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**

RESPONSE OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY TO INTERVENORS' COMMENTS

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "Companies") hereby respond to the comments of all intervenors in this proceeding. The Companies' silence on any point or issue raised by an intervenor does not constitute the Companies' agreement with or concession of any such point or issue.

I. INTRODUCTION

The Companies welcome opportunities to improve their planning and analytical processes. In that vein, the Companies carefully reviewed the intervenors' comments and critiques, and they provide a number of general responses here. (An Appendix of Detailed Responses is attached to address more discrete issues.) Ultimately, rather than undermining the Companies' 2024 Integrated Resource Plan ("IRP"), the Companies believe the intervenors' comments show the reasonableness of the Companies' IRP and its underlying assumptions, forecasts, and analyses.

In reviewing the intervenors' comments, the Companies observed that they generally fell into three categories: (1) comments that pertain to issues outside the scope of an IRP proceeding, such as retail rate and tariff matters or the conditions under which the Commission should authorize the Companies to construct new assets; (2) factual errors or unfounded criticisms, such as asserting the Companies did not model Curtailable Service Rider ("CSR") expansions or were insufficiently transparent in their IRP; and (3) *non sequitur* criticisms that essentially amount to arguing that the Companies' assumptions, forecasts, or analyses are unreasonable because there might be other reasonable assumptions, forecasts, or analyses.

Regarding the first category, i.e., comments outside the scope and purpose of an IRP proceeding, the Companies note that such issues would be more appropriately addressed in either the Companies' pending case seeking certificates of public convenience and necessity ("CPCN") or a future rate case, which the Companies anticipate filing in the first half of this year.[1] Indeed, any request for the Commission to take non-procedural action in this case must fail because, under the terms of the IRP regulation, the Commission can issue only procedural, not substantive, Orders in this proceeding.

Concerning the second category, the Companies respectfully observe that the informal exchange of ideas the IRP regulation is designed to foster is not improved by misstatements of fact, e.g., "Instead, the Companies modeling assumes the end of essentially all demand side management offerings in 2030, just as load is nearing its projected peak."[2] Such a statement, which all relevant portions of the IRP (including the Executive Summary) show to be entirely incorrect,[3] does not contribute to a constructive exchange of ideas.

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[1] *See* PPL Corporation, "4th Quarter 2024 Investor Update" at 7 (Feb. 13, 2025) ("Expect to file a base rate case in KY in the first half of 2025"), available at https://filecache.investorroom.com/mr5ir_pplweb2/1187/PPL_2024_Q4_Investor_Update_Final.pdf.

[2] Joint Intervenors Comments at 28. Notably, the AEC white paper the Joint Intervenors cite to support this misstatement actually does not support it, though it makes another false claim: "Instead, the Companies' energy savings drop rapidly after 2030." (Joint Intervenors Attachment JI-1 at 17 of 58.) The falseness of the AEC white paper's claim is shown just two pages before in Figure 5, which shows cumulative energy savings increasing every year of the IRP forecast in all three load scenarios. (Joint Intervenors Attachment JI-1 at 15 of 58.)

[3] *See, e.g.*, IRP Executive Summary at 5 ("All the load forecasts assume significant amounts of energy-reducing measures, including from the Companies' DSM-EE Programs …. For example, as shown in Table 1 above, the Companies' Mid load forecast includes … the energy efficiency effects of the Companies' proposed 2024- 2030 DSM-EE Program Plan and new programs beyond 2030."); IRP Executive Summary at 7 ("[T]he Companies' IRP analysis considered … new demand-side dispatchable resource options (beyond existing or approved dispatchable DSM and Curtailable Service Rider programs) …."); IRP Vol. I at 8-24 ("In Case No. 2022-00402, the Companies received Commission approval for their current DSM-EE Program Plan through 2030 …. For the purpose of this IRP, all

Regarding the third category of comments, it is noteworthy that intervenors with explicit renewable energy or environmental advocacy interests argue the Companies have tilted the analytical scales in favor of fossil fuel-fired resources and against renewable resources,[4] while others argue for maximizing the life of coal units and against renewable resources.[5] Such contradictory criticisms suggest the Companies' IRP analysis—which impartially evaluated a wide variety of resource plans across numerous load, fuel price, and environmental regulatory scenarios—is indeed reasonable and robust.

II. COMMISSION STAFF SHOULD DISREGARD INTERVENORS' COMMENTS OUTSIDE THE COMMISSION'S PRESCRIBED SCOPE AND PURPOSE OF AN IRP PROCEEDING, WHICH IS TO PROVIDE "REGULAR REPORTING AND COMMISSION REVIEW OF LOAD FORECASTS AND RESOURCE PLANS," NOT TO ADDRESS CPCN, RATE, OR TARIFF ISSUES.

It is useful to begin by recalling what an IRP proceeding is—and what it is not—by reviewing the Commission's IRP regulation. Doing so shows that many, if not most, of the intervenors' comments are outside the scope of this proceeding.

First and foremost, according to the Commission's IRP regulation and the history thereof, IRPs and IRP proceedings are and were always intended to be informal planning and review exercises, the sole output of which is a Commission Staff report of recommendations for the next IRP planning and review exercise. Every aspect of the Commission's IRP regulation reflects this, beginning with its statement of necessity, function, and conformity:

> This administrative regulation prescribes rules for regular *reporting* and commission *review* of load forecasts and resource plans of the state's electric utilities to meet future demand with an adequate and reliable supply of electricity at the lowest possible cost for all

approved programs are assumed to continue throughout the IRP planning period (i.e., through the end of 2039)."); IRP Vol. I at 8-26 (showing increasing peak demand impacts of DSM programs through the entire IRP planning period).

[4] *See, e.g.,* Southern Renewable Energy Association ("SREA") Comments at 3.

[5] *See, e.g.,* Attorney General ("AG") Comments at 3-7.

