COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC JOINT APPLICATION OF KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND SITE COMPATIBILITY CERTIFICATES AND APPROVAL OF A DEMAND SIDE MANAGEMENT PLAN	))))))))	CASE NO. 2022-00402

COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION
TO LOUISVILLE GAS AND ELECTRIC COMPANY
AND KENTUCKY UTILITIES COMPANY

Louisville Gas and Electric Company and Kentucky Utilities Company (jointly, LG&E/KU), pursuant to 807 KAR 5:001E, shall file with the Commission an electronic version of the following information. The information requested is due on May 4, 2023. The Commission directs LG&E/KU to the Commission's July 22, 2021 Order in Case No. 2020-00085[1] regarding filings with the Commission. Electronic documents shall be in portable document format (PDF), shall be searchable, and shall be appropriately bookmarked.

Each response shall include the question to which the response is made and shall include the name of the witness responsible for responding to the questions related to the information provided. Each response shall be answered under oath or, for

[1] Case No. 2020-00085, *Electronic Emergency Docket Related to the Novel Coronavirus COVID-19* (Ky. PSC July 22, 2021), Order (in which the Commission ordered that for case filings made on and after March 16, 2020, filers are NOT required to file the original physical copies of the filings required by 807 KAR 5:001, Section 8).

representatives of a public or private corporation or a partnership or association or a governmental agency, be accompanied by a signed certification of the preparer or the 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.

LG&E/KU shall make timely amendment to any prior response if LG&E/KU obtain information that indicates the response was incorrect or incomplete when made or, though correct or complete when made, is now incorrect or incomplete in any material respect.

For any request to which LG&E/KU fail or refuse to furnish all or part of the requested information, LG&E/KU shall provide a written explanation of the specific grounds for their failure to completely and precisely respond.

Careful attention shall be given to copied and scanned material to ensure that it is legible. When the requested information has been previously provided in this proceeding in the requested format, reference may be made to the specific location of that information in responding to this request. When applicable, the requested information shall be separately provided for total company operations and jurisdictional operations. When filing a paper containing personal information, LG&E/KU shall, in accordance with 807 KAR 5:001E, Section 4(10), encrypt or redact the paper so that personal information cannot be read.

1. Refer to the Direct Testimony of Philip A. Imber (Imber Testimony), page 4, lines 9–18. Provide the amount of NO_x emission allowances for Mill Creek Unit 2 and

Ghent 2 from 2022 to 2032 under the current rules and explain whether decreasing allowances would necessitate closing the units irrespective of the Good Neighbor Plan.

2. Refer to Imber Testimony, page 9, lines 6-10. Also refer also to LG&E/KU's response to Commission Staff's First Request for Information (Staff's First Request), Item 25.

a. Explain how the future natural gas price volatility has been included in the PLEXOS and PROSYM stage modeling when the mid gas price and mid coal to gas price ratio was used.

b. Identify each step of the resource assessment, including the PLEXOS and PROSYM modeling, at which a 250 MW simple cycle combustion turbine (SCCT) was made available as possible resource and explain how the SCCT was made available.

c. In the event there are CO_2 emission requirements, explain how much CO_2 LG&E/KU estimate would be reduced in each of the CO_2 pricing scenarios and whether the reductions, if any, are meaningful.

3. Refer to the Direct Testimony of Robert M. Conroy, page 3. Provide the estimated difference between allowance for funds used during construction using the methodology approved by the Federal Energy Regulatory Commission and LG&E/KU's full-weighted average cost of capital. Provide any supporting calculation in Excel spreadsheet format, with all formulas, columns, and rows unprotected and fully accessible.

4. Refer to the Direct Testimony of Tim A. Jones, Exhibit TAJ-1, pages 26 and 29, regarding solar adoption by LG&E/KU customers. Also refer to Exhibit TAJ-1, page

26, regarding distributed battery energy storage system installations, which represent "less than 8% of the Companies' total 3,116 distributed generation customers."

a. Explain why the adoption and modeling of battery energy storage should be different than that of solar.

b. Indicate what percentage of distributed generation that battery storage would need to represent to justify incorporating into load forecasting.

5. Refer to the Direct Testimony of Stuart A. Wilson, (Wilson Testimony) Exhibit SAW-1, 2022 Resource Assessment, Appendix D, 2022 RFP Minimum Reserve Margin Analysis, Footnote 9, page D-10 referencing the 125 MW Ragland solar facility.

a. Identify the location of the facility and the developer/owner.

b. State when LG&E/KU expects the solar facility developer/owner to file a notification of the application with Kentucky State Board on Electric Generation and Transmission Siting (Siting Board).

c. Provide a copy of the solar facility power purchase agreement between LG&E/KU and the solar facility developer/owner or, if the power purchase agreement has not been executed, the status of the pending agreement.

6. Refer to Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, page 46. Provide a copy of the most current agreement between LG&E and Louisville Air Pollution Control Board regarding limiting the operation of the Mill Creek Station in order to address the Louisville/Jefferson County ozone requirements for ozone seasons. Additionally, explain the circumstances that led to the agreement, the term of the agreement, and the remedies if LG&E were to violate the agreement.

7. Refer to the Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, page 14, Table 2.

a. Explain why there is an increase for the Peak Time Rebates 2029 fixed costs considering the costs are trending to decrease every year.

b. Explain further what the LG&E/KU mean by “summer capacity values are design-day values” when discussing the DLC-AC in footnote 7.

8. Refer to the Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, page 22, Table 4. Explain why avoided costs were not used in the fuel-price scenarios given that avoided costs include the avoided fuel, operations, and maintenance costs of a power plant.

