**COMMONWEALTH OF KENTUCKY**

**BEFORE THE PUBLIC SERVICE COMMISSION**

**In the Matter of:**

| | | |
|---|---|---|
| **ELECTRONIC 2024 INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY** | **)<br>)<br>)<br>)** | **CASE NO. 2024-00326** |

**JOINT COMMENTS OF**
**LOUISVILLE GAS AND ELECTRIC COMPANY**
**AND KENTUCKY UTILITIES COMPANY**
**REGARDING COMMISSION STAFF'S REPORT**

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "Companies"), pursuant to the Commission's scheduling order issued on May 19, 2025, in this proceeding, hereby submit their comments regarding Commission Staff's July 31, 2025 Report ("Report") on the Companies' 2024 Integrated Resource Plan ("IRP"). The Companies appreciate the considerable amount of time and focus the Commission Staff gave to preparing the Report. In particular, the Companies appreciate Commission Staff's recognition of the forecasting challenges presented by the current regulatory and economic environment and the Report's understanding that meeting the Companies' load obligations at present requires a pragmatic, "all of the above" approach. The following comments are submitted to ensure the accuracy of the Report, provide additional context for certain findings and recommendations within the Report, and otherwise address certain recommendations contained in the Report.

**REASONABLENESS OF LOAD FORECASTING**

The Companies respectfully offer the following comments regarding the Reasonableness of Load Forecasting subsection of the Report's Reasonableness and Recommendations section.

The Report states, "Specifically, Commission Staff's first concern is that LG&E/KU did not attempt to model load growth beyond 2032, despite the planning period extending through

2039."[1] It is true that the Companies did not model *economic development* load growth beyond 2032, which was consistent with how the Companies have modeled large customer load growth in prior proceedings without that approach being found unreasonable,[2] and it avoided speculating on economic development load growth beyond what was in the Companies' economic development pipeline at the time. Also, the Companies did not model economic development load growth beyond 2032 to focus the resource planning analysis on near-term resource decisions and assess how these near-term decisions are impacted by different levels of economic development load growth. But the Companies did, consistent with prior IRP load forecasts, explicitly model residential customer growth, electric vehicle growth, and heating electrification growth throughout the study period.

*Recommendation 1:*
*LG&E/KU [should] establish objective standards to determine if and when significant additional load will be added to its service territory.*[3]

Regarding this recommendation, the Companies believe the approach they have taken in their pending CPCN proceeding is an objective approach consistent with this recommendation. It entails applying probabilities associated with each economic development stage to the prospective loads in each stage to arrive at an expected value of economic development load, which the Companies believe is both objective and appropriate for forecasting significant additional load.

---

[1] Report at 50.
[2] *See, e.g., Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2021-00393, 2021 IRP Vol. I at 5-35 – 5-36 (Oct. 19, 2021).
[3] Report at 50 ¶1.

*Recommendation 2:*
*LG&E/KU [should] evaluate similarly situated utilities specifically with regards to data center load growth that actually materializes in those utilities' territories as a comparator to help LG&E/KU understand the data center landscape as LG&E/KU prepare to serve large-load customers.*[4]

Regarding this recommendation, the Companies observe that "evaluat[ing] similarly situated utilities specifically with regards to data center load growth that actually materializes in those utilities' territories" will be impracticable. Like the Companies, most (if not all) other utilities treat economic development prospects' information as confidential, making realization rates or criteria difficult or impossible to discern. Moreover, there are non-utility matters that can significantly affect data center location decisions, including tax incentives, workforce availability, and planning and zoning issues. Nonetheless, to the extent publicly available information from other similarly situated (and similarly sized) utilities may provide helpful context, the Companies will address such data in their next IRP.

*Recommendation 3:*
*More generally, Commission Staff also believe that LG&E/KU's next IRP process would benefit from not relying solely on a singular peak demand figure. ... LG&E/KU's modeling [should] include[] a scenario that reflects a 48-hour peak demand period.*[5]

The Companies respectfully observe that they did not rely solely on a singular peak demand figure. The Companies plan resources to serve load in *all* hours and assess resource adequacy based on weather events experienced over more than 50 years, which include peak weather events with varying durations. The level of reserves required for reliable service are expressed as a function of summer and winter peak demands simply to meet PLEXOS's requirements for specifying reserve requirements. Thus, the recommendation that the Companies' "modeling

[4] Report at 50 ¶2.
[5] Report at 51 ¶3.

include[] a scenario that reflects a 48-hour peak demand period" appears to be unnecessary;[6] because the Companies plan resources to serve load in all hours, a 48-hour peak demand period would appear to unnecessarily limit the scope of the Companies' resource planning.

