Confidential

From: DiEnno, Heather <[redacted]>
Sent: Wednesday, January 15, 2025 9:45 AM
To: Spanos, John J. [redacted]>; Johnston Jr., Frederick B. <[redacted]>
Cc: Daly, Karen [redacted]
Subject: RE: Chris KU Depreciation Study Comments

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John,
I think it might be best just to go ahead and schedule a call. Can you let me know your availability this week and next?

Thanks,
Heather

Confidential

From: Spanos, John J. [redacted]
Sent: Tuesday, January 14, 2025 3:11 PM
To: DiEnno, Heather [redacted]; Johnston Jr., Frederick B. <[redacted]>
Cc: Daly, Karen <[redacted]>
Subject: RE: Chris KU Depreciation Study Comments

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Heather:

These are extensive changes that I am not sure when we can get done plus I am not sure I agree.

But more importantly, you will need to send me the notes you are referencing for MC1 as isolating from other MC facilities is counter to how we perform the study.

Once you send we can look it over but I cannot change the whole methodology of our study at this time for decommissioning

John

Confidential

From: DiEnno, Heather <[redacted]>
Sent: Tuesday, January 14, 2025 2:19 PM
To: Spanos, John J. [redacted]; Johnston Jr., Frederick B. [redacted]
Cc: Daly, Karen [redacted]>
Subject: RE: Chris KU Depreciation Study Comments

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After discussion with Chris and Generation Planning, I learned that the 30 year rate for Marion and

Mercer came from a government source, the National Renewable Energy Laboratory (NREL) and we would prefer to use the 30 year life provided in that analysis.

Chris also had notes about updating the net salvage for MC1 to be what was used in the rider filing. He included the demo costs from the filing in his note, but please let me know if you need any additional information.

Let me know if you need anything else, or wish to discuss any of these items further.

Thanks,
Heather

Confidential

From: DiEnno, Heather
Sent: Tuesday, January 14, 2025 10:07 AM
To: Spanos, John J. <[redacted]; Johnston Jr., Frederick B. <[redacted]>
Cc: Daly, Karen <[redacted]>
Subject: RE: Chris KU Depreciation Study Comments

John,
I'm still gathering some info on solar and MC1, but I did want to go ahead and provide information on Mill Creek 5.

Mill Creek 5, a 640-megawatt natural gas combined-cycle (NGCC) generating unit, is expected to go in service in 2027.

From: Spanos, John J. [redacted]>
Sent: Thursday, January 09, 2025 2:55 PM
To: DiEnno, Heather <[redacted]; Johnston Jr., Frederick B. [redacted]
Cc: Daly, Karen <[redacted]>
Subject: RE: Chris KU Depreciation Study Comments

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Heather:

Just following up on this email since we have not heard back from you and cannot finalize the reports.

If we need to include Mill Creek Unit 5 in our footnoted rates then we need to know what type of unit, when it will be built etc.

Also, just confirming the solar life span issue. I believe we explained why we think 25 years should be continued to be used however, we did not have confirmation that you were okay with our position

John

Confidential

From: Spanos, John J.
Sent: Sunday, January 5, 2025 3:39 PM
To: DiEnno, Heather <[redacted]; Johnston Jr., Frederick B. [redacted]>
Cc: Daly, Karen [redacted]>
Subject: RE: Chris KU Depreciation Study Comments

I have commented on the areas that requested a response.

If you need something for Mill Creek 5 you will need to give some information

From: DiEnno, Heather [redacted]>
Sent: Friday, January 3, 2025 5:09 PM
To: Spanos, John J. [redacted]>; Johnston Jr., Frederick B. [redacted]>
Cc: Daly, Karen [redacted]>
Subject: FW: Chris KU Depreciation Study Comments

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Confidential

From: McCombs, Drew [PPL] [redacted]
Sent: Thursday, January 02, 2025 4:30 PM
To: DiEnno, Heather [redacted]; Daly, Karen <[redacted]>
Subject: Chris KU Depreciation Study Comments

Chris KU depreciation study comments.

Drew

Drew McCombs | Director, Regulatory Accounting
Controller | phone: [redacted]

PPL
220 W Main Street
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Louisville, KY, 40202

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From: [redacted]
To: [redacted]
Cc: [redacted]
Subject: RE: Mercer Solar/Marion Solar: 30 Year Design Life Confirmation
Date: Tuesday, January 21, 2025 6:58:32 PM
Attachments: image001.png
image002.png
image003.png

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Heather:

We will change the life span date for Mercer and Marion to 30 years in the report, however, this does not support changing our current estimates for other solar facilities. Those will stay as is at 25 years.

