COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND SITE COMPATIBILITY CERTIFICATES	))))	CASE NO. 2025-00045

INITIAL REQUESTS FOR INFORMATION OF KENTUCKIANS FOR THE COMMONWEALTH, KENTUCKY SOLAR ENERGY SOCIETY, METROPOLITAN HOUSING COALITION, AND MOUNTAIN ASSOCIATION TO LOUISVILLE GAS & ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY

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Dated: March 28, 2025

DEFINITIONS

1. “Document” means the original and all copies (regardless of origin and whether or not including additional writing thereon or attached thereto) of any memoranda, reports, books, manuals, instructions, directives, records, forms, notes, letters, or notices, in whatever form, stored or contained in or on whatever medium, including digital media.

2. “Study” means any written, recorded, transcribed, taped, filmed, or graphic matter, however produced or reproduced, either formally or informally, a particular issue or situation, in whatever detail, whether or not the consideration of the issue or situation is in a preliminary stage, and whether or not the consideration was discontinued prior to completion.

3. “Person” means any natural person, corporation, professional corporation, partnership, association, joint venture, proprietorship, firm, or the other business enterprise or legal entity.

4. A request to identify a natural person means to state his or her full name and business address, and last known position and business affiliation at the time in question.

5. A request to identify a document means to state the date or dates, author or originator, subject matter, all addressees and recipients, type of document (e.g., letter, memorandum, telegram, chart, etc.), identifying number, and its present location and custodian. If any such document was but is no longer in the Company’s possession or subject to its control, state what disposition was made of it and why it was so disposed.

6. A request to identify a person other than a natural person means to state its full name, the address of its principal office, and the type of entity.

7. “And” and “or” should be considered to be both conjunctive and disjunctive, unless specifically stated otherwise.

8. “Each” and “any” should be considered to be both singular and plural, unless specifically stated otherwise.

9. Words in the past tense should be considered to include the present, and words in the present tense include the past, unless specifically stated otherwise.

10. “You” or “your” means the person whose filed testimony is the subject of these data requests and, to the extent relevant and necessary to provide full and complete answers to any request, “you” or “your” may be deemed to include any other person with information relevant to any interrogatory who is or was employed by or otherwise associated with the witness or who assisted, in any way, in the preparation of the witness’ testimony.

11. “Companies”, “Louisville Gas & Electric Company and Kentucky Utilities Company”, or “LG&E-KU ”, means Louisville Gas & Electric Company and Kentucky Utilities Company, their parents or subsidiaries, and/or any of its officers, directors, employees or agents who may have knowledge of the particular matter addressed, and affiliated companies including member cooperatives.

12. “Joint Intervenors” means Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association who have been granted the status of full intervention as joint intervenors in this matter.

13. Unless otherwise specified in each individual request the term “tariff” means the tariff as filed in this matter by LG&E-KU .

14. “Commission” or “PSC” means the Kentucky Public Service Commission, including its Commissioners, personnel, and offices.

15. “AMI” means Advance Metering Infrastructure.

16. “BA” means Balancing Authority.

17. “C&I” means Commercial & Industrial.

18. “CPCN” means Certificate of Public Convenience and Necessity.

19. “CT” means Combustion Turbine.

20. “DER” means Distributed Energy Resources.

21. “DSM” means Demand Side Management.

22. “EE” means Energy Efficiency.

23. “EPC” means Engineering, Procurement, and Construction.

24. “kW” means kilowatt.

25. “kWh” means kilowatt-hour.

26. “MW” means megawatt.

27. “MWh” means megawatt-hour.

28. “NGCC” means Natural Gas Combined Cycle.

29. “OEM” means Original Equipment Manufacturer.

30. “PJM” means PJM Interconnection, a regional transmission organization.

31. “PPA” means Power Purchase Agreement.

32. “PVRR” means present value revenue requirement(s).

33. “RC” means Reliability Coordinator.

34. “RFP” means Request For Proposals.

35. “RTO” means Regional Transmission Organization.

36. “SCR” means Selective Catalytic Reduction.

37. “TSR” means Transmission Service Request.

38. “TVA” means Tennessee Valley Authority.

39. “VPP” means Virtual Power Plant.

INSTRUCTIONS

1. If any matter is evidenced by, referenced to, reflected by, represented by, or recorded in any document, please identify and produce for discovery and inspection each such document.

2. These requests for information are continuing in nature, and information which the responding party later becomes aware of, or has access to, and which is responsive to any request is to be made available to Joint Intervenors. Any studies, documents, or other subject matter not yet completed that will be relied upon during the course of this case should be so identified and provided as soon as they are completed. The Respondent is obliged to change, supplement and correct all answers to interrogatories to conform to available information, including such information as it first becomes available to the Respondent after the answers hereto are served.

3. Unless otherwise expressly provided, each data request should be construed independently and not with reference to any other interrogatory herein for purpose of limitation.

4. The answers provided should first restate the question asked and also identify the person(s) supplying the information.

5. Please answer each designated part of each information request separately. If you do not have complete information with respect to any interrogatory, so state and give as much information as you do have with respect to the matter inquired about and identify each person whom you believe may have additional information with respect thereto.

6. In the case of multiple witnesses, each interrogatory should be considered to apply to each witness who will testify to the information requested. Where copies of testimony, transcripts, or depositions are requested, each witness should respond individually to the information request.

7. Wherever the response to a request consists of a statement that the requested information is already available to Joint Intervenors, please provide a detailed citation to the document that contains the information. This citation shall include the title of the document, relevant page number(s), and, to the extent possible, paragraph number(s) and/or chart/table/figure number(s).

8. If you claim a privilege including, but not limited to, the attorney-client privilege or the work product doctrine, as grounds for not fully and completely responding to any discovery request, please describe the basis for your claim of privilege in sufficient detail so as to permit Joint Intervenors or the Commission to evaluate the validity of the claim. With respect to documents for which a privilege is claimed, please produce a "privilege log" that identifies the author, recipient, date, and subject matter of the documents or interrogatory answers for which you are asserting a claim of privilege and any other information pertinent to the claim that would enable Joint Intervenors or the Commission to evaluate the validity of such claims.

9. Whenever the documents responsive to a discovery request consist of modeling files (including inputs or output) and/or workpapers, the files and workpapers should be provided in machine-readable electronic format (e.g., Microsoft Excel), with all formulas and cell references intact.

10. The interrogatories are to be answered under oath by the witness(es) responsible for the answer.

INITIAL DATA REQUESTS PROPOUNDED TO LOUISVILLE GAS & ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY BY JOINT INTERVENORS

Joint Intervenors hereby tender the following supplemental requests for information to the Companies:

1.1. Provide all LG&E-KU responses to data requests from all parties in this proceeding, including confidential responses. Continue to provide any such documentation, until this docket is closed, on a regular basis.

1.2. To the extent not provided elsewhere, please provide any modeling, including all inputs and outputs, conducted by the Companies related to the proposed projects, including any analysis of alternatives, any capacity expansion, resource optimization, or production cost modeling.

1.3. Have the Companies attempted to estimate the incremental rate impacts should it proceed with each of the proposed CPCN projects? If so, please produce each such estimate, including supporting documentation and workpapers.

1.4. Have the Companies attempted to estimate the incremental revenue requirement impact should it proceed with each of the proposed CPCN projects? If so, please produce each such estimate, including supporting documentation and workpapers.

1.5. Please refer to the Direct Testimony of Lonnie E. Bellar, p. 3, lines 13-15. For each of the referenced potential data center projects and economic development projects in the economic development queue, specify and provide evidence of:

a. Whether and the degree to which the potential customer has secured control of the land where the project would be located, including whether the potential customer has an option on the land, has leased the land, has purchased the land, or has attempted to secure control of the land through another means;
b. Whether the potential customer has submitted a Request for Service, entered into a Service Agreement, entered into an engineering, procurement, and contraction ("EPC") agreement, or signed any other contract with the Companies;
c. Whether any studies, including Engineering Studies, have been conducted by, for, or on the potential customer;
d. Whether any transmission service requests ("TSRs") have been submitted;
e. Whether any construction, water use, or air quality permit applications have been submitted;

f. Any efforts taken to determine whether the potential customer has submitted the same project to another utility's economic development queue;
g. Any other efforts by LG&E-KU to assess the likelihood of the potential customer completing development of the project in LG&E-KU's service territory;
h. The identity of the potential ratepayer;
i. The planned or intended use of the data center or economic development project, to the extent known, including whether a data center would be used for artificial intelligence training, artificial intelligence training, or cryptocurrency mining;
j. Whether the project was submitted by a data center operator or a company that would lease a site to a data center operator;
k. Whether the project was submitted by the federal government.