9. Refer to Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, pages 22–23, discussing Stage One, Step One of the resource assessment.

a. Confirm that in the PLEXOS model there is no direct connection between the decision to retire a coal resource and the decision to build a natural gas combined cycle (NGCC) resource. If not confirmed, describe any and all constraints that directly connect the decisions and provide any documentation supporting these assumptions.

b. Provide the net present value revenue requirement (NPVRR) and CO_2 emissions associated with each model run.

10. Refer to Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, pages 22–23, discussing Stage One, Step One of the resource assessment.

a. Provide an exhaustive list of all resources that are available to be selected in Stage One, Step One.

b. State whether the decision to install selective catalytic reduction system (SCR) is reflected in the model by a new resource with the same characteristics as the coal unit that also has SCR.

c. State whether the decision to retire a coal unit is reflected in the model by the selection of a resource with the same characteristics as the coal unit and a termination date equal to the retirement. If yes, please provide a list of all resources available for selection.

d. Explain whether the proposed battery energy storage system at E.W. Brown (Brown BESS) resource is available for selection.

e. Explain in detail the constraints. If this list is not exhaustive, provide information on any missing constraint that the selection of new resources is subject to:

(1) NewGas_MC;

(2) NewGas_MCbeforeBR_CC;

(3) NewGas_MCbeforeBR_CT;

(4) ExclusiveProjectsStorage_Projects_XX (where XX are the different projects per the Companies' nomenclature);

(5) Solar+StorageOption_XX; and

(6) Solar+StorageOnly_XX.

11. Refer to Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, pages 22-24, 27-31 discussing Stage One, Step One and Stage Two, Step One of the resource assessment. Refer also to the Excel file titled CONFIDENTIAL_20221212_Combined_Solution_Views_2061-2073.xlsx (PLEXOS outputs) filed with the Joint Application.

a. Provide a list of portfolios generated in Stage One, Step One, and identify which "Run_ID" on the "Index" tab of the referenced spreadsheet corresponds to each portfolio.

b. Provide a list of portfolios generated in Stage Two, Step One, and identify which "Run_ID" on the "Index" tab of the referenced spreadsheet corresponds to each portfolio.

c. Provide a detailed description of any other PLEXOS runs that were conducted but not referenced directly in the Resource Assessment and explain the reason for conducting any such runs.

12. Refer to the Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, page 23, Table 5. Explain the reasoning behind excluding dispatchable Design Side Management (DSM) programs from the Stage One portfolio and then adding them back later in the process.

13. Refer to Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, pages 24-26, discussing Stage One, Step Two of the resource assessment.

a. Confirm that this step is a production cost modeling step.

b. Confirm that the portfolios generated for analysis in this step were not generated through optimization.

c. Provide the NPVRR and CO_2 emissions associated with each model run.

14. Refer to Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, page 26, footnote 13. Provide any workpapers or analysis supporting the claim that "the

optimal amount of solar over the fuel price scenarios with a Mid coal-to-gas price ratio is also 637 MW."

15. Refer to Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, page 28, Table 10.

a. Confirm that Brown Unit 3 is overhauled in Portfolio 3.

b. Confirm that the decision to overhaul Brown Unit 3 is made exogenously for Portfolio 3. If not confirmed, list any constraints in the model that are related to the resource decision for Brown Unit 3 in Portfolio 3.

c. For portfolios that add a single NGCC unit, Portfolio 2, Portfolio 3, and Portfolio 4, confirm that the decision to build Mill Creek NGCC rather than Brown NGCC was made exogenously.

(1) If confirmed, provide your reasoning for that decision with respect to each of the three portfolios.

(2) If not confirmed, list all constraints in the model that are related to the selection of the NGCC resources.

d. Explain why none of the portfolios developed for stress testing add one NGCC while retiring all three coal units.

16. Refer to the Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, page 28, Table 10. Explain why dispatchable DSM was not included in every scenario.

17. Refer to Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, pages 27-31 discussing Stage Two, Step One of the resource assessment.

a. Confirm that this included a capacity expansion modeling step.

b. Provide the NPVRR and CO_2 emissions associated with each model run.

c. Confirm that the solar Purchase Power Agreement (PPA) start dates in Stage Two, Step One were not limited to the actual start dates of the PPAs as proposed in responses to the RFP.

d. Provide a list of all of the resource decisions that were made exogenously for each of the portfolios generated in Stage Two, Step One.

18. Refer to Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, pages 31–33 discussing Stage Two, Step Two of the resource assessment.

a. Confirm that this step is a production cost modeling step.

b. Provide the NPVRR and CO_2 emissions associated with each model run.

c. Confirm that for Portfolios 1, 2, and 5, all the selected solar PPAs are modeled with the start dates proposed in their associated RFP responses. If not confirmed, please explain how the start dates are modeled.

d. Confirm that for Portfolios 3, 4, and 6–9, the selected solar PPAs are modeled as beginning at the beginning of the year as shown in the "Summary" tab of the Excel file titled CONFIDENTIAL_20221212_Combined_Solution_Views_2061-2073.xlsx. If not confirmed, explain how the start dates are modeled.

19. Refer to Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, pages 34–36, discussing Stage Three, Step One of the resource assessment.

a. Confirm that this step is a production cost modeling step.

b. Confirm that the portfolios generated for analysis in this step were not generated through optimization.

c. Provide the NPVRR and CO_2 emissions associated with each model run.

20. Refer to the Wilson Testimony, Exhibit SAW-1, Appendix D, 2022 RFP Minimum Reserve Margin Analysis, page D-10, Table 2. Explain why existing DSM was excluded from the Intermittent/Limited-Duration Resources.

