COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matters of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES CO. FOR AN ADJUSTMENT OF 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 SURCREDIT	)	CASE No. 2020-00349

-and-

ELECTRONIC APPLICATION OF LOUISVILLE GAS & ELECTRIC CO. FOR AN ADJUSTMENT OF 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 SURCREDIT	)	CASE No. 2020-00350

JOINT INITIAL DATA REQUESTS OF THE ATTORNEY GENERAL AND KIUC

The intervenors, the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention [“OAG”], and the Kentucky Industrial Utility Customers [“KIUC”] hereby submit the following Initial Data Requests to Kentucky Utilities Co. [“KU”], and Louisville Gas & Electric Co. [“LG&E”][hereinafter jointly referenced as “LG&E-KU” or “the Companies”] to be answered by the date specified in the Commission’s Orders of Procedure, and in accord with the following:

(1) In each case where a request seeks data provided in response to a staff request, reference to the appropriate request item will be deemed a satisfactory response.

(2) Identify the witness who will be prepared to answer questions concerning each request.

(3) Repeat the question to which each response is intended to refer. The OAG-KIUC can provide counsel for LG&E-KU with an electronic version of these questions, upon request.

(4) These requests shall be deemed continuing so as to require further and supplemental responses if the Companies receive or generate additional information within the scope of these requests between the time of the response and the time of any hearing conducted hereon.

(5) Each response shall be answered under oath or, for representatives of a public or private corporation or a partnership or association, be accompanied by a signed certification of the preparer or person supervising the preparation of the response on behalf of the entity that the response is true and accurate to the best of that person's knowledge, information, and belief formed after a reasonable inquiry.

(6) If you believe any request appears confusing, request clarification directly from Counsel for OAG-KIUC.

(7) To the extent that the specific document, workpaper or information as requested does not exist, but a similar document, workpaper or information does exist, provide the similar document, workpaper, or information.

(8) To the extent that any request may be answered by way of a computer printout, identify each variable contained in the printout which would not be self-evident to a person not familiar with the printout.

(9) If the Companies have objections to any request on the grounds that the requested information is proprietary in nature, or for any other reason, notify OAG-KIUC as soon as possible.

(10) As used herein, the words ‘‘document’’ or ‘‘documents’’ are to be construed broadly and shall mean the original of the same (and all non-identical copies or drafts thereof) and if the original is not available, the best copy available. These terms shall include all information recorded in any

written, graphic or other tangible form and shall include, without limiting the generality of the foregoing, all reports; memoranda; books or notebooks; written or recorded statements, interviews, affidavits and depositions; all letters or correspondence; telegrams, cables and telex messages; contracts, leases, insurance policies or other agreements; warnings and caution/hazard notices or labels; mechanical and electronic recordings and all information so stored, or transcripts of such recordings; calendars, appointment books, schedules, agendas and diary entries; notes or memoranda of conversations (telephonic or otherwise), meetings or conferences; legal pleadings and transcripts of legal proceedings; maps, models, charts, diagrams, graphs and other demonstrative materials; financial statements, annual reports, balance sheets and other accounting records; quotations or offers; bulletins, newsletters, pamphlets, brochures and all other similar publications; summaries or compilations of data; deeds, titles, or other instruments of ownership; blueprints and specifications; manuals, guidelines, regulations, procedures, policies and instructional materials of any type; photographs or pictures, film, microfilm and microfiche; videotapes; articles; announcements and notices of any type; surveys, studies, evaluations, tests and all research and development (R&D) materials; newspaper clippings and press releases; time cards, employee schedules or rosters, and other payroll records; cancelled checks, invoices, bills and receipts; and writings of any kind and all other tangible things upon which any handwriting, typing, printing, drawings, representations, graphic matter, magnetic or electrical impulses, or other forms of communication are recorded or produced, including audio and video recordings, computer stored information (whether or not in printout form), computer-readable media or other electronically maintained or transmitted information regardless of the media or format in which they are stored, and all other rough drafts, revised drafts (including all handwritten notes or other marks on the same) and copies of documents as hereinbefore defined by whatever means made.

(11) For any document withheld on the basis of privilege, state the following: date; author; addressee; indicated or blind copies; all persons to whom distributed, shown, or explained; and, the nature and legal basis for the privilege asserted.

(12) In the event any document called for has been destroyed or transferred beyond the control of the Companies, state: the identity of the person by whom it was destroyed or transferred, and the person authorizing the destruction or transfer; the time, place, and method of destruction or transfer; and, the reason(s) for its destruction or transfer. If destroyed or disposed of by operation of a retention policy, state the retention policy.

(13) Provide written responses, together with any and all exhibits pertaining thereto, in one or more bound volumes, separately indexed and tabbed by each response, in compliance with Kentucky Public Service Commission Regulations.

(14) "And" and "or" should be considered to be both conjunctive and disjunctive, unless specifically stated otherwise.

(15) "Each" and "any" should be considered to be both singular and plural, unless specifically stated otherwise.

Respectfully submitted,

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Certificate of Service

Pursuant to the Commission's Orders in Case No. 2020-00085, and in accord with all other applicable law, Counsel certifies that an electronic copy of the forgoing was served and filed by e-mail to the parties of record. Further, counsel for OAG will submit the paper originals of the foregoing to the Commission within 30 days after the Governor lifts the current state of emergency.

This 8th day of January, 2021

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Assistant Attorney General

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I. REVENUE REQUIREMENTS

1. Confirm that KU uses AFUDC accounting for its Virginia retail and FERC wholesale jurisdictions. If this is not correct, then provide a correct statement.

2. Confirm that neither KU nor LG&E presently use AFUDC accounting for their Kentucky retail jurisdictions. If this is not correct, then provide a correct statement.

3. Provide a copy of the Companies' accounting policies and procedures regarding AFUDC accounting for each of its jurisdictions (including Virginia). If none, then so state.

4. Indicate whether the Companies consider their request to use AFUDC accounting for their proposed AMI meters and infrastructure as an exception to its present CWIP in rate base accounting.

5. Indicate whether the Companies are opposed to the use of AFUDC accounting in lieu of their present CWIP in rate base accounting. Provide all reasons for the Companies' position.

6. Please provide a copy of the Companies' most recent Integrated Resource Plan filing.

7. Please provide a copy of the Companies' 2021 Integrated Resource Plan filing when it is available.

8. Please provide a trial balance of all income statement and balance sheet accounts for each month December 2018 through December 2020. Please provide a detailed description of the costs included in each account, including all subaccounts, whether or not specifically listed in the FERC Uniform System of Accounts ("USOA").

9. Refer to page 1 of 1 of Attachment to Filing Requirement Tab 15 of 807 KAR 5:001 Section 16(7)(b), which shows the projected capital expenditures by category of spend for the years 2020 through 2023. Please expand the table presented to split generation costs between those to be recovered through base rates and those to be recovered through other mechanisms such as the ECR. In addition, expand the table to include the actual capital expenditures in the same categories for each of the years 2017 through 2020.

10. Refer to pages 15 and 16 of Mr. Conroy's Direct Testimony and pages 8 and 9 of Mr. Seeley's Direct Testimony regarding the roll-in of certain environmental projects from ECR recovery to base rate recovery. Please provide a summary of all revenue requirement items (including capitalization, revenues, and expenses) by FERC account that would have been removed through ratemaking adjustments from the base rate revenue requirement if the projects are not rolled-in to base rates and continue to be recovered through the ECR. In addition, provide the quantification of the increase or decrease to the as-filed revenue requirement resulting from the inclusion of ECR elimination costs in base rates. Provide in electronic format with all formulas intact.

11. For each of the generating units and plants (sum of generating units at each plant), please provide copies of the 2020, 2021, 2022 and 2023 capital budgets and provide a description of the capital projects budgeted for each separated by amounts to be recovered through the ECR, other non-base rate mechanisms, or through base rates.

12. Please see the electronic file supplied in response to Staff 1-56 named "2020_Att_KU_PSC1-56_Exhibit_JJS-1__06302020_Table_2,""2020_Att_LGE_PSC1-56_Exhibit_JJS-1_(Electric-Net_Salvage)_06302020_Table_2," and "2020_Att_LGE_PSC1-56_Exhibit_JJS-1_(Gas)_06302020_Table_2" which are the electronic versions of the tables contained on pages VIII-2 through VIII-3 of Exhibit JJS-KU-1 and Exhibit JJS-LG&E-1 (Depreciation Studies attached to Mr. Spanos's Direct Testimony). Please provide all workpapers in support of the terminal and interim retirement amounts and percentages reflected in that table in electronic format with all formulas intact.

13. Refer to pages 11-12 of Mr. Spanos' Direct Testimony wherein he describes the "dismantlement component" added to the overall net salvage for each production facility. Refer also to pages VIII-2 through VIII-3 of Exhibit JJS-KU-1 and Exhibit JJS-LG&E-1 (Depreciation Studies attached to Mr. Spanos's Direct Testimony).

    a. Please describe and provide copies of all source documentation relied upon to determine that "the dismantlement or decommissioning costs for steam production facilities are best calculated at $40/KW of the assets subject to final retirement."

    b. Please provide copies for each generating facility of the calculations for the terminal net salvage component as based on the $40/KW assumption. Provide in electronic format with all formulas intact.

    c. Please provide copies of the "cost estimate of dismantlement of the Cane Run facility" referenced on page 11, lines 20-22, and identify all applicable Cane Run units.

    d. Please identify the retirement dates for all Cane Run units and all actual dismantlement costs incurred to date by year and by individual Cane Run unit. In addition, please describe the current status of all Cane Run unit retirement and/or dismantlement projects.

    e. Provide the calculations of the overall net salvage showing the interim and terminal net salvage components reflected in the present approved depreciation rates and in the depreciation rates proposed in this proceeding. Provide in electronic format with all formulas intact.

14. Please provide a copy of all notes and all workpapers and source documents drafted and/or developed by Mr. Spanos and/or his colleagues, including all electronic workpapers in live format with all formulas intact, that were not previously supplied in response to the Commission's Minimum Filing Requirements or Commission Staff's First Set of Data Requests.

15. Refer to the assets described as ECR assets on the Excel spreadsheet titled "Att_KU_PSC_1-57_Depreciation_Exp_Wkpr" and "Att_LGE_PSC_1-57_Depreciation_Exp_Wkpr" provided in response to PSC Staff 1-57. Refer also to Schedule D-2 line 140 related to the total company reductions in depreciation expense of $18,459,306 for KU and $16,625,862 for LG&E associated with the ECR mechanism in the test year. Please provide a schedule showing how the sum of the annual depreciation expense for the test year for each of the ECR assets matches the amount removed in Schedule D-2 of $18,459,306 for KU and $16,625,862 for LG&E. If the amounts do not reconcile for either Company, please explain why.

16. Refer to Exhibit LEB-2, "Analysis of Generating Unit Retirement Years" for KU and LG&E, attached to Mr. Bellar's Direct Testimony. Please provide copies of all analyses performed to generate the data and conclusions contained in the exhibit in electronic format with all formulas intact. This includes, but is not limited to, the avoided capital expenditures and related avoided increases in rate base (CWIP, plant additions, accumulated depreciation, ADIT, etc.), savings in O&M expenses by O&M expense accounts and subaccounts, and savings in other operating expenses by expense accounts by month, test year, and calendar years starting with 2021 and continuing through the final year of the analyses.

17. Refer to pages 10, line 16 and page 11, line 17 of Mr. Bellar's Direct Testimony wherein he states "possible compliance restrictions imposed by the 2015 National Ambient Air Quality Standards ("NAAQS") for ozone" and "expected future NAAQS limitations on No_x emissions," respectively. Please explain why the terms "possible" and "expected future" NAAQS restrictions were used. In other words, please explain the Companies' assessment on the status of the NAAQS restrictions currently and what is expected to change, when, and why. Provide all applicable citations as part of the response.

18. Refer to the LG&E/KU 2021 Operating Plan Generation at p. 4. With respect to the following power plants, please identify the cost to decommission/demolish those plants and explain how the costs were or are being recovered in rates: Paddy's Run Coal Plant (2017); Green River Coal Plant (February 2020); Pineville Coal Plant (2019); Tyrone Coal Plant (July 2020); Cane Run Coal Plant (completion expected 3rd quarter 2020); and Canal Station (completion expected 4th quarter 2021).