*Recommendation 4:*
*LG&E/KU should assign non-zero capacity values to solar resources in winter.*[7]

Assigning non-zero capacity value to solar resources would be incongruent with the Companies' experience with winter peaks and modeling of winter peaks in their past two IRPs. If implemented, this change would overstate the Companies' available resources during future winter peaks.[8]

It is important to bear in mind that the use of peaks for measuring system reliability does not narrow the Companies' analysis. Rather, the reserves needed to provide reliable service across all hours and in all conditions is expressed as summer and winter peaks to meet PLEXOS's modeling requirements and to accurately capture the peak hours that the Companies' system has historically experienced. The Companies' larger resource adequacy assessment remains focused on meeting their customers' resource needs at lowest cost and in all hours.

The unavailability of solar resources is a key reason why evaluating winter peaks is important to the Companies' resource adequacy assessment. As previously discussed in this case and in the Companies' 2021 IRP, the Companies opted to express the results of the Companies' reserve margin analysis using both a summer and winter peak reserve margin for two primary

---

[6] How to define a "48-hour peak demand period" is also unclear, in part because it is not a concept that has previously arisen in this proceeding. For example, is the relevant period one that includes the seasonal peak hour? If so, how should the surrounding 47 hours be chosen? Is it instead the 48-hour period with the highest average hourly demand in each season, and would that be appropriate if the seasonal peak hour does not fall within that 48-hour period? Also, from a planning perspective, what would be the relevance of such a period? These are just some of the questions that arise concerning a "48-hour peak demand period."
[7] Report at 51 ¶4.
[8] *See e.g.*, Case No. 2021-00393, Commission Staff's Report at 19, 26 (Sept. 16, 2022).

reasons.[9] First, the addition of solar generation resources, which generally have higher energy outputs during summer peaks, meant that summer reserve margins alone would not adequately demonstrate whether the Companies' resource portfolio can reliably serve customers in all hours.[10] Second and more practically, the rapid adoption of heat-pump technologies and other factors mean the Companies are now operating a dual-peaking system that experienced its highest system peaks in the last decade during winter.[11] Winter system peaks typically occur during non-daylight hours when solar energy is entirely unavailable,[12] and has been fully unavailable during system peaks occurring during Winter Storms Elliott, Heather, and Enzo.[13] Planning for the availability of a non-zero amount of solar generation during winter peaks could, therefore, produce a resource plan that cannot reliably serve the actual peaks the Companies' system will face.

Finally, assigning solar zero winter capacity value does not diminish the value of the *energy* such resources provide; indeed, the Companies' IRP Resource Assessment demonstrates the value of solar in a number of different fuel, load, and environmental scenarios even with zero winter capacity value.[14]

*Recommendation 5:*
*LG&E/KU should accelerate its transition to PLEXOS from PROSYM because the program is more up-to-date and has far greater processing speed and functionality, including producing multiple scenarios.*[15]

The Report's recommendation that the Companies continue to move to PLEXOS from PROSYM for detailed production cost modeling aligns with the Companies' existing plans, and the Companies presently expect they will use PLEXOS for this purpose in future IRPs.[16] But

[9] Case No. 2021-00393, 2021 IRP Vol. III, 2021 IRP Reserve Margin Analysis at 3 (Oct. 19, 2021).
[10] Case No. 2021-00393, 2021 IRP Vol. III, 2021 IRP Reserve Margin Analysis at 3 (Oct. 19, 2021).
[11] 2024 IRP Vol. I at 5-16 (Oct. 18, 2024).
[12] *Id.*
[13] Appendix to Responsive Comments of KU and LG&E at 27 (Mar. 28, 2025).
[14] *See, e.g.,* 2024 IRP Vol. III, 2024 IRP Resource Assessment at 30-43.
[15] Report at 51 ¶5.
[16] *Id.*

transitioning to PLEXOS will not make modeling runs faster than they have been in the past; PROSYM currently runs with far greater processing speed, measured in minutes rather than hours or days. Also, the Companies have no concerns with PROSYM's accuracy, and no party to this proceeding provided any evidence for any accuracy concerns. Moreover, the Companies have developed applications to automate the setup and summarization of PROSYM runs for scenario analysis, so a premature transition to PLEXOS for detailed production costs would limit the Companies' scenario analysis capabilities, not improve them.