1.6. For any prospective data center customers that have submitted TSRs to the Companies, please provide:
a. The TSR;
b. What year the TSR was submitted;
c. For what year of implementation was the TSR submitted;
d. How many MWs of transmission service have been requested; and
e. Whether the TSR is active, has lapsed, or has been withdrawn.

1.7. For any prospective data centers customers that have signed EPC agreements with the Companies, provide:
a. The EPC agreement;
b. What year the EPC agreement was signed;
c. For what year of implementation the EPC agreement was signed;
d. How many MWs of demand are anticipated.

1.8. With respect to the addition of large loads to the Companies' system please answer the following:
a. Are power quality assessments being conducted, such as evaluating voltage dips, harmonics, and flicker resulting from large load switching?
b. Are electromagnetic interference (EMI) studies included to assess potential impacts on nearby communications infrastructure, controls, or protection systems?
c. How are transient recovery voltage (TRV) and temporary overvoltage (TOV) events modeled and mitigated?
d. Are model validations and hardware-in-the-loop simulations being considered for loads with high variability or fast ramping profiles?

1.9. Please refer to the Direct Testimony of Lonnie E. Bellar, p. 5, lines 1-5, and the Direct Testimony of Charles R. Schram, p. 6, lines 3-7.

   a. Explain how the Companies adjusted for the departed KU municipal customers in calculating the January 22, 2025 peak's equivalence to the Companies' 2014 Polar Vortex peak; and
   b. Explain how the Companies adjusted for the Companies' load shedding in calculating the January 22, 2025 peak's equivalence to the Companies' December 2022 Winter Storm Elliot peak.

1.10. Please refer to the Direct Testimony of Lonnie E. Bellar, p. 5 lines 5-9 and the Direct Testimony of Charles R. Schram, p. 7, line 20 to p. 8 line 2.

   a. Define the Companies' contingency reserve obligation under their reserve sharing agreement with the Tennessee Valley Authority, including all applicable Transmission Reliability Margins; and
   b. Produce the Companies' reserve sharing agreement with the Tennessee Valley Authority and all supporting agreements.

1.11. Please refer to the Direct Testimony of Lonnie E. Bellar, p. 5, lines 9-14. Describe the referenced 19.4 MW customer expansion.

1.12. Please refer to the Direct Testimony of Lonnie E. Bellar, p. 6, lines 11-14. Describe any efforts that the Companies are taking now to assess and address potential resource needs beyond 2032.

1.13. Please refer to the Direct Testimony of Lonnie E. Bellar, p. 7, lines 8-14. Account for each of the factors responsible for the difference between the original estimated capital cost for Mill Creek 5 ($662 million) and the current estimated completion cost of $913.4 million, including the specific cost increase each factor is responsible for and when the Companies became aware of each specific cost increase.

1.14. Please refer to the Direct Testimony of Lonnie E. Bellar, p. 7, line 15 to p. 8 line 1.

   a. Produce the best current estimate of the final completion cost for the Brown BESS.
   b. If the current estimate of the final completion cost for the Brown BESS differs from the original estimated capital cost of $270 million, account for each of the factors responsible for the difference in cost, including the specific cost increase or decrease each factor is responsible for.
   c. Produce the referenced material procurement contracts.
   d. Produce an estimate of costs to be contained in the referenced engineering, procurement, and construction ("EPC") contracts, if an estimate exists.

1.15. Please refer to the Direct Testimony of Lonnie E. Bellar, p. 8, lines 1-4.

a. Describe how the Companies track general cost volatility associated with import tariff changes, raw materials, installation labor, and long lead electrical equipment, as well as specific cost volatility associated with lithium in the case of batteries.
b. Produce the Companies' current and historic data pertaining to cost volatility associated with import tariff changes, raw materials, installation labor, and long lead electrical equipment, as well as specific cost volatility associated with lithium in the case of batteries.
c. Produce any modeling that the Companies have conducted, including all modeling input and output files, workpapers, workbooks, and other documents used in such modeling, pertaining to cost volatility associated with import tariff changes, raw materials, installation labor, and long lead electrical equipment, as well as specific cost volatility associated with lithium in the case of batteries.

1.16. Please refer to the Direct Testimony of Lonnie E. Bellar, p. 8, lines 7-14.
a. Reconcile lines 8-9 ("The current estimated completion cost is $243.0 million") with lines 11-14 ("The Companies . . . currently estimate that project costs may increase from the noted estimate") and provide an updated estimated completion cost that accounts for anticipated increased project costs.
b. Describe each of the project costs that the Companies expect to increase, including how much the Companies anticipate each cost to increase.
c. Describe how the Companies track cost volatility associated with solar panel supply.
d. Produce the Companies' current and historic data pertaining to cost volatility associated with solar panel supply.
e. Produce any modeling that the Companies have conducted, including all modeling input and output files, workpapers, workbooks, and other documents used in such modeling, pertaining to cost volatility associated with solar panel supply.

1.17. Please refer to the Direct Testimony of Lonnie E. Bellar, p. 8, line 15 to p. 9 line 2.
a. Produce the build-transfer agreement with FRON bn, LLC.
b. For each of the factors responsible for the approximately $35 million in anticipated costs for Marion County Solar, provide the specific cost increase each factor is responsible for.

1.18. Please refer to the Direct Testimony of Lonnie E. Bellar, p. 11, lines 4-14. With regards to the referenced Unit Reservation Agreement with GE, produce:
a. The Unit Reservation Agreement with GE.
b. All information related to firm pricing for Brown 12 equipment.

c. Explain whether any portion of the $25 million paid to GE is refundable if the Commission were to deny approval, or the project did not move forward for any other reason.

1.19. Please refer to the Direct Testimony of Lonnie E. Bellar, p. 11, lines 4-14. With regards to the statement that “This requirement did not exist less than two years ago when the Companies originally proposed Brown 12,” clarify whether “This requirement” refers to the Unit Reservation Agreement or a separate requirement.

1.20. Please refer to the Direct Testimony of Lonnie E. Bellar, p. 11, lines 4-14. With regards to the statement that “It is possible that a similar requirement will be necessary for Mill Creek 6”:

a. Describe any steps that LG&E-KU has taken to establish a Unit Reservation Agreement or to secure firm prices and delivery times for Mill Creek 6 equipment.
b. Describe the current status of any efforts to secure a Unit Reservation Agreement or firm prices for Mill Creek 6 equipment.
c. Provide the date by which the Companies’ anticipate having to determine whether a Unit Reservation Agreement will be necessary for Mill Creek 6.
d. Produce any analysis or modeling related to the need for a Unit Reservation Agreement for Mill Creek 6, including all modeling input and output files, workpapers, workbooks, and other documents used in such modeling.
e. Produce all information related to the delivery time and pricing for equipment for Mill Creek 6, including projections of expected delivery time and pricing.

1.21. Regarding the estimated cost for Brown 12 of $1.383 billion and for Mill Creek 6 of $1.415 billion:

a. What is the basis for the current cost estimate for the NGCCs? In which Association for the Advancement of Cost Engineering (AACE) cost estimate class does the current estimate fall in? Please provide all documents that serve as the basis for your response.
b. Please provide any spreadsheet(s) or other documents reflecting the calculations used to create these estimates.
c. What cost guarantees, if any, are the Companies prepared to offer ratepayers for these projects?
d. In the event that costs increase, what steps, if any, would the Companies take to seek Commission approval of those additional costs?
e. Please provide the overnight capital costs of Brown 12 and Mill Creek 6, along with Mill Creek 5, defined as the construction cost excluding interest accrued during plant construction and development.

