COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT TO ITS ELECTRIC RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCHARGE	**)**	**Case No. 2020-00349**
IN THE MATTER OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT TO ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCHARGE	**)**	**Case No. 2020-00350**

Direct Testimony and Exhibits of

Michael P. Gorman

On behalf of

United States Department of Defense and all other Federal Executive Agencies

March 5, 2021

BAI
BRUBAKER & ASSOCIATES, INC.

Project 11069

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Direct Testimony of Michael P. Gorman

I. INTRODUCTION

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Managing Principal of the firm, Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing in this proceeding on behalf of the United States Department of Defense and all other Federal Executive Agencies ("DoD/FEA"). The DoD/FEA takes service from Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, "Companies") on several electric and gas rate schedules.

Q WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A This testimony outlines several positions in response to both KU electric and LG&E electric claimed revenue deficiency, class cost of service study ("COSS") and rate design, and I also comment on LG&E gas revenue deficiency, cost of service and rate design.

Q PLEASE SUMMARIZE YOUR POSITIONS CONCERNING THE CLAIMED REVENUE DEFICIENCIES BY LG&E ELECTRIC AND GAS, AND KU ELECTRIC.

A The Companies' claimed revenue deficiency for LG&E electric and gas as well as KU are overstated and should be reduced. This testimony outlines my and other DoD/FEA witnesses' recommended adjustments to the Companies' claimed revenue requirement, which impact the revenue deficiency in this proceeding.

Q PLEASE OUTLINE YOUR COMMENTS CONCERNING LG&E'S AND KU'S ELECTRIC COSS.

A I believe the Companies' electric COSS for LG&E and KU are generally reasonable. However, I recommend three adjustments to the Companies' electric COSS proposal.

1. I recommend production costs be allocated on a six coincident peak ("6 CP") rather than Loss of Load Probability ("LOLP") analysis.

2. I recommend transmission costs be allocated across rate classes in line with production capacity demands, because demands on the production system and need to deliver power for production and distribution costs require transmission capacity amounts to be designed to deliver production to distribution centers. The Companies' own evidence indicates that they design their systems in order to have adequate capacity during the peak season. Therefore, the allocation of these costs should be designed based on coincident peak demands. I recommend a 6 CP demand in line with what the Companies have stated to be reasonably in line with their production capacity study analysis.

3. I recommend the allocation of certain fixed steam unit operation and maintenance ("O&M") expenses be allocated across rate classes on demand and not energy. The Companies made a certain energy allocation for specific steam O&M accounts on the basis that these expenses vary with the amount of energy generation. I show that these expenses do not vary with energy and therefore should be allocated on the basis of the capacity fixed costs associated with these units.

Q DO YOU COMMENT ON THE COMPANIES' PROPOSED REVENUE SPREAD FOR ELECTRIC OPERATIONS AT LG&E AND KU?

A Yes. The Companies' proposed spread does not make a meaningful movement toward cost of service for each of the rate classes. Hence, I recommend a more appropriate spread of the revenue deficiency in this case by a gradual movement toward cost of service. I recommend limits on the increase to 125% of the system average increase approved by the Commission in this proceeding, and with certain classes receiving increases in revenues, I recommend no class receive a decrease. I believe this gradual movement toward cost of service will better align rates with cost of service, develop more accurate price signals, and be fair to all classes of customers.

Q ARE YOU PROPOSING ANY ADJUSTMENTS TO THE COMPANIES' RATE DESIGN FOR ELECTRIC TIME-OF-DAY ("TOD") RATES?

A Yes. For the reasons outlined in this testimony, I believe the Companies' design of their TOD rates into base, intermediate, and peak demand periods is reasonable and should be preserved. I also agree with the Companies to maintain a non-fuel energy rate component of these rate designs. However, I take issue with the Companies' proposal to recover both distribution and transmission costs in the base demand charge. I believe transmission costs largely align with system peak, and should be split between both base demand and the max demand period (intermediate and peak). I am proposing to separate transmission costs into base transmission fees and extra capacity fees. The base transmission fees will continue to be recovered in the base demand charge. The extra capacity component of transmission cost will be split between intermediate and peak demand charges. Second, I propose to remove steam production maintenance expense from the energy rate component, and include it in the intermediate and peak demand charge. Again, the Companies are proposing to include all production capacity-related charges in its intermediate and peak maximum capacity charges for this TOD rate. I believe this is reasonable because steam plant O&M expense that does not vary with energy should be classified as capacity-related, and should be recovered in the intermediate and peak demand charges.

Q DO YOU HAVE ANY COMMENTS CONCERNING THE COMPANY'S GAS COSS IN THIS PROCEEDING?

A Yes. I reviewed the Company's gas COSS and find it to be generally reasonable. I am proposing no adjustments to the Company's gas COSS in this proceeding.

Q ARE YOU PROPOSING ANY ADJUSTMENTS TO THE COMPANY'S PROPOSED REVENUE SPREAD FOR GAS OPERATIONS?

A No. The Company is proposing a gradual movement of adjustments to gas delivery rates to align with its estimated cost of service. I believe this gradual movement toward cost of service as proposed by the Company is reasonable.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q PLEASE SUMMARIZE YOUR POSITION CONCERNING THE COMPANY'S CLAIMED REVENUE DEFICIENCY FOR LG&E ELECTRIC AND LG&E GAS.

A The Company's claimed revenue deficiency for LG&E Electric and LG&E Gas is summarized below in Table 1. As shown in the table below, LG&E is proposing to increase its base rate revenues for LG&E Electric Operations by $131.1 million, and for Gas Operations by $30.0 million. I believe these revenue requirement claims are overstated for various reasons outlined in Table 1 below.

TABLE 1

LG&E Revenue Requirement Adjustments
($Millions)

Description	LG&E Electric Amount	LG&E Gas Amount
Claimed Deficiency	$131.1	$30.0
Adjustments:		
AMI Savings	$0.4	$ —
Prepaid Pension Asset	$2.8	$1.3
Employee Expense	$9.1	$3.8
Rate of Return	$17.4	$5.3
Depreciation Rate	$ —	$ —
Total Adjustments	$29.7	$10.4
Adjusted Revenue Deficiency	**$101.4**	**$19.6**

DoD/FEA is sponsoring other witnesses who propose to reduce the Company's rate of return and depreciation rates, and I will propose certain revenue requirement adjustments to the Company's claimed revenue deficiency. DoD/FEA witness Christopher C. Walters will address the Company's overall rate of return for LG&E Electric and Gas Operations, and for Kentucky Utilities. DoD/FEA witness Brian C. Andrews will address depreciation rate issues for KU Electric Operations. As outlined in the table above, the combined effect of DoD/FEA's proposed adjustments to the Company's claimed revenue deficiency will lower the increase in base rate revenues by approximately $29.7 million and $10.4 million for LG&E Electric and Gas Operations, respectively.

Q IS DoD/FEA ALSO PROPOSING ADJUSTMENTS TO THE CLAIMED REVENUE DEFICIENCY OF KENTUCKY UTILITIES?

A Yes. Shown below in Table 2 is the KU's claimed revenue deficiency of $170.1 million, adjusted for some of the same offsets sponsored by DoD/FEA witnesses Walters and Andrews, and me. The net effect of these adjustments to KU's claimed revenue deficiency reduces its revenue requirement by $69.2 million, and lowers the increase in base rate revenues from the $170.1 million proposed by KU down to $100.9 million.

TABLE 2

KU Revenue Requirement Adjustments
($Millions)

Description	Amount
Claimed Deficiency	$170.1
Adjustments:	
AMI Savings	$0.8
Prepaid Pension Asset	$2.7
Rate of Return	$26.2
Depreciation Rate	$39.5
Total Adjustments	$69.2
Adjusted Revenue Deficiency	**$100.9**

Again, DoD/FEA witnesses Mr. Walters and Mr. Andrews are sponsoring adjustments to KU's rate of return and depreciation rate.

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS ON ELECTRIC COSS.

A My conclusions and recommendations can be summarized as follows:

1. The COSS sponsored by the Companies allocate fixed transmission costs using non-coincident peaks. Transmission costs should be allocated using the same demand allocator as production costs. Non-coincident demand should be used for only distribution costs.

2. The Commission should use the six coincident peak ("6 CP") methodology to allocate the fixed production and transmission costs.

3. Steam generation maintenance expenses should be classified as demand related and allocated on the same basis as fixed production costs.

Q ARE YOU TAKING ISSUE WITH THE COMPANIES' PROPOSED SPREAD OF THE REVENUE INCREASE FOR LG&E ELECTRIC AND KU ELECTRIC?

A Yes. Based on the Companies' COSS, and their proposal for a gradual movement toward cost of service, I propose the following adjustments to the Companies' proposed spread of their revenue deficiency:

1. With a gradualistic protection of all classes, there should be a movement toward cost of service for each of the utilities.

2. I recommend that classes currently priced below cost of service receive up to 125% of the system average increase, or be adjusted to cost of service.

3. To mitigate impacts on customers currently priced below cost of service, I recommend that customer classes that are currently priced above cost of service be capped at a 0% increase. I believe this gradual movement toward cost of service will provide a balanced and equitable impact on all classes of customers, and move toward the Companies' stated objective of adjusting rates to cost of service, and designing rates to reflect the cost of providing utility services.

Q DO YOU PROPOSE ANY ADJUSTMENTS TO THE COMPANY'S DESIGN FOR TIME-OF-DAY ("TOD") RATE STRUCTURE?

A I will propose adjustments to the demand and energy charges for this rate structure, however, I support the design and the general objectives established by the Companies for the TOD design. The issues I will take with it include the amount of costs that should be recovered in the base demand charge versus the maximum peak period charges of intermediate and peak demand. Further, the Company is proposing certain recovery of production O&M expense in the energy charge to which I take exception. Specifically, this production O&M cost does not vary with energy, and therefore should be included along with the capacity allocation of the production cost or intermediate and peak demand charges, not energy.

Q DO YOU HAVE ANY CONCERNS WITH LG&E'S COSS FOR GAS OPERATIONS?

A No. I find the Company's gas COSS to be reasonable and appropriate for spreading the revenue deficiency in this proceeding. I also support the Company's proposal to make a gradual movement to cost of service based on the results of its COSS. Finally, the Company's proposed change to its gas delivery rates reasonably aligns with allocated cost of service that I believe is appropriate and reasonable.

III. REVENUE REQUIREMENT ADJUSTMENTS

III.A. Advanced Metering Infrastructure ("AMI")

Q PLEASE DESCRIBE THE COMPANIES' AMI REQUEST.

A The Companies request the Commission approve a Certificate of Public Convenience and Necessity ("CPCN") for the proposed deployment of AMI. The Companies also request approval of a ratemaking treatment that defers the AMI costs and benefits. Witness Lonnie E. Bellar addresses the Companies' AMI proposal in section VIII of his direct testimony. Mr. Bellar explains the Companies are proposing a full deployment of AMI in the electric only and combined electric and gas service territories over the next five years. Mr. Bellar sponsors Exhibit LEB-3 which is a cost/benefit analysis of various AMI deployment scenarios, including the status quo. Mr. Bellar argues that full

AMI deployment will be the least expensive way to read meters and will result in various operational and customer service improvements.

The costs and benefits of the AMI investment are not included in the Companies' test year revenue requirement. The Companies propose to defer cost recovery until the first base rate case after the project is fully implemented.

Q PLEASE EXPLAIN HOW THE COMPANIES CALCULATE THE COST OF THE AMI INVESTMENT.

A The Companies propose to record the investment as construction work in progress ("CWIP") and accrue an allowance for funds used during construction ("AFUDC") while the project is being implemented. The Companies will record a regulatory asset that includes the operating expenses associated with the project and the remaining net book value of the replaced electric meters. The Companies will also record a regulatory liability that tracks the difference between actual meter reading and field service expenses and the amount included in rates in this proceeding.

Witness Kent W. Blake provides a sample calculation of the Companies' proposal as Exhibit KWB-1. Table 3 below summarizes Mr. Blake's exhibit. The Companies estimate the net costs of CWIP, regulatory assets, regulatory liabilities, and deferred taxes to be $316.8 million.

TABLE 3

Proposed AMI Ratemaking Treatment
($ Millions)

Line	Description	Amount
	CWIP	
1	Capital Expenditures	$ 302.5
2	Capitalized Property Taxes	10.1
3	AFUDC - FERC	39.5
4	Total CWIP	$ 352.1
5	Regulatory Liability	$ (64.5)
	Regulatory Asset	
6	Operating Expenses	$ 36.8
7	Retired Meters NBV	26.8
8	AFUDC - WACC	11.3
9	Total Regulatory Asset	$ 74.9
10	ADIT	$ (45.7)
11	**Total AMI Capitalization**	**$ 316.8**

Source:
Exhibit KWB-1.

Q DO YOU RECOMMEND ANY ADJUSTMENTS TO THE TEST YEAR REVENUE REQUIREMENTS IN THIS PROCEEDING?

A Yes. I recommend the savings associated with the AMI investment during the test year be reflected in rates in this case. As shown on Exhibit KWB-1, the Companies forecast that the AMI investment will save approximately $1.2 million in meter reading and field service expenses during the test year. The Companies provided these savings by utility in response to Data Request DoD-FEA 2-26, provided as Exhibit MPG-1, pages 54-57. The breakdown of the test year savings is $398,794 for LG&E electric and $840,375 for KU. As mentioned above, the Companies propose to record these savings in a regulatory liability that will be used to offset the regulatory asset in the first base rate case after the AMI deployment is implemented.

Q IF THE TEST YEAR AMOUNT OF SAVINGS ASSOCIATED WITH AMI IS INCLUDED IN RATES, DOES THAT IMPACT THE COMPANIES' PROPOSED REGULATORY ASSET DEFERRALS YOU OUTLINED IN TABLE 3 ABOVE?

A Yes. Because the Companies will include certain operating expense savings in base rates in this case, they should track the deferral to the extent going forward operating expense savings exceed those reflected in base rates. In effect, in the Companies' proposal, there is a zero cost basis for the deferral. Under my alternative methodology, there will be a $1.2 million base rate assessment, and incremental savings above that would be recorded in the regulatory deferral as an offset to AMI capital investments as they are placed in-service.

Q DOES YOUR PROPOSED MODIFICATION IMPAIR IN ANY WAY THE COMPANIES' ABILITY TO FULLY RECOVER THEIR AMI INVESTMENT?

A No. Rather, it simply reflects some of the expected operating cost savings associated with AMI metering equipment relative to the old analog metering equipment, to be reflected in rates in this case. All incremental savings and costs will then be tracked separately. I would note that reflecting the test year savings is consistent with the Companies' stated objective of mitigating increase in rates in this proceeding caused by the economic fallout caused by the worldwide pandemic. For these reasons, I request the Commission modify the Companies' deferred treatment for AMI, and include test year savings in cost of service, and track incremental differences.

III.B. Prepaid Pension Asset

Q DO THE COMPANIES INCLUDE A PREPAID PENSION ASSET AS PART OF RATE BASE IN THIS PROCEEDING?

A Yes, the prepaid pension asset is included in the Companies' rate base as a component of working capital. Table 4 below shows the asset for each utility. The assets shown on the table are a 13-month average and represent the excess of pension trust fund assets over the projected benefit obligation.

TABLE 4

Prepaid Pension Asset
($ Millions)

Line	Description	LG&E Electric	LG&E Gas	KU
1	Base Period (13 Month Avg. 2/2020 - 2/2021)[1]	$25.6	$11.6	$30.7
2	Forecasted Period (13 Month Avg. 6/2021 - 6/2022)[2]	$42.0	$19.0	$42.7

Sources:
[1] LG&E and KU responses to Data Request DoD/FEA 2-18, provided as Exhibit MPG-1, pages 44-53.
[2] LG&E and KU responses to AG/KIUC Joint Initial Data Request Question 54, provided as Exhibit MPG-1, pages 18-27.

After accounting for the impact of accumulated deferred income taxes ("ADIT"), the net prepaid pension asset in the test year is $33.549 million for LG&E electric, $15.453 million for LG&E gas, and $34.036 million for KU.[1]

Q IS THERE COMMISSION PRECEDENT REGARDING WHEN A PREPAID PENSION ASSET IS PROPERLY INCLUDED IN A UTILITY'S COST OF SERVICE?

A Yes. The Commission in its January 13, 2021 Order in Case No. 2020-00174 determined Kentucky Power Company was <u>not</u> entitled to a return on its prepaid pension asset.

> While the Commission acknowledges Kentucky Power's assertion that there has been cash outlay to finance these prepaid assets as demonstrated in Ms. Whitney's rebuttal testimony and supporting exhibits, the Commission finds that a more reasonable method of measuring and recording Kentucky Power's pension and OPEB amounts for ratemaking purposes would be to remove the expenses attributed to these amounts for the test period because it reflects the actual amounts expended for pensions and OPEB expenses in the test period, rather than an expected future liability. As a result of this finding, the Commission reduced the revenue requirement by $5,203,831 to reflect the removal of the prepaid pension and prepaid OPEB asset and made a corresponding adjustment to increase expenses for Kentucky Power's applicable test-year pension and OPEB amounts as discussed in the Operating Income Adjustments section below.[2]

The Commission also removed an offset to pension expense in the same Order.

> As discussed in the preceding paragraphs regarding prepaid pension and prepaid OPEB assets that were included in rate base, Kentucky Power asserted that if the Commission adopted the Attorney General/KIUC's recommendations regarding the prepaid pension and prepaid OPEB assets and removed them from rate base, then a corresponding

[1] LG&E and KU responses to AG/KIUC Joint Supplemental Data Request Question 11, provided as Exhibit MPG-1, pages 28-33.

[2] Case No. 2020-00174, Final Order at 9-10.

> adjustment should be made to increase operating expenses to remove the benefit of the prepaid pension and prepaid OPEB asset that would normally reduce Kentucky Power's cost of service. The Commission finds that Kentucky Power provided sufficient evidence that there is a certain amount of cost savings attributed to the amounts recorded as a prepaid asset on Kentucky Power's books, and that the effect of increased expenses by not including the prepaid assets in rate base should be adequately reflected in the cost of service.[3]

Q WHAT IS THE IMPACT ON THE COMPANIES' REVENUE DEFICIENCY IF THE COMMISSION'S METHODOLOGY IN CASE NO. 2020-00174 WAS APPLIED IN THIS CASE?

A The Companies provided this calculation in response to AG/KIUC Joint Supplemental Data Request Question 11, provided as Exhibit MPG-1, pages 28-33. I updated the Companies' calculation to use the pre-tax rate of return sponsored by Mr. Walters. The calculation using the Companies' return is shown on pages 30 and 33 of Exhibit MPG-1. The revenue requirement impact of the Commission precedent is summarized in Table 5 below.

[3] *Id*. at 11.

TABLE 5

Case No. 2020-00174 Prepaid Pension Asset Treatment
($ Millions)

Line	Description	LG&E Electric	LG&E Gas	KU
1	Prepaid Pension Asset	($42.0)	($19.0)	($42.7)
2	Less ADIT	$8.5	$3.6	$8.7
3	Net Prepaid Pension Asset	($33.5)	($15.5)	($34.0)
4	Allocation Factor	100%	100%	94%
5	DoD/FEA Pre-Tax Rate of Return	8.46%	8.46%	8.51%
6	Rate Base / Capitalization Impact	($2.8)	($1.3)	($2.7)
7	Net Operating Income Impact	$3.3	$0.9	$2.7
8	**Net Revenue Requirement Impact**	**$0.5**	**($0.4)**	**($0.0)**

Sources:
LG&E and KU responses to AG/KIUC Joint Supplemental Data Request Question 11, provided as Exhibit MPG-1, pages 28-33.

The Companies state in the data response that they do not agree with this methodology. As shown on the table, the benefit and costs to customers of the prepaid pension asset are roughly equal.

Q DO YOU BELIEVE THE COMMISSION'S DECISION IN CASE NO. 2020-00174 SHOULD BE APPLIED IN THIS CASE?

A No. The Commission's decision in that docket is that if the prepaid pension asset is removed from rate base, then the benefit of that asset should be removed from the development of the pension expense. However, I believe the Commission should reconsider this on the basis of how the prepaid pension asset was funded. If the utility fully recovered its funding of the prepaid pension asset, then the utility and customers are fully entitled to the reduced pension expense created by recovering the pension trust fund funding by collections from customers. For this reason, I recommend the Commission remove the prepaid pension asset with no adjustment to operating expense, unless the utilities clearly establish that they have not fully recovered all contributions to the pension trust by recovery of pension expense through retail customers through cost of service.

I note that the amount of pension expense recovered in rates may not necessarily track changes in operating expense recorded by the utilities when rates are in effect. To the extent the utilities make a contribution in their trust after a rate case, that can cause the actual recorded expense to be less than the expense recovered from customers in rates. As such, in order to make a demonstrated proof of whether or not the Companies have fully recovered contributions to the trust by collections of pension expense from customers, the utilities must demonstrate what expenses have been recovered from customers and whether or not that expense recovery has been adequate to fully compensate the Companies for their contributions to the pension trust.

Q DID YOU SEEK INFORMATION FROM THE COMPANIES ON HOW THEIR PREPAID PENSION ASSET HAD BEEN FUNDED?

A Yes. The Companies provided information on the funding of their prepaid pension asset after January 1, 2019 in response to data requests.[4] I summarize the development of the pension asset from the beginning of the base period to the end of the forecasted period in Table 6 below. On January 1, 2019, the Companies' financial statements had a prepaid pension liability. The liability became an asset in 2019.

TABLE 6

<u>Prepaid Pension Asset Development</u>
($ Millions)

Line	Description	LG&E	KU
1	Beginning Balance - February 2020	$31.6	$30.7
	Adjustments:		
2	Contributions	$11.0	$4.0
3	Service Cost & Interest Cost	($38.0)	($37.3)
4	Estimated Return on Assets	$67.4	$53.7
5	Funded Status Adjustments	($1.3)	($3.2)
6	Ending Balance - June 2022	$70.8	$47.9
7	Forecasted Period 13 Month Average	$61.0	$42.7

Sources:
LG&E and KU responses to Data Request DoD/FEA 2-18, provided as Exhibit MPG-1, pages 44-53.
LG&E and KU responses to AG/KIUC Joint Initial Data Request Question 54, provided as Exhibit MPG-1, pages 18-27.

[44] LG&E and KU responses to Data Request DoD/FEA 2-18, provided as Exhibit MPG-1, pages 44-53, and AG/KIUC Joint Initial Data Request Question 54, provided as Exhibit MPG-1, pages 18-27.

As shown in the table above, the Companies' contributions to the pension trust which have contributed to the prepaid pension asset amount to around $11 million for LG&E and $4 million for KU. The Companies' data indicates that the $11 million contributions included $4 million in 2020 and 2021, and $3 million in 2022 for LG&E. For KU, the $4 million contribution consisted of a $1 million contribution in 2020, $2 million in 2021, and $1 million in 2022. These trust fund contributions by the Companies, however, have all been less than the amount of pension expense that the utilities have included in rates and will recover from customers during this same forecasted time period. Specifically, the Companies estimated the amount of pension expense included in their tariff rate cost recovery during the same time period of 2020-2022 is around $3.7 million per year for LG&E and $3.8 million per year for KU.[5]

Q WHAT DO YOU RECOMMEND?

A I recommend removing the prepaid pension asset from the Companies' cost of service. As mentioned above, the net prepaid pension asset in the test year is $33.549 million for LG&E electric, $15.453 million for LG&E gas, and $34.036 million for KU.[6] The revenue requirement impact of my adjustment is $2.8 million for LG&E electric, $1.3 million for LG&E gas, and $2.7 million for KU. My adjustment is the calculation shown on lines 1 to 6 of Table 5. Further, because the utilities have fully recovered all contributions to the pension trust by collections from customers, I recommend no

[5] LG&E and KU responses to Data Request DoD/FEA 2-17, provided as Exhibit MPG-1, pages 42-43.