Also, the only "cost" the Companies would avoid by moving to PLEXOS for detailed production cost modeling would be the extra effort required to ensure full alignment among PLEXOS and PROSYM inputs; the applications referenced in the paragraph above minimize this cost. In contrast, the benefits of PROSYM are far greater scenario analysis capabilities and speed, as well as the ability the Companies have in PROSYM to model after-the-fact billing ("AFB"); PLEXOS cannot model AFB, which the Companies will have to do outside PLEXOS using post-processing tools, e.g., R or Python.

These reasons are why the Companies have been working with PLEXOS settings to find a reasonable middle ground between run times and accuracy, and they have been deliberate and thoughtful in their transition to PLEXOS for detailed production cost modeling.

*Recommendation 6:*
*LG&E/KU should utilize both traditional coal and gas pricing in its models as comparators to its Coal-to-Gas [CTG] ratio adopted in Case No. 2022-00402.*[17]

The Companies respectfully observe it is unclear what "traditional coal and gas pricing" means, and they further observe: (1) the Companies used third-party gas price forecasts throughout their IRP modeling; (2) coal prices in the "Mid Gas, Mid CTG" scenario were a blend of bid prices

[17] Report at 51 ¶6.

and the mid CTG ratio in the first five years and entirely CTG ratios beyond that (all other fuel price scenarios used only CTG ratios for coal prices); and (3) the Commission rejected arguments that the Companies "should have projected coal prices directly as opposed to projecting coal prices based on a relationship between coal and natural gas prices" in Case No. 2022-00402.[18]

*Recommendation 7:*
*LG&E/KU should appropriately lower the capacity factor of its thermal units to align with historical data instead of assigning a 100 percent capacity contribution to each unit.*[19]

The Companies respectfully disagree with this recommendation. First, capacity factor and capacity contribution are not the same, and capacity factor does not inform capacity contribution. Second, as the Companies explained in response to PSC 2-3:

> [S]easonal reserve requirements and capacity contributions are key inputs for screening resource plans in PLEXOS. In PLEXOS, fully dispatchable resources are assumed to contribute 100% of their seasonal net capacity to meeting reserve requirements, which are specified on a net capacity basis. Thus, the capacity contribution for fully dispatchable resources is 100%. Because limited-duration resources such as battery storage and dispatchable DSM programs cannot contribute to reliability the same way fully dispatchable resources do, their capacity contributions are less than 100%. The Companies develop capacity contributions for limited-duration resources in SERVM by comparing their impact on LOLE to that of a fully dispatchable SCCT. This approach ensures the capacity contribution is an indication of the resource's ability to contribute to a seasonal net capacity reserve requirement.

Therefore, because the Companies already account for forced outage risk by specifying reserve requirements on a net capacity basis, using a capacity contribution of less than 100% for thermal units would effectively double-count the impact of forced outages and result in overbuilding resources to meet reserve margins. If the Companies adjusted both their capacity contributions

[18] *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of Demand side management plan and Approval of Fossil Fuel-Fired Generating Unit Retirements*, Case No. 2022-00402, Order at 91-94 (Ky. PSC Nov. 6, 2023).
[19] Report at 51 ¶7.

and reserve requirements (which would necessarily be lower), the change in methodology would have minimal impact on the Companies' modeling.[20] The Companies will continue to ensure that their modeling accurately accounts for the availability of their resources.

