COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC 2024 JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	)	**Case No. 2024-00326**

SIERRA CLUB'S POST-HEARING COMMENTS

I. Introduction

Sierra Club respectfully submits these post-hearing comments regarding Louisville Gas and Electric Company and Kentucky Utilities Company's (collectively referred to as "LG&E/KU" or the "Companies") proposed 2024 Integrated Resource Plan ("2024 IRP"). Sierra Club appreciates that the Companies and their counsel worked effectively to ensure that Sierra Club and its experts at Energy Futures Group had access to the Companies' Plexos model and that questions that arose during the discovery process were addressed efficiently. Ensuring meaningful and timely access to information is crucial to the public's ability to engage in Integrated Resource Plan dockets and assist the Commission in understanding the assumptions, and risks, associated with a utility's demand forecast and resource planning.

II. Subsequent Developments

Throughout the IRP process, utilities of course must make assumptions about future resource needs that will evolve over time. Here, however, subsequent to the filing of this Integrated Resource Plan in October 2024, there have been two important developments that

undercut the value of relying on this IRP as a forward-looking document. First, in February 2025, the Companies filed an application for Certificates of Public Convenience and Necessity ("CPCN") for the construction of two 645 megawatt ("MW") natural gas combined cycle combustion turbine ("NGCC") facilities, at Brown Generating Station and Mill Creek Generating Station, a 400 MW lithium-ion battery energy storage system ("BESS") at Cane Run Generation Station, and to construct selective catalytic reduction ("SCR") control technology at the Ghent Generating Station.[1] The combined cost of those still-pending proposed facilities would be more than $3.7 billion and, in support, the Companies rely on a blend of the mid- and high-load growth scenarios forecast in this IRP. In the load forecast for the CPCN application, like the 2024 IRP, almost all of the forecast increase in demand is the result of data centers. This is a new development for Kentucky, mirroring a broader national trend in proposed data center load growth, as there are no large load data centers currently operating in the Companies' service territory.

Understanding the assumptions – and risks – associated with data center load forecasting, and building new electric generation resources to meet this potential demand, is critical to protecting existing ratepayers from shouldering the risk of building new generation to serve data centers that may never materialize. Here, the Companies' mid- and high-growth forecasts for data center load growth in their service territories are far more aggressive than the forecasts of national utility experts for the entire state of Kentucky. As explained in Joint Intervenors' Comments, the Companies' mid-growth data center load forecast through 2030 would represent 9.4% of national data center growth, even though the Electric Power Research Institute's 2024

[1] Kentucky Public Service Commission, Case No. 2025-00045, Electronic Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates, Joint Application at 1-2 (Feb. 28, 2025).

report, which the Companies cite in the IRP, does not list Kentucky in the top 15 states for projected data center load growth over this time period.[2]

Second, on May 30, 2025, the Companies filed applications that, among other things, propose provisions for extremely high load factor service tariffs in Case Nos. 2025-00113[3] and 2025-00114.[4] If well-structured tariffs are approved in those dockets, they may provide important protections for existing ratepayers while ensuring the large-load customers pay their fair share of system costs for future data centers in the Companies' service territories, thereby addressing some of the concerns raised by Sierra Club and other parties in this docket.

III. Recommendations Regarding Large-Load Data Center Evaluations

Sierra Club offers the following recommendations to ensure that existing ratepayers are not unfairly burdened with the costs that arise from speculative data center projects:

1. The Commission should not approve the construction of new resources that are intended to serve large customers without establishing protections for existing ratepayers that would guarantee costs caused by these new loads are paid by the new load and prevent early exit from said large-load agreements without a stranded cost allocation to those large loads.

2. LG&E/KU's operational decisions regarding Mill Creek 3 and 4 are primarily what cause the need for a second NGCC under the mid-load scenario. But the Companies' plan to advance the second NGCC to 2031 is not adequately justified by the Companies as it is

[2] Kentucky Public Service Commission, Case No. 2025-00045, Joint Intervenors Comments, Attachment JI-1 at 20-21 (Mar. 7, 2025).
[3] https://psc.ky.gov/Case/ViewCaseFilings/2025-00113.
[4] https://psc.ky.gov/Case/ViewCaseFilings/2025-00114.

based on speculative load growth. While the Companies characterize this as a "no regrets" decision because of load growth inquiries, its puts unnecessary risk on existing ratepayers to build a new power plant for need that may never materialize.