[6] LG&E and KU responses to AG/KIUC Joint Supplemental Data Request Question 11, provided as Exhibit MPG-1, pages 28-33.

adjustment to the pension expense in this proceeding. To the extent the prepaid pension asset had the effect of lowering that pension expense, customers are entitled to that benefit because they have fully compensated the Companies for contributions to the pension trust.

<u>III.C. Employee Expense Adjustment</u>

Q DO THE COMPANIES INCLUDE A PROJECTED LEVEL OF EMPLOYEES IN THE FORECASTED TEST YEAR?

A Yes. The Companies' Schedule D-1 shows the operating expenses by account for the base period and forecasted period and explains the difference. The cost increase for several accounts is reported on Schedule D-1 as "Lower labor in base period due to vacancies as a result of hiring delays due to COVID, labor charged to capital in base period, and labor actuals in other FERC accounts in base period." The Companies expanded the explanation in response to AG-KIUC Joint Initial Data Request Question 44, provided as Exhibit MPG-1, pages 16-17:

> The base period is lower than the forecasted test period and related to a multitude of issues ranging from open positions, wage increases and higher capitalization of wages. The open positions are typically managed with overtime and supplemental contractors. Due to COVID-19, employee positions were delayed particularly in the generation FERCs due to concerns about training since it requires close proximity that could not be achieved with socially distancing guidelines and also sizable groups of employees and contractors that were not able to come into work related to COVID-19 quarantines. Additionally, supplemental contractors were also a limited resource in 2020 related to constraints from mutual assistance provided to an unusually large number of storm events and COVID-19 issues within their own workforces.

The Companies' test year employee expense assumes they will fill all open positions between January 1, 2021 and June 30, 2022.[7]

Q HOW DOES THE COMPANIES' FORECASTED EMPLOYEE HEADCOUNT COMPARE TO THEIR ACTUAL EMPLOYEE HEADCOUNT OVER THE PAST SEVERAL YEARS?

A Table 7 below summarizes the Companies' actual and forecasted headcount. The table shows that LG&E and KU plan to hire 82 and 13 employees by the end of the forecasted test year, respectively.

TABLE 7

Budgeted vs. Actual Employees

		LG&E Electric & Gas		KU	
Line	**Description**	**Actual**	**Budget**	**Actual**	**Budget**
1	YE December 2015	1,017		940	
2	YE December 2016	1,038		937	
3	YE December 2017	1,001		923	
4	YE December 2018	1,045		916	
5	YE December 2019	1,066		909	
6	YE March 2020	1,045	1,105	900	926
7	YE December 2020	1,031	1,117	905	928
8	Base Period (YE February 2021)		1,103		923
9	Forecasted Period (YE June 2022)		1,113		918
10	Vacant Positions*		82		13

Sources and Notes:
LG&E and KU responses to AG/KIUC Joint Initial Data Request Question 41, provided as Exhibit MPG-1, pages 2-5.
LG&E and KU responses to AG/KIUC Joint Initial Data Request Question 43, provided as Exhibit MPG-1, pages 6-15.
* Line 9 Budgeted - Line 7 Actual.

[7] LG&E and KU responses to AG-KIUC Joint Initial Data Request Question 43, provided as Exhibit MPG-1, pages 6-15.

The Companies provided budgeted versus actual headcount comparisons by month for March 2020 to December 2020. Lines 6 and 7 of Table 7 above show that the Companies were budgeting for more employees than they actually employed during this period. Hence, the utilities did not actually spend the full budgeted employee costs.

Q ARE THE COMPANIES' FORECASTED TEST YEAR EMPLOYEE HEADCOUNTS REASONABLE?

A The LG&E headcount is not reasonable. As shown on Table 7 above, LG&E is proposing to fill 82 vacant positions by the end of the test year. This would put LG&E's headcount well above its historical level. LG&E's average employee level was approximately 1,033 employees between 2015 and 2020, ranging from 1,066 to 1,001 employees. The six-year average of 1,033 employees is also comparable to its current employee headcount of 1,031.

The costs of LG&E's unfilled employee positions are not known and measurable because it is not known if LG&E will actually incur its full budgeted labor expense in the rate effective period. Recent history suggests LG&E will not incur the cost on its budgeted labor expense because it consistently has unfilled budgeted positions. In addition, there is no evidence that increasing the employee headcount prospectively is necessary to maintain service quality and reliability that have been provided over the last few years. Again, the costs associated with the unfilled positions budgeted employee expense are not known and measurable, and should be removed from cost of service.

Q DO THE COMPANIES SUPPORT THE FORECASTED EMPLOYEE COSTS?

A The Companies explain in response to AG-KIUC Joint Initial Data Request Question 43, provided as Exhibit MPG-1, pages 6-15, that the work associated with open positions is managed with overtime and contractors.

> The open positions are typically managed with overtime and supplemental contractors, to illustrate this the Company provided the December 31, 2018 and December 31, 2019 reports. These reports demonstrate that in a year with no extraordinary items the use of supplemental contractors offset the actual to budget headcount difference for employees – see the December 31, 2019 report. In a year with above normal storm occurrence for example 2018, the company experiences significantly higher actual than budgeted supplemental contractors. In 2020, due to COVID-19, employee positions were delayed particularly in the generation area due to concerns about training since it requires close proximity that could not be achieved with socially distancing guidelines and also sizable groups of employees and contractors that were not able to come into work related to COVID-19 quarantines. Additionally, supplemental contractors were also a limited resource in 2020 related to constraints from mutual assistance provided to an unusually large number of storm events and COVID-19 issues within their own workforces.
>
> The Company intends to fill all open positions between January 1, 2021 through June 30, 2022, and will utilize overtime and supplemental contractors as needed.

I summarized the comparison referenced above in Table 8 below.

TABLE 8

LKE Total Company
Budgeted vs. Actual Employees

		FTEs			Contractors			Total Company		
Line	**Description**	**Actual**	**Budget**	**Diff.**	**Actual**	**Budget**	**Diff.**	**Actual**	**Budget**	**Diff.**
1	YE December 2018	3,525	3,618	-93	3,091	2,668	423	6,616	6,286	330
2	YE December 2019	3,500	3,631	-131	3,136	3,026	110	6,636	6,657	-21
3	YE September 2020	3,585	3,756	-171	2,996	3,082	-86	6,581	6,838	-257
4	YE December 2020	3,600	3,752	-152	3,006	3,082	-76	6,606	6,834	-228

Source:
LG&E and KU responses to AG/KIUC Joint Initial Data Request Question 43, provided as Exhibit MPG-1, pages 6-15.

The Companies state in response to AG-KIUC Joint Initial Data Request Question 41, provided as Exhibit MPG-1, pages 2-5, that the forecasted test year costs assume costs associated with vacant positions will still be incurred.

> The budgeted columns reflect all headcount being filled. To the extent there are vacant positions, the dollars budgeted would be used for overtime and contractors to perform the work.

Q PLEASE RESPOND.

A The Companies' demonstration does not provide evidence that the difference between their actual employee expense and their budgeted employee expense is a known and measurable cost of providing service in the forecasted test year. I reached this conclusion for several reasons. First, the Companies' comparison shows the number of budgeted and actual employees and contractors in each year, but it does not show the budgeted and actual employee costs. The combined number of employees in Table 8 above includes utility contractors and the Service Company (referred to as LKE workforce at LG&E and KU).[8] The forecasted test year employee costs assume a certain level of full- and part-time employees. The Companies have not shown that the use of overtime and contractors as needed results in an accurate forecast of payroll costs in a projected test year. The Companies' comparison does not show the same amount of employee cost for employees will actually be incurred if those employees are not hired and are instead substituted with contractors or overtime.

[8] Gregory J. Meiman explains on pages 2-3 of his direct testimony that LKE has 3,585 employees. "More specifically, KU has 890 employees, LG&E has 1,035 employees, and the Service Company has 1,660 employees." The 3,585 employees can be seen on line 3 of Table 8.

Second, the Companies' forecasted labor costs include a comparable amount of overtime despite the increase in employees. Table 9 includes a portion of the payroll analysis the Companies provided as part of the filing requirements. As shown on the table, LG&E's forecasted period includes approximately 38 more employees,[9] on average, but has similar levels of overtime costs and hours in the forecasted period compared to the base period.

TABLE 9

Overtime Comparison

		LG&E		KU	
Line	**Description**	**Base Period**	**Forecasted Period**	**Base Period**	**Forecasted Period**
1	Average Number of Employees	1,074	1,112	911	921
2	Period End Number of Employees	1,103	1,113	923	918
3	Salary/Straight Time Hours	3,235,790	3,183,346	3,462,228	3,567,311
4	OverTime Hours	203,697	205,220	240,407	251,603
5	Total Man Hours	3,439,487	3,388,566	3,702,635	3,818,914
6	Ratio of OT Hours to ST Hours	6.30%	6.45%	6.94%	7.05%
7	Salary/Straight Time Dollars	$ 130,986,072	$ 135,202,195	$ 146,483,471	$ 151,299,852
8	OverTime Dollars	12,927,950	12,608,456	14,536,937	15,697,574
9	Total Labor Dollars	$ 143,914,022	$ 147,810,651	$ 161,020,408	$ 166,997,426
10	Ratio of OT Dollars to ST Dollars	9.87%	9.33%	9.92%	10.38%

Source:
Attachment to Filing Requirement, Tab 60 - 807 KAR 5:001 Section 16(8)(g).

The Companies suggested that in the historical period, they needed to assume additional overtime hours to accommodate for their actual employee levels being less than budgeted. However, in the Companies' forecast, they include an expectation of

[9] LG&E had 1,031 employees at end of 2020. Therefore, the analysis provided by the Companies assumes that LG&E filled 72 of the 82 vacant positions in the two months between December 2020 and February 2021.

filling their full budgeted employees, but increasing the number of overtime hours. As such, the Companies' explanation for the benefits of filling all budgeted employees, by eliminating the need for overtime, is not fully reflected in the Companies' forecasted cost of service in the forecasted test year. Specifically, Table 9 shows that ratio of overtime dollars to straight time dollars for LG&E only decreased from 9.87% to 9.33% despite nine months of the base period being in 2020, when LG&E operated on 1,045[10] to 1,031[11] employees. LG&E has not shown that ratepayers benefit from reduced overtime costs due to the additional employees.

Q WHAT DO YOU RECOMMENDED?

A I propose to adjust LG&E's projected employee expense to remove unfilled positions. My adjustment is provided as Exhibit MPG-2. As shown on the exhibit, I propose to reduce the number of employees in the forecasted test year by 82 positions for LG&E. My exhibit shows the operating expense for labor, off-duty,[12] benefits, and payroll taxes. I calculate an average cost per employee by taking these costs divided by the number of employees in the test year, or 1,113 for LG&E. I multiply the estimate costs per employee by my proposed employee reduction. This results in a decrease of operating expenses of $12.9 million for LG&E. I estimate the share of the decrease allocated to LG&E electric and LG&E gas as $9.1 million and $3.8 million, respectively. My

[10] March 2020, line 6 of Table 7.
[11] December 2020, line 7 of Table 7.
[12] Off-duty includes vacation, holiday, sick, short term disability, personal days, funeral leave and jury duty.

adjustment to LG&E's operating expense will have a corresponding small adjustment to remove the capitalized payroll costs associated with the 82 positions.

IV. KU AND LG&E ELECTRIC COSS

Q DID EACH OF THE COMPANIES PREPARE AN ELECTRIC COSS?

A Yes, a separate electric COSS was prepared for both KU and LG&E. The Companies' electric and gas COSS were sponsored by LG&E/KU witness William Steven Seelye, a Managing Partner with The Prime Group, LLC. Mr. Seelye also sponsored the Companies' proposed electric and gas rate design.

Q PLEASE DESCRIBE THE COMPANIES' ELECTRIC COSS.

A Mr. Seelye describes his electric COSS starting at page 102 of his testimony. Mr. Seelye outlines that he functionalized the Companies' cost of service into four separate functional assignments: (1) generation; (2) transmission; (3) distribution; and (4) other. He then classified each of the functionalized cost components into demand, energy, and customer components. After this functional assignment and classification, costs were then allocated to residential, commercial and industrial customers via the Companies' existing rate schedules as outlined in Mr. Seelye's Figure 1 at page 103 of his testimony.

Mr. Seelye functionalized generation costs into demand and energy components. For a demand allocation factor, he proposes a loss of load probability ("LOLP") methodology to allocate fixed production costs. However, based on parties' opposition to the LOLP production allocation in a previous case, he also provided two alternative production allocators based on a six coincident peak ("6 CP") methodology, and a

12 coincident peak ("12 CP") methodology. A comparison of the production demand allocator for each of the three methodologies is shown by Mr. Seelye on his Exhibit WSS-22, pages 1 and 2 for KU and LG&E, respectively.

Q DO YOU GENERALLY AGREE WITH MR. SEELYE'S DEVELOPMENT OF AN ELECTRIC COSS?

A Generally, yes. Mr. Seelye's methodology for functionalizing, classifying and then allocating electric cost of service is reasonable. However, I do take issue with three aspects of Mr. Seelye's electric COSS. Those include:

1. His proposed use of an LOLP methodology for allocating production plant costs. He believes based on the Companies' current load shape a 6 CP is the most accurate and reasonable methodology. The Companies' use of an LOLP methodology is largely tied to developing reserve planning margins, and not identifying the actual amount of capacity costs needed to meet the peak demand characteristics of customers on its system. In other words, a 6 CP methodology better aligns with cost of service.

2. The second issue I take is with the Companies' proposed allocation of transmission costs on the basis of non-coincident peaks. I believe this is unreasonable because transmission facilities should be allocated in a similar way as production facilities, based on contributions to peak demands during peak demand periods.

   The Companies acknowledge that transmission plant is used by electric utilities in order to transport power that is generated at the production facility, and delivers it to the distribution point. Hence, the cost and design of transmission plant is tied to the peak demands placed on the transmission plant from the production resources. For this reason, transmission plant should be allocated in a similar manner as production capacity costs.

3. Third, I comment on the Companies' proposed allocation of certain steam production O&M expense using an energy allocator. A review of the Companies' actual historical level of steam boiler costs shows that these costs do not vary with energy, and therefore should not be allocated on the basis of energy consumption. Rather, these costs should be allocated across rate classes consistent with the other fixed O&M costs, or on a production demand basis.

Q DO YOU BELIEVE THE ELECTRIC COSS SHOULD BE USED AS A GUIDE IN ASSIGNING COSTS ACROSS RATE CLASSES FOR THE PURPOSE OF DESIGNING ELECTRIC SERVICE RATES?

A Yes. Use of an electric COSS in spreading the revenue requirement across rate classes, and the design of rates that largely reflect the load characteristics of the class that caused the company to incur costs to serve that class, can be translated into rates that signal customers on the actual cost of the electric service provided.

Q DID MR. SEELYE DESCRIBE THE PURPOSE OF AN ELECTRIC COSS?

A Yes. At page 102 of his testimony, he stated:

> The Companies' objectives in performing the electric cost of service studies were to determine the rate of return on rate base the Companies are earning from each customer class, allocate revenue requirements as fairly as possible among all of the classes of customers the Companies serve, and provide the data necessary to develop rate components that more accurately reflect cost causation.

Q HOW DO COST-BASED RATES PROVIDE APPROPRIATE PRICE SIGNALS TO CUSTOMERS?

A Rate design is the step that takes the various rate classes' allocation of total cost of service, and converts that class revenue assignment into functionalized classification of costs, which can then be used to derive rates that provide signals of costs of service.

When the rates are designed so that the demand costs, energy costs, and customer costs are properly reflected in the demand, energy, and customer components of the rate schedules, respectively, customers are provided with the proper economic incentives to manage their loads and consumption efficiently and economically. In turn, the shift in customer loads based on these efficient prices signals to the utility the need for new investment, and/or opportunities to avoid inefficient or avoidable costs.

From a rate design perspective, overpricing the energy portion of the rate and underpricing the demand and customer components of the rate will result in a disproportionate share of revenues being collected from high energy consuming or high load factor customers and send erroneous price signals to all customers.

IV.A. Production Cost Allocation

Q HOW ARE FIXED PRODUCTION COSTS ALLOCATED IN THE COMPANIES' ELECTRIC COSS?

A The COSS use the LOLP methodology to allocate fixed production costs.

Q COULD YOU BRIEFLY DISCUSS THE LOLP METHODOLOGY FOR ALLOCATING FIXED PRODUCTION COSTS?

A The LOLP methodology represents the probability that the Companies' system demand will exceed its generation during any given hour. An LOLP is calculated for each hour. The LOLP takes into account the magnitude of the hourly load, installed generation capacity, forced outage rates, maintenance schedules and other generating operating statistics. For many of the hours when the system demand is low the LOLP is zero. LG&E witness Mr. Seelye discussed the LOLP methodology in his prefiled direct testimony.[13]

[13]Seelye Direct at 105-107.

Q ARE YOU RECOMMENDING THE COMMISSION USE THE LOLP METHODOLOGY TO ALLOCATE THE FIXED PRODUCTION COSTS?

A No, I recommend that the Commission use the 6 CP methodology to allocate the fixed production costs.

Q DID MR. SEELYE PROVIDE ALTERNATIVE ALLOCATORS FOR ALLOCATING FIXED PRODUCTION COSTS ACROSS RATE CLASSES?

A Yes. In addition to the LOLP methodology, Mr. Seelye also offered production allocators based on a 6 CP and a 12 CP methodology.

Mr. Seelye describes the 6 CP methodology as more accurately reflecting the Companies' generation planning compared to a 12 CP methodology.[14] Mr. Seelye states the Companies' system is summer peaking but also has a winter peak. Therefore, he believes the 6 CP methodology gives considerable attention to winter peak demands, which is important because it gives consideration to the loads that drive peaks in both the winter and summer periods. He states the peaks during the spring and fall do not constrain the system to the same extent during the winter and summer peaking periods. Therefore, the 12 CP methodology, which includes demands in winter, summer, spring and fall, and regards the spring and fall to be shoulder months, gives too much weights to demands during off-peak periods, which play little role in the Companies' generation planning.

He states a 6 CP methodology considers a four summer months period and a two winter months period. He does assert that the LOLP methodology is more robust and

[14]*Id*. at 108.

that it weighs all hours by the LOLPs for each hour of the year, which is a key metric in the Companies' generation system planning activities.[15]

Q WHY ARE YOU OPPOSED TO THE COMPANIES' USE OF THE LOLP METHOD AND SUPPORT THE 6 CP?

A The LOLP methodology is more complex and less transparent than the 6 CP methodology. Hence, it does not align specifically with the rate design that will provide rate signals to customers on how to efficiently consume power for the utilities. The LOLP methodology is based on a statistical analysis of all hours of generation throughout the year. In contrast, a 6 CP methodology ties to contributions to the system peak demands in the summer and winter periods. These contributions to peak demands then align with demand charges outlined in the Companies' rates, which include on-peak and off-peak periods, and base, intermediate and peak periods. It provides a clear tie between system planning to have adequate capacity resources on the system, and the rate designs used to give customers clear price signals on how to efficiently consume power and adjust their demands on the system to allow the utilities to minimize their cost of production capacity.

Q DOES THE RECORD SHOW THAT THE LOLP METHODOLOGY IS NOT WIDELY USED BY REGULATORY COMMISSIONS IN ELECTRIC COSS?

A Yes. Indeed, the Companies have acknowledged this in response to certain data requests. First, I am not aware of any regulatory commissions that use the LOLP

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[15] *Id*. at 108.

methodology to allocate fixed production costs. In response to the Commission Staff's Second Request for Information Question No. 157,[16] the Companies' cost of service witness Mr. William Seelye stated that he is unaware of any regulatory commissions that have adopted the LOLP cost of service method used in this case.

Second, general guidance on electric COSS as published by the National Association of Regulatory Utility Commissioners ("NARUC") also casts doubt on the reliability and effectiveness of use of LOLP methodology as a proper cost of service and rate design methodology.

The complexity of LOLP has also been recognized by the *Electric Utility Cost Allocation Manual* published by NARUC. In its electric manual, NARUC states the following regarding the LOLP production cost method:

> This method requires detailed analysis of hourly LOLP values and a significant data manipulation effort.[17]

The Commission should rely on a more transparent and verifiable production allocation methodology in its class COSS.

Q DOES MR. SEELYE OUTLINE THE LOAD CHARACTERISTICS WHICH ARE CONSIDERED BY THE COMPANY IN PLANNING FOR PRODUCTION GENERATION RESOURCES?

A Yes. He does this at page 108 of his testimony where it clearly states that he has a preference for the LOLP methodology, but he clearly states that a 6 CP methodology

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[16] Provided as Exhibit MPG-1, page 58.

[17] The National Association of Regulatory Utility Commissioners ("NARUC") *Electric Utility Cost Allocation Manual* published January 1992, page 62.

more accurately reflects the Companies' generation planning relative to a 12 CP methodology. Mr. Seelye goes through his assessment of the monthly peak demand loads, which are driven by customers' demands on the system. He states that the Companies plan for peak demands that occur in both the winter season (two months in his analysis) and summer season (four months in his analysis). The Companies plan for adequate generation capacity in order to meet these coincident customer demands.

I would also note that from a rate design standpoint, it is the coincident demands which are used in order to develop pricing to provide efficient price signals to customers. Hence, the 6 CP is the most common method used in the industry, provides transparent and understandable demand characteristics for customers to make informed consumption decisions, and largely reflects the Companies' planning process to ensure if they have adequate production transmission capacity. For all these reasons, and because of the non-transparent and non-standard use of LOLP methodology, I recommend the Commission adopt the 6 CP methodology for allocating production fixed costs.

IV.B. Transmission Electric Cost Allocation

Q ARE YOU PROPOSING ANY OTHER CHANGES TO THE COMPANIES' COSS?

A Yes. The Companies allocated the fixed transmission costs on non-coincident peaks ("NCP"). LG&E/KU acknowledged that they designed the capacity on their transmission system in order to deliver production capacity from the generation source to the point of distribution. In response to DoD/FEA, Q-2-9, the Companies responded as follows:

> The loads at the distribution points on the LG&E and KU's transmission system are an important factor in designing capacity on the transmission system. Ultimately, the loads at the distribution points determine the level of capacity needed to deliver power on the transmission system from the generation system to the load centers.

In terms of actual transmission planning, the Companies also responded to DoD/FEA Q-2-10, acknowledging that transmission capacity is based on coincident peak demands.

> The annual transmission expansion planning process considers multiple coincident peak demand forecasts over the next ten-year planning horizon. The process doesn't identify the number of months, but rather, peak loads which could occur during the applicable peak season. Specifically, an expected load forecast and a high load forecast are analyzed for the winter and summer peak seasons in years 1, 2, 5, and 10 to ensure customer demand can be met.

Both of these data responses are provided in total in Exhibit MPG-1, pages 39-40.

Q DID LG&E/KU ALSO ACKNOWLEDGE THE IMPORTANCE OF PROVIDING CLEAR PRICING SIGNALS TO CUSTOMERS IN SETTING DEMANDS ON THE SYSTEM TO HELP THE COMPANIES MANAGE AND MINIMIZE PRODUCTION AND TRANSMISSION COSTS?

A Yes. The Companies acknowledge that because production and transmission capacities are driven by peak demands on the system, the ability to reduce the need for additional production and transmission capacity, or to create more efficient utilization of existing resources, is driven by modifying customer demands on-peak. LG&E/KU stated as follows in response to DoD/FEA Q-2-11:[18]

> No, not without certain qualifications. Depending on the location of the customer's load, reductions in demand may not free up capacity on the transmission system. Furthermore, depending on the time period during which a customer reduces its demand, any such reduction may not provide additional benefits to the generation or transmission system. For example, if the customer reduces its demand during off-peak periods, or when either the transmission or generation system is not operating at full capacity, then any capacity that is freed up would not necessarily be used to provide service to other customers.