21. Refer to the Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, Appendix D, 2022 RFP Minimum Reserve Margin Analysis, page D-18. Refer also to Direct Testimony of Lana Isaacson (Isaacson Testimony). Exhibit LI-6 – CONFIDENTIAL LAK_AvoidedCapacityCost, page 6, Table 7.

a. For the PLEXOS and PROSYM modeling runs, state which avoided capacity capital cost was used, the SCCT capital cost in the Reserve Margin Analysis or the SCCT capital cost used in the DSM analysis. Explain why different avoided cost estimates were used in the analyses.

b. Explain why 2022 dollars are used for the DSM/EE portfolio and 2028 dollars for the minimum reserve margin. Include in the explanation whether the SCCT in 2022 dollars is the discounted amount from the 2028 amount.

c. Regarding LG&E/KU's assumptions for the cost of new capacity, explain why the avoided capacity values are reasonable. Provide and describe in specific detail how LG&E/KU defined a typical installations.

d. Refer also LG&E/KU's response to Staff's First Request for Information, Item 1 to Case No. 2022-00395.[2] LG&E/KU used the capital costs of a SCCT as the basis for avoided costs in their 2021 integrated resource plan (IRP),[3] but used the capital costs of a NGCC as the basis for avoided costs in Case No. 2022-00395. Given that LG&E/KU requests approval of a certificate of public convenience and necessity (CPCN) for two NGCCs in this proceeding, reconcile LG&E/KU's use of different bases for avoided costs in Case Nos. 2022-00395 and 2021-00393 and this case. Also, explain why the capital and related costs of a NGCC should not be used in the DSM and reserve margin studies in this proceeding.

e. Explain whether the cost-effectiveness of the proposed DSM/EE programs would increase if LG&E/KU were to base their avoided costs on an NGCC instead of an SCCT.

22. Refer to the Direct Testimony of John Bevington (Bevington Direct Testimony), page 13, lines 15-23.

a. Explain why LG&E/KU have not viewed rooftop solar as a demand-side resource and provide documentation that supports this assertion.

b. Explain why LG&E/KU are not pursuing the rooftop solar incentives as a DSM program.

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[2] See Case No. 2022-00395, *Electronic Tariff Filing Of Kentucky Utilities Company for Approval of An Economic Development Rider Special Contract With Kruger Packaging*, Companies' Response To Staff's First Request for Information, (filed Dec. 22, 2022), Item 1.

[3] Case No. 2021-00393, *Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company* (filed Oct. 19, 2021).

c. Explain how and why rapid growth is relevant to the issue of whether future incentives from a DSM-based program are necessary and why such incentives could cause customer confusion.

23. Refer to Bevington Direct Testimony, Exhibit JB-1, 2024-2030 Demand-Side Management and Energy Efficiency Program Plan, pages 5–6, indicating that the DSM/EE Program Plan is intended to continue to contribute significant energy savings while recognizing that known potential for energy savings is forecasted to decline by approximately 12 percent.

a. Explain why LG&E/KU are proposing an extensive DSM/EE portfolio if known potential is forecasted to decline.

b. Explain whether the forecasted decline in potential is benefiting LG&E/KU from a capacity need and cost savings perspective.

c. Explain how increasing market saturation of efficient technologies, new building codes, and changes in federal equipment standards will impact LG&E/KU's proposed DSM/EE programs' cost-effectiveness and overall potential.

d. Explain how these DSM/EE programs will provide LG&E/KU demand and grid stability in comparison to the proposed building of the NGCC's.

24. Refer to Bevington Direct Testimony, Exhibit JB-1, 2024-2030 DSM-EE Program Plan, pages 30-31.

a. State whether there are any differences between LG&E/KU's 2016 appliance recycling program, and the appliance recycling program LG&E/KU are proposing in this application. If there are differences, describe the differences.

b. Provide the total resource cost (TRC) score from the 2016 appliance recycling program before the program was terminated.

25. Refer to Bevington Direct Testimony, Exhibit JB-1, 2024-2030 DSM-EE Program Plan, page 41. Provide the software vendors LG&E/KU have met with to discuss software that can manage enrollment, accurately calculating savings, and issue incentives to customers enrolled in multiple programs.

26. Refer to Bevington Direct Testimony, Exhibit JB-1, 2024-2030 DSM-EE Program Plan, page 42.

a. Provide a further explanation how LG&E/KU are planning to affect the timing and level of charging for electric vehicles and electric vehicle equipment.

b. Explain how the participants in the Optimized Charging subcomponent will be able to set the parameters for LG&E/KU to issue signals or interrupt service.

c. Explain whether the Optimized Charging will be based on a critical peak pricing concept so that LG&E/KU will charge the customers a different rate to charge their EV's during higher peak times.

d. Explain whether Optimized Charging participants can override the signals or interruption based on the parameters that they set. If so, explain whether the participants will be able to qualify for the incentive in that given month.

e. Explain whether there is a rate structure that is connected to the Optimized Charging subcomponent. If so, provide the rate structure or reference to current rates.

27. Refer to Bevington Direct Testimony, Exhibit JB-1, 2024-2030 DSM-EE Program Plan, pages 48–50.

a. Explain how long LG&E/KU anticipate a peak event lasting and when peak events are expected to occur.

b. Explain whether LG&E/KU plan on making the 25 peak time events flexible and allow customers to use peak time events year-round at their convenience or if LG&E/KU anticipate allocating a set number of the events to the summer and a set number of events to the winter.

c. Explain the circumstances in which a customer enrolled in the program would no longer be considered an active participant, including how many times a customer would have to decline to participate to not receive the bonus.

d. Explain whether this program would be more beneficial for customers who have smart thermostats or other enabling technology.

28. Refer to Bevington Direct Testimony, Exhibit JB-1, 2024-2030 DSM-EE Program Plan, Appendix D, 2022 Potential Study Projection, page 10. Provide the Technical, Economic, and Achievable Potential for each of the selected programs that are included in the portfolio.