*Recommendation 8:*
*LG&E/KU should estimate the retrofitting costs and either explicitly model or allow the model to economically select retrofitting all aging coal units in its fleet to operate on natural gas instead of having the model only assume new build resources.*[21]

The Companies agree with this recommendation; indeed, the Companies did what this recommendation suggests in this IRP regarding all coal units other than those approved for retirement by the Commission (i.e., all except Mill Creek 1 and 2).[22]

*Recommendation 9:*
*LG&E/KU should begin comparing shorter weather time horizons of 5 and 10 years along with its traditional planning periods spanning 20 years. While more volatile, the comparison may alert LG&E/KU to trends quicker than the longer time horizon forecasts would.*[23]

The Companies respectfully disagree with this recommendation and the reason stated for it. As the Companies stated in response to PSC 1-4(b)-(c):

> In most cases, either a 10- or 20-year normal period provides a reasonable forecast of average weather, but because average temperatures have a limited impact on resource planning (resource planning is focused primarily on the ability to reliably serve customers in weather scenarios with extremely hot and cold temperatures) and differences between 10- and 20-year normals have no impact on resource planning ….
>
> Furthermore, for resource planning and assessing resource adequacy, the Companies will continue using 50+ years of weather data to consider an appropriately broad range of extreme hot and cold temperature scenarios.

[20] Appendix to Response of Louisville Gas and Electric Company and Kentucky Utilities Company at 23 (Mar. 28, 2025).
[21] Report at 51 ¶8.
[22] *See, e.g.,* Companies' Response to PSC 1-27; Companies' Response to JI 1-37; 2024 IRP Vol. III, 2024 IRP Resource Assessment at 30, 37, and 41-43.
[23] Report at 51 ¶9.

Therefore, the Companies' use of 20-year normal weather for load forecasting and more than fifty weather years for reliability assessment to establish a wide range of temperature extremes (ranging from -22 °F to 105 °F) fully and appropriately accounts for weather in their load forecasting and resource planning.

## REASONABLENESS OF DEMAND AND SUPPLY SIDE RESOURCE AND INTEGRATION ASSESSMENTS

The Companies respectfully disagree with a number of assertions in the discussion surrounding the recommendations in this section.

The first concerns the nature of the Companies' IRP analyses. The Report states, "Because the IRP is separate from any specific application, the utility has the necessary freedom to explore scenarios in which it has less confidence than what is traditionally required in a CPCN proceeding."[24] The Companies take their IRP analyses seriously and use the best information available to them at the time to comply with the requirements of the Commission's IRP regulation. The forecasts, scenarios, and resources they analyze are not speculative or ones in which the Companies have little confidence; rather, they result from the Companies' own data and experience, as well as credible third-party sources, and the scenarios they analyze are designed to test plausible bounding cases of what might occur in the next fifteen years. The future is always uncertain; the purpose of creating such bounding cases is to see what effects a broad range of possible future circumstances might have on resource selection to serve customers reliably and economically to minimize future regrets.

For that reason, the Companies strongly disagree with the statement that "LG&E/KU's 2024 IRP exemplifies how that principle is operationalized. … Because no data center requiring the type of load that LG&E/KU envisions in this IRP has located in its territory, all of LG&E/KU's

[24] Report at 52.

assumptions were necessarily speculative."[25] "Speculative" means "engaged in, expressing, or based on conjecture rather than knowledge";[26] "based on a guess and not on information."[27] As the Companies demonstrated in this proceeding, their projections concerning data centers derived from actual dealings with data center developers and hyperscalers, as well as information from data center trade groups and publicly available information concerning data centers, not conjecture or guesses in the absence of information.

Next, the Companies desire to clarify the record concerning the statement, "Commission Staff notes the discrepancy in that case because the proximity between the filings [i.e., between the 2021 IRP and 2022 CPCN case] raises the likelihood that the Companies were aware at the time of the IRP filing of circumstances which could require them to request approval for the more expansive resource portfolio presented in Case No. 2022-00402."[28] The Companies' IRP forecasts and analyses take months to prepare, and they cannot account for every change in circumstances that might occur late in that process. Regarding the 2021 IRP, which the Companies filed on October 19, 2021, the significant load change resulting from the BlueOval SK ("BOSK") Battery Park was not announced until September 27, 2021; there was no time to include it in the 2021 IRP load forecasts. Moreover, the Companies disclosed that fact in Volume I of the 2021 IRP: "On September 27, 2021, Ford announced plans to add twin electric vehicle battery plants. Given the proximity of the announcement to the October 19, 2021 IRP filing date, the IRP could not be updated to explicitly include the new load. With the new load, the Companies do not anticipate

[25] *Id.*
[26] Oxford Languages via Google.
[27] Cambridge Dictionary, available at https://dictionary.cambridge.org/us/dictionary/english/speculative.
[28] Report at 52.

needing additional generation capacity prior to 2028."[29] The Companies were therefore fully transparent concerning BOSK at the time of the 2021 IRP filing.