> customers within their service areas, and satisfy all related state and federal laws and regulations.[6]

Indeed, the Commission's Order creating the IRP regulation in 1990 explicitly rejected and removed from the original draft IRP regulation any formal hearings or Commission review or non-procedural Orders, choosing informal proceedings and Staff review and reporting over Commission review and any form of approval or rejection of a utility's IRP:

> The regulation issued today replaces the draft regulation's requirement for a hearing on each utility's resource plan with a provision allowing for informal conferences between the utility, Staff, and intervenors. At these conferences, all aspects of the utility's filings will be discussed. The Commission believes an informal proceeding, where parties may exchange information and ideas in a less adversarial manner, may better serve the interests of the parties and the resource planning process.
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> Consistent with the elimination of hearings in the regulation, the evaluation criteria by which the plans will be judged have also been eliminated. Evaluation criteria are an important and appropriate part of an integrated resource plan if there is a provision for the approval or disapproval of utility plans. … However, without an approval process, there is little need for evaluation criteria. …
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> The draft regulation … contained provisions for a Commission-issued report assessing the reasonableness of each utility's plan. Consistent with the elimination of hearings and the evaluation criteria, the regulation issued today provides that the Staff, not the Commission, issue a report summarizing a utility's filing and the results of the review process. …
>
> Finally, consistent with the more informal nature of the proceedings, there will be no requirement that the record developed in the resource planning process be incorporated into rate or certificate proceedings.[7]

Since the Commission adopted its IRP regulation almost 35 years ago, the only substantive revisions occurred in 1995, which shifted the IRP from a biennial to a triennial process, revised

[6] 807 KAR 5:058 Necessity, Function, and Conformity (emphases added).
[7] *An Inquiry into Kentucky's Present and Future Electric Needs and the Alternatives for Meeting those Needs*, Admin. Case No. 308, Order at 13-14 (Ky. PSC Aug. 8, 1990).

certain informational filing and filing timing requirements, and removed a provision requiring the Commission to direct Staff or a consultant to prepare a statewide resource report.[8] In other words, the only revisions to the Commission's IRP regulation made the IRP review process *less* frequent and *less* administratively burdensome, not more so.

Moreover, at least as recently as 2019, the Commission reiterated that its role in IRP proceedings is procedural, not substantive:

> *IRP filings are unique because the Commission's role under 807 KAR 5:058 is limited to addressing procedural issues and not substantive issues.* The specific procedures established under 807 KAR 5:058 include a procedural schedule that leads to a report prepared by Commission Staff (Staff) that is the final substantive action in an IRP. The Staff Report summarizes Staff's review of the IRP and provides recommendations and suggestions for subsequent IRP filings. *The regulation does not provide for an evidentiary hearing, and the Commission does not enter findings of fact or conclusions of law*.[9]

Thus, the unambiguous text of the IRP regulation and the Commission's stated reasoning for adopting it make it abundantly clear that all of the intervenors' comments asking the Commission to direct or require the Companies to do or refrain from doing a variety of things are outside the scope of an IRP proceeding, as are comments pertinent to CPCN, rate, or tariff matters.[10] Such requests or points have no place in an IRP proceeding, which—by the

[8] *See* 21 Ky. R. 2799 (May 1, 1995), available at https://apps.legislature.ky.gov/law/kar/registers/21KyR_1994-95/11_May.pdf; 22 Ky. R. 287 (Aug. 1, 1995), available at https://apps.legislature.ky.gov/law/kar/registers/22KyR_1995-96/02_Aug.pdf.

[9] *Electronic 2018 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2018-00348, Order at 5 (Ky. PSC Sept. 19, 2019) (emphases added). *But see*, *e.g.*, Case No. 2018-00348, Order (Ky. PSC July 20, 2020) (scheduling an IRP hearing but providing no legal rationale for it).

[10] *See, e.g.,* Comments of Kentucky Industrial Utilities Customers, Inc. ("KIUC") at 5 ("LG&E/KU should be required to seek Commission approval of a separate tariff for new data centers similar to Kentucky Power's proposal."); Energy Futures Group Comments on behalf of Sierra Club ("Sierra Club Comments") at 4 ("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."); KCA Comments at 9 ("The Commission should require the Companies to ensure all data center contracts properly address the cost of service, provide financial assurances in case of a default by the customer, and will not result in any increased electricity rates for existing ratepayers.").

Commission's own longstanding design and the terms of the IRP regulation—can and will result in no non-procedural Commission Order of any kind.[11] Thus, the appropriate forum for advancing arguments pertinent to CPCNs, rates, or tariffs is in a CPCN proceeding or a rate case, not here.

A few additional and related responses to certain intervenor comments follow from observing that the Commission explicitly and intentionally adopted the informal reporting and review processes reflected in the IRP regulation:

- Three intervenors used outside consultants to draft reports to support or serve as the intervenors' comments. There is nothing improper about that, but it is important to note that such reports *are not testimony*, and their drafters are not witnesses. As demonstrated above, 807 KAR 5:058 does not provide for a formal hearing or otherwise creating an evidentiary record precisely because one is not needed when the Commission will issue only procedural Orders.
- The purpose of an IRP process in Kentucky is *not* to produce a Commission-approved resource plan from which future deviations must be justified in later CPCN or rate cases. Indeed, the Commission explicitly considered and rejected that approach in adopting the IRP regulation that has served Kentucky well for almost 35 years.

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[11] The Commission must abide by the terms of the IRP regulation. *See, e.g., Hagan v. Farris*, 807 S.W.2d 488, 490 (Ky. 1991):

> An agency must be bound by the regulations it promulgates. *Shearer v. Dailey,* 312 Ky. 226, 226 S.W.2d 955 (1950). Further, the regulations adopted by an agency have the force and effect of law. *Linkous v. Darch,* 323 S.W.2d 850 (1959). An agency's interpretation of a regulation is valid, however, only if the interpretation complies with the actual language of the regulation. *Fluor Constructors, Inc. v. Occupational Safety and Health Review Commission,* 861 F.2d 936 (6th Cir.1988). KRS 13A.130 prohibits an administrative body from modifying an administrative regulation by internal policy or another form of action.

- The Joint Intervenors argue for a prefiling IRP stakeholder process.[12] But the IRP regulation and the Commission's Order adopting it are clear that the IRP process *is* the stakeholder process.[13]
- KCA recommends that "the Commission should require the Companies to provide an updated IRP incorporating the best available information prior to the Commission considering any request from the Companies impacting its generation sources."[14] But the Commission's explicit intention is for the IRP process to be an informal planning review process, not to result in a prescriptive plan a utility must execute or from which it must justify any deviation. Thus, there is no need or requirement to update or revise IRPs post-filing.