29. Refer to the Isaacson Testimony, Exhibit LI-2 2023 LG&E and KU Demand Response Assessment, Appendix A, page A-3.

a. Explain the basis using a 6.8 percent discount rate and provide any documents that support the use of that rate.

b. Explain why Cadmus is using the California Public Utilities Commission 2016 demand response cost-effectiveness protocols.

c. Explain whether the California Public Utilities Commission has provided updated demand response cost-effectiveness protocols. If so, explain the differences between the 2016 protocols and the most recent updated protocols.

d. Provide a further explanation of how the assumed 20-year product life cycle relates to each of the proposing DSM/EE programs.

e. Provide further explanation of why Cadmus used 5.8 percent and 6.2 percent line loss figures for LG&E/KU. Explain how these different figures were used by Cadmus and whether these figures were used in LG&E/KU's most recent IRP.

f. Explain whether and how LG&E/KU differentiate between service territories when deciding DSM programs. If LG&E/KU do not differentiate between service territories, then explain why LG&E/KU are using separate line loss calculations.

30. Refer to the Isaacson Testimony, Exhibit LI-2 2023 LG&E and KU Demand Response Assessment, Appendix C, Table C-1, page C-27. Provide the Achievable Potential for each program listed in a similar table.

31. Refer to the Direct Testimony of Robert Conroy, page 7, lines 19–21, regarding the return on earnings (ROE) percentage used in the Demand Side Management Cost Recovery Mechanism (DSMRC). Refer also to Isaacson Testimony, Exhibit LI-6 - CONFIDENTIAL LAK_AvoidedCapacityCost, page 6, Table 8, which applied a different ROE percentage to determine avoided capacity costs. Explain why a 9.925 ROE was not used to calculate avoided capacity costs but was used to calculate the DSMRC.

32. Refer to LG&E/KU's response to Staff's First Request, Item 4, regarding NGCC and SCCT ramp rates. Provide and explain the ramp rate LG&E/KU assumed for new SCCT units at each step of the resource assessment.

33. Refer to LG&E/KU's response to Staff's First Request, Item 4a. Provide the ability of the proposed NGCC to burn hydrogen on a percent of energy basis rather than a percent of volume basis.

34. Refer to LG&E/KU's response to Staff's First Request, Item 4c. Provide the ability of current and future SCCTs to accept hydrogen on a percent of energy basis rather than a percent of volume basis.

35. Refer to LG&E/KU's response to Staff's First Request, Item 7. Explain the impact to LG&E/KU's financial incentive if the Commission were to deny LG&E/KU's request to use the 50 basis-point ROE adder in the DSMRC.

36. Refer to LG&E/KU's response to Staff's First Request, Item 9. Confirm that the tables depicting forecasted ozone emissions reflect the additions of SCRs on Ghent Unit 2 and Mill Creek Unit 2 in 2026.

37. Refer to LG&E/KU's response to Staff's First Request, Item 13. Explain whether the discussion of the CO_2 equivalent of greenhouse gasses being less than 25,000 metric tons per year include the two proposed NGCC units at Mill Creek and Brown. Include in the response the annual emission levels for the two NGCC units.

38. Provide a cost-effectiveness analysis for each program identified in LG&E/KU's response to Staff's First Request, Item 21a–g.

39. Refer to LG&E/KU's response to Staff's First Request, Item 21.

a. For each program evaluated in JB-1, provide a breakdown of costs as follows, and explain which components were included in the TRC and PAC tests.

(1) Total incremental measure cost.

(2) Total incentive costs.

(3) Total customer costs.

b. Explain which of these cost categories were assumed for selection of DSM resources in the PLEXOS model described in Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, page 23.

40. Refer to LG&E/KU's response to Staff's First Request, Item 24c. State whether implementation of the Inflation Reduction Act (IRA) resulted in any changes to LG&E/KU's assumptions that would change LG&E/KU's forecasts and explain any such changes, including whether the changes are likely to affect resource decisions.

41. Refer to LG&E/KU's response to Staff's First Request, Item 27e.

a. Explain whether the BrightNight Marion County project will be completed and ready to generate and put energy onto the transmission network when it is transferred to LG&E/KU. If not, explain at what stage in the construction LG&E/KU will take possession and what will need to be completed before energy can be placed on the network.

b. Explain the differences in project permitting requirements that reduce the execution risk for a utility as compared to solar merchant generation developers.

42. Refer to LG&E/KU's response to Staff's First Request, Item 28. Refer also to the Wilson Testimony, Exhibit SAW-1, page 39.

a. Provide the status of OVEC's compliance with current, pending, and expected environmental rules.

b. If not addressed above, explain the anticipated costs of complying with new or expected environmental regulations.

c. If OVEC were to retire in 2028, explain what costs by category would fall to LG&E/KU and LG&E/KU's ratepayers.

43. Refer to LG&E/KU's response to Staff's First Request, Item 31d.

a. Provide the current state of negotiations with BlueOval SK for 300 MW of renewable energy.

b. If LG&E/KU's application in this proceeding was approved as proposed, explain whether LG&E/KU would issue an RFP for an additional 300 MW of renewables to serve BlueOval SK.

44. Refer to LG&E/KU's response to Staff's First Request, Item 31 and Item 40. Confirm that a residential customer with a home EV charger can take service under Tariffs RS, RTOD Energy, or RTOD Demand.

45. Refer to LG&E/KU's Response to Staff's First Request, Item 33a. Account for the PLEXOS's retirement of the existing DSM programs if the programs were considered cost effective in the DSM analysis.

46. Refer to LG&E/KU's response to the Staff's First Request for Information, Item 35.

a. State whether an analysis been conducted for a KU RTOD-Demand customer to examine the economics of battery storage for demand reduction. If not, explain why.

b. State whether LG&E/KU have considered demand reduction savings residential customers could see from battery storage if, as LG&E/KU have modeled, new loads from adoption of electric vehicles and heat electrification accelerates as predicted.

c. State whether LG&E/KU have considered the economics and adoption of distributed battery storage by commercial and industrial customers, which have higher energy and demand charges and could have lower battery costs through the purchase of more than one battery system as suggested by the Forbes article cited in LG&E/KU's response to the Staff's First Request for Information, Item 35.