As noted above, recognizing that transmission capacity is tied to customers' contributions to monthly peaks, allocating it across this way is a critical component in designing the system to provide accurate cost of service allocations, and designing efficient price signals.

Q DO YOU BELIEVE IT IS APPROPRIATE TO ALLOCATE TRANSMISSION COSTS ON THE BASIS OF NON-COINCIDENT PEAKS?

A No. Non-coincident peaks simply do not align with the coincident demand use of all the customers on the system for transmission service. Non-coincident peaks are a relevant factor for distribution costs, but as the Companies note above, and for the development of efficient price signals, it is coincident demands on transmission assets that drive the need for additional capacity, and have driven the need for making investments in the existing level of transmission capacity system. Because it is consistent with planning for transmission infrastructure investments, and accurately reflects the load characteristics of the system considered by the Companies in their

[18] Provided as Exhibit MPG-1, page 41.

planning, an allocation of transmission costs on the basis of 6 CP rather than the non-coincident peak is more appropriate, and reflects better cost causation of transmission investment costs.

<u>IV.C. Allocation of Steam Generation Maintenance Expense</u>

Q PLEASE DESCRIBE HOW THE COMPANIES CLASSIFIED OPERATING AND MAINTENANCE EXPENSE FROM STEAM GENERATING FACILITIES.

A The Company's class COSS classifies steam power production expenses in FERC Accounts 510-514 to be energy-related.

Q SHOULD PRODUCTION MAINTENANCE EXPENSE BE CLASSIFIED AS ENERGY-RELATED?

A No. Normal maintenance expense does not vary in any appreciable way with kilowatt-hour energy purchases by retail customers. Production maintenance expense is normally scheduled and budgeted on a fixed basis to keep the plant on-line and available to meet daily demands. There is no showing that production maintenance expense varies directly with retail customers sales. In fact, boilers are often kept warm during nights (low load periods) in order to meet next day demands. Also, the dispatch of plants is often a function of running costs versus alternative sources, off-system sales and purchases, renewable energy contracts and not directly related to sales to retail customers. As such, these steam O&M expenses are more fixed and budgetary in nature, and do not vary with energy generation. For this reason, these costs should be allocated in line with the actual fixed costs of the production facility, or should be classified as demand charges.

Q WHAT EVIDENCE DO YOU HAVE THAT SUPPORTS YOUR CLAIM THAT STEAM POWER MAINTENANCE EXPENSE DOES NOT VARY WITH ENERGY OUTPUT?

A I have reviewed FERC Form-1 filings for the past few years, and have examined the relationship between the steam generation maintenance expense and energy generated. This data is presented below in Table 10 for LG&E and Table 11 for KU.

TABLE 10

LOUISVILLE GAS AND ELECTRIC COMPANY
Steam Power Production Maintenance Expense

Line	Title of the FERC Account	Acct No.	2019	2018	2017	2016	2015
	Steam Power Production Maintenance Expenses ($1,000s)						
1	Maintenance Supervision and Engineering	510	$ 5,379	$ 5,519	$ 4,862	$ 4,792	$ 3,347
2	Maintenance of Structures	511	4,056	3,056	2,489	3,612	2,753
3	Maintenance of Boiler Plant	512	34,882	33,252	31,647	32,428	38,559
4	Maintenance of Electric Plant	513	9,326	9,060	6,942	7,529	5,973
5	Maintenance of Miscellaneous Steam Plant	514	2,543	2,349	2,398	2,524	9,600
6	**Total Maintenance**		$ 56,187	$ 53,235	$ 48,338	$ 50,884	$ 60,232
7	**Steam Power Generation (MWh)**		11,336,288	11,852,403	11,612,434	11,124,162	11,522,245
8	**Total Steam Maintenance Expense/Steam Power Generation ($/MWh)**		$4.96	$4.49	$4.16	$4.57	$5.23
9	**YOY Change in Steam Maintenance Expense**		5.5%	10.1%	-5.0%	-15.5%	
10	**YOY Change in Steam Power Generation (MWh)**		-4.4%	2.1%	4.4%	-3.5%	

Source: Multiple FERC Form 1s

TABLE 11

KENTUCKY UTILITIES
Steam Power Production Maintenance Expense

Line	Title of the FERC Account	Acct No.	2019	2018	2017	2016	2015
	Steam Power Production Maintenance Expenses ($1,000s)						
1	Maintenance Supervision and Engineering	510	$ 10,233	$ 10,311	$ 8,969	$ 9,374	$ 8,806
2	Maintenance of Structures	511	10,422	10,115	8,009	8,914	7,741
3	Maintenance of Boiler Plant	512	48,408	49,723	42,741	41,554	44,608
4	Maintenance of Electric Plant	513	11,775	11,503	8,629	9,691	16,582
5	Maintenance of Miscellaneous Steam Plant	514	3,225	3,466	2,843	3,184	3,008
6	**Total Maintenance**		$ 84,064	$ 85,118	$ 71,191	$ 72,717	$ 80,744
7	**Steam Power Generation (MWh)**		14,012,189	16,030,840	16,112,203	16,040,543	17,325,294
8	**Total Steam Maintenance Expense/Steam Power Generation ($/MWh)**		$6.00	$5.31	$4.42	$4.53	$4.66
9	**YOY Change in Steam Maintenance Expense**		-1.2%	19.6%	-2.1%	-9.9%	
10	**YOY Change in Steam Power Generation (MWh)**		-12.6%	-0.5%	0.4%	-7.4%	

Source: Multiple FERC Form 1s

As shown in these tables, these expenses do not vary with changes in energy generated by the underlying steam production plant.

Q HOW IS MAINTENANCE EXPENSE USUALLY CLASSIFIED FOR OTHER TYPES OF PLANT INVESTMENT?

A Maintenance expense usually is classified in a similar manner to the associated plant investment. Transmission maintenance is classified as a fixed cost similar to transmission plant. Distribution maintenance is normally classified as either demand- or customer-related in a similar manner to the associated distribution investment being maintained to provide service to customers. Production maintenance should be classified in a similar manner.

Q PLEASE SUMMARIZE YOUR RECOMMENDATION REGARDING THE APPROPRIATE CLASSIFICATION OF PRODUCTION MAINTENANCE EXPENSE.

A Production maintenance expense is a fixed cost that is required to keep the plant available to meet customer demands similar to the transmission and distribution functions. Production maintenance is a demand-related cost that does not vary with kilowatthour consumption. In fact, production maintenance often occurs during plant shutdowns when no energy is produced.

<u>IV.D. Adjusted Electric COSS</u>

Q HAVE YOU REVISED KU'S AND LG&E'S ELECTRIC COSS FOR THE THREE ISSUES YOU STATE ABOVE THAT YOU TAKE WITH THEIR DEVELOPMENT OF THEIR COSS?

A Yes. I adjusted the Companies' class COSS to substitute the 6 CP production cost allocator for the LOLP production cost allocator. Second, I modified the COSS to allocate transmission costs on a 6 CP factor rather than non-coincident peak. Finally, I reclassified steam generation maintenance expenses from energy-related to demand-related, and allocated those on the basis of production demand.

Q CAN YOU COMPARE THE RESULTS OF YOUR ELECTRIC COSS TO THAT PROPOSED BY THE COMPANIES?

A Yes. A comparison to the LG&E electric COSS is shown below in Table 12.

TABLE 12

LOUISVILLE GAS AND ELECTRIC
LOLP Cost of Service vs. DoD/FEA Cost of Service ($000)

			LGE			DoD/FEA		
		Revenue	Increase / (Decrease)			Increase / (Decrease)		
		At Current	to Reach Cost of Service			to Reach Cost of Service		
Line	Rate Class	Rates[1]	Amount[1,2]	Percent	Index	Amount[3]	Percent	Index
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Residential Rate RS	$ 431,825	$ 161,062	37.3%	3.03	$ 141,735	32.8%	2.67
2	General Service Rate GS	148,101	(19,395)	-13.1%	(1.06)	(11,390)	-7.7%	(0.62)
3	Power Service Primary Rate PS	10,055	(2,082)	-20.7%	(1.68)	(1,684)	-16.8%	(1.36)
4	Power Service Secondary Rate PS	147,449	(15,410)	-10.5%	(0.85)	(8,245)	-5.6%	(0.45)
5	TOD Rate TOD Primary	136,688	3,198	2.3%	0.19	1,783	1.3%	0.11
6	TOD Rate TOD Secondary	101,626	7,034	6.9%	0.56	10,157	10.0%	0.81
7	Retail Transmission Service Rate RTS	64,287	(96)	-0.2%	(0.01)	455	0.7%	0.06
8	Special Contract Customer	3,635	196	5.4%	0.44	393	10.8%	0.88
9	Lighting Rate RLS & LS	22,161	(3,243)	-14.6%	(1.19)	(1,983)	-8.9%	(0.73)
10	Lighting Rate LE	244	(92)	-37.6%	(3.05)	(48)	-19.6%	(1.59)
11	Lighting Rate TE	319	(63)	-19.7%	(1.60)	(63)	-19.7%	(1.60)
12	Outdoor Sports Lighting OSL	15	(15)	-93.9%	(7.63)	(16)	-102.6%	(8.34)
13	Electric Vehicle Charging EVC	2	55	3602.3%	292.71	55	3595.9%	292.19
14	Solar Share SS	237	111	46.8%	3.80	111	46.8%	3.80
15	Business Solar BS	10	9	94.4%	7.67	9	94.4%	7.67
16	Total System	$ 1,066,653	$ 131,270	12.3%	1.00	$ 131,270	12.3%	1.00

Sources
[1] LGE's LOLP class cost of service study.
[2] Calculated as the difference between net operating income at present rates and at equal rate of return, grossed up for taxes.
[3] Proposed increase in net operating income, grossed up for taxes.

As shown above, under Columns 2 through 4, I show the results of the Companies' class COSS across various rate classes. Under Columns 5 through 7, I show the results of my adjusted COSS.

Table 13 below shows a similar comparison for KU.

TABLE 13

KENTUCKY UTILITIES
LOLP Cost of Service vs. DoD/FEA Cost of Service ($000)

Line	Rate Class	Revenue At Current Rates[1]	KU Increase / (Decrease) to Reach Cost of Service Amount[1,2]	KU Percent	KU Index	DoD/FEA Increase / (Decrease) to Reach Cost of Service Amount[3]	DoD/FEA Percent	DoD/FEA Index
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Residential Rate RS	$ 611,493	$ 151,070	24.7%	2.26	$ 183,732	30.0%	2.75
2	General Service Rate GS	224,800	(31,006)	-13.8%	(1.26)	(31,541)	-14.0%	(1.28)
3	All Electric Schools Rate AES	11,901	712	6.0%	0.55	1,786	15.0%	1.37
4	Power Service Secondary Rate PSS	169,761	(16,523)	-9.7%	(0.89)	(16,461)	-9.7%	(0.89)
5	Power Service Primary Rate PSP	9,430	(2,838)	-30.1%	(2.75)	(3,059)	-32.4%	(2.97)
6	Time of Day Secondary Rate TODS	134,172	18,806	14.0%	1.28	13,573	10.1%	0.93
7	Time of Day Primary Rate TODP	250,418	40,195	16.1%	1.47	24,901	9.9%	0.91
8	Retail Transmission Service Rate RTS	82,248	11,253	13.7%	1.25	5,419	6.6%	0.60
9	Fluctuating Load Service Rate FLS	32,957	6,292	19.1%	1.75	(1,684)	-5.1%	(0.47)
10	Lighting Rate LS & RLS	30,556	(7,687)	-25.2%	(2.30)	(6,416)	-21.0%	(1.92)
11	Lighting Rate LE	307	(111)	-36.1%	(3.30)	(65)	-21.1%	(1.93)
12	Lighting Rate TE	271	(42)	-15.6%	(1.43)	(49)	-18.2%	(1.66)
13	Outdoor Sports Lighting Rate OSL	92	(54)	-58.4%	(5.34)	(68)	-73.7%	(6.74)
14	Electric Vehicle Charging Rate EV	2	48	3158.3%	288.85	48	3150.0%	288.09
15	Solar Share Rate SSP	163	296	182.0%	16.64	296	182.0%	16.64
16	Business Solar Rate BS	38	10	24.9%	2.28	10	24.9%	2.28
17	Total System	$ 1,558,608	$ 170,421	10.9%	1.00	$ 170,421	10.9%	1.00

Sources

[1] KU's LOLP class cost of service study.

[2] Calculated as the difference between net operating income at present rates and at equal rate of return, grossed up for taxes.

[3] Proposed increase in net operating income, grossed up for taxes.

V. REVENUE SPREAD

V.A. The Companies' Proposed Electric Revenue Allocation

Q PLEASE DESCRIBE HOW THE COMPANIES ARE PROPOSING TO SPREAD THEIR CLAIMED REVENUE DEFICIENCY ACROSS RATE CLASSES IN THIS PROCEEDING.

A A comparison of LG&E's current rates, cost of service, and proposed revenue spread is shown below in Table 14.

TABLE 14

LOUISVILLE GAS AND ELECTRIC
LOLP Cost of Service vs. LGE Proposed Revenue Spread ($000)

Line	Rate Class	Revenue At Current Rates[1]	Increase / (Decrease) to Reach Cost of Service Amount[1,2]	Percent	Index	LGE Proposed Increase / (Decrease) Amount[3]	Percent	Index
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Residential Rate RS	$ 431,825	$ 161,062	37.3%	3.03	$ 53,259	12.3%	1.00
2	General Service Rate GS	148,101	(19,395)	-13.1%	(1.06)	19,115	12.9%	1.05
3	Power Service Primary Rate PS	10,055	(2,082)	-20.7%	(1.68)	1,226	12.2%	0.99
4	Power Service Secondary Rate PS	147,449	(15,410)	-10.5%	(0.85)	17,924	12.2%	0.99
5	TOD Rate TOD Primary	136,688	3,198	2.3%	0.19	16,367	12.0%	0.97
6	TOD Rate TOD Secondary	101,626	7,034	6.9%	0.56	12,221	12.0%	0.98
7	Retail Transmission Service Rate RTS	64,287	(96)	-0.2%	(0.01)	7,693	12.0%	0.97
8	Special Contract Customer	3,635	196	5.4%	0.44	435	12.0%	0.97
9	Lighting Rate RLS & LS	22,161	(3,243)	-14.6%	(1.19)	2,857	12.9%	1.05
10	Lighting Rate LE	244	(92)	-37.6%	(3.05)	0	0.0%	0.00
11	Lighting Rate TE	319	(63)	-19.7%	(1.60)	(0)	0.0%	(0.00)
12	Outdoor Sports Lighting OSL	15	(15)	-93.9%	(7.63)	(2)	-10.6%	(0.86)
13	Electric Vehicle Charging EVC	2	55	3602.3%	292.71	55	3602.2%	292.70
14	Solar Share SS	237	111	46.8%	3.80	111	46.8%	3.80
15	Business Solar BS	10	9	94.4%	7.67	9	94.4%	7.67
16	Total System	$ 1,066,653	$ 131,270	12.3%	1.00	$ 131,270	12.3%	1.00

Sources
[1] LGE's LOLP class cost of service study.
[2] Calculated as the difference between net operating income at present rates and at equal rate of return, grossed up for taxes.
[3] Proposed increase in net operating income, grossed up for taxes.

As shown in the table above, the Companies are proposing to spread the increase for LG&E in a manner that does not move rates closer to cost of service. As outlined in the table above, under Column 6, the Companies' proposed increase is largely uniform across all major rate classes, and does not make gradual movements toward the cost of service as indicated under Column 3, based on the Companies' own class COSS. For these reasons, I believe the Companies' proposed spread of the increase does not move each rate class closer to cost of service.

Q HOW ARE THE COMPANIES PROPOSING TO SPREAD THE REVENUE INCREASE FOR KU ELECTRIC?

A Similar to the Companies' proposal for LG&E, I show the comparison of KU's current cost of service and proposed revenue spread in Table 15 below.

TABLE 15

KENTUCKY UTILITIES
LOLP Cost of Service vs. KU Proposed Revenue Spread ($000)

Line	Rate Class	Revenue At Current Rates[1]	Increase / (Decrease) to Reach Cost of Service: Amount[1,2]	Percent	Index	KU Proposed Increase / (Decrease): Amount[3]	Percent	Index
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Residential Rate RS	$ 611,493	$ 151,070	24.7%	2.26	$ 68,214	11.2%	1.02
2	General Service Rate GS	224,800	(31,006)	-13.8%	(1.26)	26,799	11.9%	1.09
3	All Electric Schools Rate AES	11,901	712	6.0%	0.55	1,471	12.4%	1.13
4	Power Service Secondary Rate PSS	169,761	(16,523)	-9.7%	(0.89)	18,736	11.0%	1.01
5	Power Service Primary Rate PSP	9,430	(2,838)	-30.1%	(2.75)	1,048	11.1%	1.02
6	Time of Day Secondary Rate TODS	134,172	18,806	14.0%	1.28	14,559	10.9%	0.99
7	Time of Day Primary Rate TODP	250,418	40,195	16.1%	1.47	26,945	10.8%	0.98
8	Retail Transmission Service Rate RTS	82,248	11,253	13.7%	1.25	8,785	10.7%	0.98
9	Fluctuating Load Service Rate FLS	32,957	6,292	19.1%	1.75	3,513	10.7%	0.97
10	Lighting Rate LS & RLS	30,556	(7,687)	-25.2%	(2.30)	2	0.0%	0.00
11	Lighting Rate LE	307	(111)	-36.1%	(3.30)	0	0.0%	0.00
12	Lighting Rate TE	271	(42)	-15.6%	(1.43)	0	0.0%	0.00
13	Outdoor Sports Lighting Rate OSL	92	(54)	-58.4%	(5.34)	(5)	-5.2%	(0.47)
14	Electric Vehicle Charging Rate EV	2	48	3158.3%	288.85	48	3158.3%	288.85
15	Solar Share Rate SSP	163	296	182.0%	16.64	296	182.0%	16.64
16	Business Solar Rate BS	38	10	24.9%	2.28	10	25.0%	2.28
17	Total System	$ 1,558,608	$ 170,421	10.9%	1.00	$ 170,421	10.9%	1.00

Sources
[1] KU's LOLP class cost of service study.
[2] Calculated as the difference between net operating income at present rates and at equal rate of return, grossed up for taxes.
[3] Proposed increase in net operating income, grossed up for taxes.

In a similar manner as its proposed revenue spread for LG&E described above, the Companies' proposed revenue spread for KU is largely a uniform percent increase across rate classes, and does not make a meaningful movement to cost of service for most of the rate classes. Therefore, the Companies' proposed spread more accurately reflects a uniform percent change in all rate classes, rather than a systematic effort to move each rate class to cost of service, with a gradualistic protection of customer classes which are priced significantly below current cost of service.

Q PLEASE DESCRIBE YOUR PROPOSED SPREAD OF THE REVENUE INCREASE FOR LG&E AND KU.

A I recommend that the Commission spread the increase to move each rate class toward cost of service, with a mitigation cap of any costs to be no more than 125% of the system average increase, but no class will receive a rate decrease. On the low side, I recommend no class get a rate decrease. Spreading the increase between 0% and 125% of the system average increase ensures that all classes are moved toward cost of service, but no class gets an exorbitant increase, and no class benefits by a rate decrease in the face of other classes burdened by rate increases. Further, this spread ensures that each rate class is moved toward cost of service and produces equitable adjustments to rates for all customers in this rate case without creating any significant rate burden on any specific rate class to the extent it is priced well below cost of service.

My proposed revenue spread for LG&E is shown below in Table 16.

TABLE 16

LOUISVILLE GAS AND ELECTRIC
DoD/FEA Proposed Revenue Spread ($000)

Line	Rate Class	Revenue At Current Rates[1] (1)	DoD/FEA Proposed Increase / (Decrease) Amount[2] (2)	Percent (3)	Index (4)
1	Residential Rate RS	$ 431,825	$ 66,429	15.4%	1.25
2	General Service Rate GS	148,101	12,734	8.6%	0.70
3	Power Service Primary Rate PS	10,055	865	8.6%	0.70
4	Power Service Secondary Rate PS	147,449	12,678	8.6%	0.70
5	TOD Rate TOD Primary	136,688	14,951	10.9%	0.89
6	TOD Rate TOD Secondary	101,626	15,634	15.4%	1.25
7	Retail Transmission Service Rate RTS	64,287	5,527	8.6%	0.70
8	Special Contract Customer	3,635	508	14.0%	1.14
9	Lighting Rate RLS & LS	22,161	1,905	8.6%	0.70
10	Lighting Rate LE	244	0	0.0%	0.00
11	Lighting Rate TE	319	0	0.0%	0.00
12	Outdoor Sports Lighting OSL	15	1	8.6%	0.70
13	Electric Vehicle Charging EVC	2	0	15.4%	1.25
14	Solar Share SS	237	36	15.4%	1.25
15	Business Solar BS	10	2	15.4%	1.25
16	Total System	$ 1,066,653	$ 131,270	12.3%	1.00

Sources
[1] LGE's class cost of service study.
[2] DoD/FEA alternative revenue spread.

My proposed mitigated revenue increase for LG&E is shown in Table 16 above. As shown in the table above, the increase for each of the rate classes moves these classes closer to cost of service, but the increase necessary for the residential class is mitigated to only 125% of the system average increase, which produces an increase of 15.4% in contrast to the Companies' own COSS which suggests a 24.7% increase would be needed to fully move this class to cost of service. Also, certain lighting classes will not receive a rate change, even though the Companies' proposal suggests these rate classes are currently priced above cost of service. The combination of this gradualistic movement toward cost of service will mitigate the increase on all customer classes from the Companies' filing in this proceeding, while making reasonable contributions by adjusting all rates toward cost of service.

TABLE 17

KENTUCKY UTILITIES
DoD/FEA Proposed Revenue Spread ($000)

		Revenue At Current	DoD/FEA Proposed Increase / (Decrease)		
Line	**Rate Class**	**Rates[1]**	**Amount[2]**	**Percent**	**Index**
		(1)	(2)	(3)	(4)
1	Residential Rate RS	$ 611,493	$ 83,577	13.7%	1.25
2	General Service Rate GS	224,800	8,958	4.0%	0.36
3	All Electric Schools Rate AES	11,901	1,186	10.0%	0.91
4	Power Service Secondary Rate PSS	169,761	6,765	4.0%	0.36
5	Power Service Primary Rate PSP	9,430	376	4.0%	0.36
6	Time of Day Secondary Rate TODS	134,172	18,338	13.7%	1.25
7	Time of Day Primary Rate TODP	250,418	34,226	13.7%	1.25
8	Retail Transmission Service Rate RTS	82,248	11,241	13.7%	1.25
9	Fluctuating Load Service Rate FLS	32,957	4,504	13.7%	1.25
10	Lighting Rate LS & RLS	30,556	1,218	4.0%	0.36
11	Lighting Rate LE	307	0	0.0%	0.00
12	Lighting Rate TE	271	0	0.0%	0.00
13	Outdoor Sports Lighting Rate OSL	92	4	4.0%	0.36
14	Electric Vehicle Charging Rate EV	2	0	13.7%	1.25
15	Solar Share Rate SSP	163	22	13.7%	1.25
16	Business Solar Rate BS	38	5	13.7%	1.25
17	Total System	$ 1,558,608	$ 170,421	10.9%	1.00

Sources
[1] KU's class cost of service study.
[2] DoD/FEA alternative revenue spread.

Similar to that proposed by LG&E, I am proposing a spread of the increase for KU that will move rates toward cost of service by mitigating impacts on customers' rates by ensuring that no class gets more than 125% of the system average increase and no class receives a rate decrease. This revenue spread is shown above in Table 17 above. As shown in this table, the residential class will get around a 13.7% increase, whereas the Companies' own COSS suggests this class should get an increase closer to 24.7%. Again, the Companies' own COSS suggests the increase to the residential class should be considerably more than the mitigated increase to this class I am proposing above.