19. Refer to Mr. Bellar's Direct Testimony at pages 16 and 17 regarding the demolition of and costs incurred for retired coal and gas generating plants.

    a. Please describe the present status of each of the retired plants, including the extent of facility decommissioning, dismantlement (demolition, disposal, and salvage), and site remediation to date.

    b. Please describe the Companies' accounting for the net book value of generating plants when they are retired, e.g., debit accumulated depreciation and credit gross plant in service or debit regulatory asset, debit accumulated depreciation and credit gross plant.

c. Please describe the Companies' accounting for the demolition, disposal, and salvage costs/income for the retired plants, including the FERC balance sheet and/or expense accounts used to record the costs incurred, and the expense accounts used to record the depreciation or amortization of the costs, if any. If the Companies propose to depreciate or amortize the costs incurred for the retired plants, then provide the depreciation or amortization period and the rationale for the proposed period.

d. Please provide the actual costs incurred by the Companies by month by FERC account for the demolition, disposal, and salvage costs/income for each of the retired plants through the most recent month for which actual information is available.

e. Please provide a copy of all documentation prepared by or for the Companies describing its accounting for retired generating plants, including the accounting entries for the net book value, demolition costs, materials and supplies inventories, fuel inventories, and all other costs.

f. Please provide the rate base by component and the depreciation expense for each of the retired power plants included in the claimed revenue requirement in the prior rate case filing, including any debit balances in accumulated depreciation that were reallocated to the accumulated depreciation for other power plants. Provide the schedules, workpapers, and Excel files in live format and with formulas intact relied on for your response.

g. Provide the actual depreciation expense for each of the retired power plants by month from January 2018 through the most recent month for which actual information is available.

h. Provide the operating expenses for each of the retired power plants included in the claimed revenue requirement in the prior rate case filing. Provide the schedules, workpapers, and Excel files in live format and with formulas intact relied on for your response.

i. Provide the actual operating expenses for each of the retired power plants by FERC O&M/A&G, and other operating expense accounts from January 2018 through the most recent month for which actual information is available.

j. Please provide the terminal net salvage costs related to each of the retired plants included in the claimed revenue requirement, including all rate base/capitalization components, such as a debit balance in accumulated depreciation and the related ADIT, and all operating expenses, such as depreciation expense based on the proposed depreciation rates. The quantification should include all reductions in rate base/capitalization and operating expenses from savings, if any. Please provide all calculations in live

Excel format with all formulas intact and source all assumptions and data used in the calculations.

k. Please describe the full extent of the dismantlement and site remediation, or planned if not yet completed, for each of the retired plants.

l. Please provide the year of retirement and the KW capacity during service for each of the retired plants.

m. Please provide the Companies' demolition cost estimate for each of the retired plants, including all supporting documentation.

n. Confirm that the Companies discontinue book depreciation expense upon the retirement of a generating plant and confirm that the Companies do not commence amortization in lieu of depreciation expense after the retirement of a generating plant. If both points are confirmed, then confirm that the Companies do not record a regulatory liability for the depreciation expense that was included in the revenue requirement and continues to be recovered after the retirement of a generating plant even though it no longer records depreciation or amortization expense on the retired generating plant.

20. Please provide the incentive compensation expense for (a) 2018, (b) 2019, (c) the base year, and (d) the test year by incentive compensation plan and by goal or target for each plan. This includes incentive compensation expense incurred directly by the Companies and the expense assigned and allocated to the Companies from the Service Company.

21. Please confirm that the only incentive compensation plan available is the TIA Plan provided as Exhibit GJM-1. If not confirmed, please provide copies of all other plans available to employees.

22. Provide a schedule showing per books actual O&M expenses by year and by FERC O&M/A&G expense account/subaccount for each of the calendar years 2015 through 2019, 2020 to date (identify the last month with actual data), the base year and the test year.

23. Provide a schedule showing jurisdictional actual O&M expenses by year and by FERC O&M/A&G expense account/subaccount for each of the calendar years 2015 through 2019, 2020 to date (identify the last month with actual data), the base year and the test year.

24. Please provide a schedule showing all direct assignments and allocations of costs from LKS to the Companies by FERC O&M, A&G, and each other account for 2016, 2017, 2018, 2019, 2020 to date (identify the last month with actual data), the base year, and the test year. Provide an explanation for each increase from year to year of at least $1 million or 5%, whichever is less.

25. Please provide a schedule showing the actual amount of property taxes paid by the Companies during 2020 to each taxing authority and in total.

26. For each taxing authority to which aggregate property tax payments exceeding $10,000 were made in 2020, please indicate the method of assessing asset value and whether the asset base includes or excludes CWIP in the determination of the assessed value used to determine the amount of taxes to be paid.

27. For each taxing authority to which aggregate property tax payments exceeding $10,000 were made in 2020, please indicate the time of the year when value assessments were made and when payments were due. If there are any known changes related to base year and test year assessments and changes, please describe.

28. For each taxing authority to which aggregate property tax payments exceeding $10,000 were made in 2020, please provide a copy of one property tax return or other information return submitted to each tax assessor and the associated resulting invoice related to taxes paid in 2020.

29. For each taxing authority to which aggregate property tax payments exceeding $10,000 were made in 2020, please indicate whether there is a period of temporary abatement of taxes during the construction phase of assets to be placed in service. If so, please describe in detail.

30. Please provide a schedule showing how property taxes were computed for the base year and include copies of all workpapers used to determine the amount in electronic format with all formulas intact.

31. Please provide a schedule showing how property taxes were computed for the test year and include copies of all workpapers used to determine the amount in electronic format with all formulas intact.

32. Do the Companies use credit cards that include rebates or other benefits? If the response is in the affirmative, provide the following items:

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

    b. Actual credit card rebates or other benefits by year for 2018, 2019, and 2020. For each year, state the expense accounts where these credit card rebates or other benefits are reflected and provide a detailed breakdown of those expense accounts.

33. Please provide a schedule for each Company of the amortization expense associated with each regulatory asset for (a) each year 2016 through 2020, (b) the base year and (c) the test year. Provide the balance of each regulatory asset at the beginning and end of each of those years, the amortization period that was used in each of those years, and the FERC accounts utilized to record the amortization expense. In addition, please source the amortization period to the Case No. in which the Commission approved the recovery and the amortization period, if any. If none, then so state.

34. Please provide a schedule for each Company of the amortization expense associated with each regulatory liability for (a) each calendar year 2016 through 2020, (b) the base year and (c) the test year. Provide the balance of each regulatory liability at the beginning and end of each of those years, the amortization period that was used in each of those years, and the FERC accounts utilized to record the amortization expense. In addition, please source the amortization period to the Case No. in which the Commission approved the recovery and the amortization period, if any. If none, then so state.

35. Refer to the disallowance of costs referenced on pages 13-15 of the June 22, 2017 Order in Kentucky Utilities, Inc. Case No. 2016-00370 and to pages 16-17 of the June 22, 2017 Order in Louisville Gas and Electric Company Case No. 2016-00371. For employees who participate in a defined benefit plan, please provide the total and jurisdictional amount of matching contributions made on behalf of employees who also participate in any 401 (k) retirement savings account for each Company if the Commission applied the same methodology for a similar disallowance in the instant proceeding.

36. Refer to page 22, line 7, through page 23, line 10, of Mr. Bellar's Direct Testimony wherein he describes changes to the deferred costs and amortization of generation plant outage expenses. Please provide a schedule showing the total company 2015, 2016, 2017, 2018, 2019, 2020 to date, base year and test year maintenance expenses recorded or budgeted if not yet incurred for generation plant maintenance and outage expenses by plant/unit and by FERC O&M expense account, for both Companies.

37. Refer to page 22, line 7, through page 23, line 10, of Mr. Bellar's Direct Testimony. Please provide the following information related to the deferral of generating outage costs for 2017, 2018, 2019, 2020, base year, and test year for each Company: a) beginning balance, b) cost deferrals added, c) costs amortized, and d) ending year balance. In addition, provide the quantification of cost deferrals added each year and the basis for such. Finally, identify the FERC accounts and account numbers associated with the deferrals and amortizations (balance sheet and income statement).

38. Refer to page 23, lines 5 through 10, of Mr. Bellar's Direct Testimony wherein he describes the Companies' eight-year average approach to determine the amount of generation plant outage maintenance expense recoverable in base rates. Please provide a schedule showing the total company 2017, 2018, 2019, 2020 through August 2020 and budgeted for the remainder of that year, 2021, 2022, 2023, and 2024 maintenance expenses recorded or budgeted if not yet incurred for generation plant maintenance and outage expenses by plant/unit and by FERC O&M expense account, for both Companies.

39. Refer to the variance explanation for FERC account 454 provided on Schedule D-1 to explain the decrease in test year revenues of $7.866 million for KU and $6.235 million for LG&E (Electric) from the level of base year revenues for Rent from Electric Property. That explanation reads, "Variance due to the removal of refined coal contracts from base rates in the test period." Please explain what change is being made any why and provide copies of all analyses or other support documentation that shows more details about the lower levels of revenues that are expected.

40. Please provide in an Excel spreadsheet the FTE staffing levels and related payroll (direct and burdens) by month from January 2017 through June 2022 at each generating unit/plant that the Companies have retired or plan to retire during that period of five and a half years.

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.

42. Please provide a breakdown of payroll dollars between O&M expense, capital, and all other by department and in total for the Companies for each of the years 2015-2019, the forecasted base year and the forecasted test year.

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.

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.

45. Refer to the Payroll Analysis Attachment, page 2 of 2, to Filing Requirement Tab 60 of 807 KAR5:001 Section 16(8)(g) for each Company. Refer further to the Off-duty dollars data included on lines 27-32.

    a. Please explain what kind of payroll dollars is represented in this category of costs.

    b. Please explain why O&M costs are projected to increase by 9.06% for KU and 9.00% for LG&E from the base year to the test year for this category of costs.

    c. Please explain why the ratio of O&M dollars to total dollars for this category of costs is expected to increase from 66.05% to 68.71% for KU and from 68.86% to 70.83% for LG&E from the base year to the test year.

46. Refer to the Payroll Analysis Attachment, page 2 of 2, to Filing Requirement Tab 60 of 807 KAR5:001 Section 16(8)(g) for each Company. Refer further to the ratio of O&M labor dollars data included on lines 18-19. Please explain why the ratio of O&M labor dollars is projected to increase from 66.62% to 68.75% for KU and from 68.42% to 70.25% for LG&E from the base year to the test year.

47. Please describe how the Companies removed the effects of purchase accounting from the capitalization, all rate base components, and all related expenses, such as depreciation expense and property tax expense, reflected in the filing. Provide a schedule in electronic spreadsheet format with all formulas intact showing all adjustments and providing an explanation of each such adjustment.

48. For both Companies, provide a schedule showing total Company and jurisdictional purchased power expense by month from January 2017 through the end of the test year, including the months between the end of the base year and beginning of the test year separated into the amounts included in the (a) base revenue requirement and in the (b) fuel adjustment clause. Disaggregate the expense included in the base revenue requirement by supplier in the same manner that the Company reports purchased power expense in the Form 1 on pages 326-327. Highlight and explain each actual and forecasted change in resource and/or capacity for a given resource throughout this 66-month period for the expense included in the base revenue requirement.

49. For both Companies, provide a schedule showing by month from January 2017 through the end of the test year, including the months between the end of the base year and the beginning of the test year, the (a) total off-system sales revenues and the (b) net margins. In addition, (c) provide the amount of the net margins reflected in the base revenue requirement in the base year and in the test year annotated and/or reconciled to the schedule provided in this response. Further, (d) separate the monthly net margins to reflect the sharing allocation between the Companies and customers and show the calculation of this allocation.

50. Provide a copy of the Companies' actuarial reports used for pension expense in the most recent historic calendar year, base year and test year. Annotate and/or reconcile the relevant amounts included in the report to the pension expense included in the base year and test year.

51. Provide a copy of the Companies' actuarial reports used for OPEB expense in the most recent historic calendar year, base year and test year. Annotate and/or reconcile the relevant amounts included in the report to the OPEB expense included in the base year and test year.

52. Provide the lobbying expense actually incurred in 2020 by FERC account/subaccount and payee/vendor, including expense that was incurred by affiliates, such as LG&E and KU Services Company, and charged to the Companies. In addition, provide the amount of lobbying expense actually incurred during the test year and the amount included in the test year cost of service in this proceeding in the same format.

53. Refer to Schedule B-5 page 2 of 2 at line 3, which provides the 13 month average amounts of Prepayments in Rate Base for each Company. Provide a detailed schedule of all amounts included in the per books amount of prepayments in FERC account 165 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. For all amounts in FERC account 165 subaccounts not reflected on Schedule B-5, including contra-asset amounts, explain why they are not reflected.

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.

55. Refer to Schedule B-5 page 2 of 2 at line 3 (Gas), which provides the 13 month average amounts of Prepayments in Rate Base (Gas). Provide a detailed schedule of all amounts included in the per books amount of prepayments in FERC account 165 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. For all amounts in FERC account 165 subaccounts not reflected on Schedule B-5 (Gas), including contra-asset amounts, explain why they are not reflected.

56. Refer to Schedule B-5.2, page 5 of 6 (Gas), which provides the 13 month average amounts of Additional Sources and Uses of Cash Working Capital in Rate Base (Gas).

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 Company forecasts a balance in account 184 Pension Clearing instead of $0, especially given the Company's 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 Company's 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 Company's 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.

57. Refer to Mr. Bellar's Direct Testimony at page 50 in regards to the 11 additional positions for the LG&E gas operations. Please provide a listing of the various positions, indicating which have already been filled, and the estimated salary and other payroll costs assumed for each position in the test year.

58. Refer to Tab 13-807 KAR 5:001 Section 16(6)(f).

a. Provide the underlying support for the amounts on this schedule by account/subaccount in live Excel workbook format with all formulas intact. To the extent that certain balance sheet amounts were excluded from either the additions (liabilities not included in rate base) or subtractions (assets not included in rate base), then identify each such excluded account/subaccount and provide all reasons why it was excluded.

b. Provide a list of the regulatory assets on line 25 and the amount of each regulatory asset by month and the 13-month average for the test year.

59. Please provide a narrative explanation of the status of the FERC transmission de-pancaking litigation.

60. Please refer to the LG&E/KU 2021 Operating Plan Transmission at p. 25. Are the transmission de-pancaking costs by customer (OMU $9.645 million, KMPA $7.308 million and KYMEA $10.909 million) being recovered in this rate case? Please explain.