47. Refer to LG&E/KU's response to Staff's First Request, Item 47(a), Attachment 1, 2022 Resource Assessment, March 2023 Update, pages 18–20 and 55–59.

a. State whether LG&E/KU reflect differences in the terms of coal and natural gas contracts when determining the gas to coal price ratios. If so, explain how they are reflected. If not, explain why not.

b. Explain whether longer term contracts typically are available for coal purchases as opposed to gas purchases. If so, explain why coal prices used for modeling should not remain constant for a few years before being stepped up or down based on the relevant coal to gas ratio to reflect the longer term fixed prices. If not, explain the why they are not.

48. Refer to LG&E/KU's response to Staff's First Request, Item 47(a), Attachment 1, 2022 Resource Assessment, March 2023 Update. Confirm that all updates to this document are highlighted or outlined in orange, and if this cannot be confirmed, identify all updates in this document.

49. Refer to LG&E/KU's response to Staff's First Request, Item 47(a), Attachment 1, 2022 Resource Assessment, March 2023 Update, page 23. Confirm that PLEXOS had the ability to pair a battery with a solar facility independently of what may have been included as an RFP response. If not, explain why not.

50. Refer to LG&E/KU's response to Staff's First Request, Item 47(a), Attachment 1, 2022 Resource Assessment, March 2023 Update, page 37, Table 20.

a. Assuming that none of the resources listed in the first column of Table 20 are constructed but otherwise using all of the same assumptions used to calculate the loss of load exceptions (LOLE), calculate the summer, winter, and total LOLE for the following portfolios:

(1) Continuing to operate Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3 with necessary maintenance and overhauls but without constructing new SCRs on Mill Creek Unit 2 and Ghent Unit 2.

(2) Continuing to operate Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3 with necessary maintenance and overhauls and with new SCRs on Mill Creek Unit 2 and Ghent Unit 2.

(3) Continuing to operate Mill Creek Unit 1, Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3 with necessary maintenance and overhauls but without constructing new SCRs.

(4) Continuing to operate Mill Creek Unit 1, Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3 with necessary maintenance and overhauls and with new SCRs as necessary to operate during ozone season.

(5) Continuing to operate Haefling Unit 1 and Unit 2 and Paddy's Run Unit 12, and continuing to operate Mill Creek Unit 1, Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3 with necessary maintenance and overhauls but without new SCRs.

(6) Continuing to operate Haefling Unit 1 and Unit 2 and Paddy's Run Unit 12, and continuing to operate Mill Creek Unit 1, Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3 with necessary maintenance and overhauls and with new SCRs as necessary to operate during ozone season.

b. Identify the unforced capacity value used for each unit listed above to calculate the LOLE in each instance and explain each basis for the unforced capacity value used for each unit.

51. Refer to LG&E/KU's response to Staff's First Request, Item 42 and Item 47(a), Attachment 1, 2022 Resource Assessment, March 2023 Update, page 51.

a. Explain whether the future retirements of LG&E/KU coal units other than Mill Creek units 1 and 2, Ghent Unit 2 and Brown Unit 3 were factored into the PLEXOS and PROSYM modeling. If not, confirm that the useful life of the remaining coal units extends beyond the study period.

b. Provide an update to Table 30 for LG&E/KU's remaining coal units. Include in the explanation how these values compare to the useful lives of the units.

c. Explain what remaining life/useful life was used as an input in the PLEXOS and PROSYM models.

d. Explain the characteristics of Brown Unit 3 that are primarily driving PLEXOS's retirement of Brown Unit 3 in Stage One, regardless of fuel prices.

52. Refer to LG&E/KU's response to Staff's First Request, Item 47(a), Attachment 1, 2022 Resource Assessment, March 2023 Update, page 52, Table 31.

a. State whether the stay open costs listed in Table 31 are the stay open costs that were used for Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3 in PLEXOS in Stage One, Step One of LG&E/KU's resource assessment, and if not, identify and describe the differences in stay open costs that were used in that step of the model.

b. Identify the files reflecting the stay open costs for Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3 used by PLEXOS in Stage One, Step One of the LG&E/KU's resource assessment.

c. Provide an itemized breakdown of the Ongoing Costs, Overhaul Costs (Standard), Overhaul Costs (Life Extension), and the Environmental Compliance Costs (SCR) in each year for each of the units with as much detail as much detail as possible.

d. For each cost identified in response to subpart c. of this request or included in any way in Table 31 if not separately broken out, explain LG&E/KU's methodology for projecting the cost and each basis for LG&E/KU's estimate of the cost.

e. Provide an itemized breakdown of the total expected capital costs for an SCR on Mill Creek Unit 2 and Ghent Unit 2.

f. Explain the difference between the "Standard" and the "Life Extension" Overhaul Costs and explain specifically how those costs were treated during each of the steps of the resource assessment.

53. Refer to LG&E/KU's response to Staff's First Request, Item 47(a), Attachment 1, 2022 Resource Assessment, March 2023 Update, page 55, Table 35.

a. Provide an itemized break down of the Transmission System Upgrade Costs of reflected in Table 35 with specific details, provide a description of each of the transmission systems upgrades reflected in those costs, and explain how those costs were estimated.

b. Explain, with specificity and detail, how the Transmission System Upgrade Costs of reflected in Table 35 were treated during each of the steps of the resource assessment.

c. Provide the Transmission System Upgrade Costs projected in the same manner as in Table 35 and itemized as requested in subpart a. of this Request above if Mill Creek Units 1 and 2, and Brown Unit 3 are retired, and a NGCC is added at Brown.

d. Given that transmission facilities are already present at Mill Creek, and Brown, explain why the existing facilities are inadequate and why the modeled transmission upgrades have such wide cost differentials.

e. Explain whether any of the coal unit retirements require complete removal of the units in order to make room for transmission upgrades or new generation facilities.

f. Identify and describe the ownership share of the transmission upgrades for which costs are reflected in Table 35 and in subpart c of this Request above, and explain how the associated costs will be apportioned between LG&E's and KU's customers.