Relatedly, the Companies do not believe there is a "pitfall" associated with differing load forecasts across IRP and CPCN cases.[30] The reality highlighted by the last several years is that circumstances can change quickly, even between overlapping IRP and CPCN cases. In all such cases, the Companies endeavor to use and present the best and most accurate information they reasonably can. Precisely because the future is uncertain and circumstances can change, it is noteworthy that the 2024 IRP analysis demonstrates the near-term resources in the 2024 IRP Recommended Resource Plan, particularly two new NGCCs by 2031 and the Ghent 2 SCR, are robust across a wide range of potential future scenarios, making them excellent no-regrets resources to add.

Turning to demand-side management and energy efficiency ("DSM-EE"), as the Report recognizes, and as the Companies' significant investments in these programs demonstrate, the Companies are committed to offering robust and economical DSM-EE program portfolios. The Companies address the Report's recommendations that the Companies assign capacity values to dispatchable DSM-EE programs and resources below.

*DSM-EE Recommendation 1:*
*LG&E/KU [should] assign a capacity value to current and future dispatchable DSM/EE programs and model current and future DSM/EE programs against supply side resources so that it can accurately evaluate when it needs to construct new generation.* [31]

The Companies assume this recommendation does not intend to address how the Companies evaluate DSM-EE programs and measures using the four Commission-required

[29] *See, e.g.,* Case No. 2021-00393, 2021 IRP Vol. I at 5-21 fn. 25, 5-25 fn. 29, 5-34 fn. 34, and 5-44 fn. 47.
[30] Report at 52.
[31] Report at 53 ¶1.

California Standard Practice Manual tests; the Companies use non-zero capacity values when evaluating all DSM-EE programs and measures using those tests.

That being said, the Companies agree with this recommendation concerning *dispatchable* programs and program measures; indeed, the Companies did exactly that in this IRP concerning current and future dispatchable programs and program measures.[32]

*DSM-EE Recommendation 2:*
*[F]or current and future DSM/EE programs and DER, LG&E/KU [should] assign non-zero capacity values to those resources on par, or close to on par, with supply side resources.* [33]

Again, the Companies assume this recommendation does not intend to address how the Companies evaluate DSM-EE programs and measures using the four Commission-required California Standard Practice Manual tests; the Companies use non-zero capacity values when evaluating all DSM-EE programs and measures using those tests.

As noted above, the Companies agree *dispatchable* DSM-EE programs and program measures, including those that might be characterized as DER (BYOD Energy Storage and BYOD Home Generators), should have appropriate capacity values in resource modeling; indeed, the Companies did exactly that in this IRP concerning current and future dispatchable programs and program measures.[34] But regarding the part of the recommendation that states DSM-EE programs and measures should have "capacity values … on par, or close to on par, with supply side resources," it would be inappropriate and inaccurate to assign the same capacity value to a dispatchable DSM measure with significant dispatch limitations (as all such programs and measures have) as one would assign to a fully dispatchable generating resource (e.g., a combustion

[32] *See, e.g.,* 2024 IRP Vol. III, 2024 IRP Technology Update at 21-22; 2024 IRP Vol. III, 2024 IRP Resource Adequacy Analysis at 12, 18-19; 2024 IRP Vol. III, 2024 IRP Resource Assessment at 17, Table 4.
[33] Report at 53 ¶1.
[34] *See, e.g.,* 2024 IRP Vol. III, 2024 IRP Technology Update at 21-22; 2024 IRP Vol. III, 2024 IRP Resource Adequacy Analysis at 12, 18-19; 2024 IRP Vol. III, 2024 IRP Resource Assessment at 17, Table 4.

turbine). Therefore, the Companies intend to continue assigning appropriate capacity values to resources based on their capabilities and dispatch constraints.