61. Please refer to the LG&E/KU 2021 Business Plan: Generation & OSS Forecast.

a. On page 2, please break out the Native Load Production Costs for LG&E and KU separately.

b. On page 9, please explain how the $8-12 million of projected annual CCR revenue is being handled in this case. Is it an off-set to base revenue requirements, or will it be flowed through the ECR?

62. Refer to Mr. Bellar's Direct Testimony at 20 regarding the SEEM costs.

a. Provide the SEEM costs included in the test year revenue requirement by FERC account. If none, then so state. Provide all calculations in an Excel workbook in live format with all formulas intact, for the base revenue requirement, fuel adjustment mechanism revenue requirement, and each other rider revenue requirement, if any.

b. Provide a copy of the Companies' cost benefit analysis.

63. Refer to Table 7 in Mr. Seelye's Direct Testimony at 136 and the Excel workbook provided in response to Staff 1-56 in support of that table.

a. Describe the Companies' calculation of the revenue collection lag days shown on Table 7, including, but not limited to, the lag days associated with credit/debit card, ACH, and other electronic payments.

b. Provide the Companies' calculation of the revenue collection lag days shown on Table 7.

c. Provide the Companies' calculations of the expense "lead" days shown on Table 7.

d. Describe the "Retirement Income Account Expense" line item shown on Table 7, including the specific expenses included in this line item.

e. Confirm that the accumulated depreciation subtracted from rate base is based on a thirteen-month average, which essentially results in an average of the monthly averages for the test year. If this is not correct, then provide a corrected statement and all support for the corrected statement.

f. Confirm that under the thirteen-month average calculation of accumulated depreciation, the Companies essentially are allowed a half month of return on the current month depreciation expense before it is used to increase accumulated depreciation at the end of the current month. If this is not correct, then provide a corrected statement and all support for the corrected statement.

g. Confirm that the Companies do not include regulatory assets in rate base, except for its proposal to include a regulatory asset – FAS 158 pension in other working capital (Schedule B-5.2B(2)).

h. Confirm that the Companies do not include sales taxes in the base revenue requirement.

i. Describe the Companies' accounting for sales taxes collected and remitted, i.e., whether the sales taxes collected are included in revenues and whether the sales taxes remitted are included in other taxes expense or some other expense account.

j. Explain why "school tax" is shown as a separate line item than "property taxes" and why "school tax" and "property taxes" have different "lead" days.

k. Confirm that "school taxes" are paid annually based on the assessed value at the beginning of the year. If this is correct, then provide a timeline for the accrual of the liability and any related offsetting asset, the amortizations of the liability and asset, school tax expense, and the payment of the current year's liability. If this is not correct, then provide a corrected statement and provide a timeline based on the corrected statement.

l. Refer to the prepayments included in rate base as shown on Schedule B-5.1. Describe the analysis performed to ensure that there was no overlap between the prepayments included in rate base and the related expenses included in the cash working capital calculated using the lead/lag approach, especially with respect to the amortization of the prepayments to expense. If the Companies performed an analysis, then provide a copy of it, including all support. If the Companies did not perform an analysis, then provide all reasons why the

Companies believe that the prepayments should be included in rate base, especially if the amortization of the prepayments to expense is included in the cash working capital study.

64. Refer to Schedule B-8 TC (Schedule B-8 pages 1 and 2) for KU and LG&E (Electric).

a. Explain why the Companies utilized the same amount in account 190 ADIT for the forecast year as the base year.

b. Provide a detailed schedule of the amounts in account 190 ADIT by temporary difference and by month for 2019, base year, and forecast year, as well as all supporting calculations for forecast changes in the temporary differences in each of the forecast months in the base year, if any.

c. Provide a detailed schedule of the amounts in account 281 ADIT by temporary difference and by month for 2019, base year, and forecast year, as well as all supporting calculations for forecast changes in the temporary differences in each of the forecast months in the base year, forecast bridge months between the end of the base year and the beginning of the test year, and the months in the forecast year.

d. Provide a detailed schedule of the amounts in account 282 ADIT by temporary difference and by month for 2019, base year, and forecast year, as well as all supporting calculations for forecast changes in the temporary differences in each of the forecast months in the base year, forecast bridge months between the end of the base year and the beginning of the test year, and the months in the forecast year.

e. Provide a detailed schedule of the amounts in account 283 ADIT by temporary difference and by month for 2019, base year, and forecast year, as well as all supporting calculations for forecast changes in the temporary differences in each of the forecast months in the base year, forecast bridge months between the end of the base year and the beginning of the test year, and the months in the forecast year.

65. Refer to Schedule B-8 KY (Schedule B-8 pages 3 and 4) for KU and LG&E (Electric).

a. Provide a detailed schedule of the amounts in account 190 ADIT by temporary difference and by month for 2019, base year, and forecast year, as well as all supporting calculations for forecast changes in the temporary differences in each of the forecast months in the base year, forecast bridge months between the end of the base year and the beginning of the test year, and the months in the forecast year.

b. Provide a detailed schedule of the amounts in account 281 ADIT by temporary difference and by month for 2019, base year, and forecast year, as well as all supporting calculations for forecast changes in the temporary differences in each of the forecast months in the base year, forecast bridge months between the end of the base year and the beginning of the test year, and the months in the forecast year.

c. Provide a detailed schedule of the amounts in account 282 ADIT by temporary difference and by month for 2019, base year, and forecast year, as well as all supporting calculations for forecast changes in the temporary differences in each of the forecast months in the base year, forecast bridge months between the end of the base year and the beginning of the test year, and the months in the forecast year.

d. Provide a detailed schedule of the amounts in account 283 ADIT by temporary difference and by month for 2019, base year, and forecast year, as well as all supporting calculations for forecast changes in the temporary differences in each of the forecast months in the base year, forecast bridge months between the end of the base year and the beginning of the test year, and the months in the forecast year.

66. Refer to Schedule B-8 TC (Gas) (Schedule B-8 pages 1 and 2).

a. Explain why the Company utilized the same account 190 ADIT for the forecast year as the base year.

b. Provide a detailed schedule of the account 190 ADIT by temporary difference and by month for 2019, base year, and forecast year, as well as all supporting calculations for forecast changes in the temporary differences in each of the forecast months in the base year, if any.

c. Provide a detailed schedule of the account 281 ADIT by temporary difference and by month for 2019, base year, and forecast year, as well as all supporting calculations for forecast changes in the temporary differences in each of the forecast months in the base year, forecast bridge months between the end of the base year and the beginning of the test year, and the months in the forecast year.

d. Provide a detailed schedule of the account 282 ADIT by temporary difference and by month for 2019, base year, and forecast year, as well as all supporting calculations for forecast changes in the temporary differences in each of the forecast months in the base year, forecast bridge months between the end of the base year and the beginning of the test year, and the months in the forecast year.

e. Provide a detailed schedule of the account 283 ADIT by temporary difference and by month for 2019, base year, and forecast year, as well as all supporting calculations for forecast changes in the temporary differences in each of the forecast months in the base year, forecast bridge months between the end of the base year and the beginning of the test year, and the months in the forecast year.

67. Refer to Schedule B-8 E (Gas) (Schedule B-8 pages 3 and 4).

a. Provide a detailed schedule of the account 190 ADIT by temporary difference and by month for 2019, base year, and forecast year, as well as all supporting calculations for forecast changes in the temporary differences in each of the forecast months in the base year, forecast bridge months between the end of the base year and the beginning of the test year, and the months in the forecast year.

b. Provide a detailed schedule of the account 281 ADIT by temporary difference and by month for 2019, base year, and forecast year, as well as all supporting calculations for forecast changes in the temporary differences in each of the forecast months in the base year, forecast bridge months between the end of the base year and the beginning of the test year, and the months in the forecast year.

c. Provide a detailed schedule of the account 282 ADIT by temporary difference and by month for 2019, base year, and forecast year, as well as all supporting calculations for forecast changes in the temporary differences in each of the forecast months in the base year, forecast bridge months between the end of the base year and the beginning of the test year, and the months in the forecast year.

d. Provide a detailed schedule of the account 283 ADIT by temporary difference and by month for 2019, base year, and forecast year, as well as all supporting calculations for forecast changes in the temporary differences in each of the forecast months in the base year, forecast bridge months between the end of the base year and the beginning of the test year, and the months in the forecast year.

68. Reference the Thompson testimony, p. 13:1. Explain whether expenses associated with the Coronavirus Response Fund were above the line or below the line. If the former, provide the:

a. justification for recovering such expenses from ratepayers; and
b. allocation for these expenses between ratepayer classes.

69. Reference the Thompson testimony, p. 14: 1-2, referring to a grant program to provide incentives for communities to make proactive investments in "product readiness and development."

a. Explain the meaning of "product readiness and development."
b. Explain if expenses associated with this grant program are or will be above the line, or below the line. If the former, provide the: (i) justification for recovering such expenses from ratepayers; and (ii) allocation for these expenses between ratepayer classes.

70. Reference the Blake testimony at 5: 7-11. Describe the changes in facts and circumstances the Companies have experienced in their remaining coal-fired generation fleet that must be addressed now in depreciation rates.

    a. Explain whether the retirement of Mill Creek Units no. 1 and 2, and Brown Unit no. 3 will lead to stranded costs. If so, provide the most recent stranded cost projections.
    b. Explain in detail the risk of intergenerational inequities that could develop if depreciation rates are not changed in the instant cases.

71. Reference the Blake testimony at 8: 14-16, regarding the payment LG&E received from Big Rivers Electric Corp. ("BREC") in Case No. 2019-00370. Provide the most recent update regarding any construction start date for the NuCor Steel plant in Brandenburg.

    a. Explain at what point both BREC and LG&E will consider this payment to be final and non-refundable to BREC.

    b. Explain any potential tax consequences of both the one-time payment and the annual payments BREC will make to LG&E.

72. Reference the Blake testimony, p. 9: 3-13.

    a. Provide the amount of the annual payment BREC will make to LG&E as a result of the settlement reached in Case No. 2019-00370.
    b. Explain the meaning of the phrase, ". . . . the Companies propose that such payments be directed toward economic development."
    c. Explain how LG&E's ratepayers benefit from the Company's decision to not allow ratepayers to receive any portion of the annual payments.
    d. Provide a discussion regarding all factors LG&E considered in making the decision to not return the annual payments from BREC to LG&E ratepayers.

73. Reference the Blake testimony, Exhibit KWB-1. Explain whether the Companies are seeking a regulatory asset for the remaining net book value of retired and replaced meters. If so, provide the approximate sum of that regulatory asset and how it was derived.

74. Reference the Blake testimony at 10: 1-11. Explain whether meter reading and field service expense are the only types of savings to be included in the proposed regulatory liability. If not, identify all types of savings to be included in the regulatory liability.

75. Reference the Meiman testimony generally. Explain whether the Companies consider location in setting compensation for their employees.

76. Reference the Meiman testimony at 18:19, regarding the Companies' medical clinic. Explain whether costs associated therewith are paid by shareholders or ratepayers. If the latter, provide a breakdown of those costs through the end of the forecast period.

77. Reference the Conroy testimony at 19:12-16. Explain whether the percentages cited therein include reductions for the surcredit the Companies are proposing in the instant cases.

78. Explain whether the cost of service includes any premium costs for Directors & Officers' liability insurance, either direct charged or allocated. If the response is in the affirmative, provide the following items:

    a. Amount included in the base year and forecasted period. If the amount is allocated, provide the allocations.
    b. List of officers and directors covered by the insurance.
    c. List of acts covered by the insurance.

79. Explain whether it is possible, based on the cost allocation manual and service agreements in place, for more than one service company (among LKS, PPL Services, and PPL EU Services) to provide the same kind of services to KU and LG&E.

    a. If the response is in the affirmative, fully describe the safeguards in place to prevent more than one service company from allocating duplicate charges for the same service.
    b. If the response is in the negative, fully explain the delineation and differentiation of services provided by each service company.

80. Reference Filing Requirement Tab 59,[1] pp. 2-3 (Schedule F-1),[2] and the testimony of Witness Garrett. Identify where in Mr. Garrett's testimony, or in the testimony of any other witness for the Companies, the following are provided with regard to each item of dues-related expense: (i) support for the reasonableness of each such item; and (ii) a complete explanation of the direct benefit provided to ratepayers.

81. For each line item of dues expense identified in Tab 59, Sch. F-1, pp. 2-3, identify the direct benefit to ratepayers.

82. Confirm that in LG&E rate case 2003-00433, the Commission in its Final Order dated June 30, 2004, relying in part on data broken down by NARUC operating expense category, at pp. 51-52, removed 45.35% of LG&E's dues paid to Edison Electric Institute ("EEI"), for a total exclusion of $88,614, because EEI applied that portion of the dues LG&E paid toward: (i) legislative advocacy; (ii) regulatory advocacy; and (iii) public relations [for purposes of these data requests, hereinafter jointly referred to as "covered activities"].

83. [THIS REQUEST INTENTIONALLY LEFT BLANK IN ORDER TO MAINTAIN NUMBERING WITH CASE NO. 2020-00349]

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[1] 807 KAR 5:001 Sec. 16(8)(f).
[2] Pagination is identical in both Case Nos. 2020-00349 and 2020-00350.