Q IN YOUR PROPOSED SPREADS ABOVE, YOU ARE RELYING ON THE COMPANIES' CLASS COSS. WOULD YOUR PROPOSAL CHANGE IF YOU ADJUSTED YOUR REVENUE SPREAD TO REFLECT YOUR ADJUSTMENTS TO THE COMPANIES' ELECTRIC COSS?

A No. I believe that my electric COSS produces more accurate estimates of the cost of service. However, my revenue spread to mitigate impacts to customers would be comparable to what I am proposing by relying on the Companies' class cost of service results.

VI. RATE DESIGN

VI.A. Time-of-Day Primary Service ("TODP")

Q DID LG&E/KU WITNESS SEELYE DESCRIBE THE COMPANIES' LARGE CUSTOMER RATES INCLUDING THE TODP RATE?

A Yes. Mr. Seelye states at pages 29-31 of his testimony, the Companies offer commercial and industrial customers TOD rates. He states there is a cost basis in the rate design that goes into the logic behind the rate design. Specifically, he states at page 31 that the Companies install sufficient generation resources to meet their peak demands. Peak demands occur during the summer peak months and the winter peak months during peak period conditions of 9 a.m. to 10 p.m. generally, but these vary by season. He states the Companies also install sufficient transmission and distribution facilities to deliver power to individual customers. To accommodate these demands on the system, the Companies separate their TOD rates into a base demand charge which is structured to recover transmission and distribution demand-related costs, but the maximum load characteristic is essentially unbundled between generation costs which are then recovered in the peak and intermediate demand charges.[19]

Mr. Seelye describes the TOD rates as consisting of a basic service charge, an energy charge, a maximum loads charge comprised of a peak demand charge, an intermediate demand charge and a base demand charge. He states that the demand charges are based on kVa billing units. The peak demand charge applies to billing demands (maximum demands) that occur during the weekday hours (peak demand period) from 1 p.m. to 7 p.m. during the summer months of May through September

[19] Seelye Direct at 31-32.

and 6 a.m. to noon during the winter months of October through April. The intermediate demand charge applies to billing demands that occur during the weekday hours for an intermediate demand period (from 10 a.m. to 10 p.m.) during the summer peak months, and 6 a.m. to 10 p.m. during the winter peak months. The base demand charge applies to the billing demands that occur at any time during the month.

Q ARE YOU RECOMMENDING ANY CHANGES TO THE COMPANIES' PROPOSED TODP RATE DESIGN?

A No. I support maintaining the existing TOD rate structure. However, I believe revising it to better reflect maximum demands, and costs that vary with energy and demands will improve the efficiency of the price signal produced through the TOD rate structure. Specifically, I propose two adjustments:

1. Part of the transmission costs that are currently recovered entirely in the base demand charge should be split into a base transmission demand, and an extra transmission demand. Base transmission demand costs should continue to be recovered in the base demand charge. The extra transmission costs should be split between intermediate and peak demand charges. This provides additional economic considerations for customers to minimize demands during the maximum demand period (intermediate and peak) and more efficiently utilize the Companies' existing resources. Maintaining components of transmission costs as a base demand charge, ensures that all customers pay a portion of the Companies' transmission deliveries for average demand levels.

2. The Companies have included some steam-related O&M costs in the energy charge. Specifically, the Companies propose to include steam O&M expenses associated with FERC Accounts 510 through 514 in its energy charge. These same energy costs do not vary with level of energy generation. Rather, they are relatively flat, increasing with inflation over time. Therefore, I believe it is more appropriate to recover these fixed O&M costs through the demand charges in the rate and remove them from the energy charge of the rate.

Q WHY DO YOU RECOMMEND THAT TRANSMISSION COSTS BE DISTRIBUTED ACROSS BOTH BASE DEMAND CHARGE AND INCLUDED IN INTERMEDIATE AND PEAK CHARGES?

A Transmission service cost is incurred in order to move production from the generation source to the distribution point of delivery. As such, transmission costs more closely align with production costs and should be included in the pricing elements more similar to these features. Further, separating transmission costs into a base transmission component and an extra capacity component allows for a rate design which charges for transmission charges in the base component, but shifts the extra capacity component of transmission costs into the intermediate and peaking structure. This encourages customers to reduce demands during peak periods, which lowers both production and transmission costs. This design also, however, requires all customers to pay for the normal or average use of transmission facilities in the base distribution charge.

Distributing the extra transmission charges into intermediate and peak demand components aligns with peak period costs in a manner that is very similar to that of production costs. To the extent customers can lower their intermediate and peak demands, that will reduce LG&E's and KU's peak production demands and peak costs on their transmission systems. Both of these price signals will encourage customers to shift demands off-peak, which will benefit LG&E and KU and their other customers by mitigating growth in peak demand costs, which can allow them to avoid making additional investments in production and transmission capacity.

Q WHY DO YOU BELIEVE THAT STEAM GENERATION COSTS IN FERC ACCOUNTS 510 THROUGH 514 DO NOT VARY WITH ENERGY GENERATION?

A I reached this conclusion based on a review of these costs for LG&E and KU generating units over the last five years, and the related energy generation from each of these utilities' steam units. As shown in Tables 10 and 11, the actual O&M costs for FERC Accounts 510 through 514 do not vary with energy, but are relatively stable, largely increasing with inflationary effects over the last five years. The costs have been relatively stable, where energy generation from these fossil units has varied significantly from year to year. Therefore, these costs are more fixed in nature, and do not vary directly with energy, and therefore should not be recovered in energy charges.

Q ARE YOU PROPOSING ANY OTHER CHANGES TO THE TERMS AND CONDITIONS OF THE RATE TODP?

A Yes. I am proposing a modification to the demand ratchet provision for base demand. Currently, base demand is based on a 100% ratchet provision and the Max period demands (Intermediate and Peak) include a 50% ratchet demand.[20] I believe this is inappropriate because base demand includes both distribution, which is reasonably recovered on 100% ratchet demand, but also transmission expense. Transmission expense as noted above, is incurred in order to move production capacity into the distribution system. As such, the demand component for transmission should more

[20]Filing Requirement Attachment 1, Tab 4, LGE Proposed Electric Rates PSC Electric No. 12 First Revised Original Sheet 22, and KU Filing Requirement, Tab 4, PSC No. 20 Original Sheet No. 22.

closely align with production expense. The Company uses a 50% ratchet demand for production demands.[21]

Because the base demand recovers approximately 50% distribution costs and 50% transmission costs, I am proposing a 75% ratchet demand feature for base demand, which reflects 100% demand ratchet for distribution, and a 50% demand ratchet for transmission.

Q PLEASE SUMMARIZE YOUR PROPOSED TODP RATES FOR LG&E AND KU.

A My proposed TODP rates are presented in Exhibit MPG-3 and Exhibit MPG-4, for LG&E and KU, respectively. These exhibits also show the development of these rates, and provide a rate class proof of revenue, and on page 2, I compare my proposed rates to those of the Companies.

I have lowered LG&E's and KU's proposed TODP energy charges to reflect the reclassification of steam generation maintenance expenses as demand-related. I have revised the base demand charge to include distribution costs and a base level of transmission cost. The base level of transmission cost was determined by multiplying the transmission revenue requirement by the TODP class load factor. The remaining production and transmission costs have been split between the intermediate and peak demand charges in proportion to the Companies' proposed revenues from those charges.

[21] *Id.*

<u>VI.B. LG&E'S Gas Cost of Service</u>

Q HOW IS LG&E PROPOSING TO SPREAD THE INCREASE IN ITS GAS REVENUE REQUIREMENT IN THIS PROCEEDING?

A LG&E is seeking an increase of approximately $30 million in gas costs, or about an 8.3% increase in base rates. LG&E witness Mr. Seelye developed a gas COSS that proposed to move rate classes toward cost of service by eliminating 25% of his subsidies for rate classes Residential Service Rate RGS, Firm Transportation Service Rate FT, and As Available Gas Service Rate AGSS.[22]

Q PLEASE DESCRIBE LG&E'S GAS COSS.

A Mr. Seelye describes LG&E's gas COSS at pages 121-133 of his testimony. Mr. Seelye first functionalizes, and then classifies LG&E's costs of providing gas service. The functionalization includes Storage costs, Transmission costs, Distribution costs and Other. He classifies Storage costs into demand and commodity, Transmission costs into demand, Distribution costs into demand and customer, and Other costs into specific categories. He then allocates the classified functionalized costs to Residential, Small Commercial and Industrial, Large Industrial, and Other groups.

For demand costs related to storage, transmission and distribution, he developed a demand allocator based on various categories outlined at pages 126-127 of his testimony. Mr. Seelye states that transmission plant is used to deliver gas supplies from the source to LG&E's distribution system. The cost for this transmission service is based on design day demands placed on the equipment. Distribution plant was classified

[22]Seelye Direct Testimony at 80, Table 5.

as demand and customer, where the demand component was separated between low, medium and high pressure mains. Classification between demand and customer was based on a Zero Intercept methodology.

Q DO YOU BELIEVE MR. SEELYE'S GAS COSS WAS CONSTRUCTED REASONABLY?

A Yes. I believe his allocation of transmission costs on the basis of design day demand is appropriate and reasonable. Further, his separation of distribution costs into functional areas of both demand and customer also reasonably reflects the cost causation of these facilities.

Q DO YOU HAVE ANY CONCERNS WITH MR. SEELYE'S PROPOSED ADJUSTMENTS TO TARIFF RATE CLASSES BASED ON HIS PROPOSED REVENUE SPREAD AND GAS COSS?

A No. I believe Mr. Seelye's proposed revenue spread and gas COSS are reasonably constructed and his proposal for a gradual movement to cost of service is appropriate.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Michael P. Gorman

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A In 1983, I received a Bachelor of Science Degree in Electrical Engineering from Southern Illinois University, and in 1986, I received a Master's Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield. I have also completed several graduate level economics courses.

In August of 1983, I accepted an analyst position with the Illinois Commerce Commission ("ICC"). In this position, I performed a variety of analyses for both formal and informal investigations before the ICC, including: marginal cost of energy, central dispatch, avoided cost of energy, annual system production costs, and working capital. In October of 1986, I was promoted to the position of Senior Analyst. In this position, I assumed the additional responsibilities of technical leader on projects, and my areas of responsibility were expanded to include utility financial modeling and financial analyses.

In 1987, I was promoted to Director of the Financial Analysis Department. In this position, I was responsible for all financial analyses conducted by the Staff. Among other things, I conducted analyses and sponsored testimony before the ICC on rate of return, financial integrity, financial modeling and related issues. I also supervised the development of all Staff analyses and testimony on these same issues. In addition, I supervised the Staff's review and recommendations to the Commission concerning utility plans to issue debt and equity securities.

In August of 1989, I accepted a position with Merrill-Lynch as a financial consultant. After receiving all required securities licenses, I worked with individual investors and small businesses in evaluating and selecting investments suitable to their requirements.

In September of 1990, I accepted a position with Drazen-Brubaker & Associates, Inc. ("DBA"). In April 1995, the firm of Brubaker & Associates, Inc. ("BAI") was formed. It includes most of the former DBA principals and Staff. Since 1990, I have performed various analyses and sponsored testimony on cost of capital, cost/benefits of utility mergers and acquisitions, utility reorganizations, level of operating expenses and rate base, COSS, and analyses relating to industrial jobs and economic development. I also participated in a study used to revise the financial policy for the municipal utility in Kansas City, Kansas.

At BAI, I also have extensive experience working with large energy users to distribute and critically evaluate responses to requests for proposals ("RFPs") for electric, steam, and gas energy supply from competitive energy suppliers. These analyses include the evaluation of gas supply and delivery charges, cogeneration and/or combined cycle unit feasibility studies, and the evaluation of third-party asset/supply management agreements. I have participated in rate cases on rate design and class cost of service for electric, natural gas, water and wastewater utilities. I have also analyzed commodity pricing indices and forward pricing methods for third party supply agreements, and have also conducted regional electric market price forecasts.

In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

Q HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A Yes. I have sponsored testimony on cost of capital, revenue requirements, cost of service and other issues before the Federal Energy Regulatory Commission and numerous state regulatory commissions including: Alaska, Arkansas, Arizona, California, Colorado, Delaware, the District of Columbia, Florida, Georgia, Idaho, Illinois, Indiana, Iowa, Kansas, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Oklahoma, Oregon, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, West Virginia, Wisconsin, Wyoming, and before the provincial regulatory boards in Alberta, Nova Scotia, and Quebec, Canada. I have also sponsored testimony before the Board of Public Utilities in Kansas City, Kansas; presented rate setting position reports to the regulatory board of the municipal utility in Austin, Texas, and

Salt River Project, Arizona, on behalf of industrial customers; and negotiated rate disputes for industrial customers of the Municipal Electric Authority of Georgia in the LaGrange, Georgia district.

Q PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.

A I earned the designation of Chartered Financial Analyst ("CFA") from the CFA Institute. The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting, economics, fixed income and equity valuation and professional and ethical conduct. I am a member of the CFA Institute's Financial Analyst Society.

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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT TO ITS ELECTRIC RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCHARGE	)	**Case No. 2020-00349**
IN THE MATTER OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT TO ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCHARGE	)	**Case No. 2020-00350**

STATE OF MISSOURI)
COUNTY OF ST. LOUIS) SS

VERIFICATION OF MICHAEL P. GORMAN

Michael P. Gorman, being first duly sworn, states the following: The prepared Direct Testimony and Exhibits constitute the direct testimony of Affiant in the above-styled cases. Affiant states that he would give the answers set forth in the Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

Michael P. Gorman

Subscribed and sworn to before me this 4th day of March, 2021.

Sally D. Wilhelms
Notary Public

SALLY D. WILHELMS
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis County
My Commission Expires: Aug. 5, 2024
Commission # 20078050

Exhibit MPG-1

Data Responses Referenced in the Direct Testimony of Michael P. Gorman

Witness: Michael P. Gorman

Data Responses Referenced in
<u>the Direct Testimony of Michael P. Gorman</u>

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[1] KU Attachment identical to the LG&E Attachment provided as pages 7-14.

KENTUCKY UTILITIES COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00349

Question No. 41

Responding Witness: Gregory J. Meiman

Q-41. Please provide a breakdown of the total headcount by department and in total for the Companies at December 31 for each of the years 2015-2019, the most current date available, the end of the forecasted base year and the end of forecasted test year.

A-41. See attached for a listing of headcount by department for KU and LKS. The budgeted columns reflect all headcount being filled. To the extent there are vacant positions, the dollars budgeted would be used for overtime and contractors to perform the work.

Case No. 2020-00349
Attachment 1 to Response to AG-KIUC Question 41

Meiman

Kentucky Utilities Company
Case No. 2020-00349
Question No. 41
Kentucky Utilities Company Total Headcount by Department

	Actuals						Budget	
	Dec-15	**Dec-16**	**Dec-17**	**Dec-18**	**Dec-19**	**Dec-20**	**Feb-21**	**Jun-22**
P10040: TOTAL KU COMPANY	**940**	**937**	**923**	**916**	**909**	**905**	**923**	**918**
010603 010603 - FINC & BUDGTNG-POWER PROD KU	3	4	2	2	2	2	2	2
011018 011018 - VEGETATION MANAGEMENT - KU	5	5	5	5	5	5	5	5
011050 011050 - EARLINGTON METER DEPT	3	3	3					
011061 011061 - AREA 1	7	7	7	6	6	7	6	6
011062 011062 - AREA 2	7	8	8	8	7	7	8	8
011063 011063 - AREA 3	5	4	3	5	6	6	6	6
011064 011064 - AREA 4	9	7	8	10	8	8	8	8
011065 011065 - AREA 5	8	8	8	8	8	8	8	8
011066 011066 - AREA 6	9	9	9	7	9	9	9	9
011067 011067 - AREA 7	6	6	6	6	6	6	6	6
011068 011068 - AREA 8	4	4	5	5	5	5	5	5
011069 011069 - AREA 9	12	11	12	12	13	13	13	13
011070 011070 - AREA 10	6	6	6	6	6	6	6	6
011071 011071 - AREA 11	5	5	5	5	4	5	5	5
011072 011072 - AREA 12	11	10	11	10	10	10	10	10
011090 011090 - SC AND M EARLINGTON	12	12	12	10	10	10	10	10
011345 011345 - REVENUE PROTECTION - KU	1	1	1					
011370 011370 - FIELD SERVICES - KU	46	44	43	44	44	44	44	44
011560 011560 - EARLINGTON OPERATIONS CENTER	48	47	48	46	45	47	48	48
012050 012050 - SC AND M DANVILLE	13	12	14	15	15	14	15	15
012160 012160 - DANVILLE OPERATIONS CENTER	21	20	20	22	23	23	21	21
012360 012360 - RICHMOND OPERATIONS CENTER	23	21	21	23	23	22	23	23
012460 012460 - ELIZABETHTOWN OPERATIONS CENTER	21	21	22	21	21	22	21	21
012560 012560 - SHELBYVILLE OPERATIONS CENTER	21	22	22	23	24	23	22	22
013030 013030 - LEXINGTON METER DEPT	9	9	9					
013040 013040 - SC AND M LEXINGTON	20	23	25	19	18	17	19	19
013150 013150 - LEXINGTON OPERATIONS CENTER			80	81	78	81	81	81
013180 013180 - METER READING - KU	8	8	7	7	7	6	7	7
013560 013560 - SUBSTATION RELAY, PROTECTION & CONTROL - KU				7	9	9	9	9
013660 013660 - MAYSVILLE OPERATIONS CENTER	26	26	26	27	26	27	26	26
013910 013910 - MANAGER - LEXINGTON OPERATIONS CENTER	81	79		1	1		1	1
014050 014050 - PINEVILLE METER DEPT	4	4	4					
014160 014160 - PINEVILLE OPERATIONS CENTER	20	20	20	20	20	20	20	20
014260 014260 - LONDON OPERATIONS CENTER	21	21	21	21	20	21	21	21
014370 014370 - ASSET INFORMATION - KU	12	12	13	13	15	13	15	15
014940 014940 - SC AND M PINEVILLE	10	10	10	10	10	10	9	9
015324 015324 - LEXINGTON MATERIAL LOGISTICS	4	4	4	4	4	4	4	4
015326 015326 - EARLINGTON MATERIAL LOGISTICS	4	3	3	3	3	3	3	3
015820 015820 - KU METER SHOP				16	17	17	20	20
015970 015970 - KU - TELECOMMUNICATIONS	12	12	12	12	14	14	14	14
016120 021016 - DIST ANALYTICS AND SPECIAL CONTRACTS	1	1						
016130 021020 - DIRECTOR DISTRIBUTION OPERATIONS	2	2						
016150 021035 - VP CUSTOMER SERVICES - SERVCO	1							
016220 016220 - E W BROWN - SUPT AND ADMIN	6	6	5	4	4	3	4	4
016230 016230 - EWB OPER / RESULTS	54	53	50	45	43	38	40	39
016250 016250 - EWB EQUIP MNTC	18	18	19	18	16	22	21	21
016260 016260 - EWB E AND I MNTC	19	21	21	19	18	17	17	17
016270 016270 - EWB COAL HANDLING	10	9	7	4	4	4	3	3
016300 016300 - EWB COMBUSTION TURBINE	15	14	13	14	13	15	14	14
016320 016320 - EWB ENVIRONMENTAL						2	2	1
016330 016330 - BR ENGINEERING AND TECHNICAL SERVICES		5	4	4	4	4	4	4
016340 016340 - EWB LABORATORY	3	3	3	3	3	3	5	4
016360 016360 - EWB MAINTENANCE	10	7	7	7	6	6	6	6
016370 016370 - EWB COMMERCIAL OPERATIONS	4	4	4	4	4	4	4	4
016520 016520 - GHENT - SUPERINTENDENT	9	9	8	11	11	12	12	10
016530 016530 - GHENT - PLANNING	7	10	10	9	10	10	11	11
016540 016540 - GH ENGINEERING AND TECHNICAL SERVICES	14	11	10	14	13	13	14	14
016550 016550 - GHENT - MECHANICAL MNTC	24	24	23	24	24	23	24	24
016560 016560 - GHENT - ELECTRICAL MNTC	20	21	20	17	17	17	18	18
016570 016570 - GHENT - COAL YARD	12	6	6	6	7	6	7	7
016580 016580 - GHENT - INSTRUMENT MNTC	20	24	22	21	17	19	21	21
016600 016600 - GHENT - ASST SUPT OPER	4	4	6	4	4	4	4	4
016620 016620 - GHENT - SCRUBBER MAINT	9	9	8	9	9	8	8	8
016630 016630 - GHENT - COMMERCIAL	8	8	7	7	7	7	7	7
016640 016640 - GHENT - STATION LAB	8	8	8	9	9	9	9	9
016650 016650 - GHENT - OPERATIONS SHIFTS	85	89	82	80	81	80	80	80
016660 016660 - GHENT-ASST SUPT MNTC	6	7	7	7	9	8	8	8
016670 016670 - GHENT - OUTSIDE MNTC	1	4	4	4	3	2	3	3

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 41

Responding Witness: Gregory J. Meiman

Q-41. Please provide a breakdown of the total headcount by department and in total for the Companies at December 31 for each of the years 2015-2019, the most current date available, the end of the forecasted base year and the end of forecasted test year.

A-41. See attached for a listing of headcount by department for LG&E and LKS. The budgeted columns reflect all headcount being filled. To the extent there are vacant positions, the dollars budgeted would be used for overtime and contractors to perform the work.