1.22. For each of the following resources, provide the projected capacity factor for each month, if available, once the project becomes commercially operable:
   a. Brown 12,
   b. Brown BESS,
   c. Mill Creek 5,
   d. Mill Creek 6,
   e. Cane Run BESS,
   f. Ghent 2,
   g. the Mercer County Solar Project, and
   h. the Marion County Solar Project.

1.23. For each month January-December, please list the average capacity factors for the following generation on the Utilities' systems for the past 5 years:
   a. Coal generation,
   b. Natural gas generation,
   c. Hydrogeneration,
   d. Solar generation,
   e. Wind generation, and
   f. Other (please specify).

1.24. Please refer to the Direct Testimony of Robert M. Conroy, p. 9, lines 8-11. Explain how the addition of Brown 12, Mill Creek 6, and the Cane Run BESS will, in the Companies' view, "help diversify their resource portfolio."

1.25. Please refer to the Direct Testimony of Robert M. Conroy, p. 13, lines 1-5.
   a. Have the Companies' concluded their study of the issue of electric transmission needs in connection with the proposed facilities? If so, please produce that study, including supporting workpapers.
   b. Does the Companies' position remain unchanged that they do not currently believe that electric transmission-specific CPCNs will be required for the proposed facilities? If the Companies' position has changed, please explain why and in what manner.

1.26. Please refer to the Direct Testimony of Robert M. Conroy, p. 13, lines 13-23, and explain:
   a. How was the ownership of the planned resources determined by the Companies?
   b. Explain how this compares to the planned ownership for comparable assets in Case No. 2022-00402, and the reason for any differences.

1.27. Please refer to the Direct Testimony of Robert M. Conroy, p. 14, lines 20-24.

a. When do the Companies expect to begin to recover costs under Construction Work in Progress ("CWIP") cost recovery?
b. When do the Companies expect to begin to recover costs under allowance for funds used during construction ("AFUDC")?
c. When do the Companies expect to begin to recover costs under post-in-service carrying costs ("PISCC") cost recovery?
d. To the extent known, provide an estimate of costs to be recovered under CWIP cost recovery for Mill Creek 5, Brown 12, and Mill Creek 6, on an individual project basis.
e. Have the Companies estimated incremental rate impacts of CWIP, AFUDC, and/or PISCC? If so, please produce each such estimate, including supporting documentation and workpapers.

1.28. Please refer to the Direct Testimony of Robert M. Conroy, p. 14, lines 20-24, and provide the following:
a. Any quantitative analysis the Companies have conducted to determine either ratepayer savings or ratepayer costs resulting from CWIP cost recovery. To the extent no such analysis has been conducted to quantify the impact of CWIP on ratepayers, please explain why not.
b. An explanation of all inputs and assumptions included in the Companies' calculations.

1.29. Please refer to the Direct Testimony of Robert M. Conroy, p. 14, line 24 to p. 15, line 4. Provide the estimated difference between AFUDC using the methodology approved by the Federal Energy Regulatory Commission ("FERC") and the Companies' weighted average cost of capital. Provide any supporting calculation in Excel spreadsheet format, with all formulas, columns, and rows unprotected and fully accessible.

1.30. Please refer to the Direct Testimony of Robert M. Conroy, p. 15, line 9 to p. 16, line 5, and provide the following:
a. Any quantitative analysis the Companies have conducted to determine either ratepayer savings or ratepayer costs resulting from PISCC cost recovery. To the extent no such analysis has been conducted to quantify the impact of PISCC on ratepayers, please explain why not.
b. All studies, analyses, workpapers, or other documents prepared by or relied on by the Companies that support the statement that a regulatory asset treatment of post-in-service costs would "improve the administrative efficiency for the Commission and reduce rate case costs for customers."

c. An explanation of all inputs and assumptions included in the Companies' calculations.

1.31. Please refer to the Direct Testimony of Philip A. Imber, pp. 3-6, and provide:
   a. The actual hourly NO_X emissions from each of the Companies' units for the past 5 years;
   b. The actual hourly heat input for each of the Companies' units for the past five years;
   c. Whether each unit has selective catalytic reduction systems, and indicate which hours SCRs were operational for each of the past five years;
   d. The quantity, price, transferor, and transferee of NO_X allowances purchased, sold, and traded by the Company for each facility for each of the past 5 years;
   e. Projected hourly NO_X emissions and heat inputs for each of the Companies' units for the next five years; and
   f. Projected price and availability of NO_X allowances for each of the next 5 years.

1.32. Please refer to the Direct Testimony of Philip A. Imber, p. 4, lines 18-21, and respond to the following requests:
   a. How many hours during each year's ozone season Ghent 2 could operate without SCRs, and without purchasing or trading for additional NO_X credits?
   b. How many hours, and at what expense, would Ghent 2 be able to operate without SCRs, and with purchasing or trading for additional NO_X credits, based on the Companies' estimates.
   c. Refer to the Companies' Application at page 8, table 1, and confirm Ghent 2 is included as an "Existing Resource" under the "Fully Dispatchable Generation Resources" in all years in that table. If anything other than confirmed, explain.

1.33. Please refer to the Direct Testimony of Philip A. Imber, p. 6, line 21 to p. 7, line 2, and:
   a. Provide the referenced comments of the Kentucky Attorney General, the Energy and Environment Cabinet, Louisville Metro, and Greater Louisville Inc., as well as any other comments the Companies are aware of on the January 3, 2025 proposal.
   b. Did the Companies comment on the proposal? If yes, please provide those comments; if no, why not?

1.34. Please refer to the Direct Testimony of Philip A. Imber, p. 6, line 5 to p. 7, line 7 regarding the attainment status of the Louisville-Jefferson County area for the 2015 ozone NAAQS, and respond to the following requests:

a. Have the Companies performed or caused to be performed any analysis of the relative contributions of various sources, or the impacts of emissions from its facilities, on ozone levels in the Louisville-Jefferson County area, or elsewhere?
    i. If yes, please provide any such analysis;
    ii. If no, why not?
b. Have the Companies performed or caused to be performed any photochemical air quality modeling of the formation of ozone in the Louisville-Jefferson County area or elsewhere? If yes, please provide any such modeling, including inputs, outputs, results, reports, and analysis of results.
c. Explain the relevance of the referenced piece of testimony regarding local nonattainment to the CPCN applications.

1.35. Please refer to the Direct Testimony of Philip A. Imber, p. 11, line 16 to p. 12, line 6, and provide, to the extent available to the Companies:
a. The 88 “large” coal fired generating units in Group 2E;
b. The 11 units without post-combustion controls;
c. The seasonal capacity factor for each of the past five years for each of the 88 units listed in subpart a.

1.36. Please refer to the Direct Testimony of Philip A. Imber, pp. 13-15, generally. Did the Company forecast or analyze the possibility or impact on its proposal of a Clean Power Plan or GHG Rule-like restrictions being imposed by a subsequent federal administration?
a. If yes, please provide any such forecasting or analysis;
b. If not, why not?

1.37. Please refer to the Direct Testimony of Philip A. Imber, p. 16, line 18 to p. 17 line 8. Did the Company forecast or analyze the possibility or impact on its proposal of 2024 ELG Rule-like restrictions (i.e., zero-discharge limits) being imposed by a future administration?
a. If yes, please provide any such forecasting or analysis;
b. If not, why not?

1.38. Please refer to the Direct Testimony of Philip A. Imber, p. 17, line 23 to p. 18, line 2, and state whether the Companies have submitted the referenced required air permit applications;
a. If yes, please provide copies of any applications submitted;
b. If no, please provide in a supplemental response as soon as such applications are submitted.