In sum, the Companies believe it is important to return to the purpose and process prescribed by the Commission's IRP regulation, including having an awareness of what the Commission explicitly rejected in adopting the regulation, namely all formal hearings and non-procedural Commission action of any kind. Such a return requires disregarding as irrelevant all of the intervenors' comments that, as described above, are inconsistent with the IRP regulation.

III. THE COMPANIES RESPECTFULLY SUBMIT THAT MISSTATEMENTS OF FACT AND ACCUSATIONS OF LACK OF TRANSPARENCY DO NOT CONSTRUCTIVELY CONTRIBUTE TO AN INFORMAL, NON-ADVERSARIAL EXCHANGE OF IDEAS.

Rather than belabor the point here, the Companies' Appendix of Detailed Responses addresses a number of the misstatements of fact or misrepresentations of the Companies' IRP made

[12] *See, e.g.,* Comments of Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association ("JI Comments") Attachment JI-1 at 55 ("LG&E-KU should incorporate a stakeholder process as a key element in the development of their IRP to seek meaningful feedback from Commission staff and stakeholders who are directly impacted by the resulting resource decisions").
[13] *See, e.g.,* Admin. Case No. 308, Order at 13 (Ky. PSC Aug. 8, 1990).
[14] KCA Comments at 9.

in various intervenors' comments. It suffices to say the number of such errors is not trivial and does not improve the quality of the constructive, non-adversarial, and informal exchange the Commission stated it intended to foster when it adopted the IRP regulation almost 35 years ago.[15]

In that vein, one set of assertions in the Joint Intervenors' comments is important to address here:

> The Companies did not provide information and data necessary for the review of IRP assumptions and modeling together with (and at the time of submitting) their IRP report. Public workpapers were only made available by request and to intervenors. More complete confidential workpapers were only made available to intervenors after signing an NDA. These procedures limited access and delayed review. In addition, LG&E-KU's modeling results were not presented in a way that was transparent and easy to understand for non-technical experts. Indeed, on the whole, they were not presented in the IRP report at all. Direct IRP modeling experience and/or an advanced degree in economics should not be a limiting factor in stakeholders' ability to access and interpret basic IRP findings, including quantitative comparisons of key metrics across resource plans and scenarios.[16]

First, the Commission's regulations and Orders limit the size of files parties may upload to the Commission's website.[17] Therefore, the Companies contacted the Commission Staff in advance of their IRP filing to ensure they filed the large public workpaper files appropriately, and the Commission acknowledged the Companies did what they were directed to do in that regard.[18] Thus, criticizing the Companies for "not provid[ing] information and data necessary for the review of IRP assumptions and modeling together with (and at the time of submitting) their IRP report" ignores and is inconsistent with the Commission's regulations and Orders.

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[15] Admin. Case No. 308, Order at 13 (Ky. PSC Aug. 8, 1990) ("The Commission believes an informal proceeding, where parties may exchange information and ideas in a less adversarial manner, may better serve the interests of the parties and the resource planning process.").
[16] Joint Intervenors Attachment JI-1 at 56 of 58.
[17] 807 KAR 5:001 Sec. 8(6)(b); *Electronic Review of Electronic Filing Procedures in 807 KAR 5:001, Section 8(2), (4), and (6)*, Case No. 2022-00311, Order at 3 (Ky. PSC Oct. 6, 2022).
[18] Case No. 2024-00326, Order at 3 (Ky. PSC Dec. 4, 2024) ("[T]he Commission notes that LG&E/KU reached out to Commission Staff as instructed by Case No. 2022-00402 in an attempt to resolve this issue prior to filing its IRP.").

Second, the criticism that "[m]ore complete confidential workpapers were only made available to intervenors after signing an NDA" is puzzling at best. The Commission's regulations explicitly provide for confidential treatment of materials meeting the requirements of KRS 61.878,[19] and they assume parties will enter into "protective agreements" to allow review of confidential materials.[20] Presumably the Joint Intervenors do not mean to assert the Companies should have disclosed sensitive confidential information—including non-public customer-specific information—absent a protective agreement, though it is unclear how this criticism is supposed to have any force otherwise. Regardless, it is another criticism that ignores and is inconsistent with the Commission's regulations.

Third and perhaps most importantly, on November 13, 2024—within 24 hours of being asked to do so by counsel for Joint Intervenors—counsel for the Companies both (1) provided links to the large public workpaper files to all counsel who appeared at the informal technical conference held in this proceeding on November 12, 2024, and (2) provided a draft confidentiality agreement to counsel for Joint Intervenors. The Companies did so notwithstanding that the Commission did not grant intervention to the Joint Intervenors until more than a week later on November 21, 2024.[21] Moreover, neither the Companies nor their counsel caused the almost two-month delay between when counsel for the Companies sent counsel for the Joint Intervenors a draft confidentiality agreement and when the Joint Intervenors returned the signed agreement and gained access to the confidential workpapers.[22] Thus, any insinuation that the Companies have

[19] 807 KAR 5:001 Sec. 13.
[20] 807 KAR 5:001 Sec. 13(6)(b), (9)(b)2, and (10)(c).
[21] Case No. 2024-00326, Order (Ky. PSC Nov. 21, 2024).
[22] In the interest of professional courtesy, the Companies will say only that there is documentary evidence to support the Companies' assertion.

been an obstacle to the Joint Intervenors or any other party obtaining access to workpapers in this proceeding is entirely unfounded.

Fourth and finally, there is no reasonable basis to claim that "LG&E-KU's modeling results were not presented in a way that was transparent and easy to understand for non-technical experts. Indeed, on the whole, they were not presented in the IRP report at all."[23] The Companies provided a separate Executive Summary document for the first time in an IRP proceeding to present the IRP highlights in an easily digestible format and length. The IRP itself contained a summary section in addition to the three-volume full IRP documentation. The Companies presented their IRP with a slide presentation distributed to all present at the informal technical conference, which has been available on the Commission's website since November 20, 2024.[24] The Companies responded to two rounds of data requests. And the Companies did—in the interest of transparency—produce their workpapers. It is true the workpapers are complex, but they are what the Companies actually use to perform the complex work associated with the IRP; that is why they are *workpapers*, not the IRP itself. Regardless, the record of this proceeding shows there is no basis for the Joint Intervenors' accusation, which again does not contribute to an open, non-adversarial exchange of ideas.