3. The Companies should have evaluated whether it was the lower-cost alternative to convert Ghent 2 to run on natural gas compared to its proposed retrofit with an SCR. Former coal-fired power plants that were converted to run on gas achieve a NOx emissions rate at or below the targeted emission rate that the Companies hope to achieve at Ghent 2 during ozone season with an SCR, so the Company should have considered conversion as an alternative. Energy Futures Group modeled such a scenario and found that it had a lower present value revenue requirement ("PVRR") cost than the retrofit alternative. Moreover, it had a significantly cheaper PVRR when a reasonable, less speculative amount of load growth was assumed.

4. The Companies' interconnection process for new load does not appear to shield existing customers from serious risks to the operational security and reliability of the grid that large loads may introduce and urgently needs to be reformed before new customers are interconnected.

IV. Data Center Load Forecasting

Similar to other utilities across the country, LG&E/KU had to address in its IRP how to handle unprecedented load growth in its service territory, the scale of which is still uncertain and speculative. Nationally, this aspect of data center load growth has led to new and varied approaches to planning for new large loads in demand forecasts. Utilities' approaches span the

gamut from only including new loads that have a signed service agreement to attempting to assign probabilities to various characteristics influencing the likelihood of customer interconnection. For this IRP, the Companies have reported that the load forecast includes generic assumptions around data center load growth. As the Companies stated:

> For purposes of the IRP, the Companies modeled generic data center load rather than customer-specific loads. However, the Companies used total size and ramping schedule assumptions that were based on information provided by higher-probability prospective data-center customers while also ensuring that this information was aligned with the most recent national information available. Given prospective customers and available sales tax incentives in Jefferson County, LG&E's service territory was deemed to be the most reasonable location for data centers in the Mid load forecast. Thus, the Companies modeled 1,050 MW of data center load in the LG&E service territory in the Mid load forecast. The Companies assumed 70 MW tranches of load being spaced out every 6 months starting January 2027 and continuing through January 2029 and then growing to 140 MW tranches every 6 months from July 2029 through July 2031.[5]

The Companies' approach to handling speculative load growth raises a myriad of concerns. Specifically, with respect to the load forecast, the Companies have no means to know whether inquiries from customers are duplicative of inquiries made by those same customers at other load-serving entities. One should expect that data center developers are in conversations with multiple utilities across a number of states and thus the possible load growth will be reflected in numerous utility load forecasts. Indeed, since the Companies appear to lack any barriers to entry to their load interconnection queue,[6] it is possible that inquiries are coming from customers who expect to locate elsewhere but would like to have other options available as a backup. This raises the question of how to plan for these large loads when there is a high degree of uncertainty around which service territory they will ultimately decide to locate in, the first

[5] Companies' Discovery Response to Commission Staff 21.
[6] Companies' Discovery Response to Joint Intervenors 16.

year they are expected to take service, and their projected load ramp.[7] All of these different factors result in a high degree of uncertainty around data centers. As the Companies stated in the IRP, "Due to the magnitude of data center loads, economic development is a key uncertainty in this load forecast."[8]

While the Companies have developed two additional load scenarios in addition to the base forecast, which includes the assumption of 1,050 MW of data center load, the Companies were dismissive of the probability for the low-load scenario.[9] In the high-load scenario, the Companies assumed 1,750 MW of data center load in addition to the second phase of the Blue Oval SK electric vehicle battery production facility.[10] The Companies' low-load scenario does not include any data centers and includes assumptions around some large customers leaving the service territory later in the 2030s.[11] As stated in the IRP, "Based on current economic development activity, including data centers, the Companies assign a low likelihood to the Low forecast. The 2024 IRP therefore focuses primarily on the Mid and High load forecasts, though the analysis considers all three forecasts."[12]

Sierra Club does not oppose the use of varying levels of new customers in load forecasts for IRP planning. Given the uncertainty, a wide band of assumptions is appropriate. However, it is important not to dismiss forecasts that assume lower levels of growth or no growth at all within a particular service territory because of the potential for the load to not materialize and the impact this has for the potential of overbuilding capacity. Additionally, this information helps