84. [THIS REQUEST INTENTIONALLY LEFT BLANK IN ORDER TO MAINTAIN NUMBERING WITH CASE NO. 2020-00349]

85. Reference FR 16(8)(f), Sch. F-1. For each of the following entities identified therein [hereinafter also referred to as a "Dues Requiring Organization"], confirm whether that organization engages in any one or more of the following activities: (i) one or more of the "covered activities" identified above; (ii) advertising; (iii) marketing; (iv) legislative policy research; and (v) regulatory policy research. If so confirmed with regard to any one or more of these organizations, identify that organization and provide the amount of LG&E dues which that organization applies to such activities, both in dollar terms and percentages of total dues.

a. American Gas Association (AGA);
b. Kentucky Gas Association;
c. Southern Gas Association;
d. Chartwell Inc.;
e. Class Of 85 Regulatory Response Group;
f. Climate Legal Resource Group;
g. Coal Combustion Residuals;
h. Cross Cutting Issues;
i. E Source Companies LLC;
j. Edison Electric Institute (EEI);
k. Electric Power Research Institute (EPRI);
l. Midwest Ozone Group;
m. New Source Review;
n. University Of Missouri-Fri/Pud;
o. Utility Air Regulation Group (UARG);
p. Utility Solid Waste Activities Group (USWAG); and
q. Utility Water Act Group (UWAG).

86. Provide the amount of funding that EEI provides to UARG, USWAG, and UWAG.

87. Regarding LG&E's dues paid to the AGA, provide the percentage of those dues which go to the following:

a. Public Affairs activities, including but not limited to: (i) providing members with information on legislative developments; (ii) preparing testimony, comments, and filings regarding legislative activities; and (iii) lobbying on behalf of the industry; and
b. Political Contributions;
c. Media Communications, including but not limited to: (i) institutional advertising to enhance the image of the gas industry; (ii) general promotional advertising to promote the use of natural gas over other

resources; (iii) gas-fired equipment promotions, including residential equipment such as boilers, furnaces, ranges, water heaters; (iv) commercial and industrial gas equipment; and (v) promotions of Power Generation gas equipment.

88. State whether the AGA continues to break out dues that its members pay by operating expense category, as was provided in LG&E's responses to post-hearing data requests, item no. 11, in Case No. 2003-00433.[3] Provide the most recent such break-out.

89. State whether any portion of LG&E's dues paid to the AGA, Southern Gas Association, and/or the Kentucky Gas Association are used by those organizations for any one or more of the following:

a. public affairs and/or lobbying;
b. media communications and national advertising;
c. institutional advertising to enhance the image of the gas industry;
d. general promotional advertising to promote the use of natural gas over other resources;
e. gas-fired equipment promotions, including residential equipment such as furnaces, ranges, water heaters, and commercial and industrial gas equipment; and/or
f. promotions of power generation gas equipment.

90. Explain whether the Companies pay any dues or membership fees to law firms or trade groups which maintain an affiliate engaged in any covered activities.

a. Explain whether Hunton & Williams LLP, and Venable LLP are two such law firms. If so, explain whether any such dues or fees are included as above-the-line expenses in the applications in Case Nos. 2020-00349 and/or 2020-00350.

91. If any affiliate of the Companies pays dues to one or more Dues Requiring Organizations, and a jurisdictional portion of those dues are charged back to the Companies, explain whether the dues are being recovered in rates, the amounts thereof, and precisely where they can be found in the application.

92. Provide copies[4] of Annual Reports of EEI, EPRI, and of every other Dues Requiring Organization identified in FR 16(8)(f), Sch. F-1, for each year since the conclusion of the Companies' 2018 rate cases.

93. Provide a complete copy of invoices received from each Dues Requiring Organization since the conclusion of the Companies' 2018 rate cases.

[3] Accessible at: https://psc.ky.gov/PSCSCF/2003%20cases/2003-00434/KU_Response_051704.pdf

[4] Links to web sites containing open access to the reports will suffice.

94. Confirm that since 2007, EEI no longer prepares a breakout of its activities by NARUC operating expense category.

    a. For each rate case since 2007, provide the allocation the Companies utilized in determining the exclusion of particular EEI dues.
    b. Provide a narrative explanation of the bases used for each rate case allocation provided in response to subpart a., above.

95. Provide any and all documents in the Companies' possession that depict how each Dues Requiring Organization spends the dues it collects from the Companies, including the percentage that applies to all covered activities.

96. Provide a detailed description of the services each Dues Requiring Organization provided to the Companies since the conclusion of the Companies' 2018 rate cases. Of these services or benefits, identify which ones accrue directly to ratepayers, and how.

97. Have the Companies included in operating expenses any amount for: (i) EEI Media Communications, and (ii) any similar division of any other Dues Requiring Organization?

    a. If so, state the amount, indicate in which account this has been recorded, and provide a citation to any and all Commission Orders or other authority upon which the Companies are relying for the inclusion of such expense in the test period.
    b. If not, provide an estimate of how much of the Companies' dues are being spent on media or public relations work.

98. State whether the Companies are aware whether any portion of the dues they pay to any Dues Requiring Organization are utilized to pay for any of the following expenditures, and if so, provide complete details:

    a. Influencing federal or Kentucky legislation;
    b. Any media advertising campaigns backing the Companies' or the Dues Requiring Organization's position on net metering;
    c. Expenditures on "We Stand For Energy," or "Defend My Dividend," public relations, advocacy efforts or other covered activities;
    d. Contributions from EEI, EPRI or other Dues Requiring Organizations to third-party organizations and contractors including any of the expenditures identified in a. – c., above.

99. Since the conclusion of the Companies' 2018 rate case, how much has EEI paid for its efforts to "rebrand" the utility industry? Include in your response payments to external public relations firms as well as the associated salary to any EEI staff involved in contracting, coordinating with, or promulgating internally or externally the rebranding campaign effort.

100. Provide the most recent EEI documents discussing "Results in Review," and "Corporate Goals."

101. Provide EEI's most recent IRS Form 990.

102. Do the Companies' EEI dues contribute to the salary, benefits and expenses of the EEI Executive Vice President for Public Policy and External Affairs, or any other EEI officer or employee who has led an effort EEI undertook to rebrand the utility industry?

103. Do any of the Companies' personnel actively participate on Committees and/or perform any other work for any Dues Requiring Organization or any other industry organization to which one or both Companies belong, including but not limited to EEI?

    a. If so, state specifically which employees participate, how they are compensated for their time (amount and source of compensation), and the purpose and accomplishments of any such association related work.
    b. List any and all reimbursements received from industry associations, for work performed for such organizations by the Companies' employees.

II. RETURN ON EQUITY

104. Provide all credit rating agency reports (Standard and Poor's, Moody's, Fitch) on LG&E and KU from January 2018 through the most recent month in 2021. Consider this an ongoing request such that when updated reports are filed, LG&E and KU will provide these updated reports.

105. Refer to Mr. Arbough's Direct Testimony. Provide all cost of capital exhibits from the J Schedules and associated work papers and supporting documentation in spreadsheet format with cell formulas intact. Include LG&E's and KU's weighted average cost of debt and all supporting work papers.

106. Provide the earned return on equity for LG&E and KU for the calendar years 2015 - 2019. Provide all supporting work papers and documentation, including spreadsheets with cell formulas intact.

107. Provide the historical capital structures for LG&E and KU for the calendar years 2015 - 2019. Provide supporting work papers and documentation, including spreadsheets with cell formulas intact.

108. Refer to Exhibit No. 8 attached to the Direct Testimony of Mr. McKenzie.
    a. Provide the source documents for the allowed return on equity by year.
    b. Provide updated allowed ROEs through 2020 using the latest available data. Provide this data by rate case decision.

109. Provide any analyses performed by Mr. McKenzie, Mr. Arbough, or other persons at LG&E and KU that quantify the credit metrics used by Standard and Poor's and/or Moody's showing that Mr. McKenzie's recommended ROE is necessary to maintain the Companies' financial integrity and its current credit ratings. If no such analyses were performed, please so state. If such analyses were performed, please provide all associated spreadsheets and supporting documentation.

110. Please provide all work papers and supporting documentation used by Mr. McKenzie in the preparation of his Direct Testimony and Exhibits. Please include the analyses Mr. McKenzie used to select the proxy group, the companies excluded from the group, and the basis for such exclusion.

111. Refer to page 22, lines 6 through 13 of Mr. McKenzie's Direct Testimony. If not provided previously, please provide the supporting analysis, work papers, and documentation for the increase in beta values for the proxy group and LG&E/KU.

III. COST OF SERVICE AND RATE DESIGN

112. Reference the Conroy testimony generally. Explain whether the EV charging classes are being subsidized by the other classes. If so, provide the amount of the subsidy through the forecast test period.

113. With regard to the direct testimony of David Sinclair generally, please explain if the COVID pandemic has skewed or altered the sales and load forecasts for KU, LG&E electric, and/or LG&E gas. If the answer is affirmative, please quantify the forecast adjustments (alterations) due to COVID by Company and rate schedule. If the answer is negative, please explain why recognition was not given to the COVID pandemic within the Companies' sales and load forecasts.

114. With regard to the forecasted electric hourly energy sales by class as referenced in the direct testimony of witness David Sinclair, page 12, lines 1-6, please provide each forecasted hourly energy (MWH) sales for:
    a. each KY Jurisdictional retail tariff rate schedule for KU;
    b. each KY Jurisdictional retail special contract for KU;
    c. VA Jurisdictional (total) for KU;
    d. FERC Jurisdictional for KU;
    e. KU unaffiliated (non-LG&E) off-system sales (sales for resale) delineated for each type of off-system sales as shown in the Company's FERC Form 1 (e.g., RQ, OS, SF, etc.);
    f. KU sales to LG&E;
    g. each KY Jurisdictional retail tariff rate schedule for LG&E;
    h. each KY Jurisdictional retail special contract for LG&E;
    i. FERC Jurisdictional for LG&E;

j. LG&E unaffiliated (non-KU) off-system sales (sales for resale) delineated for each type of off-system sales as shown in the Company's FERC Form 1 (e.g., RQ, OS, SF, etc.);
k. LG&E sales to KU; and,
l. total system (KU and LG&E combined).

In this response, indicate if each hourly energy amount in (a) through (l) is measured at generation or at meter. If hourly amounts in (a) through (l) are measured at meter, please provide loss factors for each item in (a) through (l). Provide in executable electronic (Excel, Microsoft Access or ASCII comma-delimited) format.

115. For each of the last two years (or the most recent 24 months available), provide the following MWH sales (loads) for every hour during the 24-month period:
a. each KY Jurisdictional retail tariff rate schedule for KU;
b. each KY Jurisdictional retail special contract for KU;
c. VA Jurisdictional (total) for KU;
d. FERC Jurisdictional for KU;
e. KU unaffiliated (non-LG&E) off-system sales (sales for resale) delineated for each type of off-system sales as shown in the Company's FERC Form 1 (e.g., RQ, OS, SF, etc.);
f. KU sales to LG&E;
g. each KY Jurisdictional retail tariff rate schedule for LG&E;
h. each KY Jurisdictional retail special contract for LG&E;
i. FERC Jurisdictional for LG&E;
j. LG&E unaffiliated (non-KU) off-system sales (sales for resale) delineated for each type of off-system sales as shown in the Company's FERC Form 1 (e.g., RQ, OS, SF, etc.);
k. LG&E sales to KU; and,
l. total system (KU and LG&E combined).

In this response, indicate if each hourly energy amount in (a) through (l) is measured at generation or at meter. If hourly amounts in (a) through (l) are measured at meter, please provide loss factors for each item in (a) through (l). Provide in executable electronic (Excel, Microsoft Access or ASCII comma-delimited) format.

116. For the most recent 36-month period, please provide monthly number of customers and kWh sales by jurisdictional rate schedule separately for KU and LG&E electric.

117. With regard to the generation, sales for resale and purchased power forecasts referenced in the direct testimony of witness David Sinclair, pages 23-28, please provide:
a. forecasted hourly (MWH) generation output by unit;
b. forecasted hourly KU purchased power from unaffiliated companies;
c. forecasted hourly KU purchased power from LG&E;
d. forecasted hourly LG&E purchased power from unaffiliated companies;
e. forecasted hourly LG&E purchased power from KU; and,
f. forecasted curtailed hourly (MW or MWH) load (at generation).

Provide in executable electronic (Excel, Microsoft Access or ASCII comma-delimited) format.

118. For each of the last two years (or the most recent 24 months available), provide the following:
   a. hourly (MWH) generation output by unit;
   b. hourly KU purchased power from unaffiliated companies;
   c. hourly KU purchased power from LG&E;
   d. hourly LG&E purchased power from unaffiliated companies;
   e. hourly LG&E purchased power from KU; and,
   f. curtailed hourly (MW or MWH) load (at generation).

   Provide in executable electronic (Excel, Microsoft Access or ASCII comma-delimited) format.

119. With regard to forecasted wholesale market electricity prices discussed in the Attachment to Filing Requirement Tab 16 – 807 KAR 5:001 Sec. 16(7)(c) G [Generation Forecast Process], please provide hourly wholesale electricity prices as utilized in the Companies' Generation Forecast Process. Provide in executable electronic (Excel, Microsoft Access or ASCII comma-delimited) format.