IV. THE COMPANIES' 2024 IRP LOAD FORECAST IS REASONABLE AND COMPLIES WITH THE IRP REGULATION.

As demonstrated in the Appendix of Detailed Responses, contrary to certain intervenors' criticisms and assertions, the Companies' 2024 IRP Load Forecast was reasonable when the Companies created it. In accordance with the requirements of the IRP regulation, the Companies provided the "base load forecast it considers most likely to occur and, to the extent available,

[23] Joint Intervenors Attachment JI-1 at 56 of 58.
[24] https://psc.ky.gov/pscscf/2024%20cases/202400326//20241120_PSC%20Letter%20Filing%20IC%20Memo%20and%20Attendance%20List%20into%20the%20Record.pdf

alternate forecasts representing lower and upper ranges of expected future growth of the load on its system."[25] The Companies' Mid and High load forecasts have ample support for their data center and other economic development load projections, and planning to serve such loads is both necessary and appropriate consistent with the Companies' obligation to serve *all* existing and future customers.[26] Finally, contrary to certain intervenor assertions, the Companies' load forecasts included reasonable amounts of energy efficiency—including customer-initiated energy efficiency—as well as distributed energy resources.

V. THE COMPANIES' APPROACH TO SUPPLY-SIDE RESOURCE MODELING REFLECTED IN THE 2024 IRP IS REASONABLE.

As noted at the outset of these Response Comments, it is noteworthy that intervenors with explicit renewable energy or environmental advocacy interests argue the Companies have tilted the analytical scales in favor of fossil fuel-fired resources and against renewable resources,[27] while others argue to extend the life of coal units and against renewable resources.[28] Such contradictory criticisms suggest the Companies' IRP analysis—which impartially evaluated a wide variety of resource plans across numerous load, fuel price, and environmental regulatory scenarios—is indeed reasonable and robust.

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[25] 807 KAR 5:058 Section 7(3).

[26] *See* 278.010(14); KRS 278.018(3); KRS 278.030(2); *Walter Callihan and Goldie Callihan v. Grayson RECC*, Case No. 10233, Order at 2-3 (Ky. PSC May 1, 1989); *The Consideration and Determination of the Appropriateness of Implementing a Ratemaking Standard Pertaining to the Purchase of Long-Term Wholesale Power by Electric Utilities as Required in Section 172 of the Energy Policy Act of 1992*, Admin. Case No. 350, Order at 7 (Ky. PSC Oct. 25, 1993); *An Assessment of Kentucky's Electric Generation, Transmission, and Distribution Needs*, Admin. Case No. 2005-0090, Order Appx. A at 60 (Ky. PSC Sept. 15, 2005); *Joint Application of Powergen PLC, LG&E Energy Corp., Louisville Gas and Electric Company, and Kentucky Utilities Company for Approval of a Merger*, Case No. 2000-00095, Order at 22-24 (Ky. PSC May 15, 2000); *Electronic Application of Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Construction of Transmission Facilities in Hardin County, Kentucky*, Case No. 2022-00066, Order at 18 (Ky. PSC July 28, 2022).

[27] *See, e.g.*, SREA Comments at 3.

[28] *See, e.g.*, AG Comments at 3-7.

Second, contrary to multiple intervenors' assertions, the Companies modeled a broad range of reasonable fuel prices and environmental regulatory scenarios as integral parts of their IRP resource planning analysis.[29] As the Companies have explained, their fuel-price forecasts are reasonable and supported by Commission precedent and recent history.[30] In addition, the Companies reasonably modeled environmental scenarios ranging from no new regulations to all recently promulgated regulations, some of which are subject to serious challenge, including the Biden administration's Clean Air Act 111(b) and (d) greenhouse gas regulations. Therefore, the Companies' analysis was both robust and consistent with the requirements of the IRP regulation.

Third, the Companies used reasonable resource price and performance data in their IRP resource planning, particularly given the nature of the IRP process:

- Notwithstanding the Southern Renewable Energy Association's recommendation,[31] it is unreasonable to expect that issuing a request for proposals ("RFP") for an IRP case will result in any useful data because: (1) potential bidders would anticipate that such an RFP is not for any actual need and thus be unlikely to respond at all; and (2) it is unlikely the responding bidders, if any, would provide responses for projects beginning more than a few years from the RFP date, adding little, if any, value to the IRP over its much longer 15-year planning horizon. It is therefore reasonable to use commercial information in the Companies' possession and data from the U.S. Department of Energy's National Renewable Energy Laboratory in modeling resources to obtain directional insight from the IRP.

[29] *See, e.g.,* JI Comments at 5-6; KCA Comments at 5-9.
[30] *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generation Unit Retirements*, Case No. 2022-00402, Order at 93-94 (Ky. PSC Nov. 6, 2023); Case No. 2024-00326, IRP Vol. III, 2024 IRP Resource Assessment at 58-67.
[31] SREA Comments at 4.

- The Companies have demonstrated their units do not have cold-weather-related correlated outages,[32] and their IRP modeling (and resource planning in general) reasonably addresses unit outages and outage risks.[33]
- The Companies have reasonably accounted for capacity contributions of all resource types, including renewables, and have not unreasonably constrained such resources in their modeling.