1.39. Please refer to the Direct Testimony of Philip A. Imber, p. 18, lines 4-13, and respond to the following requests:

a. Do the Companies anticipate application of Prevention of Significant Deterioration ("PSD") or Nonattainment New Source Review ("NNSR") for Brown 12 for emissions of each regulated pollutant? Please specify by pollutant, including rationale for applicability.
b. Do the Companies anticipate application of PSD or NNSR for Mill Creek 6 for emissions of each regulated pollutant? Please specify by pollutant, including rationale for applicability.
c. Confirm both Brown 12 and Mill Creek 6 will utilize SCR systems for NO_X emissions. If anything but confirmed, please explain.
d. Please list any other pre or post-combustion control technologies planned for Brown 12 and Mill Creek 6.
e. Do the Companies anticipate application of Louisville's Strategic Toxic Air Reduction ("STAR") Program to Mill Creek 6?
    i. If yes, have the Companies modeled or caused to be modeled the impacts of air toxics concentrations from Mill Creek 6? Please provide any such modeling results and report.
    ii. If no, why not?
f. Explain whether the Companies anticipate Mill Creek 6 will "net out" at step one of the New Source Review ("NSR") process under the Project Emissions Accounting Rule or using step two contemporaneous netting (see Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Regulations Related to Project Emissions Accounting, 89 Fed. Reg. 36,870 (May 03, 2024)).
g. Please provide the emissions increase, and if relevant the net emissions increase, for each regulated pollutant for the Mill Creek 6 project, including any netting analysis and source of reductions in emissions included in calculations.

1.40. Please explain any space constraints or the impact of construction of Mill Creek 6 and Brown 12 on landfill constraints or coal stockpiles at either facility (see the Companies' 2024 IRP Vol. 1 at 5-26).

1.41. Please identify in Companies' Exhibits 1 & 2 or similar diagrams the location of any coal combustion residual landfill, including type (e.g., Legacy coal combustion residual ("CCR")surface impoundments, CCR management units, etc.), in relation to the planned Mill Creek 6 and Brown 12 units.

1.42. Please refer to the Direct Testimony of Charles R. Schram, p. 3 lines 13-15, and provide the dates on which the Companies experienced the referenced hourly winter load variation of 2,760 MW and hourly summer load variation of 3,220 MW.

1.43. Please produce the following PPAs:
   a. The Clearway Song Sparrow PPA;
   b. The Ragland PPA;
   c. The Gage PPA;
   d. The Rhudes Creek Solar PPA;
   e. The Nacke Pike PPA; and
   f. The Grays Branch PPA.

1.44. Please identify the queue number in LG&E-KU's Generation Interconnection Queue for each of the following projects:
   a. The Clearway Song Sparrow PPA;
   b. The Ragland PPA;
   c. The Gage PPA;
   d. The Rhudes Creek Solar PPA;
   e. The Nacke Pike PPA; and
   f. The Grays Branch PPA.

1.45. To the extent known, why is each of the following projects "currently suspended" despite having a signed LGIA (identified by queue number listed in the LG&E-KU Generation Interconnection Queue):
   a. LGE-GIS-2020-001;
   b. LGE-GIS-2021-007;
   c. LGE-GIS-2021-008;
   d. LGE-GIS-2021-009;
   e. LGE-GIS-2021-011;
   f. LGE-GIS-2021-017; and
   g. LGE-GIS-2021-018.

1.46. Please refer to the Direct Testimony of Charles R. Schram, p. 9 lines 4-8. For the Ragland PPA, provide the original 2021 PPA price and the referenced new price, along with the date that the new price was proposed to the customers.

1.47. Please refer to the Direct Testimony of Charles R. Schram, p. 9 lines 9-13. For the Gage PPA, provide:
   a. The original PPA price and the price that the developer proposed in negotiations, along with the date that the new price was proposed to the Companies.

b. Any analysis and modeling, along with any supporting workpapers, that the Companies conducted when assessing whether to agree to a higher price for the Gage PPA.

1.48. Please refer to the Direct Testimony of Charles R. Schram, p. 9 line 15 to p. 10 line 2. Please provide the legal status of any applications to Hardin County for approvals for:
a. Rhudes Creek Solar; and
b. Nacke Pike.

1.49. Please refer to the Direct Testimony of Charles R. Schram, p. 10 lines 3-7. For the Grays Branch PPA, provide:
a. The original PPA price and the price that the Companies expect the project to reach.
b. Any analysis and modeling, along with any supporting workpapers, that the Companies have conducted to assess the anticipated increase in price.

1.50. Please refer to the Direct Testimony of Charles R. Schram, p. 10 lines 8-14. What project selection criteria will the Companies adopt to avoid similar challenges in the future regarding solar PPAs reaching project completion?

1.51. Please refer to the Direct Testimony of Charles R. Schram, p. 10 lines 14-15.
a. Have the Companies conducted any analysis or modeling to determine whether the PPAs would be favorable to customers at increased prices?
b. If yes, please provide any analysis and modeling, along with any supporting workpapers.

1.52. Please refer to the Direct Testimony of Charles R. Schram, p. 13 lines 5-13 and explain:
a. Whether the Companies conducted any analysis or modeling to determine how the cost of using the Mill Creek 5 NGCC power island vendor for Brown 12 and Mill Creek 6 compares to the cost of using other potential vendors, and if yes, provide that analysis and any supporting workpapers.
b. To the best of the Companies' knowledge, what is the magnitude of gas turbine backlogs at each of the three major manufacturers, Siemens Energy, GE Vernova, and Mitsubishi Power.
c. To the best of the Companies' knowledge, how have backlogs impacted Original Equipment Manufacturer ("OEM") ability to support maintenance and spare parts availability for units in-service for each of the three major manufacturers, Siemens Energy, GE Vernova, and Mitsubishi Power.

d. To the best of the Companies' knowledge, how have backlogs impacted pricing at each of the three major manufacturers, Siemens Energy, GE Vernova, and Mitsubishi Power?
e. How the Companies evaluated the dependency risk of relying on the same OEM for gas turbine procurement and the potential value of mitigating that risk through diversification of OEM suppliers.

1.53. Please refer to the Direct Testimony of Charles R. Schram, p. 13, line 19 to p. 14 line 5, and explain if the Companies have conducted any analysis or modeling to determine how the impact of cost increases for BESS projects might impact BESS PPAs differently than self-builds.

1.54. Please refer to the Direct Testimony of Charles R. Schram, p. 14, lines 5-9, and explain why, on a forward-looking basis, the Companies could not address the alluded-to challenges in BESS PPAs.

1.55. Please refer to the Direct Testimony of Charles R. Schram, p. 14, lines 13-18.
a. Explain whether the Companies are aware of any proposed pumped storage projects other than Lewis Ridge;
b. Explain whether the Companies have assessed the costs and feasibility of any pumped storage projects other than Lewis Ridge;
c. Provide the Companies' current assessment of the feasibility of the Lewis Ridge Pumped Storage project and its costs relative to other technologies such as lithium-ion batteries.

1.56. Please refer to the Direct Testimony of Charles R. Schram, p. 18 lines 1-5. For each of the projects that respondents offered to sell to the Companies, provide the project's:
a. Local permitting status;
b. Land control status;
c. Design engineering status; and
d. Anticipated or proposed development completion date.

1.57. Please refer to the Direct Testimony of Charles R. Schram, p. 18, lines 8-10.
a. Do the Companies currently own the land where all of their generation assets are located?
b. If not, specify the generation asset and land control status for any of the Companies' generation assets for which the Companies do not own the land.
c. Provide a map of the property boundaries at each of the proposed resource locations, indicating the extent of the Companies' current ownership.

1.58. For the Cane Run 7 NGCC, please provide average historical and projected costs on a yearly basis for:

a. Gas purchased on the spot market; and
b. Gas purchased on a forward basis.

1.59. Please provide the duration of the longest-duration gas supply contract the Companies currently have in place for their generators.

1.60. Please produce the Companies' contracts for gas purchased on a forward basis for Cane Run 7.

1.61. Please refer to the Direct Testimony of Charles R. Schram, p. 20, line 15 to p. 21, line 4.
   a. Please provide any assessment, analysis, or modeling, along with any workpapers, pertaining to the Companies' evaluation of its gas procurement strategy.
   b. Regarding the referenced expectation that the Companies will seek to increase their forward gas purchases as their NGCC fleet grows, please provide the anticipated percentage of gas supply that will be purchased on a future basis if the Companies develop all proposed NGCCs, if that percentage currently exists.

1.62. Please indicate whether pipeline capacity additions would be needed to support the addition of either of the two NGCCs.

1.63. For each pipeline proposed for service to each facility, please identify that pipeline's operational status, including pressure and utilization rate.