We will state the new solar sites are based on a design life that is longer than existing assets such as Simpsonville

John

Confidential

From: DiEnno, Heather [redacted]
Sent: Tuesday, January 21, 2025 3:13 PM
To: Spanos, John J. [redacted]; Johnston Jr., Frederick B. [redacted]
Cc: Daly, Karen <[redacted]
Subject: FW: Mercer Solar/Marion Solar: 30 Year Design Life Confirmation

[EXTERNAL EMAIL]: This email originated from outside the organization. Do not click links or open attachments unless you recognize the sender and know the content is safe.

Hi John,
Please see the information from Chris regarding Mercer and Marion solar.

Thanks,
Heather

Confidential

From: Garrett, Christopher [PPL] [redacted]
Sent: Tuesday, January 21, 2025 3:12 PM
To: DiEnno, Heather <[redacted]>
Cc: McCombs, Drew [PPL] [redacted]
Subject: FW: Mercer Solar/Marion Solar: 30 Year Design Life Confirmation

FYI, here are the bid requirements for the solar facilities which support the 30-year life. Let me know if John needs any additional information.

Chris

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From: Tummonds, David <[redacted]
Sent: Tuesday, January 21, 2025 2:51 PM
To: Garrett, Christopher [redacted]
Subject: FW: Mercer Solar/Marion Solar: 30 Year Design Life Confirmation

Chris,
Please see screenshots from both the Marion and Mercer specifications below.

Dave

Confidential

From: Brown, Elijah [redacted]
Sent: Tuesday, January 21, 2025 2:50 PM
To: Tummonds, David <[redacted]>
Subject: Mercer Solar/Marion Solar: 30 Year Design Life Confirmation

Dave,
I confirmed with Bright Night yesterday during the EPC discussion on-site that their basis of bid sent to bidders includes a design life of 30 years. This matches the Mercer Co. design life of 30 years used for its basis of bid as well both Mercer and Marion screenshots are below indicating 30-year design life.

Mercer Solar Technical Docs

SECTION 011100 – SUMMARY OF WORK continued

Site and Environmental Criteria

Project design shall be based upon the design conditions listed below and included in **Exhibit S**:

Table 1-1
Existing Site Design Conditions

Minimum/Maximum Dry Bulb Temperature (for inverter design)	-0.4°F/94.2°F (ASHRAE 2021 extreme annual – mean)
Extreme low temperature (for module string design)	-0.4F (ASHRAE extreme low annual) Contractor has option of using SAM model for string sizing.
Environmental Conditions	Per Site Constraints Map and Environmental Study
Maximum storm water velocity and depth	To be determined as part of design
Wetlands	Per Site Constraints Map
Floodplains	Per Site Constraints Map and Hydrology Study
Subsurface Soil Conditions	Per final Geotechnical Report

Design Criteria

A. Project and individual components shall have a minimum design life of 30 years.
B. Project shall be designed for automatic operation.
C. Project electrical design will be in compliance with applicable codes and standards listed in this Agreement unless otherwise noted.
D. Dissimilar metals in contact anywhere in system shall be avoided where possible to eliminate the possibility of galvanic corrosion. Lugs shall be selected for dissimilar metals where applicable.
E. During engineering design, Contractor shall work with the Owner when determining all signage, labeling and nomenclature.

Systems and Equipment

A. Provisions shall be included in the design of all systems to allow the performance of all routine maintenance without requiring a plant shut down.
B. Contractor shall:

SECTION 011100 – SUMMARY OF WORK continued

1. Receive, inspect, store, unload, maintain, erect, clean, align, and prepare all equipment in strict accordance with equipment manufacturer's instructions prior to Substantial Completion.
2. Provide lifting lugs on all equipment components or system components requiring removal for routine maintenance and weighing over 80 lbs.
3. Design the facility for a life of 30 years consistent with good engineering practice for solar generation facilities. However, it is understood that some of the equipment will require routine maintenance and possible replacement during the life of the facility.