Finally, the Companies reasonably modeled transmission and access to or dependence upon out-of-state resources. The suggestion that the Companies should model greater reliance on out-of-state resources ignores the unambiguous policy directives of the Kentucky General Assembly and the Commission that Kentucky should be resource sufficient, not reliant on neighboring systems or markets for long-term energy resources.[34]

VI. THE COMPANIES' APPROACH TO DEMAND-SIDE RESOURCES REFLECTED IN THE 2024 IRP IS REASONABLE.

The Companies explicitly included new dispatchable demand-side management ("DSM") program measures and a Curtailable Service Rider ("CSR") program expansion in their resource modeling (in addition to the considerable amounts of energy efficiency and distributed generation included in the Companies' 2024 IRP Load Forecast). As noted in the 2024 IRP Resource Assessment, the Companies' models consistently selected the new DSM program measures (which

[32] *See, e.g.,* IRP Vol. III, 2024 IRP Resource Adequacy Analysis at 23.
[33] *See, e.g.,* Companies' Responses to PSC 2-14 and SC 1-5(b).
[34] *See* KRS 164.2807(1)(f) and (j); *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generation Unit Retirements,* Case No. 2022-00402, Order at 177 (Ky. PSC Nov. 6, 2023), quoting *Electronic Tariff Filing of East Kentucky Power Cooperative, Inc. and Its Member Distribution Cooperatives for Approval of Proposed Changes to Their Qualified Cogeneration and Small Power Production Facilities Tariffs*, Case No. 2021-00198, Order at 5 n. 10 (Ky. PSC Oct. 26, 2021).

were modeled at zero fixed cost) but did not select a CSR expansion during the IRP analysis period, which the Companies modeled on the same terms as they provide CSR service today.

Second, the Companies recently received approval for a new 2024-2030 DSM-EE Program Plan they are in the early stages of implementing. The additional load the Companies are forecasting relative to what they assumed in formulating the 2024-2030 DSM-EE Program Plan consists almost exclusively of 95% average load factor data center customers; by necessity, such loads are not well suited for utility-provided DSM-EE programs. Thus, it is unsurprising that there is not a significant amount of additional cost-effective DSM-EE in IRP modeling, though the load forecast assumes a substantial amount of customer-initiated energy efficiency, as well as energy savings created by the Companies' efforts enabled by their recent AMI deployment, in addition to what the Companies' DSM-EE programs will provide.

In sum, the Companies' IRP reasonably accounted for demand-side resources and energy efficiency savings.

VII. THE COMMISSION STAFF SHOULD DISREGARD THE JOINT INTERVENORS' RECOMMENDATION TO IMPLEMENT OTHER STATES' IRP APPROACHES, INCLUDING ACCOUNTING FOR INFORMATION THAT WOULD NOT BE JURISDICTIONAL TO THE COMMISSION.

The Joint Intervenors suggest the Companies should have included "non-cost criteria … in the selection of a preferred plan,"[35] and they further recommend using a "scorecard" including "environmental sustainability, affordability, reliability, resilience, cost risk, market exposure, and execution risk," which Duke Energy Indiana apparently provided in a recent IRP.[36] The Companies respectfully disagree and note that this IRP is subject to the Commission's IRP regulation, not the requirements or criteria of other states' IRPs, and the Commission has stated it

[35] JI Comments at 5.
[36] JI Comments Attachment JI-1 at 48-49.

lacks jurisdiction over matters such as environmental sustainability.[37] Moreover, although the terms quoted above are somewhat vague, the Companies' IRP process and the recommended plan do indeed address compliance with environmental regulations, serving customers at the lowest reasonable cost, reliability, resilience, fuel price risk, and execution risk.[38] Thus, the Companies' IRP satisfies the requirements of the Commission's IRP regulation, which has been unchanged for almost 30 years.

VIII. CONCLUSION

The comments filed by the intervenors do not undermine the reasonableness of the Companies' 2024 IRP. Importantly, the IRP meets the requirements of Kentucky's IRP regulation, and its recommended resource plan is reasonable, particularly in the near term, because it is robust across a wide range of fuel price and environmental regulatory scenarios.

The Companies look forward to receiving Commission Staff's report at the conclusion of this proceeding.

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[37] *See, e.g., Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Certain Existing, Demand-Side Management and Energy Efficiency Programs*, Case No. 2017-00441, Order at 28 (Ky. PSC Oct. 5, 2018). *See also Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, a Certificate of Public Convenience and Necessity, Approval of Ownership of Gas Service Lines and Risers, and a Gas Line Surcharge*, Case No. 2012-00222, Order at 4 (Ky. PSC Oct. 17, 2012) (quoting *Enviro Power, LLC v. Public Service Commission of Kentucky*, 2007 WL 289328 at 3 (Ky. App. 2007) (not to be published) ("'[R]ates' or 'service' … are the only two subjects under the jurisdiction of the PSC.")).

[38] The Companies do not address market risk because the IRP assumes no reliance on markets to supply their customers' needs. This is fully consistent with the Commission's Orders and the Kentucky General Assembly's policy directives. *See* KRS 164.2807(1)(f) and (j); *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generation Unit Retirements*, Case No. 2022-00402, Order at 177 (Ky. PSC Nov. 6, 2023), quoting *Electronic Tariff Filing of East Kentucky Power Cooperative, Inc. and Its Member Distribution Cooperatives for Approval of Proposed Changes to Their Qualified Cogeneration and Small Power Production Facilities Tariffs*, Case No. 2021-00198, Order at 5 n. 10 (Ky. PSC Oct. 26, 2021).

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CERTIFICATE OF COMPLIANCE

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 March 28, 2025, and that there are currently no parties in this proceeding that the Commission has excused from participation by electronic means.

Counsel for Kentucky Utilities Company
and Louisville Gas and Electric Company

Responses to Comments of the Attorney General

1. Page 4: "PPL, the parent Company of LG&E/KU has an 'ambitious goal to achieve net-zero carbon emissions by 2050,' and targets a 70% emissions reduction by 2035. The Companies admit that their actions contribute to and help inform PPL's emissions goals.[1] The Attorney General is concerned that there is a potential for the corporate goals of PPL to run contrary to the policy and law of the Commonwealth at a time when the Companies decide whether to retire fossil-fuel fired units. To that end, the Companies should exercise care to ensure that their retirement decisions are consistent with Kentucky law and are not driven by the policy goals of its corporate parent."

    a. To be clear, the Companies are not proposing any retirements in this proceeding, which is a planning exercise. No resource decisions are made herein.

    b. This concern is unsupported by the record. The AG has not identified—because it does not exist—any aspect of the Companies' IRP modeling or analysis suggesting the Companies have slanted or skewed their assumptions or models in any way.

    c. It is telling that the AG makes this argument while the intervenors with environmentalist or renewable energy advocacy commitments argue essentially the opposite.

    d. The Companies' objective function is safe and reliable service at the lowest reasonable cost, which must be consistent with applicable local, state, and federal law. The Companies modeled a wide range of possible environmental constraints while also modeling the fossil fuel-fired retirement constraints of KRS 278.264.