120. For each of the last two years (or most recent 24 months available), provide actual hourly wholesale market electricity prices consistent with the PJM-South Import pricing point as discussed in the Attachment to Filing Requirement Tab 16 – 807 KAR 5:001 Sec. 16(7)(c) G [Generation Forecast Process]. Provide in executable electronic (Excel, Microsoft Access or ASCII comma-delimited) format.

121. With regard to Mr. Seelye's LOLP study, provide a detailed explanation along with all mathematical formulae showing how hourly LOLP was calculated. In this response, specifically explain how off-system sales, wholesale purchases of power, curtailment capabilities, reserve margin requirements, and outage rates are considered, evaluated, and quantified in developing hourly LOLP.

122. With regard to Mr. Seelye's LOLP study, provide all analyses, workpapers, spreadsheets, etc. showing the following:
   a. forecasted hourly system Loss of Load Probability;
   b. forecasted hourly system load (MW);
   c. forecasted hourly forced outage MW (by unit as available);
   d. forecasted hourly planned outage MW (by unit as available);
   e. forecasted available generation production from KU/LG&E-owned facilities;
   f. forecasted wholesale sales (if applicable or utilized in determining hourly LOLP);
   g. forecasted wholesale purchased power (if applicable or utilized in determining hourly LOLP); and,

h. forecasted required reserve margin (percent or MW as applicable).

In this response, provide all data and formulae necessary to replicate each hourly system Loss of Load Probability. Provide all data in executable electronic (Excel) format. If data is not available in Excel format, provide ASCII comma-delimited format with all fields defined.

123. Provide LG&E and KU individual and combined generation reserve margins for the following period:
   a. fully forecasted test year;
   b. most recent actual period during 2020;
   c. actual as of year-end 2019; and,
   d. actual as of year-end 2018.

124. Provide all workpapers, analyses, spreadsheets, etc. showing the development of each class' weighted LOLP as shown in Exhibit WSS-21. Provide in executable electronic (Excel) format.

125. With regard to the Companies' 2018 Integrated Resource Plan ("IRP"),[5] please provide an unredacted copy of Table 8-6 (page 8-11 of Report).

126. For each KU and LG&E generating unit owned individually, jointly, or partially, provide the following for the most recent actual 12-months available:
   a. names of owners (and ownership percentages);
   b. type of fuel(s);
   c. total nameplate (rated) capacity (MW);
   d. total and individual company gross investment at the end of the period;
   e. total individual company depreciation reserve at the end of the period;
   f. total and individual company annual book depreciation expense;
   g. gross kWh produced during the period; and,
   h. net (less station use) kWh produced during the period.

   Provide in executable electronic (Excel) format.

127. For each KU and LG&E generating unit owned individually, jointly, or partially, provide the following for the fully forecasted test year:
   a. names of owners (and ownership percentages);
   b. type of fuel(s);
   c. total nameplate (rated) capacity (MW);
   d. total and individual company gross investment at the end of the period;
   e. total individual company depreciation reserve at the end of the period;
   f. total and individual company annual book depreciation expense;
   g. gross kWh produced during the period; and,

[5] In Re: Electronic 2018 Joint Integrated Resource Plan Of Louisville Gas And Electric Company And Kentucky Utilities Company, Case No. 2018-00348.

h. net (less station use) kWh produced during the period.

Provide in executable electronic (Excel) format.

128. Provide the combined KU and LG&E generating order of dispatch by unit and the basis for this order of dispatch.

129. For each KU and LG&E generating unit, provide average monthly and annual fuel costs per kWh during the most recent 12-months available. Provide in executable electronic (Excel) format.

130. For each KU and LG&E generating unit, provide forecasted average monthly and annual fuel costs per kWh for the fully forecasted test year. Provide in executable electronic (Excel) format.

131. For each KU KY Jurisdictional sales for resale customer whose sales and revenue are included in the forecasted test year, provide the following:
a. name of customer;
b. type(s) of service (e.g., firm requirements, short-term opportunity, etc.);
c. maximum contract demand;
d. demand charge(s) per KW;
e. energy charge(s) per KWh;
f. fixed charge(s) per day or per month;
g. other rate charge(s) per unit;
h. forecasted test year hourly loads as available;
i. forecasted test year monthly actual demands;
j. forecasted test year monthly billed demands;
k. forecasted test year kWh; and,
l. forecasted test year revenues.

Provide in executable electronic (Excel) format.

132. For each LG&E KY Jurisdictional sales for resale customer whose sales and revenue are included in the forecasted test year, provide the following:
a. name of customer;
b. type(s) of service (e.g., firm requirements, short-term opportunity, etc.);
c. maximum contract demand;
d. demand charge(s) per KW;
e. energy charge(s) per kWh;
f. fixed charge(s) per day or per month;
g. other rate charge(s) per unit;
h. forecasted test year hourly loads as available;
i. forecasted test year monthly actual demands;
j. forecasted test year monthly billed demands;
k. forecasted test year kWh; and,
l. forecasted test year revenues.

Provide in executable electronic (Excel) format.

133. With regard to Mr. Seelye's KU class cost of service study Excel model, Mr. Seelye shows total KU system sales for resale revenue of $8,863,601. This amount is equal to $9,557,872.60 minus $694,271.50. In this regard, please provide a detailed explanation along with all calculations showing the development of $9,557,872.60 and $694,271.50.

134. With regard to Mr. Seelye's LG&E electric class cost of service study Excel model, Mr. Seelye shows total LG&E system sales for resale revenue of $34,405,720. This amount is equal to $42,910,931 minus $6,102,286 minus $2,402,925. In this regard, please provide a detailed explanation along with all calculations showing the development of $42,910,931, $6,102,286 and $2,402,925.

135. Explain why electric sales for resale customers are not allocated any costs in Mr. Seelye's cost of service studies but rather, revenues are credited back to jurisdictional customers. In this regard, also explain how the loads associated with sales for resale are considered and reflected in Mr. Seelye's LOLP method.

136. For each electric (KU and LG&E) negotiated or special contract rate customer, please provide:
    a. KU or LG&E customer;
    b. name of customer;
    c. copy of contract;
    d. type of service (firm, interruptible, etc.);
    e. reasons, support, and all analyses showing the need for a negotiated or special contract rate;
    f. cost support and analyses for negotiated or special contract rate;
    g. forecasted test period revenues at current and proposed rates;
    h. forecasted test period billing determinants;
    i. voltage level at which customer is served (e.g., transmission, sub-transmission, primary, etc.);
    j. jurisdictional annual coincident peak demand for each of the last three years;
    k. jurisdictional annual non-coincident peak demand for each of the last three years; and,
    l. identification of the class in which each customer is included in Mr. Seelye's electric class cost of service study.

137. With regard to the curtailable load credits reflected in the fully forecasted test year and Mr. Seelye's class cost of service studies, provide the level (megawatts) of curtailable load embedded in the revenue credit separately by each rate schedule and by CSR-1 and CSR-2 separately for KU and LG&E.

138. Provide a detailed itemization of each requested curtailment during the last five years. In this response, provide the date, duration, requested load curtailment by individual customer

and by CSR-1 and CSR-2, along with the amount of load actually curtailed separately for KU and LG&E.

139. Please explain in detail how KU and LG&E treat curtailment buy-through revenues in setting base rates and/or modifying its Fuel Adjustment Clause.

140. Please identify and explain detail how KU and LG&E treat test-year curtailment buy-through revenue in the electric cost-of-service studies filed in this case.

141. Provide the most recent KU and LG&E (individually) loss factors for energy and demand separated by voltage level; i.e., transmission, sub-transmission, primary, secondary.

142. Provide the current number of KU retail jurisdictional customers (accounts) by rate schedule for each zip code within the Company's service area. Note: lighting accounts may be excluded from this data set. Provide in executable electronic (Excel) format.

143. Provide the current number of LG&E retail jurisdictional customers (accounts) by rate schedule for each zip code within the Company's service area. Note: lighting accounts may be excluded from this data set. Provide in executable electronic (Excel) format.

144. With regard to the Company's KU CCOSS, explain why Rate PS-Secondary, Rate TOD-Secondary, and Outdoor Sports Lighting (OSL) are not allocated any secondary lines (overhead or underground) costs.

145. With regard to the Company's LG&E CCOSS, explain why Rate PS-Secondary is allocated secondary demand-classified costs for distribution primary and secondary lines but no customer-classified costs.

146. With regard to the Company's LG&E CCOSS, explain why Rate TOD-Secondary is not allocated any secondary distribution lines costs (demand or customer).

147. With respect to KU Rate Schedule TE (Traffic Energy), please provide a separation of the current number of traffic signals that are metered and unmetered.

148. With respect to KU Rate Schedule LE (Lighting Energy), please provide a separation of the current number of lights or connections that are metered and unmetered. In this regard, if multiple lighting fixtures are included in a single account, provide the number of accounts that are metered and unmetered.

149. With respect to KU Rate Schedule TE (Traffic Energy), please provide the current number of separate accounts; i.e., number of bills rendered monthly.

150. With respect to KU Rate Schedule LE (Lighting Energy), please provide the current number of separate accounts; i.e., number of bills rendered monthly.

151. With regard to KU and LG&E electric, please provide an executable electronic (Excel) copy of the Companies' revenue proof at current and proposed rates.

152. Please provide a copy of all presentations made to the Kentucky PSC and/or the Kentucky OAG regarding KU/LG&E's potential subscription to the Southeast Energy Exchange Market ("SEEM").

153. Please provide a copy of all filings made with the FERC regarding KU/LG&E's participation in SEEM.

154. Please explain how KU/LG&E's potential participation in a SEEM will or may impact:
   a. the dispatch of the Companies' generating assets;
   b. levels of purchased power;
   c. levels of sales for resale; and,
   d. system loss of load probabilities.

155. For the most recent 36-month period, please provide monthly number of customers and CCF or therm sales by jurisdictional rate schedule for LG&E gas.

156. With regard to LG&E gas and Mr. Seelye's Exhibit WSS-35, please provide:
   a. all source documents and workpapers supporting degree days of 3,585 and 3,677; and,
   b. an explanation of why Residential and Commercial degree days are 3,585 while the other class degree days are 3,677.

Provide all workpapers in executable electronic (Excel) format.

157. With regard to LG&E gas and Mr. Seelye's Exhibits WSS-35 and WSS-38, please explain why the development of the mains allocator is based on a design day temperature of -14ºF (79 degree days) while the storage allocator is based on 4ºF (61 degree days).

158. For each LG&E gas negotiated or special contract rate customer, please provide:
   a. name of customer;
   b. copy of contract;
   c. type of service (firm, interruptible, etc.);
   d. reasons, support, and all analyses showing the need for a negotiated or special contract rate;
   e. cost support and analyses for negotiated or special contract rate;
   f. forecasted test period revenues at current and proposed rates;
   g. forecasted test period billing determinants;
   h. jurisdictional annual coincident peak demand for each of the last three years;
   i. jurisdictional annual non-coincident peak demand for each of the last three years; and,
   j. identification of the class in which each customer is included in Mr. Seelye's gas class cost of service study.

159. For each of the last three years, please provide daily natural gas injections and withdrawals from storage. If daily amounts are not available, provide monthly natural gas injections and withdrawals. Provide in executable electronic (Excel) format.

160. With regard to LG&E gas, please provide an executable electronic (Excel) copy of the Company's revenue proof at current and proposed rates.

161. Please provide the excel version of Mr. Sinclair's Exhibits DSS-1 and DSS-2, including all supporting schedules, also in excel.

162. Please provide, by month, the actual gWh sales and mW/mVa billing demands by rate schedule for the portion of the "base period" that is projected in Mr. Sinclair's Exhibits DSS-1 and DSS-2. This would be the monthly sales data for the period September 2020 through December 2020. Please provide the requested information in excel format with formulas intact.

163. With regard to Mr. Sinclair's testimony on page 9, please provide the names of the 30 major account customers surveyed and indicate which utility they take service on.

164. Please provide all supporting workpapers in excel format with formulas, including all excel models used to develop the Companies' base period and test year revenue forecasts by rate schedule.

165. Please provide, in excel spreadsheet format, the electric sales forecast, by month, by rate class, by Company that supports the 2021 Business Plan Electric Load Forecast (KAR 5:001 Sec. 16(7)(c)C).

166. For each Company, please identify any large customer loads expected in the Future Test Year on rates RTS, TOD-PRI, TOD-SEC and FLS) that the Company is currently aware of but were not included in the test year projected mWh and revenues. For each such customer, provide the customer's name, the rate class on which the customer is expected to take service, the mWh expected by month during the test year the base revenues expected by month during the test year.

167. With respect to the Companies' response to the previous question, please indicate whether the Companies have provided any incentives and/or discounts (e,g., discounted contracts) associated with such customer. If there were such incentives and/or discounts provided, please provide the specific incentives/discount provisions associated with such customer.

168. Please state whether KU has included the kWh sales and kVa billing demand, and revenues associated with the announced expansion project of Phoenix Paper Wickliffe in Ballard County in future test year billing determinants and revenues. If these billing determinants and revenues have been included in the future test year, please provide for each month the kWh sales, kVa billing demand and revenue, by rate element (e.g. kWh)

and adjustment clause associated with this expansion. Also, please identify the rate schedule for service to this customer.

169. To the extent that the sales forecast shown in Schedule M-2.2 is different for any rate class from the 2021 Business Plan Electric Forecast GWh, please provide a reconciliation and an explanation for any differences.

170. Please provide an analysis of the actual base period kWh energy sales through December 2020 on a weather normalized basis for each rate class.