Louisville Gas and Electric Company
Case No. 2020-00350
Question No. 41
Louisville Gas and Electric Company Total Headcount by Department

	Actuals						Budget	
	Dec-15	Dec-16	Dec-17	Dec-18	Dec-19	Dec-20	Feb-21	Jun-22
P01000: TOTAL LGE UTILITY	**1017**	**1038**	**1001**	**1045**	**1066**	**1031**	**1103**	**1113**
001075 001075 - TECH. AND SAFETY TRAINING DIST - LGE	1	1	1	1	1	1	1	1
001220 001220 - BUSINESS OFFICES - LGE	10	11	12	13	13	11	14	14
001280 001280 - METER READING - LGE	7	7	7	6	7	7	7	7
001295 001295 - FIELD SERVICE - LGE	24	21	22	21	22	22	22	22
001320 001320 - REVENUE PROTECTION - LGE	1	1						
001345 001345 - METER SHOP LGE	13	13	13	13	12	13	15	15
002060 002060 - CENT ENG/CONST MGMT	3	3	3		1	1	1	1
002120 002120 - OHIO FALLS	6	9	9	7	8	7	7	7
002130 002130 - CANE RUN CCGT - LGE	43	44	39	45	45	44	46	46
002140 002140 - OTH PROD OPR/MTCE			5	4	5	3	4	4
002280 021016 - DIST ANALYTICS AND SPECIAL CONTRACTS	1							
002320 002320 - MC-COMMON PLANT	99	96	89	90	92	84	89	88
002330 002330 - MC ENGINEERING AND TECHNICAL SERVICES	1	9	10	12	16	12	18	18
002340 002340 - MC COMMERCIAL OPERATIONS	9	9	8	5	6	5	5	5
002350 002350 - MC-LABORATORY	11	12	13	12	13	13	15	15
002401 002401 - GEN. MGR. MILL CREEK STATION	8	10	10	13	13	9	12	12
002480 002480 - MGR. MILL CREEK MAINTENANCE	24	17	13	17	17	17	17	17
002481 002481 - MILL CREEK MECHANICAL MAINTENANCE	32	31	29	30	31	30	31	31
002482 002482 - MILL CREEK I/E MAINTENANCE	32	32	30	31	31	30	32	32
002530 021070 - DIRECTOR - ASSET MANAGEMENT	2	1						
002560 021072 - ELECTRICAL ENGINEERING AND PLANNING GROUP - LKS	1							
002603 002603 - FINC & BUDGTNG-POWER PROD LG&E	3	3	3	3	3	3	3	3
002650 002650 - GENERAL MANAGER - TC	6	6	6	6	6	6	6	6
002670 002670 - TRIMBLE COUNTY - COMMERCIAL OPERATIONS	5	4	4	4	4	3	4	4
002680 002680 - TC ENGINEERING AND TECHNICAL SERVICES	14	12	11	12	14	13	20	20
002710 002710 - TC-LABORATORY	6	8	7	9	8	7	7	7
002720 002720 - TC OPERATIONS	9	9	13	14	14	16	15	14
002730 002730 - TC OPER-A WATCH	12	15	14	12	15	14	15	15
002740 002740 - TC OPER-B WATCH	14	14	15	14	15	13	15	15
002750 002750 - TC OPER-C WATCH	14	13	13	14	13	14	15	15
002760 002760 - TC OPER-D WATCH	16	15	14	15	15	14	15	15
002770 002770 - TC-MAINTENANCE SVCS	14	15	14	16	15	17	16	16
002780 002780 - TC-MAINTENANCE I/E	31	30	29	32	35	32	37	37
002790 002790 - TC-MTCE MECHANICAL	24	23	21	22	27	24	28	28
002820 002820 - MC-MATERIAL HANDLING	17	17	15	14	12	11	11	11
002840 002840 - TC-MATERIAL HANDLING	5	6	5	5	5	5	5	5
003030 003030 - SUBSTATION OPS.	11	10	9	10	10	10	10	10
003110 003110 - TRANSFORMERS SERVICES	8	8	7	7	5	4	7	7
003160 003160 - SC M LOUISVILLE	28	30	29	19	18	19	18	18
003210 003210 - FORESTRY	2	2	2	2	2	2	2	2
003300 003300 - ELECTRIC CONSTRUCTION CREWS-ESC	43	45	43	45	36	32	38	38
003320 003320 - STREET LIGHTING-LGE			3	3	3	3	3	3
003385 003385 - LINE LOCATING	1	2	2	2	1	2	2	2
003400 003400 - ELECTRIC CONSTRUCTION CREWS-AOC	48	45	45	43	37	42	40	40
003410 003410 - JOINT TRENCH ENHANCE AND CONNECT NETWORK	5	5	3	3	3	3	3	3
003430 003430 - NETWORK OPS. 3PH COMMERCIAL	27	27	27	26	19	22	22	22
003440 003440 - UNDERGROUND CONSTRUCTION					11	12	12	12
003450 003450 - MANAGER ELECTRIC DISTRIBUTION	6	8	8	10	16	17	16	16
003470 003470 - PERFORMANCE METRICS	7	6	5	6	6	5	6	6
003550 021075 - DESIGN, CONST. AND MATERIALS STANDARD - DIST	1							
003560 003560 - SUBSTATION RELAY, PROTECTION & CONTROL - LGE				10	11	9	11	11
004010 004010 - MANAGER DISTRIBUTION DESIGN	7	1	1					
004040 004040 - DISTRIBUTION DESIGN	24	32	33	34	35	37	36	36
004060 004060 - GAS DIST. CONTRACT CONSTRUCTION	17	17	18	21	24	23	22	22
004100 004100 - DIRECTOR - GAS CONSTRUCTION AND OPERATIONS AND ENGINEERING	2	2	2	1	1	1	1	1
004140 004140 - MANAGER, GAS CONSTRUCTION	7	8	8	9	9	9	11	11
004190 004190 - GAS DIST OPRS-REPAIR AND MAINTAIN	45	46	46	46	48	48	50	51
004220 004220 - SVC DEL-BARDSTOWN	3	4	4	4	4	4	4	4
004270 004270 - GAS DISPATCH	10	10	10	9	12	12	12	12
004280 004280 - GAS TROUBLE	16	20	20	19	18	17	17	17
004290 004290 - METER SHOP	5	5	5	5	6	7	8	8
004370 004370 - ASSET INFORMATION LGE	11	11	11	11	11	9	11	11
004380 004380 - GAS-ENGINEERS	11	11	12	13	13	12	15	15
004385 004385 - TRANSMISSION INTEGRITY & COMPLIANCE	9	9	8	10	9	10	15	16
004450 004450 - CORROSION CONTROL	10	11	10	14	13	15	14	14
004470 004470 - MULDRAUGH STORAGE	37	45	38	35	33	32	33	33
004475 004475 - DIR. GAS CONTROL AND STORAGE - LGE	1	1	1	3	3	3	4	4
004480 004480 - MAGNOLIA STORAGE	30	32	27	27	24	22	22	22
004490 004490 - GAS CONTROL	10	11	10	14	15	17	15	17
004500 004500 - INSTR., MEASUREMENT	8	8	9	11	11	10	10	12
004510 004510 - SYSTEM REGULATION OPERATION	17	17	16	17	17	17	18	20
004560 004560 - GAS PROCUREMENT	6	6	6	6	6	6	6	6
004600 004600 - GAS REGULATORY SERVICES	13	13	13	15	15	13	15	15

KENTUCKY UTILITIES COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00349

Question No. 43

Responding Witness: Gregory J. Meiman

Q-43. Refer to Schedule D-1. A number of the FERC account adjustment reasons indicate that base period costs were low “due to vacancies as a result of hiring delays due to Covid.” Please provide a listing of all vacancies by position and department for each month during the base year that the Companies assume to be filled during the test year.

A-43. Attached are headcount reports utilized by the Company as reflecting actual versus budget for the period March 31, 2020 through December 31, 2020. The Company has also included the reports that management utilizes on a quarterly basis comparing actual vs budget which includes supplemental contractors to provide the overall headcount view. The open positions are typically managed with overtime and supplemental contractors, to illustrate this the Company provided the December 31, 2018 and December 31, 2019 reports. These reports demonstrate that in a year with no extraordinary items the use of supplemental contractors offset the actual to budget headcount difference for employees – see the December 31, 2019 report. In a year with above normal storm occurrence for example 2018, the company experiences significantly higher actual than budgeted supplemental contractors. In 2020, due to COVID-19, employee positions were delayed particularly in the generation area due to concerns about training since it requires close proximity that could not be achieved with socially distancing guidelines and also sizable groups of employees and contractors that were not able to come into work related to COVID-19 quarantines. Additionally, supplemental contractors were also a limited resource in 2020 related to constraints from mutual assistance provided to an unusually large number of storm events and COVID-19 issues within their own workforces.

The Company intends to fill all open positions between January 1, 2021 through June 30, 2022, and will utilize overtime and supplemental contractors as needed.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

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The Company intends to fill all open positions between January 1, 2021 through June 30, 2022, and will utilize overtime and supplemental contractors as needed.

LKE Employee and Supplemental Contractor Resources - December 31, 2020

Higher than Budget or prior year sctual is shown in (Brackets)

	Full-Time, Part-Time and Interns			Supplemental Contractors (SCs)			Total Employees and SCs			Variance to 12/31/2020 Budget			Variance to 12/31/2019 Actual		
	12/31/20 Actual	12/31/20 Budget	12/31/19 Actual	12/31/20 Actual	12/31/20 Budget	12/31/19 Actual	12/31/20 Actual	12/31/20 Budget	12/31/19 Actual	Employees	Supplemental Contractors	Total	Employees	Supplemental Contractors	Total
Power Production	873	941	909	444	461	438	1,317	1,402	1,347	68	17	85	36	(6)	30
Customer Services	676	687	668	590	578	592	1,266	1,265	1,260	11	(12)	(1)	(8)	2	(6)
Electric Distribution	740	755	730	1,002	1,043	1,165	1,742	1,798	1,895	15	41	56	(10)	163	153
Transmission	172	176	171	499	502	439	671	678	610	4	3	7	(1)	(60)	(61)
Gas	289	316	293	325	386	375	614	702	668	27	61	88	4	50	54
ES&A	115	130	122	15	20	24	130	150	146	15	5	20	7	9	16
Safety & TT	39	38	40	1	2	2	40	40	42	(1)	1	-	1	1	2
Environmental	22	24	22	1	-	1	23	24	23	2	(1)		-	-	-
COO	2	2	2	-	-	-	2	2	2	-	-	-	-	-	-
Total Operations	2,928	3,069	2,957	2,877	2,992	3,036	5,805	6,061	5,993	141	115	256	29	159	188
IT	325	334	321	95	58	68	420	392	389	9	(37)	(28)	(4)	(27)	(31)
CFO	225	225	213	33	31	31	258	256	244	-	(2)	(2)	(12)	(2)	(14)
General Counsel	34	37	37	-	-	-	34	37	37	3	-	3	3	-	3
Corporate Communications	27	27	28	1	1	1	28	28	29	-			1		
Human Resources	59	58	61	-	-	-	59	58	61	(1)	-	(1)	2	-	2
CEO and President	2	2	2	-	-	-	2	2	2	-	-	-	-	-	-
Total LKE	3,600	3,752	3,619	3,006	3,082	3,136	6,606	6,834	6,755	152	76	228	19	130	149

LKE Employee and Supplemental Contractor Resources - September 30, 2020

Higher than Budget or prior year sctual is shown in (Brackets)

	Full-Time, Part-Time and Interns			Supplemental Contractors (SCs)			Total Employees and SCs			Variance to 9/30/2020 Budget			Variance to 12/31/2019 Actual		
	9/30/20 Actual	9/30/20 Budget	12/31/19 Actual	9/30/20 Actual	9/30/20 Budget	12/31/19 Actual	9/30/20 Actual	9/30/20 Budget	12/31/19 Actual	Employees	Supplemental Contractors	Total	Employees	Supplemental Contractors	Total
Power Production	864	941	909	446	461	438	1,310	1,402	1,347	77	15	92	45	(8)	37
Customer Services	662	687	668	579	578	592	1,241	1,265	1,260	25	(1)	24	6	13	19
Electric Distribution	739	755	730	1,027	1,043	1,165	1,766	1,798	1,895	16	16	32	(9)	138	129
Transmission	179	180	171	488	502	439	667	682	610	1	14	15	(8)	(49)	(57)
Gas	291	317	293	323	386	375	614	703	668	26	63	89	2	52	54
ES&A	117	129	122	14	20	24	131	149	146	12	6	18	5	10	15
Safety & TT	38	38	40	2	2	2	40	40	42	-	-	-	2	-	2
Environmental	22	24	22	1	-	1	23	24	23	2	(1)		-	-	-
COO	2	2	2	-	-	-	2	2	2	-	-	-	-	-	-
Total Operations	2,914	3,073	2,957	2,880	2,992	3,036	5,794	6,065	5,993	159	112	271	43	156	199
IT	323	334	321	84	58	68	407	392	389	11	(26)	(15)	(2)	(16)	(18)
CFO	227	225	213	31	31	31	258	256	244	(2)	-	(2)	(14)	-	(14)
General Counsel	33	37	37	-	-	-	33	37	37	4	-	4	4	-	4
Corporate Communications	28	27	28	1	1	1	29	28	29	(1)			-		
Human Resources	58	58	61	-	-	-	58	58	61	-	-	-	3	-	3
CEO and President	2	2	2	-	-	-	2	2	2	-	-	-	-	-	-
Total LKE	3,585	3,756	3,619	2,996	3,082	3,136	6,581	6,838	6,755	171	86	257	34	140	174

LKE Employee and Supplemental Contractor Resources - December 31, 2019

	Regular Full-Time and Part-Time Employees [1]			Supplemental Contractors (SC's)			Total Employees and SC's [1]			Higher than Budget or 12/31/18 Actual is shown in (Brackets) — Variance to 12/31/2019 Budget			Variance to 12/31/2018 Actual		
	12/31/19 Actual	12/31/19 Budget	12/31/18 Actual	12/31/19 Actual	12/31/19 Budget	12/31/18 Actual	12/31/19 Actual	12/31/19 Budget	12/31/18 Actual	Employees	Supplemental Contractors	Total	Employees	Supplemental Contractors	Total
Power Production	874	907	878	438	455	437	1,312	1,362	1,315	33	17	50	4	(1)	3
Customer Services	664	696	685	592	597	647	1,256	1,293	1,332	32	5	37	21	55	76
Electric Distribution	718	730	732	1,165	1,068	1,034	1,883	1,798	1,766	12	(97)	(85)	14	(131)	(117)
Transmission	162	167	164	439	473	477	601	640	641	5	34	39	2	38	40
Project Engineering	51	60	57	24	34	42	75	94	99	9	10	19	6	18	24
Gas	288	302	285	375	309	355	663	611	640	14	(66)	(52)	(3)	(20)	(23)
ES&A	60	60	60	-	-	-	60	60	60	-	-	-	-	-	-
Safety & TT	40	38	36	2	2	2	42	40	38	(2)	-	(2)	(4)	-	(4)
Environmental	21	22	23	1	-	-	22	22	23	1	(1)		2	(1)	1
COO	2	2	2	-	-	-	2	2	2	-	-	-	-	-	-
Total Operations	2,880	2,984	2,922	3,036	2,938	2,994	5,916	5,922	5,916	104	(98)	6	42	(42)	-
IT	298	312	287	68	60	69	366	372	356	14	(8)	6	(11)	1	(10)
CFO	200	210	195	31	27	27	231	237	222	10	(4)	6	(5)	(4)	(9)
General Counsel	36	38	36	-	-	-	36	38	36	2	-	2	-	-	-
Corporate Communications	26	26	26	1	1	1	27	27	27	-			-		
Human Resources	58	59	57	-	-	-	58	59	57	1	-	1	(1)	-	(1)
CEO and President	2	2	2	-	-	-	2	2	2	-	-	-	-	-	-
Total LKE	3,500	3,631	3,525	3,136	3,026	3,091	6,636	6,657	6,616	131	(110)	21	25	(45)	(20)

[1] Excludes Co-ops and Interns.

LKE Employee and Supplemental Contractor Resources - December 31, 2018

Higher than Budget or 12/31/17 Actual is shown in (Brackets)

	Regular Full-Time and Part-Time Employees [1]			Supplemental Contractors (SC's)			Total Employees and SC's [1]			Variance to 12/31/2018 Budget			Variance to 12/31/2017 Actual		
	12/31/18 Actual	12/31/18 Budget	12/31/17 Actual	12/31/18 Actual	12/31/18 Budget	12/31/17 Actual	12/31/18 Actual	12/31/18 Budget	12/31/17 Actual	Employees	Supplemental Contractors	Total	Employees	Supplemental Contractors	Total
Power Production	878	893	874	437	436	421	1,315	1,329	1,295	15	(1)	14	(4)	(16)	(20)
Customer Services	685	707	684	647	596	599	1,332	1,303	1,283	22	(51)	(29)	(1)	(48)	(49)
Electric Distribution	732	727	712	1,034	902	883	1,766	1,629	1,595	(5)	(132)	(137)	(20)	(151)	(171)
Transmission	164	165	161	477	389	381	641	554	542	1	(88)	(87)	(3)	(96)	(99)
Project Engineering	57	60	56	42	27	21	99	87	77	3	(15)	(12)	(1)	(21)	(22)
Gas Distribution	285	296	274	355	261	276	640	557	550	11	(94)	(83)	(11)	(79)	(90)
ES&A	60	64	65	-	-	-	60	64	65	4	-	4	5	-	5
Safety & TT	36	35	31	2	2	1	38	37	32	(1)	-	(1)	(5)	(1)	(6)
Environmental	23	22	22	-	-	-	23	22	22	(1)	-		(1)	-	(1)
COO	2	2	2	-	-	-	2	2	2	-	-	-	-	-	-
Total Operations	2,922	2,971	2,881	2,994	2,613	2,582	5,916	5,584	5,463	49	(381)	(332)	(41)	(412)	(453)
IT	287	312	286	69	31	32	356	343	318	25	(38)	(13)	(1)	(37)	(38)
CFO	195	210	209	27	23	25	222	233	234	15	(4)	11	14	(2)	12
General Counsel	36	38	35	-	-	-	36	38	35	2	-	2	(1)	-	(1)
Corporate Communications	26	26	25	1	1	1	27	27	26	-			(1)		
Human Resources	57	56	54	-	-	-	57	56	54	(1)	-	(1)	(3)	-	(3)
Enterprise Security	-	1	1	-	-	-	-	1	1	1	-		1	-	
CEO and President	2	4	4	-	-	-	2	4	4	2	-	2	2	-	2
Total LKE	3,525	3,618	3,495	3,091	2,668	2,640	6,616	6,286	6,135	93	(423)	(330)	(30)	(451)	(481)

[1] Excludes Co-ops and Interns.

Certified
Enterprise-wide Headcount Report
All Employees (Full-Time, Part-Time and Coops/Interns, Temporaries currently on our Payroll)
March 31, 2020

	Actual				Budget				Variance (Unfavorable)			
	KU	LGE	LGE & KU	Total	KU	LGE	LGE & KU	Total	KU	LGE	LGE & KU	Total
Grand Total:	**900**	**1,045**	**1,651**	**3,596**	**926**	**1,105**	**1,711**	**3,742**	**26**	**60**	**60**	**146**
Chairman CEO and President			2	2			2	2				
Total Chairman CEO and President			**2**	**2**			**2**	**2**				
Chief Financial Officer			2	2			2	2				
Chief Information Officer	14	10	298	322	14	12	308	334		2	10	12
Controller			75	75			78	78			3	3
Dir Audit Services			13	13			16	16			3	3
Dir Supply Chain	7		51	58	7		52	59			1	1
Treasurer	2	3	48	53	2	3	49	54			1	1
VP State Regulation and Rates			15	15			16	16			1	1
Total Chief Financial Officer	**23**	**13**	**502**	**538**	**23**	**15**	**521**	**559**		**2**	**19**	**21**
Chief Operating Officer			2	2			2	2				
Dir Safety & Tech Training		1	38	39		1	37	38			(1)	(1)
Director Environmental Affairs			23	23			24	24			1	1
VP Customer Services	157	62	445	664	157	68	458	683		6	13	19
VP Electric Distribution	378	220	131	729	385	235	134	754	7	15	3	25
VP Energy Supply and Analysis			121	121			127	127			6	6
VP Gas Distribution		288	4	292		308	4	312		20		20
VP Power Production	342	461	86	889	361	478	98	937	19	17	12	48
VP Transmission			175	175			181	181			6	6
Total Chief Operating Officer	**877**	**1,032**	**1,025**	**2,934**	**903**	**1,090**	**1,065**	**3,058**	**26**	**58**	**40**	**124**

Certified
Enterprise-wide Headcount Report
All Employees (Full-Time, Part-Time and Coops/Interns, Temporaries currently on our Payroll)
March 31, 2020

	Actual				Budget				Variance (Unfavorable)			
	KU	LGE	LGE & KU	Total	KU	LGE	LGE & KU	Total	KU	LGE	LGE & KU	Total
Gen Counsel/Compl/ Corp Secr			2	2			2	2				
Dir Compliance and Ethics			8	8			8	8				
Dir Federal Policy&Sr Counsel			6	6			3	3			(3)	(3)
Dir Legal Serv/Assoc Gen Cnsl			9	9			8	8			(1)	(1)
Sr Corporate Attorney (026900E			7	7			13	13			6	6
VP External Affairs			4	4			4	4				
Total Gen Counsel/Compl/ Corp Secr			**36**	**36**			**38**	**38**			**2**	**2**
VP Communications&Corp Respon			4	4			4	4				
Dir Brand Adv Cust&Digtl Comm			10	10			10	10				
Director Media Relations			4	4			3	3			(1)	(1)
Mgr Internal Communications			4	4			4	4				
VP Corporate Resp&Comm Affairs			6	6			6	6				
Total VP Communications&Corp Respon			**28**	**28**			**27**	**27**			**(1)**	**(1)**
VP Human Resources			2	2			2	2				
Dir Human Resources(025200)			10	10			11	11			1	1
Dir Human Resources(025300)			20	20			18	18			(2)	(2)
Dir Human Resources (025700)			18	18			20	20			2	2
Mgr Corp Health & Wellness			8	8			7	7			(1)	(1)
Total VP Human Resources			**58**	**58**			**58**	**58**				

Certified
Enterprise-wide Headcount Report
All Employees (Full-Time, Part-Time and Coops/Interns, Temporaries currently on our Payroll)
December 31, 2020

	Actual				Budget				Variance (Unfavorable)			
	KU	LGE	LGE & KU	Total	KU	LGE	LGE & KU	Total	KU	LGE	LGE & KU	Total
Grand Total:	**905**	**1,031**	**1,664**	**3,600**	**928**	**1,117**	**1,707**	**3,752**	**23**	**86**	**43**	**152**
Chief Financial Officer			2	2			2	2				
Chief Information Officer	14	10	301	325	14	12	308	334		2	7	9
Controller			78	78			78	78				
Dir Audit Services			14	14			16	16			2	2
Dir Supply Chain	7		51	58	7		52	59			1	1
Treasurer	2	3	53	58	2	3	49	54			(4)	(4)
VP State Regulation and Rates			15	15			16	16			1	1
Total Chief Financial Officer	**23**	**13**	**514**	**550**	**23**	**15**	**521**	**559**		**2**	**7**	**9**
Chief Operating Officer			2	2			2	2				
Dir Safety & Tech Training		1	38	39		1	37	38			(1)	(1)
Director Environmental Affairs			22	22			24	24			2	2
VP Customer Services	157	62	457	676	160	69	458	687	3	7	1	11
VP Electric Distribution	384	226	130	740	385	235	135	755	1	9	5	15
VP Energy Supply and Analysis			115	115			130	130			15	15
VP Gas Distribution		285	4	289		312	4	316		27		27
VP Power Production	341	444	88	873	360	485	96	941	19	41	8	68
VP Transmission			172	172			176	176			4	4
Total Chief Operating Officer	**882**	**1,018**	**1,028**	**2,928**	**905**	**1,102**	**1,062**	**3,069**	**23**	**84**	**34**	**141**
Gen Counsel/Compl/ Corp Secr			2	2			2	2				

Certified
Enterprise-wide Headcount Report
All Employees (Full-Time, Part-Time and Coops/Interns, Temporaries currently on our Payroll)
December 31, 2020

	Actual				Budget				Variance (Unfavorable)			
	KU	LGE	LGE & KU	Total	KU	LGE	LGE & KU	Total	KU	LGE	LGE & KU	Total
Dir Compliance and Ethics			8	8			8	8				
Dir Federal Policy&Sr Counsel			4	4			3	3			(1)	(1)
Dir Legal Serv/Assoc Gen Cnsl			8	8			8	8				
Sr Corporate Attorney (026900E			7	7			12	12			5	5
VP External Affairs			5	5			4	4			(1)	(1)
Total Gen Counsel/Compl/ Corp Secr			**34**	**34**			**37**	**37**			**3**	**3**
President and CEO			2	2			2	2				
Total President and CEO			**2**	**2**			**2**	**2**				
VP Communications&Corp Respon			4	4			4	4				
Dir Brand Adv Cust&Digtl Comm			9	9			10	10			1	1
Director Media Relations			4	4			3	3			(1)	(1)
Mgr Internal Communications			4	4			4	4				
VP Corporate Resp&Comm Affairs			6	6			6	6				
Total VP Communications&Corp Respon			**27**	**27**			**27**	**27**				
VP Human Resources			2	2			2	2				
Dir Human Resources(025200)			11	11			11	11				
Dir Human Resources(025300)			19	19			18	18			(1)	(1)
Dir Human Resources (025700)			19	19			20	20			1	1
Mgr Corp Health & Wellness			8	8			7	7			(1)	(1)
Total VP Human Resources			**59**	**59**			**58**	**58**			**(1)**	**(1)**

KENTUCKY UTILITIES COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00349

Question No. 44

Responding Witness: Gregory J. Meiman

Q-44. Refer to Schedule D-1. A number of the FERC account adjustment reasons indicate that base period costs were low "due to vacancies as a result of hiring delays due to Covid." Please provide a listing of the lower amounts in the base year for all vacancies by FERC account.