2. Pages 9-10: "As the Companies are aware, environmental regulation is an ever-evolving landscape. Within the last two months, that landscape has shifted once again.[2] This is undoubtedly a difficult time to be a decision-maker at a utility. Unfortunately, utility decision-makers are often faced with the unenviable task of making long-term investment decisions in a regulatory environment that increasingly encounters great short-term volatility. That fact is not lost on the Attorney General.

    As a general matter, it would be understandable that a decision-maker might attempt to forecast which policy might win out in the long-term and let that policy guide its decision-making. And indeed, forecasting a variety of factors is a necessary part of the IRP process. But as energy laws and policies change, it is important that utilities abide by the laws and policies that are in effect at that time."

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[1] See Response to AG Supplemental Data Request 2-2.
[2] *Unleashing American Energy*, Executive Order January 20, 2025.

a. The Companies appreciate the AG's points. But as noted above, the Companies have not attempted to unduly shortcut any analytical or modeling process by "attempt[ing] to forecast which policy might win out in the long-term and let that policy guide its decision-making"; rather, the Companies have modeled a wide range of possible future fuel, environmental, and load scenarios to understand which kinds of resources are most robust across a broad array of possible future scenarios.

Responses to Comments of the Joint Intervenors
(Joint Intervenors Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association)

1. Page 28: "Instead, the Companies['] modeling assumes the end of essentially all demand side management offerings in 2030, just as load is nearing its projected peak."

    a. This statement is incorrect.[3] The Companies modeled DSM programs throughout the analysis period.

2. Page 34: "The 2024 IRP notes the Company has begun to assess offering a BYOB (Bring Your Own Battery) demand response program, but its deployment targets are exceedingly modest. The IRP projects peak demand savings from battery storage of 0.97 MW by 2030 and 1.77 MW by 2035. Contrast this with Massachusetts, which as of 2020 had installed 286 MW of customer-sited batteries within 2 years of program implementation or Green Mountain Power in Vermont, which had 2,500 customers participating in its BYOB program as of 2023."

    a. The Joint Intervenors do not provide any citations for their claims about Massachusetts or Green Mountain Power in Vermont, so it is unclear where the Joint Intervenors are getting their information.

    b. Regardless, as the Companies noted in their IRP, as of the end of 2023 the Companies' net metering customers had a total of 286 battery installations with a total battery storage capacity of 1.85 MW.[4] These numbers are unsurprising because Kentucky has much lower electric rates than Massachusetts and Vermont,[5] reducing price arbitrage opportunities across time-varying rates and for pairing with distributed generation. Rather than compare to utilities and states with vastly different rates and incentive structures, the Companies based their projections on peer utilities.[6]

3. Page 35: "Evaluate the use of rebates or other incentives to promote distributed energy resources, including demand response. … [Evaluate] reopening or creation of new

[3] *See, e.g.,* IRP Executive Summary at 5 ("All the load forecasts assume significant amounts of energy-reducing measures, including from the Companies' DSM-EE Programs …. For example, as shown in Table 1 above, the Companies' Mid load forecast includes … the energy efficiency effects of the Companies' proposed 2024- 2030 DSM-EE Program Plan and new programs beyond 2030."); IRP Executive Summary at 7 ("[T]he Companies' IRP analysis considered … new demand-side dispatchable resource options (beyond existing or approved dispatchable DSM and Curtailable Service Rider programs) …."); IRP Vol. I at 8-24 ("In Case No. 2022-00402, the Companies received Commission approval for their current DSM-EE Program Plan through 2030 …. For the purpose of this IRP, all approved programs are assumed to continue throughout the IRP planning period (i.e., through the end of 2039)."); IRP Vol. I at 8-26 (showing increasing peak demand impacts of DSM programs through the entire IRP planning period).

[4] IRP Vol. I at 7-19.

[5] *See, e.g.,* U.S. Energy Information Administration, "Electric Power Monthly, Table 5.6.A. Average Price of Electricity to Ultimate Customers by End-Use Sector by State, December 2024 and 2023 (Cents per Kilowatthour)," available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.

[6] *See, e.g.,* Companies' Response to JI 1.81(b) and (c).

curtailable service rider, large-load demand response, and[/]or direct load control programs[.]"

a. Most of the expansion in the Companies' 2024-2030 DSM-EE Program Plan includes demand response expansion (Connected Solutions for residential customers and Business Demand Response for larger customers).

b. The Companies continue to offer their nonresidential demand response program and enhanced it in the 2024-2030 DSM-EE Program Plan.

c. The Companies' IRP did analyze expanding their existing Curtailable Service Rider, which proved to be uneconomical in all scenarios.

d. The Companies' IRP did analyze certain DR program measures, which are included in the IRP Recommended Resource Plan.

4. Pages 36-37: "The Companies identify three factors that may inspire a DSM-EE Plan update, but none include cost-effectiveness of demand-side resources to mitigate higher costs of supply-side additions …. Perhaps that was an oversight, and the Companies would agree that … [their] guidestar remains provision of service through least-risk, least-cost portfolios."

   a. It was not an oversight; rather, because cost-benefit analyses are always part of DSM-EE planning, it seemed unnecessary to say. Moreover, the Companies have consistently and repeatedly said their goal is the provision of safe and reliable service at the lowest reasonable cost. Nothing about that has changed.