[7] Load ramp is the level of demand requested by the data center. For example, the customer might report that initial demand will be 100 MW in the first year, 200 MW in the second year, and 300 MW in the third year.
[8] LG&E/KU 2024 IRP, Volume 1 at 7-13.
[9] Companies' Discovery Response to Sierra Club 1-13(a).
[10] LG&E/KU 2024 IRP, Volume 1 at 5-16.
[11] *Id.* at 5-17.
[12] *Id.* at 5-15.

clarify what precipitates resource plan changes, which is essential for appropriate allocation of costs. As the Companies reported, "[t]here have not been any projects that have made formal announcements to date, including an announced load or ramp schedule."[13]

As set out in Sierra Club's previously submitted comments in this docket,[14] as the Commission and Commission staff consider requests to approve service contracts for new large-load data centers – or to approve the building of new electric generating units necessitated by load growth associated with data centers – there are several important questions that the Commission should ensure utilities in Kentucky address:[15]

Protecting Existing Customers:

- What measures are being taken to ensure that costs and risks associated with potential large new loads are not being passed onto existing customers?
- What financial safeguards are in place to ensure that debts or financial obligations do not adversely impact ratepayers?
- Will existing customers be subsidizing infrastructure investments or operational costs in any way? Why or why not? How is this guaranteed?
- What is the plan for dealing with stranded assets if large-load customers do not materialize or leave the queue?
- What contingency plans are in place to ensure that demand from large-load customers that does not materialize does not adversely affect existing customers?
- How is the utility assuring that large-load customers will remain in the region long-term? Will they pay exit fees to ensure that assets built to serve them do not become stranded costs passed to other ratepayers?
- Are existing customers adequately represented and educated on the benefits and risks presented by large-load customers? Is the Commission ensuring that ratepayers and stakeholders have opportunities for informed input into current and future decisions?
- How are existing customers and ratepayers being protected from higher-energy costs, given the large increase in demand?

[13] Companies' Discovery Response to Sierra Club 1-12(f).
[14] *See* pages 12-17 of Energy Futures Group's report submitted as part of Sierra Club's Comments in this docket.
[15] A version of these questions was published in Elevate Energy Consulting (March 2025). Practical Guidance and Considerations for Large Load Interconnections. [Draft Working Paper]. Available at: https://gridlab.org/portfolio-item/practical-guidance-and-considerations-for-large-load-interconnections/.

- What are the projected economic benefits (e.g., job creation, tax revenue) of approving this request? Are they focused in specific counties, or are they spread evenly across areas served by the utility?

Large Load Application Process:

- What information is required for the initial large-load interconnection request, and is it adequate to assess the credibility, certainty, and readiness of the interconnection customer to seek transmission service?
- How does the transmission provider assess the adequacy and completeness of the information provided at the time of interconnection request to ensure that all technical requirements are met by the proposed facility?
- What financial commitments (i.e., deposits) are required for large-load interconnection requests? Do those financial commitments escalate throughout the interconnection process?
- What site control requirements exist for large-load interconnection requests, and are these considered as part of a "readiness" assessment?
- If site control is not required, are there deposit requirements to cover the cost of the load interconnection study?
- What technical and financial capabilities are required for an interconnection customer to be deemed a credible applicant? Are those criteria made public?

Large Load Interconnection Requirements:

- Are the large-load interconnections requests intended to connect to the distribution system or transmission system? Who is the interconnecting entity? Are these customers distribution-connected and seeking interconnection service or are they directly transmission-connected?
- How are the distribution and transmission providers coordinating interconnection requirements to ensure alignment of transmission and distribution system reliability needs?
- Have the distribution and/or transmission providers established clear, effective, and consistent interconnection requirements for large loads?
- Do those requirements include data sharing, modeling, operational performance limitations (e.g., ramp rate limits), oscillations, ride-through performance, monitoring data, and event analysis support?

Large-Load Queue Management:

- Does the utility have a dedicated queue process for large-load interconnection requests?