A-44. See attached for the breakdown of labor cost by FERC for the base period compared to the forecasted period. The base period is lower than the forecasted test period and related to a multitude of issues ranging from open positions, wage increases and higher capitalization of wages. The open positions are typically managed with overtime and supplemental contractors. Due to COVID-19, employee positions were delayed particularly in the generation FERCs due to concerns about training since it requires close proximity that could not be achieved with socially distancing guidelines and also sizable groups of employees and contractors that were not able to come into work related to COVID-19 quarantines. Additionally, supplemental contractors were also a limited resource in 2020 related to constraints from mutual assistance provided to an unusually large number of storm events and COVID-19 issues within their own workforces.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 44

Responding Witness: Gregory J. Meiman

Q-44. Refer to Schedule D-1. A number of the FERC account adjustment reasons indicate that base period costs were low “due to vacancies as a result of hiring delays due to Covid.” Please provide a listing of the lower amounts in the base year for all vacancies by FERC account.

A-44. See attached for the breakdown of labor cost by FERC for the base period compared to the forecasted period. The base period is lower than the forecasted test period and related to a multitude of issues ranging from open positions, wage increases and higher capitalization of wages. The open positions are typically managed with overtime and supplemental contractors. Due to COVID-19, employee positions were delayed particularly in the generation FERCs due to concerns about training since it requires close proximity that could not be achieved with socially distancing guidelines and also sizable groups of employees and contractors that were not able to come into work related to COVID-19 quarantines. Additionally, supplemental contractors were also a limited resource in 2020 related to constraints from mutual assistance provided to an unusually large number of storm events and COVID-19 issues within their own workforces.

KENTUCKY UTILITIES COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00349

Question No. 54

Responding Witness: Christopher M. Garrett

Q-54. 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 2020, during the base year, for the months March 2021 through June 2021, 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. Explain why the Companies forecast a balance in account 184 Pension Clearing instead of $0, especially given the Companies' forecast of pension expense in the test year.

g. 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.

h. 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.

i. Provide a description of the Regulatory Liability - Postretirement in account 254.

j. Provide all support for the Regulatory Liability - Postretirement, 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.

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

l. 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 this is confirmed, then describe the basis for this practice. Cite to Commission orders to the extent relied on for this purpose.

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

A-54.

a. See attached.

b. The prepaid pension in account 128 on Schedule B-5.2, page 5 of 6, is the thirteen-month average from June 2021-June 2022 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 August 2020 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 attached, page 1.

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 June 2021-June 2022 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 August

2020 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. It was also adjusted in December of 2020 for the anticipated impact of the 2020 pension settlement.

e. See attached, page 2.

f. 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 August 2020 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.

g. 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 June 2021-June 2022 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 August 2020 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 August 2020 is held constant throughout the forecast period.

h. See attached, page 3.

i. The Regulatory Liability - Postretirement in account 254 on Schedule B-5.2, page 5 of 6, is the thirteen-month average from June 2021-June 2022 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 August 2020 and projecting it forward based upon forecasted amortization of prior service cost and gains and losses.

j. See attached, page 4.

k. See the response to part f.

l. Confirmed. The Companies included Regulatory Asset – FAS 158 Pension on Schedule B-5.2 in its 2018 rate cases and the Commission accepted the Company's' position.[1] The Companies propose the same treatment in this case. Additionally, the Virginia Commission approved the inclusion of this regulatory asset in rate base in the previous two Virginia rate cases.[2]

   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. 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.

m. Confirmed, for KU. KU only includes the Regulatory Liability – Post Retirement as it relates to this specific schedule. LG&E does not have a Regulatory Liability – Post Retirement balance. KU included Regulatory Liability - Postretirement on Schedule B-5.2 in its 2018 rate cases and the Commission accepted the Companies' position.[3] KU proposes the same treatment in this case. Additionally, the Virginia Commission approved the inclusion of this regulatory liability in rate base in the previous two Virginia rate cases.[4]

   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. 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.

   The Companies also note that they do include the regulatory liability associated with excess ADIT in rate base in the ADIT balance on Schedule B-6.

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[1] Case No. 2018-00294, Order (Ky. PSC Apr. 30, 2019); Case No. 2018-00295, Order (Ky. PSC Apr. 30, 2019).
[2] Case Nos. PUR 2017-00106 and PUR 2019-00060.
[3] Case No. 2018-00294, Order (Ky. PSC Apr. 30, 2019).
[4] Case Nos. PUR 2017-00106 and PUR 2019-00060.

Kentucky Utilities

	a-Aug 2020	Sep 2020	Oct 2020	Nov 2020	Dec 2020	Jan 2021	Feb 2021	Mar 2021	Apr 2021
Special Funds									
128.1 - Other spec funds - investments	28,540	29,273	30,006	30,739	31,472	34,198	34,924	35,650	36,376
Change in forecasted balance from prior month		733	733	733	733	2,726	726	726	726
Components of change in balance from prior month:									
Monthly Service Cost, Interest Cost & EROA		(733)	(733)	(733)	(733)	726	726	726	726
Annual Estimated Contribution						p.6a 2,000			
		(733)	(733)	(733)	(733)	2,726	726	726	726

	May 2021	Jun 2021	Jul 2021	Aug 2021	Sep 2021	Oct 2021	Nov 2021	Dec 2021
Special Funds								
128.1 - Other spec funds - investments	37,101	37,827	38,553	39,279	40,004	40,730	41,456	42,182
Change in forecasted balance from prior month	726	726	726	726	726	726	726	726
Components of change in balance from prior month:								
Monthly Service Cost, Interest Cost & EROA	726	726	726	726	726	726	726	726
Annual Estimated Contribution								
	726	726	726	726	726	726	726	726

	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	**13 Month AVG JUN-22**
Special Funds							
128.1 - Other spec funds - investments	43,970	44,758	45,547	46,335	47,123	47,912	42,744
Change in forecasted balance from prior month	1,788	788	788	788	788	788	Schedule B-5.2
Components of change in balance from prior month:							
Monthly Service Cost, Interest Cost & EROA	788	788	788	788	788	788	
Annual Estimated Contribution	p.6a 1,000						
	1,788	788	788	788	788	788	

Components of account balance Aug 2020:		
Actuary Report	30,690	p.3
Funded Status	(3,150)	p.4
Pension Contribution	1,000	p.11
	28,540	

Components of Monthly Service Cost, Interest Cost & EROA:	p.5	2020	p.6	2021	p.6	2022
Service Cost		6,753		6,608		6,126
Interest Cost		14,625		13,752		13,478
Estimated Return on Assets		(30,175)		(29,069)		(29,064)
Annual Total		(8,798)		(8,709)		(9,460)
Monthly Total		(733)		(726)		(788)

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 54

Responding Witness: Christopher M. Garrett

Q-54. 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 2020, during the base year, for the months March 2021 through June 2021, 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. Explain why the Companies forecast a balance in account 184 Pension Clearing instead of $0, especially given the Companies' forecast of pension expense in the test year.

g. 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.

h. 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.

i. Provide a description of the Regulatory Liability - Postretirement in account 254.

j. Provide all support for the Regulatory Liability - Postretirement, 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.

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

l. 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 this is confirmed, then describe the basis for this practice. Cite to Commission orders to the extent relied on for this purpose.

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

A-54.

a. See attached.

b. The prepaid pension in account 128 on Schedule B-5.2, page 5 of 6, is the thirteen-month average from June 2021-June 2022 of the forecasted prepaid pension. The balance represents an excess of pension trust fund assets allocated to LG&E over PBO. The forecast was derived by taking the actual balance of the account as of August 2020 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 attached, page 1.

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 June 2021-June 2022 of the forecasted pension and postretirement regulatory assets. The balance represents accumulated unamortized prior service costs and net actuarial losses of the plans. The forecast was derived by taking the actual balance of the account as of August 2020 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 LG&E for LG&E's portion of the difference in the double corridor and 15-year amortization for LKS. It was also adjusted in December of 2020 for the anticipated impact of the 2020 pension settlement.

e. See attached, page 2.

f. 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 August 2020 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.

g. 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 June 2021-June 2022 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 LG&E. The forecast for postretirement was derived by taking the actual balance of the account as of August 2020 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 August 2020 is held constant throughout the forecast period.

h. See attached, page 3.

i. There is no balance referenced on Schedule B-5.2, page 5 of 6 for account 254 Regulatory Liability – Postretirement. Were there a balance, it would represent accumulated unamortized prior service costs and net actuarial gains of the postretirement plan.

j. See the response to subpart i.

k. See the response to subpart f.

l. Confirmed. The Companies included Regulatory Asset – FAS 158 Pension on Schedule B-5.2 in its 2018 rate cases and the Commission accepted the Companies' position.[1] The Companies propose the same treatment in this case. 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. 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.

m. See the response to part i. above indicating that there is no Regulatory Liability – Post Retirement balance for LG&E. LG&E has a regulatory asset balance for post retirement per part d. above. LG&E has not included any regulatory liability balances on this schedule consistent with its treatment in the previous rate case.[2]

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. 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.

The Companies also note that they include the regulatory liability associated with excess ADIT in rate base in the ADIT balance on Schedule B-6.

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[1] Case No. 2018-00294, Order (Ky. PSC Apr. 30, 2019); Case No. 2018-00295, Order (Ky. PSC Apr. 30, 2019).
[2] Case No. 2018-00295, Order (Ky. PSC Apr. 30, 2019).

Louisville Gas & Electric

	a-Aug 2020	Sep 2020	Oct 2020	Nov 2020	Dec 2020	Jan 2021	Feb 2021	Mar 2021	Apr 2021	May 2021	Jun 2021	Jul 2021
Special Funds												
128.1 - Other spec funds - investments-LG&E Electric	23,635	24,573	25,512	26,450	27,388	31,050	31,957	32,864	33,772	34,679	35,586	36,494
128.1 - Other spec funds - investments-LG&E Gas	10,688	11,113	11,537	11,961	12,385	14,041	14,452	14,862	15,272	15,683	16,093	16,503
	34,324	35,686	37,049	38,411	39,773	45,091	46,409	47,726	49,044	50,362	51,679	52,997
Change in forecasted balance from prior month		1,362	1,362	1,362	1,362	5,318	1,318	1,318	1,318	1,318	1,318	1,318
Components of change in balance from prior month:												
Monthly Service Cost, Interest Cost & EROA		(1,362)	(1,362)	(1,362)	(1,362)	1,318	1,318	1,318	1,318	1,318	1,318	1,318
Annual Estimated Contribution					p.6a	4,000						
		(1,362)	(1,362)	(1,362)	(1,362)	5,318	1,318	1,318	1,318	1,318	1,318	1,318

	Aug 2021	Sep 2021	Oct 2021	Nov 2021	Dec 2021	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	13 Month AVG JUN-22
Special Funds												Schedule B-5.2
128.1 - Other spec funds - investments-LG&E Electric	37,401	38,308	39,216	40,123	41,030	44,037	44,977	45,918	46,859	47,799	48,740	42,037
128.1 - Other spec funds - investments-LG&E Gas	16,914	17,324	17,734	18,144	18,555	19,914	20,340	20,765	21,190	21,616	22,041	19,010
	54,314	55,632	56,950	58,267	59,585	63,951	65,317	66,683	68,049	69,415	70,781	61,048
Change in forecasted balance from prior month	1,318	1,318	1,318	1,318	1,318	4,366	1,366	1,366	1,366	1,366	1,366	
Components of change in balance from prior month:												
Monthly Service Cost, Interest Cost & EROA	1,318	1,318	1,318	1,318	1,318	1,366	1,366	1,366	1,366	1,366	1,366	
Annual Estimated Contribution					p.6a	3,000						
	1,318	1,318	1,318	1,318	1,318	4,366	1,366	1,366	1,366	1,366	1,366	

Components of account balance Aug 2020:		
Actuary Report	31,615	p.3
Funded Status	(1,291)	p.4
Pension Contribution	4,000	p.11
	34,324	

Components of Monthly Service Cost, Interest Cost & EROA:	p.5 2020	p.6 2021	p.6 2022
Service Cost	3,445	3,580	3,381
Interest Cost	18,500	17,147	16,504
Estimated Return on Assets	(38,295)	(36,539)	(36,277)
Annual Total	(16,350)	(15,812)	(16,392)
Monthly Total	(1,362)	(1,318)	(1,366)

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.

Kentucky Utilities Company
Prepaid Pension Asset (PPA) Analysis
$ thousands

	Forecasted Test Year 30-Jun-22	
Rate Base / Capitalization Impact:		
PPA - 13 mo. avg	(42,744)	Excel tab-1
ADIT (inclusive of excess ADIT reg. liability)	8,709	Excel tab-5
Total Rate Base / Capitalization (PPA)	(34,036)	
KY Jurisdictional Rate Base Percentage	93.60%	See response to AG-KIUC 1-58 for support for this rate.
KY Jurisdictional Rate Base / Capitalization (PPA)	(31,857)	
Rate of Return - Pretax	9.02%	Excel tab-3
Rev. Requirement Impact of exclusion of PPA in Rate Base / Capitalization	(2,874)	
Net Operating Income Impact:		
Excess ADIT Amortization included in Surcredit	756	Excel tab-5
Gross-Up	1.339047	Sch H-1
Excess ADIT Amortization including gross-up	1,013	
EROA/PBGC	1,871	Excel tab-1
Subotal	2,884	
KY Jurisdictional Percentage	93.60%	
Rev. Requirement offsetting NOI Impact	2,699	
Net Revenue Requirement Change if KY Power method is used	**(174)**	

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.

Louisville Gas and Electric Company
Prepaid Pension Asset (PPA) Analysis

	Forecasted Test Year 30-Jun-22 Electric	Gas	
Rate Base / Capitalization Impact:			
PPA - 13 mo. avg	(42,037)	(19,010)	Excel tab-1
ADIT	8,489	3,557	Excel tab-5
Total Rate Base / Capitalization (PPA)	(33,549)	(15,453)	
Rate of Return - Pretax	8.97%	8.97%	Excel tab-3
Rev. Requirement Impact of exclusion of PPA in Rate Base / Capitalization	(3,009)	(1,386)	
Net Operating Income Impact:			
Excess ADIT Amortization included in Surcredit	825	(78)	Excel tab-5
Gross-Up	1.337837	1.337837	Sch H-1
Excess ADIT Amortization including gross-up	1,103	(105)	
EROA/PBGC	2,212	1,000	Excel tab-1
Rev. Requirement offsetting NOI Impact	3,315	895	
Net Revenue Requirement Change if KY Power method is used	**306**	**(491)**	

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. 25

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

Q-25. Refer to the breakdown of payroll dollars provided in response to AG-KIUC DR 1-42, which appears to combine the costs for LG&E's electric and gas operations. In the same format, provide a breakdown of payroll dollars between O&M expense, capital, and all other by department and in total separately for LG&E's electric and gas operations for each of the years 2015-2019, the forecasted base year and the forecasted test year.

A-25. See attached.

Expenditure Org	Expenditure Org Description	Operating	Mechanism	Below the Line	Other I/S	Capitalized	Other B/S	Total
029645	DATA ANALYTICS - LKS	(10,504)	-	-	-	-	-	(10,504)
029660	DIRECTOR - POWER SUPPLY	901,824	-	-	-	-	-	901,824
029750	PROJECT ENGINEERING	41,556	-	-	-	1,892,437	1,965	1,935,958
029760	GENERATION SAFETY	232,992	-	-	-	7	-	232,999
	Total Base Year Electric Labor	**68,862,465**	**971,678**	**88,433**	**12,271**	**17,254,545**	**14,643,548**	**101,832,941**
	Total Off-Duty	**10,403,535**	**131,367**	**26,040**	**1,154**	**2,506,387**	**2,039,111**	**15,107,594**
	Total Employee Benefits	**27,426,064**	**172,163**	**69,237**	**3,070**	**6,211,787**	**5,423,331**	**39,305,652**
	Total Payroll Taxes	**7,059,584**	**24,165**	**15,047**	**681**	**1,738,728**	**1,285,123**	**10,123,328**
	Total Base Year Electric Payroll Costs	**113,751,648**	**1,299,372**	**198,758**	**17,176**	**27,711,447**	**23,391,112**	**166,369,514**

Expenditure Org	Expenditure Org Description	Operating	Mechanism	Below the Line	Other I/S	Capitalized	Other B/S	Total
026625	TRANSPORT ENGINEERING	107,161	-	-	-	195,378	-	302,539
026630	DATA NETWORKING	129,912	-	-	-	19,723	-	149,635
026635	WORKSTATION ENGINEERING	102,418	-	-	-	(11,816)	-	90,602
026636	IT CIP INFRASTRUCTURE	104,973	-	-	-	3,599	-	108,572
026637	DATA CENTER OPERATIONS	229,321	-	-	-	30,984	-	260,306
026638	GLOBAL NOC	54,645	-	-	-	7,863	-	62,507
026645	UNIFIED COMMUNICATIONS AND COLLABORATION	124,488	-	-	-	8,351	-	132,838
026646	INFRASTRUCTURE SERVICES	216,769	-	-	-	5,915	-	222,684
026680	CLIENT SUPPORT SERVICES	20,879	-	-	-	-	-	20,879
026740	IT SECURITY AND RISK MANAGEMENT	43,072	-	-	-	-	-	43,072
026742	IT SECURITY	153,404	-	-	-	2,330	-	155,734
026744	IT SECURITY RISK MANAGEMENT	94,639	-	-	-	8,998	-	103,637
026760	IT TRAINING	40,380	-	-	-	-	-	40,380
026772	TECHNOLOGY SUPPORT CENTER	118,850	-	-	-	115	-	118,964
026774	DESKTOP OPERATIONS	94,412	-	2	-	29,133	-	123,547
026850	VP EXTERNAL AFFAIRS	-	-	125,889	-	-	-	125,889
026900	LEGAL DEPARTMENT - LKS	318,378	-	-	-	(5,309)	-	313,068
026905	COMPLIANCE DEPT	98,788	-	-	-	-	-	98,788
026910	GENERAL COUNSEL - LKS	49,747	-	-	-	-	-	49,747
026920	DIRECTOR - CORPORATE COMMUNICATION	49,734	-	-	-	-	-	49,734
026925	VP CORPORATE RESPONSIBILITY AND COMMUNITY AFFAIRS	59,290	-	-	-	-	-	59,290
026940	MANAGER EXTERNAL AND BRAND COMMUNICATION	169,670	-	-	-	2,745	-	172,415
027600	IT BUSINESS SERVICES	42,821	-	-	-	-	-	42,821
027610	IT PROJECT MANAGEMENT OFFICE	95,249	-	-	-	59,914	-	155,163
027620	IT BUSINESS ANALYSIS	88,460	-	-	-	43,808	-	132,268
027630	IT QUALITY ASSURANCE	30,764	-	-	-	7,229	-	37,993
027650	IT BUSINESS RELATIONSHIP MGR - CONSOLIDATED	64,958	-	-	-	3,978	-	68,936
027660	IT SERVICE MANAGEMENT	36,340	-	-	-	135	-	36,475
027800	IT APPLICATION PLANNING, EXECUTION AND SUPPORT	8,079	-	-	-	-	-	8,079
027810	IT DEVELOPMENT AND SUPPORT - FINANCIAL APPS	88,939	-	-	-	55,417	-	144,357
027820	IT DEVELOPMENT AND SUPPORT - CUSTOMER SERVICE	135,308	-	-	-	65,397	-	200,705
027840	IT DEVELOPMENT AND SUPPORT - OPERATIONS	133,563	-	-	-	41,283	-	174,846
027850	IT DEVELOPMENT AND SUPPORT - INTERNAL APPS	107,428	-	-	-	16,833	-	124,261
027860	IT DEVELOPMENT AND SUPPORT - MOBILE AND .NET PLATFORMS	119,345	-	-	-	28,044	-	147,389
027870	IT DEVELOPMENT AND SUPPORT	42,089	-	-	-	25,751	-	67,841
029640	SVP ENERGY SUPPLY AND ANALYSIS	13,110	-	-	-	(5,039)	-	8,070
029660	DIRECTOR - POWER SUPPLY	47,089	-	-	-	-	-	47,089
029750	PROJECT ENGINEERING	-	-	-	-	(462,913)	-	(462,913)
029760	GENERATION SAFETY	190	-	-	-	(7)	-	183
	Total Base Year Gas Labor	**29,606,242**	**240,776**	**127,812**	**-**	**8,339,140**	**3,767,111**	**42,081,081**
	Total Off-Duty	**4,299,119**	**54,285**	**10,761**	**477**	**1,035,730**	**842,635**	**6,243,008**
	Total Employee Benefits	**11,333,449**	**71,144**	**28,611**	**1,269**	**2,566,936**	**2,241,118**	**16,242,527**
	Total Payroll Taxes	**2,917,277**	**9,986**	**6,218**	**281**	**718,506**	**531,060**	**4,183,328**
	Total Base Year Gas Payroll Costs	**48,156,087**	**376,191**	**173,402**	**2,027**	**12,660,312**	**7,381,924**	**68,749,944**
	Total Base Year Electric and Gas Payroll Costs	**161,907,735**	**1,675,564**	**372,160**	**19,203**	**40,371,759**	**30,773,036**	**235,119,458**

Expenditure Org	Expenditure Org Description	Operating	Mechanism	Below the Line	Other I/S	Capitalized	Other B/S	Total
026630	DATA NETWORKING	459,534	-	-	-	101,533	-	561,067
026635	WORKSTATION ENGINEERING	325,365	-	-	-	86,006	-	411,372
026636	IT CIP INFRASTRUCTURE	294,582	-	-	-	41,091	-	335,673
026637	DATA CENTER OPERATIONS	789,887	-	-	-	70,760	-	860,647
026638	GLOBAL NOC	183,085	-	-	-	19,435	-	202,520
026645	UNIFIED COMMUNICATIONS AND COLLABORATION	321,911	-	-	-	87,834	-	409,745
026646	INFRASTRUCTURE SERVICES	692,003	-	-	-	10,245	-	702,247
026680	CLIENT SUPPORT SERVICES	69,081	-	-	-	-	-	69,081
026740	IT SECURITY AND RISK MANAGEMENT	134,874	-	-	-	-	-	134,874
026742	IT SECURITY	475,298	-	-	-	11,606	-	486,904
026744	IT SECURITY RISK MANAGEMENT	274,901	-	-	-	40,449	-	315,350
026760	IT TRAINING	125,555	-	-	-	-	-	125,555
026772	TECHNOLOGY SUPPORT CENTER	389,736	-	-	-	-	-	389,736
026774	DESKTOP OPERATIONS	284,287	-	-	-	96,737	-	381,024
026900	LEGAL DEPARTMENT - LKS	754,438	-	-	-	19,553	-	773,991
026905	COMPLIANCE DEPT	309,770	-	-	-	-	-	309,770
026910	GENERAL COUNSEL - LKS	126,844	-	-	-	-	-	126,844
026920	DIRECTOR - CORPORATE COMMUNICATION	134,566	-	-	-	-	-	134,566
026925	VP CORPORATE RESPONSIBILITY AND COMMUNITY AFFAIRS	182,227	-	-	-	-	-	182,227
026940	MANAGER EXTERNAL AND BRAND COMMUNICATION	523,670	-	-	-	-	-	523,670
027600	IT BUSINESS SERVICES	151,445	-	-	-	-	-	151,445
027610	IT PROJECT MANAGEMENT OFFICE	435,738	-	-	-	202,711	-	638,449
027620	IT BUSINESS ANALYSIS	285,531	-	-	-	214,368	-	499,899
027630	IT QUALITY ASSURANCE	58,809	-	-	-	69,345	-	128,154
027650	IT BUSINESS RELATIONSHIP MGR - CONSOLIDATED	252,558	-	-	-	-	-	252,558
027660	IT SERVICE MANAGEMENT	103,328	-	-	-	-	-	103,328
027810	IT DEVELOPMENT AND SUPPORT - FINANCIAL APPS	440,839	-	-	-	55,833	-	496,671
027820	IT DEVELOPMENT AND SUPPORT - CUSTOMER SERVICE	90,338	-	-	-	519,324	-	609,661
027840	IT DEVELOPMENT AND SUPPORT - OPERATIONS	400,643	-	-	-	218,102	-	618,744
027850	IT DEVELOPMENT AND SUPPORT - INTERNAL APPS	379,882	-	-	-	40,978	-	420,860
027860	IT DEVELOPMENT AND SUPPORT - MOBILE AND .NET PLATFORMS	452,853	-	-	-	107,620	-	560,473
027870	IT DEVELOPMENT AND SUPPORT	203,725	-	-	-	65,538	-	269,263
029640	SVP ENERGY SUPPLY AND ANALYSIS	76,108	-	-	-	18,462	-	94,570
029645	DATA ANALYTICS - LKS	176,564	-	-	-	-	-	176,564
029660	DIRECTOR - POWER SUPPLY	965,888	-	-	-	-	-	965,888
029750	PROJECT ENGINEERING	56,527	-	-	-	1,888,035	-	1,944,563
029760	GENERATION SAFETY	224,775	-	-	-	-	-	224,775
	Total Test Year Electric Labor	**72,925,474**	**443,065**	**-**	**13,200**	**16,666,392**	**15,235,256**	**105,283,387**
	Total Off-Duty	**11,414,746**	**75,334**	**25,364**	**-**	**2,365,522**	**2,235,198**	**16,116,164**
	Total Employee Benefits	**31,975,365**	**203,715**	**68,401**	**-**	**6,521,407**	**5,629,371**	**44,398,259**
	Total Payroll Taxes	**7,403,784**	**48,076**	**14,144**	**-**	**1,694,765**	**1,351,897**	**10,512,667**
	Total Test Year Electric Payroll Costs	**123,719,368**	**770,191**	**107,910**	**13,200**	**27,248,086**	**24,451,722**	**176,310,477**