Finally, regarding non-dispatchable DER (i.e., not dispatchable by the Companies), the Companies account for contributions of cost-effective DER to offsetting load and energy requirements in their load forecast.

## **ADDITIONAL RECOMMENDATIONS**

The Report next offers four additional recommendations, which the Companies address below.

*Additional Recommendation 1:*
*LG&E/KU should investigate whether capacity and energy are available with transmission upgrades to serve large load customers who want to come online before 2032.*[35]

*Additional Recommendation 2:*
*LG&E/KU should utilize the objective standard recommended above to rerun its models and resources, accounting for any necessary transmission upgrades to allow for the economic selection of imported capacity and energy resources instead of solely modeling reliance on constructing and operating new generation. This could include the joint ownership of a capacity resource where capacity economies of scale would make joint ownership economical.*[36]

*Additional Recommendation 4:*
*LG&E/KU should investigate the cost of new renewable resources without tax advantages. As part of the analysis Commission Staff would recommend that LG&E/KU determine whether other load, or transmission upgrades, could serve the load at less cost to ratepayers.*[37]

As an initial matter regarding these recommendations, the General Assembly has stated in KRS 164.2807(1)(f), "It is in the interest of the Commonwealth that it be able to generate sufficient electricity *within its borders* to serve its own industrial, residential, and commercial demand and to power its own economy."[38]

[35] Report at 54 ¶1.
[36] Report at 54 ¶2.
[37] Report at 54 ¶4.
[38] Emphasis added.

Moreover, the Commission has stated a policy favoring maintaining sufficient owned or contracted generation rather than relying on markets to serve customers:

> [W]hatever benefits there may be to RTO membership, a capacity market is not a replacement for a vertically integrated utility having sufficient generation capacity owned or contracted for to serve their retail customers. The Commission expects our vertically integrated utilities, in furtherance of their service, and now reliability, obligations to replace generation capacity with "steel in the ground" or a Power Purchase Agreement. [39]

Earlier this year, the Commission reiterated its position:

> The Commission has previously emphasized the importance of utilities maintaining sufficient owned capacity rather than relying on market purchases. The Commission continues to value "steel in the ground" investments as a prudent and reliable means to serve native load.[40]

During Duke Energy Kentucky's recent case regarding its request to become a full participant in PJM's base residual and incremental auction construct, the Commission stated the shortfall risks in the PJM system were strong evidence supporting a continued steel-in-the-ground approach:

> The strain on the broader PJM footprint is evidence that the Commission's long-standing preference for steel-in-the-ground generation is prudent and necessary to protect ratepayers. Therefore, the Commission is concerned by Duke Kentucky's projected timeline to construct, and make operational, new generation.[41]

The underlying principle holds here: the reliability and cost-stability of utility owned and operated generation are generally favored over importing energy and capacity.

---

[39] Case No. 2022-00402, Order at 95 (Ky. PSC Nov. 6, 2023).

[40] *Electronic Application of East Kentucky Power Cooperative, Inc. for 1) A Certificate of Public Convenience and Necessity to Construct a New Generation Resource; 2) A Site Compatibility Certificate; and 3) Other General Relief*, Case No. 2024-00310, Order at 31 (Ky. PSC May 20, 2025).

[41] *Electronic Application of Duke Energy, Inc. to Become a Full Participant in the PJM Interconnection LLC, Base Residual and Incremental Auction Construct for the 2027/2028 Delivery Year and for Necessary Accounting and Tariff Changes*, Case No. 2024-00285, Order at 25 (Ky. PSC May 16, 2025).

Also, there are practical, real-world reasons why the Companies have not included market imports as selectable resources in their modeling. From a modeling standpoint, making imported energy a selectable resource is unreasonable and risky resource planning because it involves speculating on market prices, which are highly volatile—indeed, market energy pricing can run up into the hundreds and even thousands of dollars per MWh, reflecting market congestion and scarcity in times of short supply rather than fuel costs—and are likely to create unreasonable bias because of the uncertainty of this data in the modeling.[42] Simply put, incorporating volatile imports into modeling risks creating a portfolio that could fail to reliably serve the Companies' service territories.