1.64. Regarding the Mill Creek 5, Mill Creek 6, and Brown 12 NGCCs:
   a. Has LG&E-KU entered into any contracts for the transportation of gas? If yes, please provide all such contracts.
   b. Has LG&E-KU received any cost estimates from the pipelines serving Brown and Mill Creek for the transportation of gas to Mill Creek 5, Mill Creek 6, and Brown 12? If yes, please provide all cost estimates.

1.65. Please produce the Companies' contracts and agreements with Texas Gas Transmission, Tennessee Gas, and Texas Eastern for firm gas transportation to its Brown and Mill Creek stations.

1.66. For Brown's simple-cycle combustion turbines, please specify what percentage of gas is transported by Tennessee Gas compared to Texas Eastern.

1.67. For the Brown NGCC, please specify what percentage of gas the Companies expect to be transported by Tennessee Gas compared to Texas Eastern.

1.68. Please refer to the Direct Testimony of Charles R. Schram, p. 23, lines 17-19. Regarding the Final Order in the Winter Storm Elliot investigation case, please explain whether the Companies' have taken the following steps, and if not, why not:

   a. Accounting for incremental outage rates that can occur during extreme weather when modeling reliability benefits in its resource planning.
   b. A quantitative analysis of the potential reliability benefits to LG&E-KU's customers of RTO membership.
   c. Evaluated the improvement or expansion of the Curtailable Service Rider ("CSR") Program, including the creation of new curtailable service riders to protect more vulnerable customers from load shed or amendments to Curtailable Service Rider-1 (CSR-1) and Curtailable Service Rider-2 (CSR-2) to increase penalties for non-compliance.
   d. Sought or improved agreements with other Balancing Authorities regarding purchasing power in an emergency situation.
   e. Implemented changes to their customer communication and public appeal process to notify customers of the need of conserving energy to reduce load and to keep customers informed and prepared in case of necessary energy curtailments or firm load shedding.

1.69. Please refer to the Direct Testimony of Charles R. Schram, p. 24, lines 12-15, and provide the historical transaction details for gas transport to the Brown Simple Cycle Combustion Turbines ("SCCTs"), along with any projected transaction details, if those projections exist.

1.70. Please refer to the Direct Testimony of Charles R. Schram, p. 24, lines 15-17, and produce the referenced agreement with Tennessee Gas for a portion of its gas transportation requirements to serve its retail gas customers.

1.71. Please provide the Firm Transportation costs assumed in the Companies' analyses indicating annual/monthly costs and term.

1.72. Please refer to the Direct Testimony of David L. Tummonds, p. 3 lines 1-3.

   a. Provide a detailed list of all sites considered for the location of the proposed NGCCs.
   b. Of the sites considered, please explain to what extent land availability was a determining factor in choosing Brown or Mill Creek instead.

1.73. Please refer to the Direct Testimony of David L. Tummonds, p. 3, lines 9-19. Describe the differences in cost, construction, and operation of a 2x1 NGCC like Cane Run 7 and the 1x1 single-shaft NGCCs proposed in this case.

1.74. Please refer to the Direct Testimony of David L. Tummonds. p. 4, and provide the following:
   a. Any assessment, analysis, or modeling, along with any workpapers, pertaining to the Companies' evaluation of the acquisition and construction of a single, larger NGCC instead of the two proposed NGCCs.
   b. Any information related to the cost or availability of a larger NGCC that the Companies' developed, relied upon, or received from either GE, Mitsubishi, or Siemens. If the Companies' do not have any further information relating to the cost or availability of a larger NGCC, please explain why no such inquiry was made.
   c. Explain any disadvantages the Companies identified in constructing two NGCCs instead of a single larger NGCC at just one location.

1.75. Please refer to the Direct Testimony of David L. Tummonds, p. 7, lines 15-17. Beyond a "good experience with GE," what other factors have the Companies' taken under consideration in developing their plan to use GE for both Brown 12 and Mill Creek 6.

1.76. Please refer to the Direct Testimony of David L. Tummonds, p. 7, line 18 to p. 8 line 2. Explain the Independent Transmission Organization ("ITO") requirement that requires the Companies to wait until November 2025 to submit a generation interconnection request for Mill Creek 6.

1.77. Please refer to the Direct Testimony of David L. Tummonds, p. 8, lines 3-10.
   a. Did the Companies consider any engineering firm other than HDR for this proposal?
   b. Besides familiarity, what other considerations did the Companies' take into account in choosing HDR to serve as the Owner's Engineer ("OE")?
   c. Confirm that the Companies intend to use HDR as the OE for both Brown 12 and Mill Creek 6.

1.78. Please refer to the Direct Testimony of David L. Tummonds, p. 8, lines 12-15. When do the Companies' anticipate issuing a request for proposals ("RFP") for the EPC contractor?

1.79. Please refer to the Direct Testimony of David L. Tummonds, p. 10, lines 17-18. Have the Companies' quantified the potential increase in costs, should delay occur at any stage in the acquisition, construction, or in-service date of Brown 12 or Mill Creek 6? If yes, provide all cost estimates.

1.80. Please refer to the Direct Testimony of David L. Tummonds, p. 10, lines 20-22. Explain the reasons for the differences in fixed and variable costs between the two proposed NGCCs.

1.81. Please refer to the Direct Testimony of David L. Tummonds, p. 11, lines 3-11.
   a. Provide any analyses that support the Companies' conclusion that the proposed NGCCs will be able to transmit power using the existing network of transmission infrastructure.
   b. Explain the "limited modifications" the Companies anticipate will be necessary for the proposed NGCCs to transmit power using the existing network of transmission infrastructure.

1.82. Please refer to the Direct Testimony of David L. Tummonds, p. 11, lines 16-22.
   a. Provide the cost estimate developed for the Ghent BESS.
   b. If site space was not a limiting factor at the Cane Run site, would the Companies' propose a larger BESS system? If so, what size?
   c. Did the Companies consider any locations for the BESS where site space did not necessitate limiting the BESS to 400 MW?
   d. Did the Companies consider any locations other than Cane Run and Ghent?
      i. If yes, provide any such comparison or analysis.
      ii. If not, why not?

1.83. Please refer to the Direct Testimony of David L. Tummonds, p. 13, lines 5-8. Have the Companies completed the engineering planning for the BESS?
   a. If yes, please provide the engineering planning results.
   b. If not, why not, and when do the Companies anticipate completing such planning?

1.84. Please refer to the Direct Testimony of David L. Tummonds, p. 13, lines 20-21. Of the SCRs constructed on the Companies' coal-fired units, were any of those projects delivered at a capital cost higher than initially estimated? If so, please identify the project, the initial capital cost estimate, and the final capital cost to construct.

1.85. Please refer to the Direct Testimony of Stuart Wilson, p. 7, lines 2-6, 8-12; p. 8, lines 4-11, providing various estimates of the likelihood of Energy Emergency Alert 1 and 3 events. For each scenario presented, please:
   a. Explain the assumptions and calculations used to determine the likelihood of an Energy Emergency Alert 1, and provide supporting workpapers, if any.
   b. Explain the assumptions and calculations used to determine the likelihood of an Energy Emergency Alert 3, and provide supporting workpapers, if any.
   c. Explain how each percentage likelihood compares with a Loss of Load Expectation ("LOLE") of one day in ten years.

1.86. Please identify each instance over the last ten years when the Companies declared an Energy Emergency Alert 1, and describe the circumstances in each such instance.

1.87. Please refer to the Direct Testimony of Stuart Wilson, p. 12, lines 3-6, regarding projected annual energy reductions of 1,500 GWh by 2032, please disaggregate the annual contributions of each of the following:
   a. Customer-initiated energy efficiency improvements;
   b. Advanced metering infrastructure related conservation voltage reduction;
   c. ePortal savings;
   d. Distributed generation;
   e. The energy-efficiency effects of the Companies' 2024-2030 DSM-EE Plan; and
   f. The assumed impacts of the Companies' DSM-EE programs beyond 2030.

1.88. Please provide an update on the DSM/EE Potential Study that Resource Innovations started work on for the Companies in September 2024, including when the study will be completed. If the study has already been completed, please produce a copy and supporting workpapers.

1.89. Please provide a progress report on all existing DSM/Energy Efficiency and Demand Response programs, from January 2024 through March 1, 2025, including for each program and incentive:
   a. Number of customers participating or enrolled each month;
   b. Program expenditures;
   c. Cumulative MW savings (and compare to program goals);
   d. Cumulative MWh savings (and compare to program goals).