Expenditure Org	Expenditure Org Description	Operating	Mechanism	Below the Line	Other I/S	Capitalized	Other B/S	Total
026135	DIRECTOR - ACCOUNTING AND REGULATORY REPORTING	22,919	-	-	-	-	-	22,919
026140	MANAGER - FINANCIAL PLANNING	71,336	-	-	-	-	-	71,336
026145	SHARED SERVICES & CORPORATE BUDGETING	64,339	-	-	-	-	-	64,339
026155	FINANCIAL REPORTING	55,637	-	-	-	-	-	55,637
026160	REGULATORY ACCOUNTING AND REPORTING	65,510	-	-	-	-	-	65,510
026170	MANAGER - CUSTOMER ACCOUNTING	522,884	-	-	-	-	-	522,884
026175	TRANSMISSION, GAS, & ES BUDGETING	129,065	-	-	-	-	-	129,065
026190	CORPORATE ACCOUNTING	77,623	-	-	-	-	-	77,623
026200	SUPPLY CHAIN SUPPORT	78,181	-	-	-	-	1,279	79,460
026310	MANAGER PAYROLL	51,263	-	-	-	-	-	51,263
026330	TREASURER	35,492	-	-	-	-	-	35,492
026350	RISK MANAGEMENT	32,677	-	-	-	-	-	32,677
026370	CORPORATE FINANCE	51,756	-	-	-	-	-	51,756
026390	CREDIT/CONTRACT ADMINISTRATION	37,055	-	-	-	-	-	37,055
026400	AUDIT SERVICES	132,639	-	-	-	-	-	132,639
026490	CHIEF INFORMATION OFFICER	34,782	-	-	-	-	-	34,782
026600	IT INFRASTRUCTURE AND OPERATIONS	100,885	-	-	-	8,778	-	109,663
026625	TRANSPORT ENGINEERING	117,719	-	-	-	43,611	-	161,330
026630	DATA NETWORKING	153,178	-	-	-	45,616	-	198,794
026635	WORKSTATION ENGINEERING	108,455	-	-	-	38,640	-	147,096
026636	IT CIP INFRASTRUCTURE	98,194	-	-	-	18,461	-	116,655
026637	DATA CENTER OPERATIONS	263,296	-	-	-	31,791	-	295,086
026638	GLOBAL NOC	61,028	-	-	-	8,732	-	69,760
026645	UNIFIED COMMUNICATIONS AND COLLABORATION	107,304	-	-	-	39,462	-	146,765
026646	INFRASTRUCTURE SERVICES	230,668	-	-	-	4,603	-	235,270
026680	CLIENT SUPPORT SERVICES	23,027	-	-	-	-	-	23,027
026740	IT SECURITY AND RISK MANAGEMENT	44,958	-	-	-	-	-	44,958
026742	IT SECURITY	158,433	-	-	-	5,214	-	163,647
026744	IT SECURITY RISK MANAGEMENT	91,634	-	-	-	18,173	-	109,806
026760	IT TRAINING	41,852	-	-	-	-	-	41,852
026772	TECHNOLOGY SUPPORT CENTER	129,912	-	-	-	-	-	129,912
026774	DESKTOP OPERATIONS	94,762	-	-	-	43,462	-	138,224
026850	VP EXTERNAL AFFAIRS	-	-	211,207	-	-	-	211,207
026900	LEGAL DEPARTMENT - LKS	251,479	-	-	-	-	-	251,479
026905	COMPLIANCE DEPT	103,257	-	-	-	-	-	103,257
026910	GENERAL COUNSEL - LKS	42,281	-	-	-	-	-	42,281
026920	DIRECTOR - CORPORATE COMMUNICATION	44,855	-	-	-	-	-	44,855
026925	VP CORPORATE RESPONSIBILITY AND COMMUNITY AFFAIRS	60,742	-	-	-	-	-	60,742
026940	MANAGER EXTERNAL AND BRAND COMMUNICATION	174,557	-	-	-	-	-	174,557
027600	IT BUSINESS SERVICES	50,482	-	-	-	-	-	50,482
027610	IT PROJECT MANAGEMENT OFFICE	145,246	-	-	-	91,073	-	236,319
027620	IT BUSINESS ANALYSIS	95,177	-	-	-	96,310	-	191,487
027630	IT QUALITY ASSURANCE	19,603	-	-	-	31,155	-	50,758
027650	IT BUSINESS RELATIONSHIP MGR - CONSOLIDATED	84,186	-	-	-	-	-	84,186
027660	IT SERVICE MANAGEMENT	34,443	-	-	-	-	-	34,443
027810	IT DEVELOPMENT AND SUPPORT - FINANCIAL APPS	146,946	-	-	-	25,084	-	172,030
027820	IT DEVELOPMENT AND SUPPORT - CUSTOMER SERVICE	30,113	-	-	-	233,319	-	263,432
027840	IT DEVELOPMENT AND SUPPORT - OPERATIONS	133,548	-	-	-	97,988	-	231,535
027850	IT DEVELOPMENT AND SUPPORT - INTERNAL APPS	126,627	-	-	-	18,411	-	145,038
027860	IT DEVELOPMENT AND SUPPORT - MOBILE AND .NET PLATFORMS	150,951	-	-	-	48,351	-	199,302
027870	IT DEVELOPMENT AND SUPPORT	67,908	-	-	-	29,445	-	97,353
	Total Test Year Gas Labor	**30,918,739**	**240,399**	**211,207**	**-**	**7,094,790**	**4,062,128**	**42,527,263**
	Total Off-Duty	**4,610,774**	**30,430**	**10,245**	**-**	**955,509**	**902,867**	**6,509,824**
	Total Employee Benefits	**12,915,853**	**82,287**	**27,629**	**-**	**2,634,201**	**2,273,879**	**17,933,850**
	Total Payroll Taxes	**2,990,620**	**19,420**	**5,713**	**-**	**684,569**	**546,074**	**4,246,396**
	Total Test Year Gas Payroll Costs	**51,435,987**	**372,535**	**254,795**	**-**	**11,369,069**	**7,784,948**	**71,217,333**
	Total Test Year Electric and Gas Payroll Costs	**175,155,355**	**1,142,726**	**362,705**	**13,200**	**38,617,155**	**32,236,670**	**247,527,811**

Most other labor costs are not allocated to the expenditure org (department) level and are accounted for in Corporate.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Second Request for Information of the
United States Department of Defense and All Other Federal Executive Agencies
Dated February 5, 2021

Case No. 2020-00350

Question No. 9

Responding Witness: William Steven Seelye

Q-2-9. LG&E separates service into functional components: production, transmission and distribution. Does LG&E agree that the transmission function acts as a delivery component which transports production from a generation source to the distribution point? Please explain your answer.

A-2-9. Yes. The loads at the distribution points on the LG&E and KU's transmission system are an important factor in designing capacity on the transmission system. Ultimately, the loads at the distribution points determine the level of capacity needed to deliver power on the transmission system from the generation system to the load centers. However, with the emergence of distributed generation and distributed battery storage the delivery of power from a generation source to distribution points can also take place on a utility's distribution system.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Second Request for Information of the
United States Department of Defense and All Other Federal Executive Agencies
Dated February 5, 2021

Case No. 2020-00350

Question No. 10

Responding Witness: Lonnie E. Bellar

Q-2-10. Concerning the design of adequate capacity to operate transmission functional infrastructure, does LG&E design the capacity requirements for transmission assets based on single, coincident peak demand on the facility for that over multiple months. Please explain your answer and identify the number of months typically considered in designing the load serving capacity of transmission facilities.

A-2-10. The annual transmission expansion planning process considers multiple coincident peak demand forecasts over the next ten-year planning horizon. The process doesn't identify the number of months, but rather, peak loads which could occur during the applicable peak season. Specifically, an expected load forecast and a high load forecast are analyzed for the winter and summer peak seasons in years 1, 2, 5, and 10 to ensure customer demand can be met.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Second Request for Information of the
United States Department of Defense and All Other Federal Executive Agencies
Dated February 5, 2021

Case No. 2020-00350

Question No. 11

Responding Witness: Lonnie E. Bellar / William Steven Seelye

Q-2-11. Concerning the production and transmission functionalization of electric service, does LG&E agree that to the extent one customer modifies their demands on the system which reduces demands on production and transmission facilities, would that free up production and transmission capacity that can be used to provide service to other customers. Please explain your answer.

A-2-11. No, not without certain qualifications. Depending on the location of the customer's load, reductions in demand may not free up capacity on the transmission system. Furthermore, depending on the time period during which a customer reduces its demand, any such reduction may not provide additional benefits to the generation or transmission system. For example, if the customer reduces its demand during off-peak periods, or when either the transmission or generation system is not operating at full capacity, then any capacity that is freed up would not necessarily be used to provide service to other customers.

KENTUCKY UTILITIES COMPANY

Response to Second Request for Information of the United States Department of Defense and All Other Federal Executive Agencies Dated February 5, 2021

Case No. 2020-00349

Question No. 17

Responding Witness: Daniel K. Arbough

Q-2-17. Please provide the amount of pension expense that was approved in the Company's last base rate case and is currently being recovered in rates. If this amount is not available, please provide the most recent Commission approved level of pension expense and the Order where it was approved.

A-2-17. The amount of pension expense that was included in the test year in KU Case No. 2018-00294 test year was $3,803,093.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Second Request for Information of the
United States Department of Defense and All Other Federal Executive Agencies
Dated February 5, 2021

Case No. 2020-00350

Question No. 17

Responding Witness: Daniel K. Arbough

Q-2-17. Please provide the amount of pension expense that was approved in the Company's last base rate case and is currently being recovered in rates. If this amount is not available, please provide the most recent Commission approved level of pension expense and the Order where it was approved.

A-2-17. The amount of pension expense that was included in the test year in LG&E Case No. 2018-00295 was $3,679,425.

KENTUCKY UTILITIES COMPANY

Response to Second Request for Information of the United States Department of Defense and All Other Federal Executive Agencies Dated February 5, 2021

Case No. 2020-00349

Question No. 18

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

Q-2-18. Referring to the $30,691,840 base period prepaid pension asset included on Schedule B-5.2, page 2, please answer the following questions:

a. Cite all Commission orders that allow for the inclusion of a prepaid pension asset in rate base.

b. Provide workpapers in Microsoft Excel, with all formulas intact, supporting the development of the prepaid pension asset.

c. If not already provided in response to part b., please provide workpapers in Microsoft Excel, with all formulas intact, showing the development of the prepaid pension asset, annual pension expense, and pension trust funding on an annual basis since inception and over the period where the prepaid asset balance was accumulated up through the end of the base period.

d. If not already provided in response to part b., please separately identify annual cash contributions by the Company, excess returns earned on the prepaid pension asset, and other factors (explain) that resulted in annual changes to the prepaid pension asset since inception and through the end of the base period.

e. Please identify the amount of discretionary contributions the Company has made to the prepaid pension asset since inception and through the end of the base period.

f. Please identify the ERISA minimum pension contribution since inception and through the end of the base period.

g. Please provide the amount of the prepaid pension asset at the end of the base period if the Company only made the ERISA minimum contribution.

A-2-18.

a. The Companies have included the prepaid pension asset in rate base as part of the balance sheet analyses of cash working capital consistent with the treatment utilized in the previous base rate cases, Case Nos. 2018-00294 and 2018-00295. See the response to AG-KIUC 2-11 for an analysis of the inclusion of the prepaid pension asset in rate base.

   In Kentucky-American Water's ("KAW") 1997 rate case, the Attorney General recommended that KAW's rate base be reduced to reflect its accrued pension liability. KAW agreed with the AG's adjustment "providing the Commission also finds that if the accrued balance reverses in the future and a pension asset is created, then the asset should be included as a base rate addition."[1] The Commission agreed with KAW "because it would be unfair to its stockholders to recognize the accrued pension balance only when it results in a rate base reduction."[2]

   KU further notes that it has used capitalization, not rate base, as its valuation method for the past 40 years. KU believes that capitalization remains the most objective measure of valuation and sees no reason to transition away from capitalization.

b. The $30,691,840 base period prepaid pension asset included on Schedule B-5.2, page 2, is the thirteen-month average of the actual and forecasted balance of the FERC 128 account. See attachment #1, provided in Excel format, which shows the development of the prepaid pension asset from 2019 when KU's allocation of the pension plan was in a liability position to the forecasted prepaid pension balances as of February 2021. Attachment #2 provides supporting information for attachment #1.

   The combination of the service cost, interest cost, and estimated return on assets components of pension cost for 2019 along with the impact of the actuarial re-valuation of the plan resulted in KU's allocation of the pension plan changing from a liability balance to a prepaid balance.

c. The development of the prepaid asset and pension trust funding are provided in part b. See attachment #1, provided in Excel format, for annual pension expense for 2019-2021.

d. Cash contributions to the pension plan are provided in part b. The returns on the pension assets are included in the calculation of the market related value of the assets, which is calculated by the Company's actuaries. The Company does not have an actuarial calculation isolating the excess returns on the

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[1] *Application of Kentucky-American Water Company to Increase Its Rates,* Case No. 97-034, Order at 29-30 (Ky. PSC Sept. 30, 1997).
[2] *Id.*

prepaid pension assets. There are no other factors which resulted in changes to the prepaid pension assets other than those noted in the development of the pension assets provided in part b.

e. KU made cash contributions to its pension plan in the following amounts in 2019 and 2020.

KU	2019	2020
Cash Contributions	-	3,000,000

f. Financial reporting under U.S. GAAP is completed at the company level, so financial reporting information is readily available for KU. However, minimum required contributions for LG&E and KU Energy's defined benefit retirement plan are determined only at the plan level based on ERISA minimum funding regulations. As such, minimum required contributions are not available explicitly by company.

g. The Company is not able to provide this calculation as explained in part f.

Case No. 2020-00349
Attachment 1 to Response to DOD-2 Question No. 18b
Page 1 of 2
Arbough and Garrett

Kentucky Utilities

	a-Feb 2020	a-Mar 2020	a-Apr 2020	a-May 2020	a-Jun 2020	a-Jul 2020	a-Aug 2020	Sep 2020	Oct 2020	Nov 2020	Dec 2020	Jan 2021	Feb 2021	13 Month AVG Feb-21
Special Funds														
128.1 - Other spec funds - investments	30,690	31,690	30,690	30,690	28,540	27,540	28,540	29,273	30,006	30,739	31,472	34,198	34,924	30,692
														Schedule B-5.2

Development of the Prepaid Pension Asset:

1/1/2019	Accumulated (liability)/prepaid	(1,499)	pdf p.1
2019	Service Cost, Interest Cost & EROA	7,944	
2019	Funded Status Adjustments	24,245	
12/31/2019	Accumulated (liability)/prepaid	30,690	See response to AG-KIUC 2-54 pdf p.15 for support for this amount.
2020	Service Cost, Interest Cost & EROA	0	**
2020	Funded Status Adjustments	(3,150)	See response to AG-KIUC 2-54 pdf p.17 for support for this amount.
2020	Contribution	1,000	See response to AG-KIUC 2-54 pdf p.34 for support for this amount.
8/31/2020	Accumulated (liability)/prepaid	28,540	
2020	Service Cost, Interest Cost & EROA	2,933	**
12/31/2020	Accumulated (liability)/prepaid	31,472	
2021	Service Cost, Interest Cost & EROA	1,452	**
2021	Contribution	2,000	See response to AG-KIUC 2-54 pdf p.22 for support for this amount.
2/28/2021	Accumulated (liability)/prepaid	34,924	

Components of Monthly Service Cost, Interest Cost & EROA:	pdf p.2 Jan-Dec 2019	Sept-Dec 2020	See response to AG-KIUC 2-54 pdf p.18 for support for these amounts.	Jan-Feb 2021	See response to AG-KIUC 2-54 pdf p.21 for support for these amounts.
Service Cost	6,397	6,753		6,608	
Interest Cost	16,786	14,625		13,752	
Estimated Return on Assets	(31,128)	(30,175)		(29,069)	
Annual Total	(7,944)	(8,798)		(8,709)	
# of Months Included	12	4		2	
Monthly Total	(7,944)	(2,933)		(1,452)	

Components of Funded Status	2019	
Actuary Report	30,690	See response to AG-KIUC 2-54 pdf p.15 for support for this amount.
Preliminary Trial Balance	(704)	pdf p.3
Amortization of Prior Service Cost	(565)	pdf p.2
Amortization of Gains and Losses	(5,176)	pdf p.2
	24,245	

** Note: Service Cost, Interest Cost & EROA are tracked in FERC 184 accounts during the year and are only closed to the prepaid or liability balance at year end; therefore they are not included in August actual amounts for FERC 128. However, for forecasting purposes, they are closed to either the prepaid or liability balance on a monthly basis.

Annual Pension Expense 2019-2021

2019 Actual	
Total KU	FERC Subaccount
$ 4,326,419	926101 - PENSION SERVICE COST - BURDENS
105,555	926196 - PENSION EXP- VA
25,906	926197 - PENSION EXP- FERC AND TENN.
(5,541,740)	926198 - PENSION NON SERVICE COST - BURDENS
4,488,967	926911 - PENSION SERVICE COST - BURDENS INDIRECT
475,461	926998 - PENSION NON SERVICE COSTS - BURDENS INDIRECT
$ 3,880,568	Total KU

2020 Actual	
Total KU	FERC Subaccount
$ 4,599,180	926101 - PENSION SERVICE COST - BURDENS
586,038	926196 - PENSION EXP- VA
144,718	926197 - PENSION EXP- FERC AND TENN.
(4,666,358)	926198 - PENSION NON SERVICE COST - BURDENS
5,000,926	926911 - PENSION SERVICE COST - BURDENS INDIRECT
834,952	926998 - PENSION NON SERVICE COSTS - BURDENS INDIRECT
$ 6,499,456	Total KU

2021 Estimated	
Total KU	FERC Subaccount
$ 9,334,130	926101 - PENSION SERVICE COST - BURDENS
283,272	926197 - PENSION EXP- FERC AND TENN.
(1,490,545)	926198 - PENSION NON SERVICE COST - BURDENS
(11,020)	926911 - PENSION SERVICE COST - BURDENS INDIRECT
$ 8,115,837	Total KU

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Second Request for Information of the
United States Department of Defense and All Other Federal Executive Agencies
Dated February 5, 2021

Case No. 2020-00350

Question No. 18

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

Q-2-18. Referring to the $25,629,156 base period prepaid pension asset included on Schedule B-5.2, page 2, please answer the following questions:

a. Cite all Commission orders that allow for the inclusion of a prepaid pension asset in rate base.

b. Provide workpapers in Microsoft Excel, with all formulas intact, supporting the development of the prepaid pension asset.

c. If not already provided in response to part b., please provide workpapers in Microsoft Excel, with all formulas intact, showing the development of the prepaid pension asset, annual pension expense, and pension trust funding, on an annual basis since inception and over the period where the prepaid asset balance was accumulated up through the end of the base period.

d. If not already provided in response to part b., please separately identify annual cash contributions by the Company, excess returns earned on the prepaid pension asset, and other factors (explain) that resulted in annual changes to the prepaid pension asset since inception and through the end of the base period.

e. Please identify the amount of discretionary contributions the Company has made to the prepaid pension asset since inception and through the end of the base period.

f. Please identify the ERISA minimum pension contribution since inception and through the end of the base period.

g. Please provide the amount of the prepaid pension asset at the end of the base period if the Company only made the ERISA minimum contribution

A-2-18.

a. The Companies have included the prepaid pension asset in rate base as part of the balance sheet analyses of cash working capital consistent with the treatment utilized in the previous base rate cases, Case Nos. 2018-00294 and 2018-00295. See the response to AG-KIUC 2-11 for an analysis of the inclusion of the prepaid pension asset in rate base.

   In Kentucky-American Water's ("KAW") 1997 rate case, the Attorney General recommended that KAW's rate base be reduced to reflect its accrued pension liability. KAW agreed with the AG's adjustment "providing the Commission also finds that if the accrued balance reverses in the future and a pension asset is created, then the asset should be included as a base rate addition."[1] The Commission agreed with KAW "because it would be unfair to its stockholders to recognize the accrued pension balance only when it results in a rate base reduction."[2]

   LG&E further notes that it has used capitalization, not rate base, as its valuation method for the past 40 years. LG&E believes that capitalization remains the most objective measure of valuation and sees no reason to transition away from capitalization.

b. The $25,629,156 base period prepaid pension asset included on Schedule B-5.2, page 2, is the thirteen-month average of the actual and forecasted balance of the FERC 128 account which was allocated to electric operations. See attachment #1, provided in Excel format, which shows the development of the prepaid pension asset from 2019 when LG&E's allocation of the pension plan was in a liability position to the forecasted prepaid pension balances as of February 2021. Attachment #2 provides supporting information for attachment #1.

   The combination of the service cost, interest cost, and estimated return on assets components of pension cost for 2019 along with the impact of the actuarial re-valuation of the plan resulted in LG&E's allocation of the pension plan changing from a liability balance to a prepaid balance.

c. The development of the prepaid asset and pension trust funding are provided in part b. See attachment #1, provided in Excel format, for annual pension expense for 2019-2021.

d. Cash contributions to the pension plan are provided in part b. The returns on the pension assets are included in the calculation of the market related value of the assets, which is calculated by the Company's actuaries. The Company does

[1] *Application of Kentucky-American Water Company to Increase Its Rates,* Case No. 97-034, Order at 29-30 (Ky. PSC Sept. 30, 1997).
[2] *Id.*

not have an actuarial calculation isolating the excess returns on the prepaid pension assets. There are no other factors which resulted in changes to the prepaid pension assets other than those noted in the development of the pension assets provided in part b.

e. LG&E made cash contributions to its pension plans in the following amounts in 2019 and 2020.