5. Page 37 (footnotes omitted): "Based on data responses, in 2024, the Companies sought a DSM-EE potential study addressing Residential, Commercial, and Industrial sectors. Presumably, such a potential study would recalculate avoided cost values used for cost-effectiveness screening and testing. But it is unclear whether or when that updated picture of cost-effective potential would be put to use through expanded and modified programs. Again, DSM-EE potential appears to be an afterthought, pursued after committing customers to billions of dollars in capital projects, if at all."

   a. DSM-EE was not an afterthought. As noted, the Companies are currently conducting a DSM-EE potential study and anticipate it will be final mid-year. But when the Companies were conducting their IRP analysis, they had just begun implementing their 2024-2030 DSM-EE Program Plan, which the Commission approved in November 2023. The likelihood that a great trove of achievable DSM-EE potential had appeared in less than a year is low at best.

   b. Moreover, the load additions the Companies anticipate in this IRP are extremely high load factor, making them unlikely candidates for cost-effective DSM-EE programming.

c. As the Companies have repeatedly noted throughout the IRP itself and this proceeding, their load forecast includes energy efficiency assumptions (and related demand reductions) well beyond those included in DSM-EE programs.

d. It is unclear what the Joint Intervenors mean by asserting the Companies have "commit[ed] customers to billions of dollars in capital projects" before conducting a DSM-EE potential study, but it is not within the scope of this proceeding, and there is no sense in which the Companies have unreasonably or imprudently "commit[ed] customers to billions of dollars in capital projects."

6. Page 51: "[T]he Companies have made important improvements in this IRP yet still do not adequately evaluate all potentially cost-effective resource options and fail to do not [*sic*] provide the level of comprehensive analysis needed to support an actionable plan for the next 15 years."

   a. There is no support for the Joint Intervenors' assertion. They have conducted no modeling or cost-benefit analysis, which would be the *minimum* requirement for credibly asserting that the Companies have "not adequately evaluate[d] all potentially cost-effective resource options."

   b. The Joint Intervenors fail to understand the purpose of an IRP in Kentucky. It is not and never has been to provide "an actionable plan for the next 15 years." If that were its purpose, it would be unnecessary to file a new IRP every three years.

7. Attachment JI-1 at 7 – 12 (9 – 14 of 58): "Best Practice A.1. Load Forecasting"

   a. The Joint Intervenors' consultant, Applied Economics Clinic ("AEC"), claims the Companies provided inadequate support for their residential customer forecast and data center forecast, but both forecasts are well-documented in the IRP and reasonable. In addition, all workpapers were provided when the IRP was filed. As discussed in IRP Volume II, the Companies' residential customer forecasts are specified econometrically as a function of population according to a reputable data source (S&P Global). The forecasts consider regional trends and account, for example, for the fact that customer growth differs in urban and rural areas. Unsurprisingly, forecasted customer growth is consistent with history in the near-term and slows in the latter part of the planning period as the forecast of population slows.

8. Attachment JI-1 at 12 – 15 (14 – 17 of 58): "Best Practice A.2. Demand Side Resources"

   a. Contrary to AEC's assertions, energy efficiency-related energy savings do not "drop rapidly after 2030" (page 17 of 28). Instead, as seen in Figure 7-2 of 2024 IRP Volume I, the combined impact of LG&E-KU-sponsored and customer-initiated energy efficiency improvements are assumed to increase throughout the IRP planning period.

b. AEC asserts that the Companies did not evaluate as part of the 2024 IRP "more aggressive options to increase use of the curtailable service rider and demand conservation program" despite the 2021 IRP Staff Report recommendation along those lines. This assertion is incorrect. The Companies' analysis of new dispatchable DSM programs and extended CSR program is well documented in the 2024 IRP Resource Assessment.

9. Attachment JI-1 at 15 – 17 (17 – 19 of 58): "Best Practice A.3. Behind-the-meter resources"

   a. Contrary to AEC's assertions, the Companies' distributed solar forecasts are well documented and reasonable.[7]

   b. Furthermore, the Companies' forecast does not "omit" behind-the-meter batteries (page 19 of 28). As explained by the Companies, distributed battery storage installations are implicitly assumed to grow as customers grow. Given current penetration levels, this approach is reasonable and in no way diminishes the quality of the Companies' resource planning decisions.

10. Attachment JI-1 at 18 – 19 (20 – 21 of 58): "Best Practice A.4. Electrification loads"

   a. Contrary to AEC's assertions, the Companies' electric vehicle and electrification assumptions are well documented and reasonable.[8]

   b. In addition, the Companies documented the ways their planning process appropriately accounts for climate change in their response to JI 1-53.

11. Attachment JI-1 at 19 – 22 (21 – 23 of 58): "Best Practice A.5. Large load customers"

   a. The Companies' approach to forecasting large loads was reasonable. To the extent AEC is arguing the Companies should include in their load forecasts only announced economic development projects or those under contract, only the Companies' Low IRP load forecast (zero economic development load) would have been reasonable because, for example, the Camp Ground Road data center project was not announced when the IRP was filed. But an IRP load forecast with zero economic development load would clearly have been too low.

   b. On the other hand, planning for all possible data center projects in the economic development queue (more than 6,000 MW) would almost certainly result in overbuilding generation.

[7] *See* 2024 IRP Volume I Section 7.(7).(b).7.
[8] *See* 2024 IRP Volume I Section 7.(7).(b).8 and 7.(7).(b).9; 2024 IRP Volume II Section 4.6.

c. The level of economic development load in the Companies' Mid and High load forecasts was reasonable when the Companies developed the IRP and appropriately reflected information available at the time.

12. Attachment JI-1 at 22 – 23 (23 – 24 of 58): "Best Practice B.1. All-resource RFP"

    a. As stated in the Companies' Responsive Comments, it is unreasonable to expect that issuing RFPs for an IRP analysis will result in any useful data due to bidders' anticipation that such an RFP is not for any actual need and due to the IRP's 15-year planning horizon. It is therefore reasonable to use commercial information in the Companies' possession and data from the U.S. Department of Energy's National Renewable Energy Laboratory in modeling resources to obtain directional insight from the IRP.

13. Attachment JI-1 at 23 – 25 (25 – 27 of 58): "Best Practice B.2. Modeled resources"

    a. AEC criticizes the Companies for not modeling a utility-scale solar-plus-storage resource. But as explained in the Companies' response to SREA 1-1, pairing renewables with battery storage, and requiring battery storage to be charged only by the renewables, reduces the likelihood that the battery will be charged when needed and therefore reduces the value of the battery.

    b. AEC criticizes the Companies for "imposing artificial limits on renewable energy resources." Given the incremental nature of portfolio changes in most scenarios, the Companies' renewable energy limits are reasonable.