1.90. Please identify any additional DSM, Energy Efficiency, or Demand Response Programs the Companies have evaluated since January 2024. Please describe any such new programs the Companies plan to implement in the next three years.

1.91. In the last three years, has LG&E/KU studied, or caused to be studied, residential customers' energy burden? If so, please produce the results of each such study. If not, please explain why not.

1.92. During the development of the present CPCN application, did the Companies evaluate the potential for managed distributed energy resources ("DERs"), also known as a Virtual Power Plant ("VPP") to supply a portion of the Companies' forecasted new resource requirements? Please provide all analysis and workpapers with formulas intact.

1.93. Please provide DSM-EE Annual Reports for the five previous complete program years.

a. Please provide reports as filed with the Commission
b. For each program, by program year, please provide projected and actual costs, participation, and gross and net savings
c. For each program, by program year, please provide a listing of measures installed/incentivized and quantities of each
d. Please provide electronic workpapers in fully functional Excel format with formulas intact.
e. Please provide the Companies' assumed avoided energy and capacity cost values used for purposes of DSM/EE potential evaluations, DSM/EE program planning, integrated resource planning, or CPCN development over the last five years. Please include the avoided cost values as initially filed in Case No. 2022-00402 and as updated in May 2023, as well as avoided cost values developed for use in Resource Innovations' DSM/EE Potential Study for the Companies.

1.94. Please provide an update on the Evaluation, Measurement, and Verification ("EM&V") study that ADM Associates started work on for the Companies in October 2024.

a. If the study has already been completed, please produce a copy and supporting workpapers.
b. If the study has not been completed, please provide available data on DSM/EE program performance since January 2024, including but not limited to, program expenses, number of participants, housing types served, measures installed, estimated savings, administration expenses, and marketing expenses.

1.95. Please explain in sufficient detail to allow independent verification the analysis used to determine the appropriateness of including nearly 1,500 GWh of reductions (as opposed to any other savings level) by 2032 from customer-initiated energy efficiency improvements, AMI-related conservation load reduction and ePortal savings, distributed generation, and the energy efficiency effects of the Companies' proposed 2024-2030 DSM-EE Program Plan as well as new programs beyond 2030. Please produce related inputs, assumptions, and workpapers.

1.96. Please refer to the Direct Testimony of Stuart Wilson, p.17, lines 13-15, stating "the Companies' PLEXOS modeling tool could retire any resource at any time subject to the timing and replacement constraint of KRS 278.264 or keep existing coal units in service and incur stay-open costs for each affected unit."

a. Please explain how “timing . . . constraint of KRS 278.264” was included in the PLEXOS modeling.
b. Please explain how “replacement constraint of KRS 278.264” was included in the PLEXOS modeling.
c. Have the Companies modeled any sensitivities in which the timing and replacement constraints imposed by KRS 278.264 are not included? If so, please provide the results of such sensitivity analyses.

1.97. Please refer to the Direct Testimony of Stuart Wilson, p.19, lines 4-7, and produce:
  a. Each of the 2024 IRP Resource Assessment fuel price scenarios; and
  b. Each of the fuel price scenarios used in the Companies’ 2022 CPCN case.

1.98. Please provide the Companies’ actual average monthly cost of coal since January 2022.

1.99. Please provide the Companies’ actual average monthly cost of gas since January 2022.

1.100. Please produce each third-party coal price forecast, developed since January 2024, in the Companies’ possession.

1.101. Please produce each third-party gas price forecast, developed since January 2024, in the Companies’ possession.

1.102. To the extent known, do any entities other than the Companies use a coal-to-gas ratio to forecast coal prices? Please name each, if any.

1.103. Since the 2022 CPCN, have the Companies sought independent peer review of its coal-to-gas ratio approach to forecasting coal prices?
  a. If so, please describe the peer review process, identify the reviewers, and provide all documentation of the process and result(s).
  b. If not, please explain why not.

1.104. In each of the last five years, on a monthly basis, please state the amount of:
  a. Spot coal purchases
  b. Contract coal purchases
  c. Spot natural gas purchases
  d. Contract natural gas purchases

  Note: To the extent that the Companies differentiate purchase types for either fuel in terms other than “spot” and “contract,” please describe and respond using the Companies’ internal terminology.

1.105. Please refer to the Direct Testimony of Stuart Wilson, p. 15, lines 11-13, stating "Regarding BESS options, the Companies developed cost estimates for 100 MW, four-hour BESS increments at Cane Run and Ghent based on the Companies' most recent estimates for the 125 MW, four-hour Brown BESS."

a. Please provide the Companies' "most recent estimates for the 125 MW, four-hour Brown BESS."
b. Please produce the third-party battery storage project proposals received in response to the Companies' 2022 Request for Proposals (Case No. 2022-00402).
c. Please produce the Companies' 4-hour BESS proposal(s) submitted in response to the 2022 RFP.

1.106. Please refer to the Direct Testimony of Stuart Wilson, p. 16, n.15, and answer the following requests.

a. Please provide all assumptions used to model the Bring Your Own Device Energy Storage program.
b. Please describe in full in the assumed program design for the Bring Your Own Device Energy Storage program, including program budget specifying each relevant cost category (e.g., program administration; program incentives and rebates; marketing).
c. Please provide all assumptions used to model the Bring Your Own Device Home Generators program.
d. Please describe in full in the assumed program design for the Bring Your Own Device Home Generators program, including program budget specifying each relevant cost category (e.g., program administration; program incentives and rebates; marketing).
e. Please explain how the Companies expect expanding the existing Business Demand Response program to customers with loads ranging from 50 kW to 200 kW will affect program participation.
f. Please explain how the Companies determined a 50 kW to 200 kW range would be a reasonable eligibility range for the Business Demand Response program.
g. Did the Companies evaluate the potential reasonableness of increasing the program budget for the existing Business Demand Response program? If so, please provide the results of each such evaluation in the last year, including supporting workpapers. If not, please explain why not.

1.107. Please confirm that the Companies' Ex. SAW-1, 2025 Resource Assessment modeling does not attempt to account for off-system sales or purchases. If anything but confirmed, please explain.

1.108. Please refer to Ex. SAW-1, 2025 Resource Assessment, at p.40, n.61.

a. Please produce the referenced Build and Transfer Agreement.
b. Please explain the Companies' role in relation to the Firm Date milestone.
c. Please explain how the Companies are "tracking closely" the uncertainty related to the Firm Date milestone in the Build and Transfer Agreement, and provide supporting documentation, if any.

1.109. Please refer to Ex. SAW-1, 2025 Resource Assessment, at p.41, stating that stay-open costs did "not include carrying costs for prior investments or costs for projects that would not be affected by unit retirements in this analysis, such as ash pond closures."

a. For each of the existing units listed in Ex. SAW-1, 2025 Resource Assessment, Table 17, at p.40, please provide an itemized list of excluded costs for prior investments, including total project costs and amount still being recovered from customers.
b. For each of the existing units listed in Ex. SAW-1, 2025 Resource Assessment, Table 17, at p.40, please provide an itemized list of excluded "costs for projects that would not be affected by unit retirements … such as ash pond closures." Please include individual project costs, amount already recovered from ratepayers, and amount still to be recovered from customers.

1.110. Please refer to Ex. SAW-1, 2025 Resource Assessment, p. 47, stating:

> The Companies' pricing analysis was focused on the period from 2012 through 2021 because the CTG price ratio resulting from spot market pricing between 2022 and 2024 reflects extreme and aberrant market conditions that would inappropriately skew long-term price forecasts. While spot market prices continued to show an above-average ratio through 2024, the Companies' Business Plan open position shows prices returning to the historical average ratio of 0.57 observed over the ten-year period from 2012 to 2021. At this coal-to-gas price ratio, the cost of coal and NGCC energy is very similar, regardless of the level of gas prices.

a. Did the Companies calculate coal-to-gas ("CTG") price ratios using spot market pricing during any period of time including and between 2022 and 2024?
    i. If so, please produce each such calculation.
    ii. If not, please explain the basis for the Companies' stated belief that including spot market pricing between 2022 and 2024 would have inappropriately skewed long-term price forecasts.
b. If not already provided, please produce the workpaper underlying Figure 13 of Ex. SAW-1, 2025 Resource Assessment.