171. With regard to 807 KAR 5:001 Sec. 16(7)(c)B (Electric Sales & Demand Forecast Process), please provide an explanation of how the individual customer information from customer surveys or is incorporated into the forecast, including whether such information is combined with econometric forecast results for the rate class.

172. Please provide a description of the methodology used to develop the avoided cost rates reflected in Rider SQF. Also provide, in excel format with formulas, the support for the most recent update of avoided costs paid under Rider SQF.

173. Please provide each of the class cost of service models presented in Seelye Exhibits WSS-21 and 22 (LOLP, 12 CP, 6 CP) in excel format with formulas. Also provide all supporting workpapers, including excel spreadsheets with formulas. At a minimum, include the following supporting information:
    a. the excel models used to develop the projected test year hourly system and rate class loads.
    b. an excel spreadsheet containing the LOLP hourly results and the development of the LOLP rate class demand allocation factors, the 12 CP rate class demand allocation factors and the 6 CP rate class demand allocation factors.
    c. the loss study used to support the energy and demand loss factors used in the class cost of service study.

174. Please provide each excel model, with formulas, used to produce each of Mr. Seelye's exhibits.

175. Please provide, in excel format, for each rate class, by Company, monthly coincident peak demand at the generation level (i.e., including losses), for the test year. These rate classes should correspond to the rate classes used in Mr. Seelye's class cost of service studies.

176. To the extent not provided in response to the previous question, please provide the following information for each rate class/rate schedule included as a separate class in the class cost of service study for the test year 12 months ending June 2022:
    a. monthly system peak load (LGE and KU separately stated and combined).
    b. the load of each rate class at the time of the monthly LGE/KU system peak, showing the following:

i. load at meter
ii. losses
iii. load at generation

c. Monthly mWh energy at the generation voltage level for the rate class/rate schedule.
d. Energy and demand loss factors for each voltage level, by rate class/rate schedule, at which customers on the rate class/rate schedule take service.
e. Monthly mWh energy sales at the meter, separately stated for each voltage at which customers in each rate class/rate schedule take service, by rate class/rate schedule (for example, the metered mWh for Rate PS secondary and Rate PS primary by month).

177. With regard to Exhibit WSS-21 (LOLP), pages 1 and 2, please provide all supporting workpapers, in excel format with all formulas intact, used to develop this exhibit. This would include, but not be limited to:
    a. hourly system load
    b. hourly rate class load at:
        i. meter
        ii. generation voltage
        iii. loss factor used to convert metered load into load at generation
    c. hourly LOLP for the combined KU-LGE system

178. Please provide the output of the analysis used to develop hourly LOLP. Provide in excel format, with formulas intact.

179. Provide, for the years 2020, 2019, 2018, and 2017) the following actual information:
    a. monthly system peak load (LGE and KU separately stated and combined system.
    b. date and hour of the LGE + KU monthly peaks
    c. date and hour of the separate LGE and KU monthly peaks

180. Please provide in excel spreadsheet format, by month, by Company, by rate class, the following information for each of the past 3 years:
    a. actual kWh sales
    b. weather normalized kWh sales using the same weather normalization methodology that is used by the Companies and PPL in the Quarterly Earnings Call Presentations
    c. the number of customers

181. Please provide the following information regarding the development of rate class hourly loads for the projected test year ending June 30, 2022:
    a. A narrative fully explaining the methodology used by the Companies to develop hourly loads by rate class, including each adjustment made to reconcile these rate class hourly loads to the Companies' load and energy forecast for the test year.

b. All workpapers showing the development of test year hourly loads by rate class.

182. With regard to the LOLP analysis used in the class cost of service study, please provide the following:
   a. an explanation of how tie line capacity to other utilities was treated in the analysis.
   b. an explanation of whether there were any adjustments to hourly loads in the development of the LOLP analysis.
   c. a detailed description of the methodology used to calculate the hourly LOLP results.

183. Please provide any information available to Mr. Seelye, the Prime Group or LG&E/KU regarding the following:
   a. Any regulatory jurisdiction that has adopted the LOLP cost of service method used by Mr. Seelye in this case.
   b. For each such jurisdiction, please provide a copy of a Commission Order addressing this issue.
   c. Identification of any electric utility that supported the LOLP method in testimony before a state regulatory commission. Please identify the name of the utility, the case number and a copy of the testimony.
   d. Identification of any electric utility in KY that has presented testimony before the KPSC in support of the LOLP cost of service method. For each such utility, please provide the name of the utility, the case number and a copy of the testimony.

184. Please provide any testimony, papers or presentations prepared by Mr. Seelye or any other employee of the Prime Group in the past ten years which addresses the LOLP cost of service methodology. This would include all testimony (other than prior LGE/KU proceedings), papers or presentations supporting the LOLP method and testimony opposing the LOLP method.

185. With regard to the Rate FLS, please identify, by month for the last 3 years, each curtailment pursuant to the following provision of the FLS tariff:
   a. "SYSTEM CONTINGENCIES AND INDUSTRY SYSTEM PERFORMANCE CRITERIA:

      i. Company reserves the right to interrupt up to 95% of Customer's load to facilitate Company compliance with system contingencies and with industry performance criteria. Customer will permit Company to install electronic equipment and associated real-time metering to permit Company interruption of Customer's load. Such equipment will immediately notify Customer five (5) minutes before an electronically initiated interruption that will begin immediately thereafter and last no longer than ten (10) minutes nor shall the interruptions exceed twenty (20) per month. Such interruptions will not be accumulated nor credited against annual hours, if any, under either Rider CSR-1 or CSR-2. Company's right to interrupt under this provision is restricted to responses to unplanned outage or de-rates of LG&E and KU Energy LLC System (LKE System) owned or purchased generation or when Automatic Reserve Sharing is invoked. LKE System, as used herein, shall consist of KU and LG&E. At Customer's request, Company shall provide documentation of the need for interruption under this provision within sixty (60) days of the end of the applicable billing period."

ii. For each such curtailment, provide the following information:

b. The length of the interruption, and the date and hour of the interruption.
c. The MW amount of load interrupted.
d. The specific reason (e.g., unplanned outage or de-rate of LG&E and KU owned generation or when Automatic Reserve Sharing is invoked) for the curtailment.
e. The specific actions taken by LKE during the 10-minute interruption to respond to the unplanned outage or de-rate, once the 10-minute maximum interruption period is completed (for example, start-up a quick start unit, rely on spinning reserve capacity, etc.).

186. With regard to the FLS "SYSTEM CONTINGENCIES AND INDUSTRY SYSTEM PERFORMANCE CRITERIA," please provide the following:
   a. a detailed explanation of Automatic Reserve Sharing, including LKE's obligations under that provision.
   b. identification of each instance during the past 3 years in which Automatic Reserve Sharing was invoked, including the name of the party invoking this provision.
   c. LKE's obligations under the Automatic Reserve Sharing provision
   d. identification of each instance during the past 3 years in which LKE relied on Automatic Reserve Sharing, and a description of the reason(s) for LKE's need for Automatic Reserve Sharing.

187. With regard to the FLS "SYSTEM CONTINGENCIES AND INDUSTRY SYSTEM PERFORMANCE CRITERIA," provision, please explain how the Companies would respond to unplanned outage or derates of LG&E and KU Energy LLC System (LKE System) owned or purchased generation or when Automatic Reserve Sharing is invoked if this curtailment provision was not in the FLS tariff.

188. Please provide copies of a unit cost of service analysis (e.g., Rate RTS unit energy costs per kWh, unit demand costs per kVa, customer cost per customer) based on each of the 3 class cost of service studies presented by the Companies in this case (LOLP, 12 CP, 6 CP).

189. Please provide, for each rate class serving coal mine or coal extraction customers, an excel schedule (with formulas) identical to Schedule M-2.3 comprised of billing determinants for only coal mine or coal extraction customers. For example, provide a version of Schedule M-2.3 for Rate PTOD, as shown on M-2.3, page 11 of 26, containing

only billing determinants and revenues for customers in the coal mine or coal extraction industry.

190. For Rate Schedules TODP and RTS please provide the following information.
   a. The MWh energy usage for the 20 largest customers for both the base and future test year periods.
   b. Please confirm that the North American Industry Classification System for each of the 20 largest customers is Sections 21, 22, 31,32 or 33. If that is not true as to any individual customer, then please so identify.
   c. The test year MWh energy on each rate schedule, separately stated by rate schedule, for customers:
      iii. Classified under NAICS Section 21, 22, 31, 32 or 33.
      iv. All other customers taking service on the rate schedule.

191. For Rate Schedules TODP and RTS, please provide the following information regarding the design of proposed rates:
   a. A narrative explaining the methodology used to develop the proposed kWh energy charge of each rate. Also provide an explanation for the 21% increase in the proposed energy charge of each rate.
   b. A complete set of workpapers, including excel spreadsheets with formulas, showing the development of the energy charge, with specific references and citations to TABs, cell references in the class cost of service study.

192. Please provide the MWh energy associated with customers engaged in the extraction or processing of coal, by rate schedule, for the following periods:
   a. The most recent 5-year historic period (e.g., 2016 through 2020) by year.
   b. The Base period in this case.
   c. The project test year in this case.

IV. AMI

193. Refer to Witness Blake Testimony, page 10 at 4, which states, "The Companies also propose to record a regulatory liability until its first base rate proceedings following implementation to the extent their actual meter reading and field service expenses are less than the forecast test period level embedded into base rates during these current proceedings." The OAG understands the stated intention is to secure for customers the meter reading and field service expense reduction benefits anticipated during the deployment period.

   a. Please describe any commitments the Companies are willing to make regarding the level of expense reductions reflected as rate reductions after the deployment period, for example, through test-year adjustments in the rate case used to recover AMI investment costs. If the Companies are not willing to make such commitments, please explain why not.

b. Please describe any commitments the Companies are willing to make to measuring actual expense reductions, and the Companies' recommendations on a measurement approach. If the Companies are not willing to make such a commitment, please explain why not.
c. Describe any commitments the Companies make, or are willing to make to sharing the risk of shortfalls of actual expense reductions from projected expense reductions. If the Companies are not willing to make such a commitment, please explain why not.

194. Refer to Witness Blake Testimony, page 24, line 16, which describes how six robotic process automation projects resulted in a reduction of one full time headcount and three interns.

a. Describe each of the six robotic process automation (RPA) projects. Include in these descriptions how the associated work processes were performed prior to RPA implementation, and how the RPA project automates them.
b. Provide the amount the Companies capitalized for each of the six RPA projects.
c. Provide the period (in years or months) over which each of the six RPA projects will be depreciated.
d. Provide the salary and benefits associated with the one full time headcount in 2019.
e. Provide the salary and benefits associated with the three interns in 2019.

195. Refer to Witness Blake testimony, Exhibit KWB-2, page 1. For each of the items under the "Status Quo Case", provide the actual amounts incorporated into the revenue requirement calculations for the test year used in this rate case:

a. Cost of Capital – Existing Meters;
b. Depreciation – Existing Meters;
c. Revenue Requirement – New Meters;
d. Revenue Requirement – Voltage Meters;
e. Revenue Requirement – Handhelds and MAM;
f. Revenue Requirement – Other;
g. Meter Reading;
h. Field Services; and
i. Property Taxes – Existing Meters

196. Refer to Witness Blake testimony, Exhibit KWB-2, page 2 (15-yr Meter Life). Provide detailed calculations by year for the following items under the "AMI Case":

a. Regulatory Asset Amortization (please include details for each of the three components – deferred operating expenses, net book value of electric meters replaced, and the differences between AFUDC as proposed vs. FERC methodology); and
b. Regulatory Liability Amortization (please include details for each of the four components – meter reading, field services, ADIT for retired & replaced meters, and ADIT for AMI Placed in Service for Income Tax Purposes).

197. Refer to Witness Blake testimony, Exhibit KWB-2, page 3 (20-year Meter Life). Provide detailed calculations by year for the following items under the "AMI Case":

a. Regulatory Asset Amortization (please include details for each of the three components – deferred operating expenses, net book value of electric meters replaced, and the differences between AFUDC as proposed vs. FERC methodology); and
b. Regulatory Liability Amortization (please include details for each of the four components – meter reading, field services, ADIT for retired & replaced meters, and ADIT for AMI Placed in Service for Income Tax Purposes).

198. Explain whether there is any difference in the projected life spans of the residential electric meters, as compared with that for the proposed commercial and industrial meters.

199. Provide the projected life spans of: (i) the AMI communications module LG&E proposes to attach to gas meters located within the LG&E electric service territory; and (ii) the encoder receiver transmitter to be attached to gas meters in LG&E's gas-only service area, which will enable the use of AMR technology.

a. If the batteries designed to be used for the equipment in both subparts (i) and (ii) above carry a different life span, provide that projected life span.

200. Refer to Witness Blake Testimony, pages 23-30, which describes the Companies' efforts to reduce costs, as well as pages 30-31, which describes the Companies' business and financial planning processes designed to improve efficiency and productivity. Refer also to Witness Blake Testimony, page 18: 18-23, which describes the communications network the Companies propose to install for its smart meter (AMI) deployment. The OAG is aware that the present value of building and operating such communications networks, including capital and O&M, likely amounts to tens of millions of dollars. Provide any financial analyses the Companies completed comparing the cost to install and operate their own meter mesh communications network to the cost to secure meter data communications services from public wireless data network providers such as AT&T and Verizon Wireless. If the Companies completed no such analysis, please explain why not.