54. Refer to LG&E/KU's response to Staff's First Request, Item 47(a), Attachment 1, 2022 Resource Assessment, March 2023 Update, page 55, Table 35.

a. Explain whether LG&E/KU undertook a transmission analysis regarding any of the proposed solar PPAs, including the four that were selected in the optimal portfolio or the Mercer and Marion solar projects.

b. With respect to the PPAs, including the Marion County project, because solar merchant generators are responsible for transmission system upgrades and interconnection costs, explain what transmission costs would be incurred by LG&E/KU and why these costs are uncertain.

c. Explain whether the transmission costs related to the solar PPAs, and the Mercer and Marion solar projects are included in the PLEXOS and PROSYM modelling runs. If so, explain which transmission costs are included and in which model. If not, explain whether the models may have selected amounts of solar uneconomically at the expense of other generation resources.

55. Refer to LG&E/KU's response to Staff's First Request, Item 47(a), 2022 Resource Assessment, Generation Planning & Analysis, March 2023 Update, page 25, Tables 7 and 8. Refer also to Case No. 2022-00098 in which East Kentucky Power Companies (EKPC) indicated that the simultaneous outage of the LG&E/KU's Brown Unit 3 and EKPC's Cooper Station Units 1 and 2 could cause issues in serving load in the southern Kentucky area.[4]

a. Explain whether there would be adequate voltage support for the southern part of the KU system with the retirement of the Brown Unit 3 in a scenario in

[4] Case No. 2022-00098, *Electronic 2022 Integrated Resource Plan of East Kentucky Power Cooperative, Inc.* (Ky. PSC Mar. 9, 2023), Order, Commission Staff's Report on the 2022 Integrated Resource Plan of East Kentucky Power Cooperative, Inc. at 37.

which the proposed Brown NGCC unit is not added. Include in the response a scenario with EKPC's Cooper Station online and not online.

b. Explain whether a portfolio that retires Brown Unit 3 but does not add the Brown NGCC unit is a viable alternative.

56. Refer to LG&E/KU's response to Staff's First Request, Item 47(a), Attachment 1, 2022 Resource Assessment, March 2023 Update, page 34. Explain why the Mercer County self-build Project and the Marion County asset purchase Project were not included as a resource option to the PLEXOS model in Stage One of the analysis.

57. Refer to LG&E/KU's response to Staff's First Request, Item 47(a), 2022 Resource Assessment, Generation Planning & Analysis, March 2023 Update, page 34. For the Marion Project:

a. Describe the status of the Marion Project siting and development.

b. Explain whether this project is subject to the Siting Board jurisdiction and, if an application has been filed with the Siting Board, provide the case number.

c. Provide a copy of the asset purchase contract between LG&E/KU and the Marion Project developer or owner.

d. Explain whether a transmission line and substation will have to be constructed to connect the project to LG&E/KU's transmission system and, if so, provide a description of the facilities.

e. Explain whether the developer is responsible for ensuring all the transmission studies are completed.

f. Explain whether there are any transmission network upgrades connected to this project and, if so, explain whether LG&E/KU are paying those costs or reimbursing the developer as part of the contract price.

58. Refer to LG&E/KU's response to Staff's First Request, Item 47(a), Attachment 1, 2022 Resource Assessment, Generation Planning & Analysis, March 2023 Update, pages 13 and 34. For the Mercer Project:

a. Explain the meaning of the statement, "LG&E/KU's Project Engineering group therefore revised their self-build proposal to suit the proposal at the Mercer County site, resulting in a 120 MW self-build solar proposal in Mercer County . . . . ." Include in the response whether LG&E/KU acquired the proposed project from the developer and the Project Engineering group will develop the project from that stage.

b. Describe the current development stage of the project and whether any land has been acquired or leased.

c. Explain whether a transmission line and substation transmission system upgrades will have to be construction as a part of this project and, if so, whether these costs were included in the modeling.

59. Refer to LG&E/KU's response to Staff's First Request, Item 47(a), Attachment 1, 2022 Resource Assessment, Appendix D, 2022 RFP Minimum Reserve Margin Analysis, page D-14.

a. Identify the number of times curtailable service rider (CSR) customers have been interrupted in each of the last five years.

b. Explain whether all customers on the CSR Tariff were interrupted during winter storm Elliott. If not, explain why not.

c. Explain whether the load forecast included all the non-dispatchable DSM program savings that have been proposed by LG&E/KU. If not, explain why not.

d. Explain whether the reserve margin analysis incorporated all the proposed DSM program dispatchable interruption savings. If not, explain why not.

60. Refer to LG&E/KU's response to Staff's First Request, Item 48. Explain whether the solar PPAs and the Mercer and the Marion solar facilities, once completed, will be always be dispatched first.

61. Refer to LG&E/KU's response to Staff's First Request, Item 28 and Item 48.

a. Identify and describe the cost of the OVEC energy that LG&E/KU are obligated to take and, explain where in the dispatch stack OVEC be dispatched but for the contractual obligation.

b. If LG&E/KU owned the OVEC units outright, explain whether this would be one of the units being retired as opposed to the units being retired in the preferred portfolio.

c. Confirm that the energy received from OVEC is dispatched first due to the contractual obligation to take the energy regardless of price.