1.111. Please refer to Ex. SAW-1, 2025 Resource Assessment, Table 23 p. 48, and p. 49, stating that “[t]he Mid Gas, Mid CTG Ratio scenario reflects a blend of coal price bids and a third-party coal price forecast for 2025-2029 and a constant 0.57 CTG ratio thereafter. All other scenarios reflect constant CTG ratios in all years.” Have the Companies performed, or caused to be performed, any statistical analysis of the correlation between historical coal and gas prices (e.g., calculation of correlation coefficient)? If so, please produce each such analysis, including supporting workpapers in native format with formulas intact.

1.112. Please refer to Ex. SAW-1, 2025 Resource Assessment, p. 49, n.74, stating that “[t]he mid coal-to-gas price ratio (0.57) is the average coal-to-gas ratio over the ten-year period from 2012 to 2021 and approximates the ratio of NGCC and coal operating costs.”

a. Over the same ten-year period, what was the ratio of Cane Run 7 operating costs and Brown Unit 3 operating costs?
b. Over the same ten-year period, what was the ratio of Cane Run 7 operating costs and Ghent Unit 2 operating costs?
c. Over the same ten-year period, what was the ratio of Cane Run 7 operating costs and Mill Creek 3 operating costs?
d. Over the same ten-year period, what was the ratio of Cane Run 7 operating costs and Mill Creek 4 operating costs?

1.113. Please confirm that the Companies’ most recent assessment of CVR potential is reflected in the “CVR Potential Study” created by the Companies’ Generation Planning and Electric Distribution Planning group in October 2020, and filed with the Commission as Ex. LEB-3, Appendix D. If anything but confirmed, please produce the Companies’ most recent assessment of CVR potential.

1.114. Did the Companies consider or assess reciprocating internal combustion engine (“RICE”) generators as potential resource additions?

a. If yes, please provide all analysis or modeling, along with all workpapers, assumptions, inputs, and outputs.
b. If not, why not?

1.115. Please refer to the Direct Testimony of Tim Jones, p. 4.

a. Identify each of LG&E-KU’s peak demand during each hour of Winter Storm Gerri.
b. Identify each of LG&E-KU’s peak demand during each hour of Winter Storm Elliott.
c. Identify each of LG&E-KU’s peak demand during each hour of Winter Storm Enzo.

d. Identify each of LG&E-KU's installed peak winter generation capacity in the years 2022-2024.
e. For each of the years 2025 through 2045, identify the total number of hours in which you forecast that the Companies' peak demand will exceed each of:
    i. The currently installed peak winter generation.
    ii. The currently installed peak winter generation and the addition of one NGCC.
    iii. The currently installed peak winter generation and the proposed CPCN projects.

1.116. Please refer to the Direct Testimony of Tim Jones, p. 8, lines 5-10, which states: "Simply stated, the 2025 CPCN Load Forecast *is* the 2024 IRP Mid load forecast extended to 2054 and adjusted to include the 2024 IRP High load forecast's economic development load, i.e., the 2025 CPCN Load Forecast includes 1,750 MW of data center load by 2032 and the 120 MW BOSK Phase Two load, whereas the 2024 Mid Load Forecast includes only 1,050 MW of data center load and excludes BOSK Phase Two."
a. Justify the choice of the mid load forecast scaled up for additional data center load. Why is this the most reasonable assumption for CPCN consideration?
b. Provide all calculations and background materials used in selecting the mid load forecast adjusted to include the high data center forecast.

1.117. Please provide a detailed explanation of LG&E-KU's rationale for selecting load forecasts for resource planning.
a. On what basis should a utility plan for load in CPCN proceedings?
b. Should a relatively high forecast be used? Please explain why or why not.
c. What are the negative consequences to a utility of overestimating future load in resource planning?
d. What are the negative consequences to ratepayers of overestimating future load in resource planning?

1.118. Please refer to the Direct Testimony of Tim Jones, p. 12, lines 5-8, explaining that "[i]n addition to its size, the projected economic development load, particularly BOSK and data center load, is unlike nearly all other customer loads because it has a high load factor (assumed to be 95% for data centers and 90% for BOSK), much higher than the Companies' current average system load factor (about 56% in 2024)."
a. Does the stated current average system load factor of 56% include all customer classes?

b. Please identify the twenty highest load factor accounts currently taking service from the Companies. For each account, please also state the applicable rate schedule(s), peak demand, and monthly energy usage.
c. Please provide the Companies' basis for assuming a 95% load factor for data centers and a 90% load factor for BlueOval SK Battery Park ("BOSK").
d. Are the Companies aware of evidence that data centers do or do not, nationwide, participate in demand response programs?

1.119. Confirm that the 2024 IRP load forecast and 2025 CPCN load forecast are the first two forecasts by the Companies to explicitly include data center customer growth. If anything but confirmed, please explain.

1.120. Please provide a written description, a workbook (in an Excel spreadsheet with formulae intact, along with all inputs, outputs, and related data), and any relevant background materials comparing the load forecasts used in this CPCN to the forecasts used to develop the 2024 IRP. Include descriptions and data disaggregated by customer type. Include annual demand, summer and winter peak, number of customers, use per customer, and total usage. Include any load scenarios considered in either the CPCN or the IRP.

1.121. Please provide historical and forecasted annual demand and winter/summer peak broken down by scenario and customer class; forecasts should include number of customers, use per customer, and total usage.

1.122. Please provide all existing and new planned demand-side resources included in annual demand and peak forecasts by scenario. Include all related background materials and a written explanation of all assumptions.

1.123. Please provide all existing and expected customer behind-the-meter ("BTM") resources included in annual and peak forecasts by scenario. Include all related background materials and a written explanation of all assumptions.

1.124. Please provide projections of all new loads, such as those from electrification of transportation (i.e., electric vehicles) and buildings (i.e., electric heat pumps) sectors included in annual and peak forecasts by scenario. Include all related background materials and a written explanation of all assumptions.

1.125. Please provide assumptions regarding all new large load customers (e.g., data centers, cryptocurrency mining, new large industrial loads, etc.) included in annual and peak forecasts by scenario. Include all related background materials and a written explanation of all assumptions.

1.126. Please provide all fuel price projections used in modeling by scenario with clear evidence and justification. Include all related background materials and a written explanation of all assumptions.

   a. What is the data source used to develop the Companies' gas price projections?
   b. What is the data source used to develop the Companies' coal price projections?

1.127. Did Mr. Jones, or any member of the team responsible for the 2024 IRP load forecast or 2025 CPCN load forecast, attend any training or continuing education courses specifically addressing how to approach the unique challenges of forecasting potential data center customer demand changes? If so please, please identify each such training or course and produce any related documents in the Companies' possession.

1.128. What energy-related factors are used by data center developers in choosing location besides electricity rates? Do data centers prefer places with renewable generation, green tariffs, behind the meter storage/generation, or DR programs?

1.129. Please identify and produce each reference document, manual, guide, or other resource used to inform the Companies' approach to forecasting potential data center customer demand changes in either the 2024 IRP or the 2025 CPCN load forecast.

1.130. Please refer to the Direct Testimony of Tim Jones, p. 13, lines 5-7, which states: "John Bevington observes in his testimony that the data center developers with whom the Companies have interacted have expressed no interest in either DSM-EE programs or curtailable service."

   a. Reconcile Mr. Jones' statement with the Direct Testimony of John Bevington, p. 14 lines 17-18. When Mr. Bevington refers to his experience with data centers, is he referring to the same interactions between the Companies and data center developers as Mr. Jones?
   b. What specific DSM-EE or curtailable service products and programs did LG&E-KU offer to data center developers? Provide written descriptions as well as data regarding savings and costs.
   c. What specific data center developers did LG&E-KU provide this information to?
   d. What is the combined expected load by year of those data center projects?
   e. Provide any evidence of the non-speculative nature of those projects, including but not limited to real estate purchased, permits applied for, TSRs submitted, and EPC agreements signed.