- Is this queue process administered by the transmission or distribution organization (or department), and how are these organizations and departments collaborating with each other through the process?
- What type of queue process is used – serial, cluster, other? What is the reasoning for the type of queue process used?
- If using a serial queue process, what checks and balances are in place to ensure that load interconnection requests are processed in a timely manner and that speculative interconnection requests are removed from the queue without causing unnecessary backlogs or delays for other legitimate requests?
- Are there defined timelines for how long a large-load interconnection request can remain in the queue before being removed?
- Are clear, explicit queue milestones and timelines established that hold the large-load customer accountable to move the queue process along?

Large-Load Operational and Performance Considerations:

- Does the transmission provider require the large-load customer to provide some form of narrative or other data that explains how the large-load facility will operate when connected to the bulk power system?
- Is the large-load customer required to provide the following information to the transmission provider/transmission planner?
    - Facility electrical topology and single-line diagram
    - Protection and control systems throughout the facility and their associated settings
    - Load voltage and frequency ride-through curves (threshold and duration)
    - Load variation narrative and explanation (frequency and magnitude of variations)
    - Expected ramp rates
    - Restoration settings
    - UPS protection and control settings
    - Load composition information
    - Auxiliary equipment capabilities, ratings, and protection settings
    - Explanation and technical details related to fast ramping and oscillatory behavior
    - Power quality impacts
    - Short-circuit levels
    - Backup generation and grid-paralleled generation information
    - Transformer and other equipment ratings, documentation, etc.

Load Forecasting:

- Is there a defined or formalized methodology for determining when large-load interconnection requests enter system demand forecasts and are subsequently

included in integrated resource planning and other long-term transmission or resource procurement activities?

- What specific interconnection milestones (site control, financial, technical, etc.) must be met for considering large loads in models and studies?
- How are large loads differentiated from other demand growth projections? If speculative large loads are included, what factors are being considered to inform the probability of interconnection? Do these factors include forecasts of market trends specific to each industry (e.g., data centers) and potential limitations to the total capacity growth (e.g., available water resources or fiber optic cable capacity)?

Large-Load Modeling:

- Have large-load modeling requirements been established by the transmission provider or transmission planner? Do they include production cost, steady-state powerflow, dynamic stability, EMT, and short-circuit models?
- Are these models required as part of the large-load interconnection application? Or are they required at later stages throughout the interconnection study process? Are these milestones established and enforced?
- How are these models verified to be accurate representations of the equipment proposed?
- Are there any post-event data collection procedures in place at the large-load points of interconnection?

Large-Load Interconnection Studies:

- What is the process and what are the milestones for initiating large-load interconnection studies?
- Are any types of cursory or high-level analyses done prior to conducting a more comprehensive interconnection study? Why or why not?
- What type of large-load studies are conducted for each interconnection request (see study-specific questions below)?
- What specific criteria are used to determine whether each type of study is conducted (e.g., interconnection request size)? Is this codified and made available publicly?
- What are the average costs of conducting large-load interconnection studies?
- Is there a staffing and training plan in place to address the forecasted increase in large-load interconnection requests?
- What mechanisms exist for recovering transmission system costs from large-load interconnection customer requests? Are large-load customers paying for studies performed by the transmission provider, whether qualitative or quantitative? If not, how are these costs covered by the utility?

- **Production Cost Analysis Studies:**

    - Are 8,760-hour studies being conducted to ensure that large-loads can be met at all hours of the day, given the projected resource mix proposed by the utility?
    - Are large load demand profiles (daily, seasonal, price-sensitive, and other variabilities) documented, well-understood by the utility, and modeled appropriately?

- **Powerflow and Contingency Analysis Studies:**
    - Which powerflow base cases are used to conduct steady-state thermal and voltage violation analysis? More specifically, which seasons and dispatch conditions are modeled and why?
    - What contingencies are tested in these studies?
    - Are N-1-1 operating conditions considered?

- **Dynamic Stability Studies:**
    - What method is used to reduce the list of contingencies to study in dynamic simulations? How many contingencies are studied for each load interconnection in this domain?
    - Are electromechanical oscillations considered in dynamic studies?
    - Are the resonant effects of data center AI load ramping/variability considered in these studies (i.e., a form of forced oscillation)?
    - How are the stability impacts on nearby generators considered in these studies?
    - Are motor restart studies conducted?