201. Refer to Witness Blake Testimony, Exhibit KWB-1, page 1, line entitled “Capital Expenditures”. Refer also to Mr. Blake’s Testimony, pages 18-19, which describes various capital items required to provide AMI functionality. Provide the details of the “Capital Expenditures” line item be year for each of the five years indicated in this schedule. Be sure to included, at a minimum, the cost details for the items described in Mr. Blake’s Testimony, including, but not limited to:

  a. RF mesh network design, hardware, installation, and testing;
  b. Meters (excluding the remote service switch);
  c. Meter remote service switches;
  d. Any other optional Meter features and capabilities (such as Zigbee or other home area/energy management network communications chips);
  e. Meter testing, handling, and Installation; and
  f. Each of the seven meter software applications described on page 19 of Mr. Blake’s Testimony.

202. Refer to Witness Blake Testimony, Exhibit KWB-1, page 1, line “Remaining Net Book Value – Retired & Replaced Meters”. Refer also to Witness Bellar Testimony, Exhibit LEB-3, Table 2, which indicates that the Companies will replace (or augment) 756,000 meters. Provide details which indicate that the book value of meters and/or other equipment removed from service to complete the AMI deployment the Companies have proposed totals the $26.8 million listed on Exhibit KWB-1, page 1.

203. Refer to Witness Bellar Testimony, Exhibit LEB-3, Table 1 on page 4.

  a. The referenced analysis appears to cover a 30-year period. Please explain why the Companies believe this is the most appropriate period for the referenced analysis.
  b. Provide an active MS Excel worksheet or workbook, with all formulas intact and available for review, offering the details behind each of the options in Column (A) (PVRR, AMR becomes obsolete) and each of the options in Column (B) (PVRR, AMR Remains Viable) by year from 2021-2050 (8 worksheets/workbooks in total), including:

    i. Status Quo (A, B)
    ii. Full AMI (A, B)
    iii. AMI + AMR GO (A, B)
    iv. Full AMR (A, B)

204. Refer to Witness Bellar Testimony, Exhibit LEB-3, pages 17-19, which describe the Companies’ concerns regarding potential AMR obsolescence risks.

  a. Provide the exact report or other data source used to create Figure 8. (The OAG was unable to locate the data source after navigating to the link provided.)

b. Confirm that the data listed in Figure 8 consists only of electric meters. If this cannot be confirmed please explain.

c. The OAG is aware that hundreds of millions of natural gas and water meters in the U.S. are read monthly by utilities via AMR, including those utilities which do not offer electric service (and thereby have no tie-in to electric AMI technology). Discuss how this fact could mitigate AMR obsolescence risk.

d. Refer to the Companies' response to subpart (c) of this question. Identify and describe the technologies increasingly available to operators of natural gas and water utilities which might contribute to AMR obsolescence risks.

e. AMI technologies are also subject to obsolescence risks. Describe the steps the Companies took to address AMI obsolescence risk during AMI plan development, and identify any such evidence in materials the Companies provided in the two instant proceedings (Case Nos. 2020-00349 and 2020-00359).

f. Identify any evidence of the AMI obsolescence risk reduction actions provided in response to subpart (e) of this question among the materials the Companies provided in the two instant proceedings.

205. Refer to Witness Bellar Testimony, Exhibit LEB-3, page 16, regarding the expansion of AMR in the Companies' "gas only" service area.

a. Identify alternatives to AMR expansion the Companies considered to reading gas meters in the "gas only" service area.

b. Provide any and all analyses the Companies completed to compare these alternatives to each other, and which resulted in the choice of AMR expansion for the gas only service area. If the Companies did not complete such analyses/comparisons, please explain why not.

206. Refer to Witness Bellar Testimony, Exhibit LEB-3, page 15, which states, "After Commission approval is received, any in-scope electric meters that fail prior to or outside the meter deployment project in a different part of the service territory will be replaced with AMI meters as they fail."

a. Provide a list of meters, and the counts of each, which have failed by year from 2015-2019. In this list of meters, include identifiers such as 1) manufacturer; 2) model; 3) type (electromechanical or electronic); 4) phase (single vs. polyphase).

b. The OAG is aware that the Companies have been considering an AMI transition since at least 2010, when the Companies' parent, PPL Corporation, began installing smart meters in Pennsylvania. Explain why the Companies have not been following the replacement process described in the quoted statement, above, on a routine basis to reduce the stranded costs associated with an anticipated AMI transition.

c. Provide any analyses the Companies completed historically – for example since 2010, when AMI meters became commonly available, or since 2012, when electric AMI meter installations first surpassed electric AMR meter installations in the U.S. -- which indicated that continuing to replace failed meters with "dumb" (non-AMI) meters would be less costly for customers overall than replacing failed meters with AMI meters in anticipation of a future AMI transition. If the Companies never completed any such analyses, please explain why not.

207. Refer to Witness Bellar Testimony, Exhibit LEB-3, page 15, which explains that AMI data will enable the Companies to anticipate transformer failures.

a. Explain how AMI capabilities will be used to anticipate transformer failures.
b. Provide any analyses the Companies have completed which indicates that the incremental cost to residential customers of prospective replacement of distribution transformers before they fail (present value of revenue requirement) is less than the economic benefits to residential customers of the associated reliability improvements.

208. Refer to Witness Bellar Testimony, at 56: 9-10, which indicates that customers want AMI meters. In support of this statement, Mr. Bellar notes that 20,000 customers have opted-in to the Companies' existing voluntary AMI offer, with 5,200 customers on a waiting list. Provide any customer research the Companies have conducted which indicates the current level of interest in AMI capabilities among the Companies' customers overall.

209. Refer to Witness Bellar Testimony, Exhibit LEB-3, pages 15-16, which allude to several types of potential AMI benefits which are difficult to quantify, including reduced usage on inactive meters, bad-debt write offs, and theft, which will increase the Companies' billed sales volumes and/or revenues to the extent they can be accomplished. However, the OAG notes that none of these benefits will result in rate reductions for customers until they are 1) implemented to their maximum benefit potential; and 2) included in a rate case test year, test year adjustment, bad debt accrual rate reduction, or sales volume forecast.

a. Describe any commitments the Companies are willing to make to maximizing the revenue improvement potential of smart meters.
b. Describe any commitments the Companies are willing to make to measuring the actual revenue improvements delivered from smart meters.
c. Describe any commitments the Companies are willing to make to ensure all revenue improvements from smart meters are represented in the test year, test year adjustments, sales volume forecasts, or bad debt accrual rates of the rate case in which the Companies seek to secure AMI cost recovery.

210. Refer to Witness Bellar Testimony, Exhibit LEB-3, Appendix A, Tables 26 and 27 on pages A-19 and A-20.

a. For the AMI +AMR_GO scenario, provide the calculations, assumptions, estimates, and other details associated with the ePortal Fuel Savings projection for each year from 2021-2050. Any worksheets provided in response should be active with no protected cells, all calculations available for review, no pasted values, and all input data cited as to sources. Please include all assumptions, such as customers counts/sales volume forecasts by year, and low and high marginal cost of energy forecasts by year, from 2021-2050, with your response.

b. For the AMI+AMR_GO scenario, provide the calculations, assumptions, estimates, and other details associated with the CVR Fuel Savings projection for each year from 2021-2050. Any worksheets provided in response should be active with no protected cells, all calculations available for review, no pasted values, and all input data cited as to sources. Please include all assumptions not included in response to (a), (confirming any data not also provided in response to (b) are the same), such as number of circuits, percentage of circuits, sales volume forecasts by circuit, etc. with your response.

211. Refer to Witness Saunders Testimony, Appendix A, regarding e-Portal capabilities. Provide any commitments the Companies are willing to make regarding the measurement and reporting each year of the count of the:

a. unique number of customers who have accessed their own usage dashboard in the e-Portal at least once each year (slides A-2 and A-3);

b. unique number of customers who have accessed their own usage dashboard in the e-Portal more than once in the last year, by access frequency (2 times, 3 times, 4 times, etc.);

c. customers enrolled in the Threshold Notifications feature (slide A-6) of the e-Portal each year;

d. customers with a current Property Profile completed in the e-Portal each year;

e. customers who are making consumption data available to third parties on an ongoing (no end date) basis (slide A-12) through the e-Portal each year;

f. customers receiving service under the RTOD-E rate; and

g. customers receiving service under the RTOD-D rate.

212. Refer to Witness Bellar Testimony, Exhibit LEB-3, Appendix E, the e-Portal energy reduction analysis completed by Tetra Tech.

a. Explain in detail how the results of the analysis were used to project annual energy savings from the e-Portal. For example, were the (discounted) energy savings percentages simply multiplied by forecast energy billings by residential and small commercial customers to project energy use reductions?

b. Describe any commitments the Companies are willing to make regarding the measurement of actual energy use reductions from the e-Portal, and describe the Companies' recommended measurement approach. If the Companies are not willing to make any such commitment, please explain why not.

213. Refer to Witness Bellar Testimony, Exhibit LEB-3, Appendix D, the CVR Potential Study. Page 8 of the Study identifies three voltage control thresholds: 116, 117, and 118 volts, resulting in annual energy reductions of 2.61, 1.99, and 1.40 percent respectively. Refer also to the Companies' response to the OAG-KIUC DR 1-206 (b), above.

a. Confirm that CVR can be implemented with a relatively few smart meters or line sensors per circuit, and does not require full system-wide AMI deployment. If this cannot be confirmed, please explain.

b. The OAG understands that CVR can be implemented without a full system-wide smart meter deployment. If so, for purposes of an "apples to apples" comparison, it would be important to add CVR-related fuel cost savings to the AMR scenarios. Explain why the Companies did not estimate CVR fuel savings using only a relatively few smart meters or line sensors in the AMR scenarios.

c. Explain in detail how the results of the CVR potential study were used to project annual energy savings from CVR. For example, does the CVR potential study multiply the energy savings percentages by the forecast energy billed on the 404 "candidate" circuits to project annual energy reductions from CVR?

d. The OAG is aware of two approaches to implementing CVR. One is static, in which field equipment settings (load tap changers, voltage regulators, cap banks, etc.) are modified periodically to reduce average circuit voltage. The other is dynamic, in which field assets are upgraded or replaced to accept remote wireless control, and in which settings are optimized continuously based on instructions from software populated with data from field sensors in near real time. Which approach did the Companies assume when selecting the three voltage control thresholds?

e. Identify where in the Companies' response to OAG-KIUC DR 1-199 (b), above, the incremental O&M and/or capital costs of the CVR approach identified in subpart (d) of this question can be found. If these costs are not included in analyses which include CVR benefits, please explain why not.

f. Provide any studies or analyses the Companies completed comparing the energy savings potential and benefit-cost analyses of the "static" approach described in subpart (d) of this question to the "dynamic" approach described in subpart (d) of this question. If no such studies or analyses have been completed, please explain why not.

g. Describe any commitments the Companies are willing to make regarding the measurement and reporting of actual energy use (or voltage) reductions from CVR, and describe the Companies' recommended measurement approach. If the Companies are not willing to make any such commitment, please explain why not.

214. Refer to Witness Bellar's testimony, at 62: 14, regarding access to near-real time usage data. The OAG is aware that some AMI meters are equipped with wireless communications capabilities which allow customers to "tap into" meter data in near real time via their existing home area wireless networks. The OAG understands this capability is typically enabled via a device (typically called a "bridge") between the meter and a customer's home area wireless network which the customer must purchase or secure from a third party (or which could conceivably be supplied by a utility as part of a demand-side management program or an unregulated home energy management services offering).

a. Does the Companies' selected AMI vendor offer this home area network wireless communications capability as an option?
b. Do the Companies plan to install meters with this capability? If so, please discuss the extent to which this capability will be deployed, as well as the Companies' plans, if any, to utilize the capability.
c. Describe any commitments the Companies are willing to make to ensure that such a capability will not be used to secure any advantage for the Companies or unregulated affiliates over third parties competing in unregulated home energy management services markets, or over third parties offering "bridge" devices.

215. Refer to Witness Bellar's testimony, at 58:17, which indicates the Companies' commitment to offer a prepay program. The OAG understands that prepayment programs offer cost reductions to utilities, including reductions in working capital requirements/associated interest expense (normally needed to fund accounts receivable), and reductions in bad debt provision rates. Describe any commitments the Companies are willing to make that such cost reductions will be incorporated into the prepaid rates the Companies will offer.

216. Refer to Witness Bellar's testimony, at 58:17, which indicates the Companies' commitment to offer time-of-day rates. Describe any commitments the Companies are willing to make regarding the types or results of time-of-day rates offered, including:

a. A commitment to offer a time-of-day rate with a critical peak price feature;
b. A commitment to offer a universal (all customer) peak-time rebate program;
c. A commitment as to the minimum percentage of residential customers who elect to receive service on a time-of-day rate;
d. A commitment as to the reductions in system peak demand (in MW) secured through time-of-day rates with critical peak price or peak time rebate features;
e. Any other commitments related to time-of-day rates the Companies believe will increase the value of AMI to customers.