62. Refer to LG&E/KU's response to Staff's First Request, Item 50 and Item 53e.

a. Provide and explain the Present Value Revenue Requirement (PVRR) for the Final Portfolio and the Economically Optimal Portfolio supporting each of the PVRR entries in the table.

b. Provide an update to the Table using the format in part a above by including the value of Renewable Energy Credits (RECs).

c. Explain which party to the four solar PPAs retains the associated renewable energy credit.

d. Explain, if known, whether the developers/owners of the four solar PPAs have figured in the incentives in the Inflation Reduction Act (IRA).

63. Refer to LG&E/KU's response to Staff's First Request, Item 52b.

a. Provide a detailed description of the resources that were excluded due to "Pipeline diversity/multiple NGCC per site."

b. Provide a detailed explanation of LG&E/KU's rationale for excluding these resources, including any concerns it has over pipeline diversity and risk factors associated with having multiple NGCCs at a single site.

64. Refer to LG&E/KU's response to Staff's First Request, Item 53f.

a. Because battery storage shifts energy in time and does not produce energy, explain why battery storage should be counted in the reserve margin and why this does not represent double counting of another generation resource's capacity.

b. Explain whether LG&E/KU's solar facilities produce any energy during winter peak hours.

c. Provide a chart showing the solar facilities' expected energy output and LG&E/KU's demand that demonstrates and justifies giving zero capacity credit to solar facilities in the winter heating season.

65. Refer to LG&E/KU's response to Staff's First Request, Item 53f. Refer also to Wilson Testimony, Exhibit SAW-1, Table 13, page 32.

a. Explain whether all the resources in the Table provided in response to Item 53f are included in column 1 of Exhibit SAW-1, Table 13, with the exception of the

Brown BESS and the Mercer and Marion county solar builds. If not, explain the differences.

b. Provide the reserve margin associated with Exhibit SAW-1,Table 13, column 1.

c. Explain whether there are operational services over the course of a year within this portfolio as compared to Table 13 that are greater than the additional costs of adding the Brown BESS and the Mercer and Marion county solar builds.

d. Explain why the Existing Dispatchable DSM decreases every year during the summer.

66. Refer to LG&E/KU's response to Staff's First Request, Item 57.

a. Provide the effective load carrying capability (ELCC) values for each of LG&E/KU's existing units, the proposed NGCC units, the four proposed solar PPAs, and the Mercer and Marion solar facilities.

b. Confirm that LG&E/KU's response to Item 57e is stating that there were no transmission costs included in the PLEXOS modeling (Stage One, Step One) or the PROSYM modeling (Stage One, Step Two).

67. Refer to LG&E/KU's response to Staff's First Request, Item 58. Refer also to LG&E/KU's response to the Attorney General's First Request for Information, Item 30(I).

a. If LG&E/KU's proposed portfolio had been in service during winter storm Elliott, explain whether the NGCC units at Brown and Mill Creek stations would have been able to perform without interruption or derated due to fuel supply related issues.

b. Provide a copy of the letter from copy of Texas Gas Transmission describing changes to its operating procedures and upgrades to its system.

c. State whether any of the LG&E/KU's natural gas storage fields have been retired or closed in the last 3 years or will be retired/closed. If so, explain the reasons and how this additional capacity and supply will be replaced.

68. Refer to LG&E/KU's response to Staff's First Request, Item 70.

a. Confirm that once the customers complete the installation of the audit kits and fill out the rebate forms that LG&E/KU will engage with a third party to ensure completion of the audit kits before issuing the rebate.

b. Explain whether LG&E/KU are aware of any upfront costs for engaging in a third-party vendor to ensure of the audit kits competition.

69. Refer to LG&E/KU's response to Staff's First Request, Item 72. Explain whether LG&E/KU would consider implementing a DSM/EE program if the DSM/EE program had substantial capacity savings but is barely considered not cost-effective.

70. Refer to LG&E/KU's response to Staff's First Request, Item 74b and c.

a. LG&E/KU states that 53 percent of industrial customers elected to opt-out of the DSM/EE programs but that LG&E/KU do not record the reasons for opting out. Explain the process for how a participant opts out of a DSM/EE program and the reasons why LG&E/KU do not ask why industrial customers are opting out.

b. Explain the impact participation levels have on DSM/EE programs when considering cost-effectiveness.

71. Refer to LG&E/KU's response to Staff's First Request, Item 87. Given the relatively low cost of an SCCT resource in the current analysis, explain why this resource

was not selected in LG&E/KU's initial PLEXOS modeling runs. Include a comprehensive description of factors that led to this outcome, including all modeling assumptions that either limited SCCT selection or promoted/required NGCC selection.

72. Refer to LG&E/KU's response to Staff's First Request, Item 92, which discussed how including carbon capture and sequestration (CCS) in NGCC resource evaluation differed from the 2021 IRP and this proceeding. State whether SCCT would be the preferable option if NGCC was found to require CCS.

73. Refer to LG&E/KU's response to Staff's First Request, Item 104.

a. Provide a map of the Texas Gas Transmission pipeline showing the zones and the major receipt and delivery points.

b. Provide a map of the Texas Eastern and Tennessee Gas pipelines showing the zones and the major receipt and delivery points.

c. Identify the points at which LG&E/KU expect to take delivery of gas from the pipeline for its proposed NGCC Units from each of the pipelines.

d. Identify the points at which gas purchased by LG&E/KU for electric generation and transported on the Texas Gas Transmission, Texas Eastern, or Tennessee Gas pipeline has been received onto each pipeline in each of the last 3 years and the quantities of gas received at each such point.

e. Explain and provide any analysis performed by LG&E/KU regarding whether there will be sufficient capacity on the Texas Gas Transmission or Tennessee Gas pipelines to serve existing gas units, the proposed NGCC units, and gas units being proposed by other utilities.