- **Short-Circuit Studies:**
    - Are breaker duty studies conducted?
    - Are short-circuit studies (e.g., ASPEN, CAPE, etc.) conducted for large load-interconnections or are these studies only conducted in positive sequence simulation platforms?
    - How are impacts to protection systems analyzed for large-load interconnections?
    - What protection system modifications are commonly required for these large loads?
    - What long-term effects are large loads having on short-circuit levels across the system? Are these effects positive or negative?

- **Electromagnetic Transient ("EMT") Studies:**
    - Are EMT studies being conducted for large-load interconnections? If not, why not?

- Are fast-ramping and oscillatory behaviors of data centers, particularly AI data centers, studied by the utility in the EMT domain? How is the utility studying potential electromagnetic transients (e.g., capacitor switching)?
- How are subsynchronous oscillations, subsychronous control interactions, and/or subsynchronous torsional interactions being studied to ensure large loads do not cause serious adverse impacts or damage with existing power electronic controllers or synchronous generators?

Transmission Network Upgrades:

- How is the utility coordinating with stakeholders to address transmission network performance deficiencies and assess potential network upgrades required for large-load interconnections?
- What alternative solutions are considered as part of network upgrades beyond transmission infrastructure investments?
- What advanced technologies are included in these assessments? Examples include grid-forming (GFM) inverter technology, FACTS devices, high-voltage DC (HVDC) technologies, powerflow control, etc.

Cost Allocation for Network Upgrades:

- Are the large load customers' direct connection facilities allocated the full costs of network upgrades?
- Is this consistent across transmission and distribution connections? Are existing load service requirements for typical residential, commercial, and smaller industrial facilities used for large-load interconnections? Do practices need to adapt for large-load customers, even if dispersed across multiple distribution load points?
- Is the large load-customer entitled to any refund or discount of contributions made to direct connection costs?
- How are broader network upgrade costs allocated to large load customers?
- For any costs not fully accounted for by the large-load customer, what cost-allocation methodology is used for allocating the broader upgrades to large-load customers versus being considered "network benefits"?
- How does the cost allocation methodology compare with utilities in different states or regions, and why?
- How are the full suite of network impacts considered in the cost allocation considerations? Examples include increased congestion levels, voltage issues, degradations in stability, reduced operational maintenance windows, etc.

Resource Portfolio:

- What types of generation facilities will be built (e.g., natural gas, renewable, batteries, hybrid) to serve these large load customers and how do they align with the directive to make just and reasonable investments?

- Are energy and capacity considerations adequately assessed, including ensuring energy availability across 8,760 hours, energy security and resource availability, and resilience to extreme weather conditions?

V. Conclusion

Sierra Club appreciates the opportunity to participate in this IRP process. As explained in Sierra Club's comments submitted previously in this docket, the national boom in data center construction and operation poses new opportunities and challenges to Kentucky and presents issues that utilities and utility commissions across the country must confront. While there are a range of utility practices for incorporating potential data centers into load forecasts and resource planning, Sierra Club believes it is important for the Commission to provide direction to utilities in Kentucky to help guide the way in which utilities forecast data center load growth and plan new generation projects to meet projected demand. Through that process it is critically important to build in protections for existing ratepayers to ensure they do not have to shoulder the costs from speculative data center proposals. The recommendations set out above, if adopted, would help achieve those common goals. Sierra Club appreciates the Commission's consideration of these recommendations.

Dated: June 16, 2025

Respectfully submitted,

/s/ Joe F. Childers
Joe F. Childers, Esq.
Childers & Baxter, PLLC
The Lexington Building
201 West Short Street, Suite 300
Lexington, KY 40507
(859) 253-9824
joe@jchilderslaw.com

Of counsel
(not licensed in Kentucky)

Kristin A. Henry
Sierra Club
2101 Webster Street, Suite 1300
Oakland, CA 94612
kristin.henry@sierraclub.org

Nathaniel T. Shoaff
Sierra Club

2101 Webster Street, Suite 1300
Oakland, CA 94612
nathaniel.shoaff@sierraclub.org

CERTIFICATE OF SERVICE

This is to certify that the foregoing copy of Sierra Club's Post Hearing Comments in this action is being electronically transmitted to the Commission on June 16, 2025, and that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding.

/s/ Joe F. Childers
JOE F. CHILDERS