Turning from market purchases to potential contracted resources not owned by the Companies that additional transmission might allow the Companies to access, at present there is no reason to believe that such capacity and energy can be acquired economically from neighboring systems. As NERC's reliability assessments show, there are impending risks of energy and capacity shortfalls in PJM and MISO.[43] These shortfall risks mean that any imported capacity and energy the Companies might acquire via a power purchase agreement with resources in those RTOs would likely be from newly constructed resources, which would serve only to add costs (transmission service costs and potentially new transmission capital costs) to resources that could be more economically located in the Companies' service territories.[44] Given the choice between either constructing generation within the Companies' service territories or paying for a third party

---

[42] Appendix to Response of Louisville Gas and Electric Company and Kentucky Utilities Company at 28 (Mar. 28, 2025).

[43] Appendix to Response of Louisville Gas and Electric Company and Kentucky Utilities Company at 28 (Mar. 28, 2025) (citing NERC 2024 Long-Term Reliability Assessment at 6 (Dec. 2024), available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf). These supply-side issues in other systems will also present a challenge as the Companies investigate the availability of existing capacity and energy to serve large load customers in the near term.

[44] Appendix to Response of Louisville Gas and Electric Company and Kentucky Utilities Company at 22 (Mar. 28, 2025).

to construct generation elsewhere, which the Companies would then have to pay significant transmission costs to access,[45] it is unreasonable to treat the latter option as economical.

Nonetheless, the Companies will address these recommendations in their next IRP, including the portions concerning joint unit ownership and tax incentives for renewable resources.

*Additional Recommendation 3:*
*LG&E/KU should investigate and present the costs of extending the service life of its current generation units. Then, where reasonably practical, allow the model to economically select unit life extensions as a potential short term resource option toward obtaining its least economic generation portfolio.*[46]

The Companies agree with this recommendation; indeed, the Companies' modeling of service life extensions for their units was a component of their 2024 IRP Resource Assessment.[47] Allowing the PLEXOS model to make retirement selections was an important component of the 2024 IRP, and was allowed for all units without Commission-approved retirement dates. The Companies plan to maintain this approach in future IRPs.

**<u>Conclusion</u>**

The Companies commend the Commission Staff for the thorough Report and its recommendations. As required by 807 KAR 5:058 Sec. 11(4), the Companies will appropriately respond to Staff's comments and recommendations in their next IRP.

---

[45] Notably, even firm transmission service can be curtailed to maintain reliable operation of the bulk electric system. *See* Companies' Response to PSC 1-26(a)-(b).
[46] Report at 54 ¶1.
[47] *See* 2024 IRP Vol. III, Resource Assessment at 53-54 (Oct. 18, 2024).

Dated: August 22, 2025

Respectfully submitted,

W. Duncan Crosby III
Stoll Keenon Ogden PLLC
400 West Market Street, Suite 2700
Louisville, Kentucky 40202
Telephone: (502) 333-6000
Fax : (502) 333-6099
duncan.crosby@skofirm.com

Lindsey W. Ingram III
Mary Ellen Wimberly
Stoll Keenon Ogden PLLC
300 West Vine Street, Suite 2100
Lexington, Kentucky 40507
Telephone: (859) 231-3000
Fax: (859) 253-1093
l.ingram@skofirm.com
maryellen.wimberly@skofirm.com

Allyson K. Sturgeon
Vice President and Deputy
General Counsel – Regulatory
Sara V. Judd
Senior Counsel
PPL Services Corporation
2701 Eastpoint Parkway
Louisville, Kentucky 40223
Telephone: (502) 627-2088
Fax : (502) 627-3367
ASturgeon@pplweb.com
SVJudd@pplweb.com

*Counsel for Louisville Gas and Electric Company*
*and Kentucky Utilities Company*

**CERTIFICATE OF SERVICE**

In accordance with the Commission's Order of July 22, 2021 in Case No. 2020-00085 (Electronic Emergency Docket Related to the Novel Coronavirus COVID-19), this is to certify that the electronic filing has been transmitted to the Commission on August 22, 2025; and that there are currently no parties in this proceeding that the Commission has excused from participation by electronic means.

*Counsel for Louisville Gas and Electric Company and Kentucky Utilities Company*