74. Refer to LG&E/KU's response to Staff's First Request, Item 104 and Item 105. Refer also to North American Electric Reliability Corporation (NERC) Contingency Reserves, available at www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-WECC-3.pdf.

a. Provide the summer and winter installed capacity (ICAP) and unforced capacity (UCAP) values for Cane Run 7, Paddy's Run, and the Trimble County SCCTs.

b. State whether the addition of the proposed Mill Creek NGCC unit would make the loss of the Texas Gas Transmission pipeline the most severe single contingency on LG&E/KU's system and in its Balancing Area, and explain each basis for LG&E/KU's response.

c. State whether the addition of the proposed Mill Creek NGCC unit would affect the amount of contingency reserves LG&E/KU must maintain and explain each basis for LG&E/KU's response.

d. Given LG&E/KU's current reliance on the Texas Gas Transmission pipeline and the availability of two pipelines to serve the proposed Brown NGCC unit, explain why LG&E/KU selected building an NGCC unit at Mill Creek instead of Brown in the event that SCR was added to Ghent Unit 2 and only a single new NGCC unit was selected.

75. Refer to the LG&E/KU's response to Sierra Club's Initial Request for Information, Item 13.

a. Provide a detailed, itemized breakdown of what costs are included in the Capital Expenditures, Fixed O&M, and Variable O&M for Mill Creek NGCC and Brown.

b. Explain how these costs are connected to the PLEXOS input files such as:

(1) Variable_OM_NewGas.csv;

(2) CONFIDENTIAL\FOM_22RFP_AssetsInclBuildCostECC.csv;

(3) AnnualCosts.csv; and

(4) Any other files used to model these costs.

c. State whether the Capital Expenditures cost include transmission costs such as voltage support.

d. State whether a transmission analysis has been performed to assess whether other portfolio decisions (new build or retirement) could impact the need for voltage support at the siting of potential NGCC builds, and if so, provide the transmission analysis.

76. Refer to LG&E/KU's response to the Attorney General's Initial Requests for Information, Item 13, Attachment 1. Given that the proposed Mill Creek NGCC will be served by the Texas Gas Transmission pipeline, and LG&E/KU have not investigated providing a second gas supply source to the proposed plant, explain how the inability of the Texas Gas Transmission pipeline to meet the contractual delivery obligations during Winter Storm Elliot factors into the firm capacity rating of the Mill Creek NGCC.

77. Provide the methodology used to justify a 100 percent firm capacity rating for the NGCC and SCCT plants for calculating minimum reserve margin, and any supporting workpapers.

78. Provide the total existing distributed generation capacity in LG&E/KU's territory including battery energy storage.

79. a. Describe the firm gas transmission capacity required to supply the proposed new NGCC units to ensure firm generation capability.

b. Provide the incremental firm gas delivery required (e.g., Dth/day) for each new unit.

c. Provide the firm gas transport already secured by LG&E/KU, identifying the corresponding pipelines, and any new incremental gas deliverability required to ensure firm supply to these new units.

80. Explain the reasoning behind including a carbon price adder in production cost modeling, but not including it in any of the capacity expansion steps.

81. Refer to Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, Exhibit SAW-1, pages 22–23, section 4.4.1 "Stage One, Step One: Portfolio Development and Screening with PLEXOS," which describes the initial capacity expansion modeling performed in PLEXOS. Provide the results of additional PLEXOS modeling runs using identical assumptions to those used in Stage One, Step One as described in the 2022 Resource Assessment, with only the following modifications:[5]

a. Capacity contribution of new thermal resources:

[5] If LG&E/KU cannot complete the modeling runs by May 4, 2023, LG&E/KU may file a motion requesting an extension and providing the estimated date this response will be filed.

(1) The assumed capacity contribution of each new thermal resource option should not equal 100 percent of its nameplate value and should instead be updated to equal the resource's correct ELCC value (i.e., accounting for historical performance and unforced outages).

(2) If LG&E/KU has not performed any analysis to determine the correct ELCC value of new thermal resources, the seasonal UCAP value should be used instead. If the seasonal UCAP values are also not known, an ELCC value of 90 percent should be used.

(3) If LG&E/KU has not yet conducted analysis to determine the correct ELCC values of its thermal resources, i.e. using the SERVM model, then this analysis should be conducted in parallel to this request for additional model runs.

b. Book life of new thermal resources:

(1) New CC or CT units should assume a book life of 20 years to correspond to a net-zero by 2050 framework.

(2) Additional resource options can be added to reflect a 35-40 year book life for new CC or CT units, but these options should also be updated to include the incremental capital costs of either CCS or green H2, including production, transportation, and storage.

c. Availability of new solar and storage resources:

(1) Each of the RFP responses should be made available for selection by the model as a capacity resource

(2) The Brown BESS should be made available for selection by the model as a capacity resource

d. Build Constraints:

(1) Remove all constraints that require a CC unit to be built on or before any date the model selects for a coal unit to be retired. For example, new builds should be driven by portfolio-level reserve margin requirements, not specific unit retirements.

(2) Remove all constraints for the order of CCs to be built. For example, some of the new resource options appear to include a required sequence of additions, such as “NewGas_MCbeforeBR_CC”, “NewGas_MCbeforeBR_CT”.

e. Coal Unit operations options:

(1) For the Mill Creek and Ghent coal units, the additional options should be included in addition to retirement and SCR installation. This should include:

(a) Seasonal operation whereby generation is limited to only months outside of the ozone season.

(b) Mothballing the units such that they could return to operation at a later date depending on how LG&E/KU’s needs evolve.

(2) For each coal unit retirement date, ensure that retirement is an option the model can select in any year rather than a pre-specified subset of years.

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DATED APR 14 2023

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