Operating Criteria

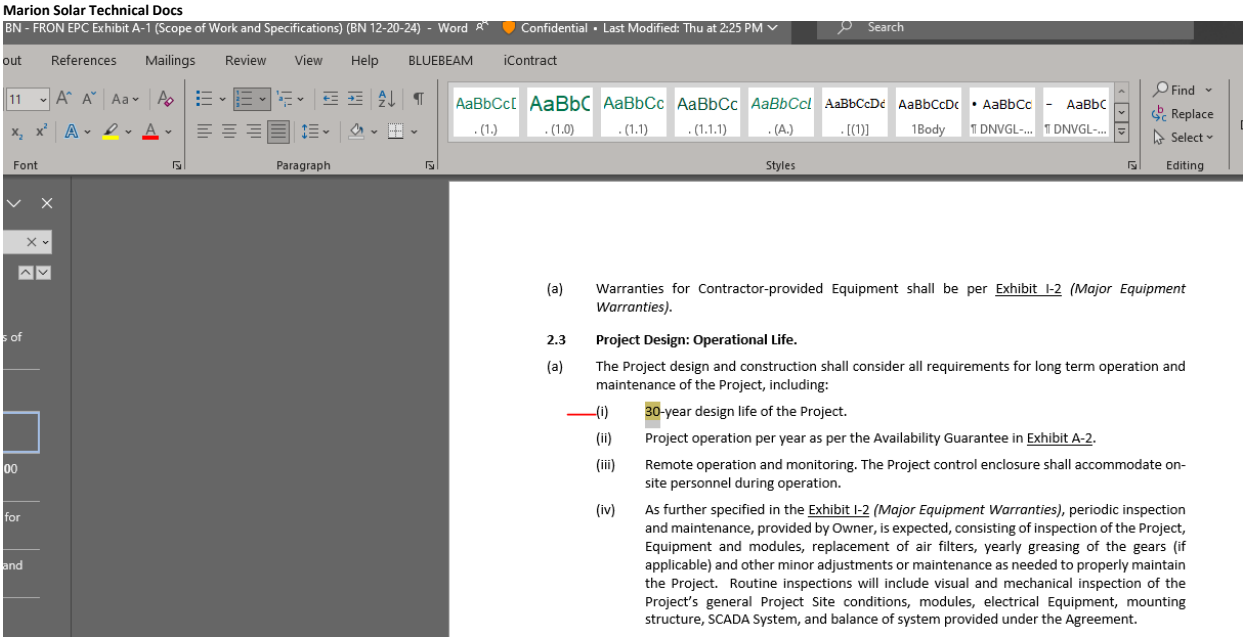
A. DC grid voltage: 1500 volts DC or greater, grounded or floating, ungrounded.
B. AC Medium voltage: 34.5 kV, 60Hz
C. DC & AC electrical systems under 1000V shall be radially configured. Medium voltage AC transformer systems shall be radially configured with loop feed features. No redundancy is required.
D. Convenience Power: 120VAC
E. Instrumentation voltage: 24VDC or 125VDC
F. Communications network: Ethernet via direct buried fiber optic within the arrays to the Communications Interface. Fiber optic to all field equipment shall be designed in a 'collapsed loop' configuration, at a minimum, to provide redundant path back to SCADA system.
G. The DC/AC ratio of each inverter skid assembly shall be within 5% of the overall project DC/AC ratio.

Codes, Regulations and Standards

A. In the event that any Applicable Law or Industry Standard does not govern specific features of any item of equipment and materials, Temporary Work or system, Contractor or Original Equipment Manufacturer (OEM) standards shall be applied, with Owner's approval. Where local codes or ordinances will have an impact on the design, Owner and Contractor shall jointly address these with the local authorities having jurisdiction.
B. Listed herein are the principal codes and standards applicable in the design, fabrication and installation of the Project; these are not intended to be all inclusive. Where local codes or ordinances will have an impact on the design, Contractor shall be responsible for meeting the codes or obtaining variances from local authorities having jurisdiction.
C. Contractor shall design and construct the Project in accordance **Exhibit N**

In the case where standards have conflicting requirements, Owner and Contractor will develop a mutual agreement of the prevailing standards.

Marion Solar Technical Docs



(a) Warranties for Contractor-provided Equipment shall be per Exhibit I-2 *(Major Equipment Warranties)*.

2.3 Project Design: Operational Life.

(a) The Project design and construction shall consider all requirements for long term operation and maintenance of the Project, including:

(i) 30-year design life of the Project.

(ii) Project operation per year as per the Availability Guarantee in Exhibit A-2.

(iii) Remote operation and monitoring. The Project control enclosure shall accommodate on-site personnel during operation.

(iv) As further specified in the Exhibit I-2 *(Major Equipment Warranties)*, periodic inspection and maintenance, provided by Owner, is expected, consisting of inspection of the Project, Equipment and modules, replacement of air filters, yearly greasing of the gears (if applicable) and other minor adjustments or maintenance as needed to properly maintain the Project. Routine inspections will include visual and mechanical inspection of the Project's general Project Site conditions, modules, electrical Equipment, mounting structure, SCADA System, and balance of system provided under the Agreement.

Thanks,
Elijah

Manager, Major Capital Projects |Project Engineering |LG&E and KU Energy, LLC
820 West Broadway, Louisville, KY 40202
O: [redacted]

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