217. Refer to Witness Bellar's testimony, Exhibit LEB-3, page 12, which states ". . . off-cycle meter reads, move-out and move-in orders, and disconnect and reconnect orders are completed with an in-person visit to the customer's premise." The OAG understands that the Companies will be installing meters with remote disconnect capabilities if the AMI CPCN is approved.

a. Confirm that, to the extent AMI meters with remote disconnect capabilities are installed, remote disconnections for non-payment will still involve an in-person visit to the customer's premise, and that compliance with this and all other consumer protections in current PSC regulations associated with disconnection for non-payment will continue. If this cannot be confirmed, please explain any and all departures from such regulations the Companies are requesting.

b. Refer to the Companies' response to subpart (a) of this question, as well as to the PVRR Table on page 56 of Mr. Bellar's testimony. Confirm that the figures in the Table assume that in-person visits and all other consumer protections associated with disconnections for non-payment will continue if the AMI CPCN is approved. If this cannot be confirmed, provide modifications to the figures in the Table which would reflect continued compliance with these consumer protections.

218. Refer to Witness Saunders' testimony on the AMI Customer Engagement and Communication Plan, Exhibit ELS-2, generally, and to Witness Bellar's testimony related to the AMI CPCN, pages 53-63, generally. The OAG notes no discussion on how the Companies intend to use the increased information on customers' energy usage smart meters make available.

a. Provide the Companies' current customer data usage policy. Highlight those sections of the policy which detail how, and for what purposes, the Companies are permitted to use customer data, including energy usage data, today.

b. Provide all modifications to the current customer data usage policy the Companies will make if the AMI CPCN is approved.

219. Refer to Witness Bellar's testimony related to the AMI CPCN, pages 53-63, generally.

a. Confirm that the AMI meters the Companies propose to install will enable demand rates for residential customers. If this cannot be confirmed, please explain.

b. Describe any commitments the Companies are willing to make regarding demand rates for residential customers. For example, are the Companies willing to commit that residential demand rates will not be offered on anything other than a voluntary (i.e., not default) basis?

220. Refer to Witness Saunders' testimony, Appendix (MyMeter Screenshots), slide A-12, regarding customer authorization of third-party access to customer usage data. Confirm

that the Companies commit to full compliance with Green Button's Connect My Data standard. If this cannot be confirmed, please explain.

221. Reference the Blake testimony at 10: 18-23 through 11: 1-5. Explain whether it would be cost effective to delay the AMI project by the amount of time necessary for the Companies' existing meters to be fully depreciated, and how doing so would affect the NPV values.

222. Reference the Blake testimony at 11: 21-22, in which he states that the proposed AMI capital project is a single project that includes interdependent systems. Explain whether it could be possible for the Companies to share any back-office computer hardware and software that their affiliate, PPL Electric Co. has deployed for its AMI project.

223. Reference the Blake testimony at 13: 20-21, in which he states, with regard to the proposed AMI project, that several state public utility commissions have approved other utilities' requests to accrue AFUDC using the utility's WACC. Explain what benefit would accrue to ratepayers in the event the Kentucky Commission should approve this request.

224. Reference the Blake testimony at 16: 8-22 through 17: 1-12. Confirm that under the Companies' analysis, by the fifth year following complete deployment, net benefits of the proposed AMI project will have exceeded net costs, such that ratepayers will not be paying any costs for the project.

225. Reference the Bellar testimony generally. Provide the undepreciated costs for existing meters at the current time. Provide also the projected undepreciated costs at the time of the proposed AMI project's completion.

226. Reference the Bellar testimony generally. Provide a discussion of whether the proposed system-wide AMI rollout would increase the risk of cybersecurity threats, and describe the actions the Companies propose to mitigate any such threat increase.

227. Reference the Wolfe testimony at 21:16-18. Explain whether the benefits to distribution management resulting from AMI deployment discussed therein can be tracked and quantified. If so, please describe that process.

228. Reference the Wolfe testimony at 27:5-7, wherein he states: "AMI meters can enhance fault locating and isolation, and service restoration capabilities once the final phase of the advanced distribution management system [ADMS] is deployed." Clarify whether it is the final phase of ADMS, or AMI to which he is referring.

229. Reference the Wolfe testimony, Exhibit JKW-1, p. 27. Explain whether there is any duplication between Volt/VAR Optimization program, discussed on this page, and the Conservation Voltage Reduction program, as part of the proposed AMI project.

230. Reference numerical paragraph 20 in the LG&E application, and its identical counterpart in the KU application numerical paragraph 18, wherein it is stated, *inter alia*: "The

proposed savings derive from . . . fuel savings resulting from the ability to leverage AMI to reduce customers' energy usage by incrementally lowering distribution voltages."

a. Explain how much more expense the Companies will incur for additional distribution grid upgrades in order to achieve the stated savings in either or both of the Conservation Voltage Reduction and Volt/VAR Optimization programs.

b. Explain whether the sums identified in subpart a. to this question were factored into the AMI cost-benefit analysis. If not, explain why not.

231. Reference the Wolfe testimony, Exhibit JKW-2, p. 5. Under the heading "Why this matters," describe how the Companies propose to "tune" the AMI system with other distribution operations data resources.

a. Regarding all such "tuning," describe in complete detail how much is necessary to provide full functionality to the proposed AMI system, and how much is tuning is related to other distribution system enhancements not related to AMI functionality.

b. With regard to your response to subpart a. of this question, provide: (i) all applicable cost estimates; and (ii) any benefit-cost analyses for such "tuning" the Companies may have conducted.

c. Explain whether the sums identified in subpart b. to this question were factored into the AMI cost-benefit analysis. If not, explain why not.

232. Reference Application Exhibit 5, p. 3 (identical in both dockets) regarding commercial and industrial metering, the statement under the "Highlights" column that states "Unsurpassed 10KV surge protection for safety." Explain if the surge protection referenced here refers to the entire structure, or only to the meter itself. Provide the same information with regard to the residential meters the Companies propose to deploy.

233. Explain whether the Companies will be installing AMI in the ODP service territory. If so, could that deployment lead to synergies and/or cost savings for LG&E-KU ratepayers? Explain.

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234. Reference the Thompson testimony, p. 19: 6-21. Explain how the Companies' and PPL Corporation's voluntary goal of reducing CO_2 70% by 2040, and 80% by 2050 will impact the Companies' decision-making related to identifying, procuring and supplying the least-cost resource for meeting their customers' energy needs.

235. Reference the Blake testimony at 3: 1-3, wherein he states the Companies sought ways to. ". . . make these proceedings the last base rate cases the Companies will file for a number of years. . .". Explain what measures the Companies are willing to take in this regard.

236. Reference the Bellar testimony at 9: 1-9. Confirm that projected retirement dates for seven generating units have been moved forward, among them: (i) Mill Creek Unit 1 from 2034 to 2024; (ii) Brown Unit 3 from 2035 to 2028; and (iii) Mill Creek Unit 2 from 2034 to 2028. Given that the Companies will lose over 800 MW of capacity in less than ten years:

    a. explain if there will be stranded costs for any of these units;
    b. provide the Companies' projected reserve capacity margin for 2028 in light of these updated retirement dates; and
    c. explain whether the Companies will need to procure additional generation capacity at some point in the next several years.

237. Reference the Bellar testimony at 10:21-11:1. Provide a copy of the referenced April 2020 Agreement with the Louisville Air Pollution Control Board.

238. Reference the Bellar testimony at 10: 15-19, in which he states neither Mill Creek Unit 1 nor Mill Creek Unit 2 are equipped with selective catalytic reduction ("SCR") technology. Explain whether Mill Creek Units 3 and 4 are equipped with SCR technology.

239. Reference the Bellar testimony at 11: 6-7. Provide the basis for the statement, ". . . it is reasonable to expect Jefferson County to be escalated to moderate non-attainment in 2021 . . ."

240. Reference the Bellar testimony at 12: 5-13.

    a. Explain whether the Companies have considered whether any modifications to their current outage and maintenance practices might make it cost-effective to extend the projected useful life of Brown Unit 3 beyond 2028. If so, identify such potential modifications.
    b. Identify the nature of the $23.1 million capital investment that would have to be made on Brown Unit 3 if its useful life was extended beyond 2028.
    c. Identify the nature of the $8 million in annual O&M costs that would be incurred if the useful life of Brown Unit 3 was extended beyond 2028.

241. Reference the Bellar testimony at 12: 14-19. Explain whether any potential stranded costs were considered in the cost-benefit analysis of whether continued operation of Mill Creek Units 1 and 2, and Brown Unit 3 would be economical beyond their respective revised projected retirement dates? If not, why not?

242. Reference the chart in the Bellar testimony found at pp. 13-14. Provide a detailed breakdown of these capital projects.

243. Reference the Bellar testimony beginning at p. 17. Explain whether the Companies are seeking any authorizations in the instant cases regarding the Southeast Energy Exchange Market.

244. Reference the Bellar testimony at p. 40. Provide all workpapers associated with the development of the chart at the top of this page.

245. Reference the Bellar testimony generally. List all transmission capital projects with an expense of greater than $10 million to occur within the next five years.

246. Reference the Bellar testimony at 38:19-21. Provide the costs for implementing Work Studio.

247. Reference the Bellar testimony at 51: 14-19. Provide the costs for implementing the referenced GIS system, and explain whether it is required by any PHMSA regulations. If so, provide the citation to the appropriate regulation(s).

248. Reference the chart in the Bellar testimony at p. 52. Provide a detailed explanation and breakout for each individual item of expense under the following categories:

    a. $30 M for "Other," under "Enhance the Network"; and
    b. $38.4 M "Other," under "Maintain the Network."

249. Reference Exhibit LEB-4. Confirm that beginning in 2024, KU will begin deploying a Distributed Energy Resource Management System (DERMS).

    a. Provide any cost-benefit analyses the Companies may have conducted regarding a DERMS deployment.
    b. Explain whether LG&E will begin deploying DERMS, and if so, when.

250. Reference the Wolfe testimony at 7: 12-18. Provide the expenses for deploying distribution SCADA software as part of the Distribution Automation project.

    a. Provide a quantification of the costs and benefits of the Distribution Automation project from its inception to date.

251. Reference the Wolfe testimony at 9: 4-12. Explain whether the Customers Experiencing Multiple Interruptions program is targeted toward customers on the ten worst performing circuits of both Companies. If not, would it be more cost-effective to do so?

252. Reference the Wolfe testimony at 14: 15-21 through 15: 1-11. Explain whether 2-way flow is occurring on the Companies' distribution system today. If so, identify the circuits.

    a. If no 2-way flow is occurring, explain why KU in 2024 will deploy a DERMS system, as depicted in Exhibit LEB-4.

253. Reference the Wolfe testimony at 15: 12-24, regarding the Asset Investment Strategy (AIS) model and processes. Provide details regarding the benefit/cost analyses that the AIS prioritization algorithm conducts.

254. Reference the Wolfe testimony at 16: 1-8. Provide a detailed breakdown of the $40.4 million in distribution automation expense.

    a. Provide copies of all benefit/cost analyses conducted through AIS regarding this expense.
    b. Explain whether deployment of distribution automation on some or all of the Companies' ten worst-performing circuits has been given consideration. If so, provide any benefit/cost analyses associated with any such deployment.

255. Reference the Wolfe testimony, Exhibit JKW-1, Figures 11, 12 and 13 at pp. 29-30. In the same format as depicted in each of those Figures, provide the tree-related outages for calendar year 2020 to date.

256. Reference the Wolfe testimony generally. Explain whether the Companies have conducted any studies or analyses of the potential for distributed energy resources on their grid. If so, provide copies of all such documents.

257. Reference the Wolfe testimony generally. Provide a detailed analysis of vegetation management costs for the previous two years, together with forecasted costs for each of the next five (5) years.

258. Reference the chart found in the Wolfe testimony at p. 16. Provide a detailed breakdown of all projected costs under "Enhance the Network," and "Maintain the Network," for both Companies.

    a. Provide copies of all benefit/cost analyses conducted through AIS regarding each such expense.

259. Reference the Saunders testimony at 23:8. Explain whether the word "absorbed" means that shareholders paid that amount as opposed to it being collected from ratepayers.

260. Reference the Saunders testimony at 22-23. Discuss in detail the need for $86 M in facility improvements, including itemized workpapers supporting the proposed amounts.

261. Reference the Saunders testimony at pp. 35-36, in particular the chart on p. 36. Explain why for underground service, KU owns the service line but in the LG&E service territory, the customer owns the service line.

    a. Explain whether the ownership of underground service lines is identical for all customer classes, or whether it is limited only to residential customers.
    b. For each of the past five years, provide the sums KU has spent on maintenance and repair of underground service lines, broken down by class.

262. Reference the Saunders testimony at pp. 37-38. Explain whether the proposed HomeServe warranty would cover maintenance and repair costs of underground service lines for both LG&E customers, and KU customers. If not, explain fully why not.

263. Reference the Saunders testimony at p. 39, wherein she states, "The Companies aim to support economic development and growth in Kentucky interstate corridors by providing infrastructure necessary for the future of transportation and customer demands." Explain whether the companies' shareholders will be supporting the economic development, or the ratepayers.

264. Reference the Saunders testimony generally. Provide copies of the contracts with Olameter, Scope Services, and Ops Plus.

265. Reference the Saunders testimony at p. 40. Discuss the impact of the Energy and Environment Cabinet's Beneficiary Mitigation Plan, which can be found at https://eec.ky.gov/Documents/Final%20Mitigation%20Plan%20-%20june%202020.pdf on the proposal described by Saunders. Were the proposals approved or incorporated in the Beneficiary Mitigation Plan? Are these proposals still viable?