LGE	2019	2020
Cash Contributions	650,363	8,000,000

f. Financial reporting under U.S. GAAP is completed at the company level, so financial reporting information is readily available for LG&E. However, minimum required contributions for LG&E and KU Energy's defined benefit retirement plan (and prior to January 1, 2020, LG&E's defined benefit retirement plan) are determined only at the plan level based on ERISA minimum funding regulations. As such, minimum required contributions are not available explicitly by company.

g. The Company is not able to provide this calculation as explained in part f.

Louisville Gas & Electric

	a-Feb 2020	a-Mar 2020	a-Apr 2020	a-May 2020	a-Jun 2020	a-Jul 2020	a-Aug 2020	Sep 2020	Oct 2020	Nov 2020	Dec 2020	Jan 2021	Feb 2021	**13 Month AVG Feb-2021**	
Special Funds															
128.1 - Other spec funds - investments-LG&E Elect	21,770	24,525	24,525	24,525	23,635	23,635	23,635	24,573	25,512	26,450	27,388	31,050	31,957	25,629	Schedule B-5.2
128.1 - Other spec funds - investments-LG&E Gas	9,845	11,091	11,091	11,091	10,688	10,688	10,688	11,113	11,537	11,961	12,385	14,041	14,452	11,590	Schedule B-5.2
	31,615	35,615	35,615	35,615	34,324	34,324	34,324	35,686	37,049	38,411	39,773	45,091	46,409		

1/1/2019	Accumulated (liability)/prepaid	(10,619)	pdf p.1
2019	Service Cost, Interest Cost & EROA	14,834	
2019	Funded Status Adjustments	26,750	
2019	Contribution	650	pdf p.2
12/31/2019	Accumulated (liability)/prepaid	31,615	See response to AG-KIUC 2-54 pdf p.14 for support for this amount.
2020	Service Cost, Interest Cost & EROA	0	**
2020	Funded Status Adjustments	(1,291)	See response to AG-KIUC 2-54 pdf p.16 for support for this amount.
2020	Contribution	4,000	See response to AG-KIUC 2-54 pdf p.34 for support for this amount.
8/31/2020	Accumulated (liability)/prepaid	34,323	
2020	Service Cost, Interest Cost & EROA	5,450	**
12/31/2020	Accumulated (liability)/prepaid	39,773	
2021	Service Cost, Interest Cost & EROA	2,635	**
2021	Contribution	4,000	See response to AG-KIUC 2-54 pdf p.21 for support for this amount.
2/28/2020	Accumulated (liability)/prepaid	46,409	

Components of Monthly Service Cost, Interest Cost & EROA:	GE Non-Union 2019	LGE Union 2019	LGE Total Jan-Dec 2019	Aug-Nov 2020		Jan-Feb 2021	
	pdf p.3	pdf p.4			See response to AG-KIUC 2-54 pdf p.17 for support for these amounts.		See response to AG-KIUC 2-54 pdf p.20 for support for these amounts.
Service Cost	1,942	1,154	3,096	3,445		3,580	
Interest Cost	9,910	11,008	20,918	18,500		17,147	
Estimated Return on Assets	(17,612)	(21,236)	(38,848)	(38,295)		(36,539)	
Annual Total	(5,760)	(9,074)	(14,834)	(16,350)		(15,812)	
# of Months Included			12	4		2	
Monthly Total			(14,834)	(5,450)		(2,635)	

Components of Funded Status Adjustments	LGE Non-Union 2019	
Actuary Report	31,615	See response to AG-KIUC 2-54 pdf p.14 for support for this amount.
Transfer to 228 FERC to 128 FERC	11,350	pdf p.5
Amortization of Prior Service Cost LGE Non-Union	(410)	pdf p.3
Amortization of Gains and Losses LGE Non-Union	(4,550)	pdf p.3
Amortization of Prior Service Cost LGE Union	(5,218)	pdf p.4
Amortization of Gains and Losses LGE Union	(6,038)	pdf p.4
	26,750	

** Note: Service Cost, Interest Cost & EROA are tracked in FERC 184 accounts during the year and are only closed to the prepaid or liability balance at year end; therefore they are not included in August actual amounts for FERC 128. However, for forecasting purposes, they are closed to either the prepaid or liability balance on a monthly basis.

Annual Pension Expense 2019-2021

2019 Actual			
Electric	Gas	Total LGE	FERC Subaccount
$ 1,269,619	$ 712,699	$ 1,982,318	926101 - PENSION SERVICE COST - BURDENS
(729,028)	(358,596)	(1,087,624)	926198 - PENSION NON SERVICE COST - BURDENS
3,065,056	667,048	3,732,104	926911 - PENSION SERVICE COST - BURDENS INDIRECT
322,442	70,971	393,413	926998 - PENSION NON SERVICE COSTS - BURDENS INDIRECT
$ 3,928,089	$ 1,092,122	$ 5,020,211	Total LGE

2020 Actual			
Electric	Gas	Total LGE	FERC Subaccount
$ 1,367,183	$ 824,551	$ 2,191,734	926101 - PENSION SERVICE COST - BURDENS
(807,652)	(387,894)	(1,195,546)	926198 - PENSION NON SERVICE COST - BURDENS
3,424,108	798,143	4,222,251	926911 - PENSION SERVICE COST - BURDENS INDIRECT
567,439	129,441	696,880	926998 - PENSION NON SERVICE COSTS - BURDENS INDIRECT
$ 4,551,078	$ 1,364,241	$ 5,915,319	Total LGE

2021 Estimated			
Common	Electric	Total LGE	FERC Subaccount
$ 6,969,973	$ (538,047)	$ 6,431,926	926101 - PENSION SERVICE COST - BURDENS
1,784,755		1,784,755	926198 - PENSION NON SERVICE COST - BURDENS
	16,887	16,887	926117 - CLOSED 05/18 - PENSION NON SERVICE COST - BURDENS
$ 8,754,728	$ (521,160)	$ 8,233,568	Total LGE

KENTUCKY UTILITIES COMPANY

Response to Second Request for Information of the
United States Department of Defense and All Other Federal Executive Agencies
Dated February 5, 2021

Case No. 2020-00349

Question No. 26

Responding Witness: Kent W. Blake

Q-2-26. Please provide a copy of Exhibit KWB-1 that includes only KU costs.

A-2-26. See the attachment being provided in Excel format. Exhibit KWB-1 was prepared for these proceedings on a combined utility basis. In order to be responsive to this request, the attachment includes an allocation of all costs capitalized within CWIP, regulatory assets, regulatory liabilities, and accumulated deferred income taxes between LG&E and KU such that, when combined, the figures shown tie to the as filed Exhibit KWB-1.

KU
AMI Project Ratemaking
Implementation Period

	Implementation Period					
	7/1/21 to 6/30/22	7/1/22 to 6/30/23	7/1/23 to 6/30/24	7/1/24 to 6/30/25	7/1/25 to 6/30/26	Total
CWIP						
Capital Expenditures	$20,433,485	$39,107,491	$41,832,230	$35,394,704	$18,582,840	$155,350,751
Capitalized Property Taxes	12,938	147,814	535,579	1,100,900	2,801,195	4,598,426
AFUDC - Equity (FERC)	378,781	1,447,968	2,972,881	4,194,307	3,933,211	12,927,148
AFUDC - Debt (FERC)	148,552	566,765	1,193,170	1,788,131	1,720,434	5,417,052
	$20,973,756	$41,270,038	$46,533,860	$42,478,042	$27,037,681	**$178,293,377**
Regulatory Liability - Meter Reading & Field Services	($840,375)	($3,737,240)	($8,324,416)	($11,434,634)	($13,690,910)	**($38,027,575)**
Regulatory Assets						
AMI Implementation Expenses	$1,496,063	$4,988,402	$5,396,079	$4,828,391	$3,816,618	$20,525,553
Remaining Net Book Value - Retired & Replaced Meters						18,492,138
AFUDC - Equity (WACC>FERC)	207,071	626,460	1,320,743	2,218,694	1,979,081	6,352,050
AFUDC - Debt (WACC > FERC)	58,687	167,043	325,657	480,404	370,621	1,402,412
	$1,761,822	$5,781,906	$7,042,479	$7,527,488	$6,166,320	**$46,772,154**
ADIT - Retired & Replaced Meters						($5,370,092)
ADIT - AMI Placed In Service For Income Tax Purposes						($19,540,420)
Total AMI Capitalization						**$162,127,443**

Assumptions and Information

Implementation Start Date (w/ 3 month mobilization)	7/1/2021				
Implementation Completion Date	3/31/2026				
Return on Equity	10.00%				
Average Cost of Debt	4.02%				
Capital Structure	53:47				
Income Tax Rate	24.95%				
Blended Property Tax Rate	1.57%	1.59%	1.61%	1.63%	1.76%
AFUDC Average Equity Rate (FERC)	3.46%	3.73%	3.70%	3.50%	3.56%
AFUDC Average Debt Rate (FERC)	1.36%	1.46%	1.49%	1.49%	1.56%
AFUDC Average Equity Rate (WACC)	5.34%	5.34%	5.34%	5.34%	5.34%
AFUDC Average Debt Rate (WACC)	1.89%	1.89%	1.89%	1.89%	1.89%
Monthly Average CWIP Balance	$10,963,264	$38,819,515	$80,348,133	$120,008,794	$147,518,477
Beginning of Year CWIP Subject to Prop Tax (2022-2026)	$1,653,404	$16,997,613	$49,776,798	$85,755,852	$119,332,925

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Second Request for Information of the
United States Department of Defense and All Other Federal Executive Agencies
Dated February 5, 2021

Case No. 2020-00350

Question No. 26

Responding Witness: Kent W. Blake

Q-2-26. Please provide a copy of Exhibit KWB-1 that includes only LG&E costs.

A-2-26. See the attachment being provided in Excel format. Exhibit KWB-1 was prepared for these proceedings on a combined utility basis. In order to be responsive to this request, the attachment includes an allocation of all costs capitalized within CWIP, regulatory assets, regulatory liabilities, and accumulated deferred income taxes between LG&E and KU such that, when combined, the figures shown tie to the as filed Exhibit KWB-1.

LG&E
AMI Project Ratemaking
Implementation Period

	Implementation Period					
	7/1/21 to 6/30/22	7/1/22 to 6/30/23	7/1/23 to 6/30/24	7/1/24 to 6/30/25	7/1/25 to 6/30/26	Total
CWIP						
Capital Expenditures	$17,781,556	$39,853,620	$40,814,413	$31,631,345	$17,071,378	$147,152,313
Capitalized Property Taxes	11,042	189,969	712,488	1,425,745	3,116,894	5,456,139
AFUDC - Equity (FERC)	208,191	1,251,632	3,419,967	5,387,613	5,272,120	15,539,523
AFUDC - Debt (FERC)	91,199	483,916	1,247,190	1,938,156	1,865,681	5,626,141
	$18,091,987	$41,779,137	$46,194,059	$40,382,860	$27,326,073	**$173,774,117**
Regulatory Liability - Meter Reading & Field Services	($398,794)	($2,847,602)	($6,026,218)	($7,906,001)	($9,323,409)	**($26,502,024)**
Regulatory Assets						
AMI Implementation Expenses	$1,317,060	$4,329,864	$4,476,131	$3,417,661	$2,701,198	$16,241,914
Remaining Net Book Value - Retired & Replaced Meters						8,347,825
AFUDC - Equity (WACC>FERC)	284,077	692,682	771,670	777,311	328,880	2,854,620
AFUDC - Debt (WACC > FERC)	78,740	187,294	199,833	190,079	67,878	723,824
	$1,679,877	$5,209,840	$5,447,635	$4,385,051	$3,097,956	**$28,168,183**
ADIT - Retired & Replaced Meters						($2,319,129)
ADIT - AMI Placed In Service For Income Tax Purposes						($18,420,670)
Total AMI Capitalization						**$154,700,477**

Assumptions and Information					
Implementation Start Date (w/ 3 month mobilization)	7/1/2021				
Implementation Completion Date	3/31/2026				
Return on Equity	10.00%				
Average Cost of Debt	4.02%				
Capital Structure	53:47				
Income Tax Rate	24.95%				
Blended Property Tax Rate	1.83%	1.86%	1.88%	1.91%	1.76%
AFUDC Average Equity Rate (FERC)	2.26%	3.44%	4.36%	4.67%	5.03%
AFUDC Average Debt Rate (FERC)	0.99%	1.33%	1.59%	1.68%	1.78%
AFUDC Average Equity Rate (WACC)	5.34%	5.34%	5.34%	5.34%	5.34%
AFUDC Average Debt Rate (WACC)	1.84%	1.84%	1.84%	1.84%	1.84%
Monthly Average CWIP Balance	$9,211,973	$36,384,663	$78,439,619	$115,366,451	$139,751,350
Beginning of Year CWIP Subject to Prop Tax (2022-2026)	$1,208,789	$19,291,257	$56,671,479	$93,373,445	$126,293,058

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 157

Responding Witness: William Steven Seelye

Q-157. State whether LG&E is aware of a LOLP COSS being approved in other state jurisdictions. If so, provide the state and docket number.

A-157. Mr. Seelye has not performed a review of the cost-of-service studies approved in most other jurisdictions, but he is unaware of an LOLP COSS being approved in other jurisdictions. However, the LOLP methodology is identified in the NARUC *Electric Utility Cost Allocation Manual*, at page 62, as a reasonable methodology for allocating production fixed costs in an embedded cost of service study. See attached.

Exhibit MPG-2

Employee Adjustment

Witness: Michael P. Gorman

LOUISVILLE GAS AND ELECTRIC

Employee Adjustment
($000)

		O&M			Capitalized
Line	**Description**	**LG&E Electric (1)**	**LG&E Gas (2)**	**Total LG&E (3)**	**Total LG&E (4)**
	Base Period				
1	Labor	$ 68,862	$ 29,606	$ 98,469	$ 25,594
2	Off-Duty[1]	10,404	4,299	14,703	3,542
3	Benefits	27,426	11,333	38,760	8,779
4	Payroll Taxes	7,060	2,917	9,977	2,457
5	Total Payroll Costs	$ 113,752	$ 48,156	$ 161,908	$ 40,372
	Forecasted Period				
6	Labor	$ 72,925	$ 30,919	$ 103,844	$ 23,761
7	Off-Duty[1]	11,415	4,611	16,026	3,321
8	Benefits	31,975	12,916	44,891	9,156
9	Payroll Taxes	7,404	2,991	10,394	2,379
10	Total Payroll Costs	$ 123,719	$ 51,436	$ 175,155	$ 38,617
11	Forecasted Period Number of Employees (YE June 2022)			1,113	
12	Estimated Cost Per Employee			$ 157	
13	Proposed Employee Adjustment			82	
14	Impact[2]	$ 9,115	$ 3,790	$ 12,905	

Sources and Notes:
LG&E response to AG/KIUC Joint Supplemental Data Request Question 25, provided as Exhibit MPG-1, pages 34-38.

[1] Off-duty includes vacation, holiday, sick, short term disability, personal days, funeral leave and jury duty.

[2] Line 12 * Line 13. Electric and Gas allocation based on share of total payroll costs

Exhibit MPG-3

LGE Proof of Revenue at DoD/FEA Proposed Rates, Comparison of LGE and DoD/FEA Proposed Rates, and Revised Rate Design

Witness: Michael P. Gorman

LOUISVILLE GAS AND ELECTRIC

Proof of Revenue at DoD/FEA Proposed Rates

Line	Description	Annual Billing Units[1]	LG&E Proposed[1] Rate	LG&E Proposed[1] Cost	DoD/FEA Proposed[2] Rate	DoD/FEA Proposed[2] Cost
		(1)	(2)	(3)	(4)	(5)
1	Basic Service Charge ($/Day)	48,032	$ 10.84	$ 520,667	$ 10.84	$ 520,667
2	Energy Charge ($/kWh)	1,992,826,476	$0.03236	$ 64,487,865	$0.02732	$ 54,441,479
	Demand Charge ($/kVA)					
3	Base	5,354,606	$ 3.33	$ 17,830,838	$ 2.85	$ 15,255,407
4	Intermediate	4,410,142	$ 7.36	$ 32,458,642	$ 8.62	$ 38,016,562
5	Peak	4,306,226	$ 9.58	$ 41,253,647	$ 11.22	$ 48,317,544
6	Redundant Capacity Factor	36,570	$ 1.31	$ 47,907	$ 1.31	$ 47,907
7	Economic Development Rider - Base			$ (28,890)		$ (28,890)
8	Economic Development Rider - Intermediate			$ (52,538)		$ (52,538)
9	Economic Development Rider - Peak			$ (69,089)		$ (69,089)
10	Total			$156,449,048		$156,449,048

Sources

[1] Schedule M-2.3-E, page 9 of 26.

[2] Exhibit MPG-3, page 3 of 3.

LOUISVILLE GAS AND ELECTRIC

Comparison of LGE and DoD/FEA Proposed Rates

Line	Description	Current Rates[1] (1)	LGE Proposed Rate[1] (2)	Increase from Current (3)	DoD/FEA Proposed Rate[2] (4)	Increase from Current (5)
1	Basic Service Charge ($/Day)	$ 10.84	$ 10.84	0.0%	$ 10.84	0.0%
2	Energy Charge ($/kWh)	$ 0.02744	$ 0.03236	17.9%	$ 0.02732	-0.4%
	Demand Charge ($/kVA)					
3	Base	$ 2.34	$ 3.33	42.3%	$ 2.85	21.8%
4	Intermediate	$ 7.15	$ 7.36	2.9%	$ 8.62	20.6%
5	Peak	$ 9.32	$ 9.58	2.8%	$ 11.22	20.4%
6	Redundant Capacity Factor	$ 1.41	$ 1.31	-7.1%	$ 1.31	-7.1%

Sources

[1] Schedule M-2.3-E, page 9 of 26.

[2] Exhibit MPG-3, page 1 of 3.

LOUISVILLE GAS AND ELECTRIC

Revised Rate Design

Line	Description	Amount	DoD/FEA Proposed Rate Design: Description	Amount	Billing Units[2]	Rate
			TODP kWh	1,992,826,476		
	LGE Allocated Rev. Req.[1]		TODP NCP kW (From COSS)	321,647		
1	Production Energy	$ 64,474,145	TODP Load Factor	70.7%		
2	Production Demand	70,156,845	1- TODP Load Factor	29.3%		
3	Transmission Demand	8,842,402				
4	Distribution Demand	9,001,434	LGE TODP Production Energy O&M[3]	$ 68,825,160		
5	Distribution Customer	432,885	Revised Production Energy O&M[4]	$ 58,778,775		
6	Total	$ 152,907,711	Difference	$ 10,046,386		
	LG&E Proposed Rate Design[2]					
7	Energy	$ 64,487,865	Energy	$ 54,441,479	1,992,826,476	$ 0.027
8	Base Demand	17,830,838	Base Demand	15,255,407	5,354,606	$ 2.849
9	Intermediate Demand	32,458,642	Intermediate Demand	38,016,562	4,410,142	$ 8.620
10	Peak Demand	41,253,647	Peak Demand	48,317,544	4,306,226	$ 11.220
11	Customer	520,667	Customer	520,667	48,032	$ 10.840
12	Total	$ 156,551,659	Total	$ 156,551,659		
	Total Int. & Peak Demand	73,712,289				
13	Intermediate %	44.0%				
14	Peak %	56.0%				

Sources and Notes
[1] LGE's LOLP COSS with Unit Costs
[2] Schedule M-2.3-E, page 9 of 26.
[3] LGE's LOLP COSS
[4] LGE LOLP COSS after reclassification of steam generation maintenance expense

Exhibit MPG-4

KU Proof of Revenue
at DoD/FEA Proposed Rates,
Comparison of KU and
DoD/FEA Proposed Rates,
and Revised Rate Design

Witness: Michael P. Gorman

KENTUCKY UTILITIES

Proof of Revenue at DoD/FEA Proposed Rates

Line	Description	Annual Billing Units[1] (1)	LG&E Proposed[1] Rate (2)	LG&E Proposed[1] Cost (3)	DoD/FEA Proposed[2] Rate (4)	DoD/FEA Proposed[2] Cost (5)
1	Basic Service Charge ($/Day)	93,271	$ 10.84	$ 1,011,061	$ 10.84	$ 1,011,061
2	Energy Charge ($/kWh)	3,951,918,371	$ 0.03128	$ 123,616,007	$ 0.02702	$ 106,776,530
	Demand Charge ($/kVA)					
3	Base	10,620,000	$ 2.79	$ 29,629,800	$ 2.25	$ 23,873,576
4	Intermediate	8,647,332	$ 6.71	$ 58,023,596	$ 7.88	$ 68,165,888
5	Peak	8,522,176	$ 8.36	$ 71,245,395	$ 9.82	$ 83,698,804
6	Redundant Capacity Rider	128,239	$ 0.92	$ 117,980	$ 0.92	$ 117,980
7	Economic Development Rider - Base			$ (400,389)		$ (400,389)
8	Economic Development Rider - Intermediate			$ (864,255)		$ (864,255)
9	Economic Development Rider - Peak			$ (1,070,239)		$ (1,070,239)
10	Total			$ 281,308,955		$ 281,308,955

Sources

[1] Schedule M-2.3 page 10 of 26.

[2] Exhibit MPG-4, page 3 of 3.

Kentucky Utilities

Comparison of KU and DoD/FEA Proposed Rates

Line	Description	Current Rates[1] (1)	LGE Proposed Rate[1] (2)	Increase from Current (3)	DoD/FEA Proposed Rate[2] (4)	Increase from Current (5)
1	Basic Service Charge ($/Day)	$ 10.84	$ 10.84	0.0%	$ 10.84	0.0%
2	Energy Charge ($/kWh)	$ 0.02573	$ 0.03128	21.6%	$ 0.02702	5.0%
	Demand Charge ($/kVA)					
3	Base	$ 2.03	$ 2.79	37.4%	$ 2.25	10.7%
4	Intermediate	$ 6.84	$ 6.71	-1.9%	$ 7.88	15.2%
5	Peak	$ 8.52	$ 8.36	-1.9%	$ 9.82	15.3%
6	Redundant Capacity Factor	$ 0.99	$ 0.92	-7.1%	$ 0.92	-7.1%

Sources

[1] Schedule M-2.3 page 10 of 26.

[2] Exhibit MPG-4, page 1 of 3.

KENTUCKY UTILITIES

Revised Rate Design

Line	Description	Amount	DoD/FEA Proposed Rate Design: Description	DoD/FEA Proposed Rate Design: Amount	Billing Units[2]	Rate
			TODP kWh	3,951,918,371		
	KU Allocated Rev. Req.[1]		TODP NCP kW (From COSS)	640,911		
1	Production Energy	$ 123,665,626	TODP Load Factor	70.4%		
2	Production Demand	122,057,251	1- TODP Load Factor	29.6%		
3	Transmission Demand	19,431,359				
4	Distribution Demand	10,195,997	KU TODP Production Energy O&M[3]	$ 124,399,061		
5	Distribution Customer	1,008,379	Revised Production Energy O&M[4]	$ 107,559,584		
6	Total	$ 276,358,612	Difference	$ 16,839,477		
	KU Proposed Rate Design[2]					
7	Energy	$ 123,616,007	Energy	$ 106,776,530	3,951,918,371	$ 0.027
8	Base Demand	29,629,800	Base Demand	23,873,576	10,620,000	$ 2.248
9	Intermediate Demand	58,023,596	Intermediate Demand	68,165,888	8,647,332	$ 7.883
10	Peak Demand	71,245,395	Peak Demand	83,698,804	8,522,176	$ 9.821
11	Customer	1,011,061	Customer	1,011,061	93,271	$ 10.840
12	Total	$ 283,525,858	Total	$ 283,525,858		
	Total Int. & Peak Demand	$ 129,268,991				
13	Intermediate %	44.9%				
14	Peak %	55.1%				

Sources and Notes

[1] KU's LOLP COSS with Unit Costs

[2] Schedule M-2.3, page 10 of 26.

[3] KU's LOLP COSS

[4] KU LOLP COSS after reclassification of steam generation maintenance expense