1.131. Please refer to the Direct Testimony of Tim Jones, p. 13 lines 7-10, which states: "Moreover, such customers already have a strong financial incentive to be as energy-efficient as reasonably possible, making it unlikely the Companies could develop and offer cost-effective energy-efficiency programs for such customers."

a. What commercial and industrial energy efficiency, demand response or curtailable load programs does LG&E-KU offer to its current customers?
b. Why do C&I customers participate in those programs?
c. Do LG&E-KU's existing C&I customers have strong financial incentives to be as energy-efficient as possible?
d. How do planned data center customers' incentives differ from existing C&I customers?

1.132. Please refer to the Direct Testimony of Tim Jones, p. 21, lines 21-23, stating that "weather-normalized variances from the Companies' recent load forecasts have been low, and the forecasts have proven to be reasonable and reliable for resource planning."

a. As used in the referenced testimony, do "recent load forecasts" refer to the 2021 IRP Load Forecast and the 2022 CPCN-DSM Load Forecast? If not, please explain.
b. Please provide the Companies' weather-normalized sales, annually and segregated by customer class, in the 10-year period of 2015-2024.

1.133. Please refer to the Direct Testimony of Tim Jones, p. 23, Figure 6. Confirm that Figure 6 reflects daily maximum and minimum loads for all customers in the Mid load forecast scenario, including new data center customers. If anything but confirmed, please explain.

1.134. Please refer to the Direct Testimony of Tim Jones, pp. 33-34, and answer the following requests.

a. Have the Companies evaluated or caused to be evaluated the impact of potential rate structure changes on influencing customers' adoption rate of distributed energy resources, particularly solar and storage resources? If so, please produce each such evaluation, including supporting documentation and workpapers.
b. Confirm that the Companies anticipate filing general electric rate cases by July 1, 2025. If anything but confirmed, please explain.
c. Approximately when would the Companies expect tariff changes approved in their next general electric rate cases to go into effect?

1.135. Please refer to the Direct Testimony of Tim Jones, p. 36, stating, "[c]urrently, the Companies do not have access to data concerning how these customers use their batteries, and the Companies lack data as to what extent non-net metering customers have battery storage because there is no mechanism to obtain such data today."

a. Please explain in full the Companies' plan to develop data concerning how customers use their batteries.
b. Please explain in full the Companies' plan to develop data concerning the extent to which non-net metering customers have battery storage systems.

1.136. Have the Companies evaluated a Bring Your Own Battery ("BYOB") demand response program, as discussed in their most recent IRP filing?

a. If yes, please provide all documents and spreadsheets (with formulas intact) used and produced in the analysis. If no, why not?
b. Do the Companies have plans to implement a BYOB program? If yes, please provide all details concerning the plan, including budget, program goals (MW and MWh of battery deployed over what time frame), and program structure.

1.137. Please refer to the Direct Testimony of Tim Jones, pp. 37-38, and provide the inputs, assumptions, outputs, and workpapers related to the Companies net metering and Qualifying Facility ("QF") customer forecasts.

1.138. Please provide the number of customers in each rate class for LG&E-KU.

1.139. Please provide a summary of the demand charges and kWh charges for each rate class that includes a demand charge.

1.140. How many of LG&E-KU's customers have an annual peak demand greater than:

a. 50 kW
b. 100 kW
c. 250 kW
d. 500 kW
e. 1 MW
f. 5 MW
g. 10 MW
h. 20 MW
i. 50 MW

1.141. According to PPL's Second Quarter 2024 Investor Update presentation, "active data center requests" to the Companies "have increased to more than 2 GWs over 2027-2033, with about 350 MW in advanced stages."

a. Please define "active request" as used in the referenced presentation.
b. Please define "advanced stages" as used in the referenced presentation.
c. Please describe each "stage" that a data center request would progress through from initial contact with the Companies to delivery of electric services.

d. Please state the number of combined load of active data center requests currently before the Companies, if any.

1.142. Please provide an electronic copy of all presentations made by or given to PPL leadership team in the last 12 months, that identifies, summarizes, analyzes, or evaluates the impacts of data centers or other new large load facilities to PPL, the Companies' or its customers, including, but not limited to, factors considered by such facilities in making siting decisions, load growth, energy consumption, revenue generation, rate impacts, bill impacts, subsidies or cross-subsidies associated with such facilities, use of special contracts, modifications to applicable rates or tariffs, electric interconnection agreements, economic development, and inquiries received by the Companies' for interconnection.

1.143. Please refer to the Direct Testimony of John Bevington, p. 4, lines 13-16. Provide a detailed list of all energy-intensive "mega projects" that have been announced within the Companies' territories in the past 5 years.

1.144. Please refer to the Direct Testimony of John Bevington, p. 7, lines 2-5. Provide an estimate of the size of data center projects the Companies are working to develop outside of Jefferson County.

1.145. Please refer to the Direct Testimony of John Bevington, p. 8, lines 16-19, stating that "Kentucky is located in close proximity to major data centers in neighboring states. Based on my discussion with data center developers, I understand there are advantages in latency and redundancy to locating data centers near other data centers."

a. Explain how the Companies' define "in close proximity" as used in the above sentence.
b. Provide a list of all major data centers in neighboring states to which the Companies are referring to.
c. Explain the latency and redundancy advantages mentioned.
d. To what extent does such latency and redundancy allow for shifting of computing needs between data centers?

1.146. Please refer to the Direct Testimony of John Bevington, p. 8, lines 19-21, stating that "Land in Kentucky is also relatively inexpensive when compared with other markets where data center development has been thriving and reaching a point of market saturation."

a. Explain what "other markets" the Companies' are referring to.
b. Explain what is meant by the statement that data center development is "reaching a point of market saturation."

c. What “Land in Kentucky” is being referred to? What is the relative price difference of land in Jefferson County compared to other areas of the state?

1.147. Please refer to the Direct Testimony of John Bevington, p. 9, describing the benefits data centers will provide to the Commonwealth. Explain what benefits, if any, the Companies anticipate data centers will provide to LG&E-KU customers specifically.

1.148. Please refer to the Direct Testimony of John Bevington, p. 9, lines 16-19, describing Meta’s pledge to work with Entergy Louisiana to bring at least 1,500 MW of new renewable energy to the grid.

a. Have the Companies’ potential data center customers expressed interest in renewable energy resources to meet their projected demand?
b. Do the Companies’ intend to bolster their renewable energy resource portfolio to attract potential data center customers? If so, please explain. If not, why not?

1.149. Please refer to the Direct Testimony of John Bevington, p. 13, discussing the process for a large load like a data center to locate in the Companies’ service territory. Do the Companies currently plan to submit a transmission service request (“TSR”) for any potential large load customer to complete the TSR process prior to the in service date proposed for Brown 12?

1.150. Please refer to the Direct Testimony of John Bevington, p. 14, lines 11-14. For a large load like a data center:

a. What is the average time from TSR being complete to the signing of an EPC agreement?
b. What is the average time from the signing of an EPC agreement to the start of construction?
c. What is the average time from the start of construction to the customer coming online?

1.151. What share of total U.S. data center load does LG&E-KU expect in its territory? Please provide all relevant materials and workpapers along with a written explanation.

1.152. If the projected new data center load does not materialize, what will be the consequences of the proposed new resource build for:

a. The Companies, and
b. Ratepayer costs.

1.153. What is the earliest year in which new data center load could reasonably be expected to come online in LG&E-KU’s territory? Explain why.

1.154. Please describe any investments that the Companies have made or plan to make in:

a. Distribution grid management software platforms, including Advanced Distribution Management Systems, and
b. Distributed Energy Resource Management Systems.

[Signature on next page]

Respectfully Submitted,

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Counsel for Joint Intervenors
Kentuckians for the Commonwealth,
Kentucky Solar Energy Society,
Metropolitan Housing Coalition, and
Mountain Association

CERTIFICATE OF SERVICE

In accordance with the Commission’s July 22, 2021 Order in Case No. 2020-00085, *Electronic Emergency Docket Related to the Novel Coronavirus COVID-19*, this is to certify that the electronic filing was submitted to the Commission on March 28, 2025; that the documents in this electronic filing are a true representation of the materials prepared for the filing; and that the Commission has not excused any party from electronic filing procedures for this case at this time.

Byron L. Gary