14. Attachment JI-1 at 25 – 28 (27 – 30 of 58): "Best Practice B.3. Regulatory costs"

    a. AEC claims the Companies failed to fully evaluate carbon risk by not evaluating scenarios with a cost for carbon emissions. But the Companies appropriately evaluated carbon risk by modeling the regulation the EPA proposed to limit carbon emissions (i.e., the GHG Rule). The GHG Rule imposes significant costs on carbon emissions, albeit not through a carbon tax. A carbon tax or CO_2 price may be an appropriate consideration in a future IRP if the GHG Rule is repealed.

    b. Additional responses to points AEC made in this section are below.

15. Attachment JI-1 at 26 (28 of 58): The Companies' treatment of the GHG Rule as 'low likelihood' eliminates it from full consideration in identifying a least-cost plan …."

    a. The Companies also treated the "No New Regulations" scenario as low likelihood. It would be unreasonable to treat all possible future scenarios as equally likely when there are reasons to assign them different likelihoods.

    b. Moreover, as the Companies' GHG Rule modeling shows, the IRP Recommended Resource Plan includes resources that would be needed in the GHG Rule scenarios, particularly in the near term.

16. Attachment JI-1 page 26 (28 of 58): "Although the Companies' Recommended Resource Plan takes a 'no regrets' approach supports the elimination from consideration of potential CO_2 regulation (as well as high economic development load growth), their modeling of the Recommended Resource Plan does not transparently demonstrate how the risk of future climate regulation was addressed."

    a. The Companies disagree. They were very clear about how they addressed future climate and other environmental regulation, and they were clear about how they selected the resources in the IRP Recommended Resource Plan. Whether the Joint Intervenors' consultant would have chosen a different plan is another matter; simply having a difference of opinion does not make the Companies' approach unreasonable.

17. Attachment JI-1 at 26-27 (28 to 29 of 58): AEC criticizes the Companies for not modeling carbon pricing instead of or in addition to the final Greenhouse Gas Rules under Clean Air Act 111(b) and (d), suggesting the Companies' approach is somehow contrary to the Commission Staff's 2021 IRP Report.

    a. Commission Staff's 2021 IRP Report actually said this:

    > Commission Staff also disagrees, in part, with statements in LG&E/KU's post-hearing comments indicating that recent developments support its assumption that carbon regulation is likely to be achieved through application of the NSPS alone. Commission Staff agrees that limitations imposed on the EPA in West Virginia v. EPA make it more likely that it would attempt to regulate carbon emissions through the direct regulation of generating facilities and statements from the current administration and incentives in the Inflation Reduction Act support that prospect. However, given questions about the feasibility of CCS, it is unclear whether the EPA could regulate carbon through constraints on specific generating units and such regulation could be held up for some time in litigation even if they did. Given the urgency with which many view the need to address carbon emissions, Commission Staff believes such issues and potential delays in other forms of regulation raise the prospect, particularly over a timeline of 15 years or more, that a federal price or tax on CO_2 emissions could be implemented through the reconciliation process in the same way the tax on methane emissions was imposed in the Inflation Reduction Act. Thus, Commission Staff believes that the regulatory risk or prospect of a tax on CO_2 emissions should be seriously considered and discussed in detail in LG&E/KU's next IRP and any assumption regarding a CO_2 price or

tax, including that a CO_2 price is unlikely, should be fully supported such that the reasonableness of the assumption can be assessed.[9]

b. After the Commission Staff wrote its 2021 IRP Report but before the Companies filed their 2024 IRP, the EPA issued and finalized its Greenhouse Gas Rules. At the time the Companies filed their IRP, though the rules were being challenged, there was no indication of any pursuit at the federal, state, or local level of any kind of carbon tax or pricing approach that would have affected the Companies. It was therefore appropriate for the Companies to conduct their Greenhouse Gas modeling as they did, i.e., by modeling the effects of the final Greenhouse Gas Rules, not a set of hypothetical carbon prices.

18. Attachment JI-1 page 27 (29 of 58): "*Mercury Air Toxics Standard (MATS) update*: Adopted in early 2024, the standard most importantly lowers the limit for particulate matter (PM, as a surrogate to be measured for heavy metals) from 0.030 to 0.010 pounds (lbs) per million British thermal units (MMBtu). The Companies say they are already monitoring compliance at all applicable units, but the rule will mean a tighter margin between emissions levels and the limit, meaning exceedances could happen more easily and there would be more difficulty with monitoring at such refined levels. Additional compliance measures such as control efficiency or monitoring upgrades were not modeled in any scenario."

    a. The Companies' monitoring systems already comply with the MATS rule; additional upgrades are not warranted in the modeling. Incremental operations and maintenance costs to address enhanced preventative maintenance to address a lower compliance margin is not a material cost in the modeling process.

19. Attachment JI-1 pages 27-28 (29-30 of 58): "*Fine Particulate Matter (PM2.5) NAAQS*: This standard was lowered from 12 to 9 micrograms per cubic meter ($\mu g/m^3$) effective May 6, 2024. The most recent data show only one monitor in the Louisville area exceeding the new standard. However, because EPA designates entire "Air Pollution Control Regions" based on the worst performing, or "design value," monitor in the region, the entire Louisville area could face a nonattainment designation. The designations process is ongoing, but a nonattainment designation could potentially come in early 2026, with attainment plans due late 2027, and a deadline to attain the standard likely being 2032. Like the ozone standard discussed in Companies' IRP, this means the Commonwealth and Louisville Air Pollution Control District will be responsible for driving local reductions to achieve attainment, including requiring Reasonably Available Control Technologies and Reasonably Available Control Measures (RACT/RACM) no later than 2031. Again, Companies failed to take potential additional control measures into account and model for the possibility of additional control upgrades being required."

[9] *Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2021-00393, Order Appx. (Commission Staff Report) at 61-62 (Ky. PSC Sept. 19, 2022) (internal footnotes omitted).

a. This comment shows a lack of understanding of the Companies' generation fleet. All units in the fleet contemplated for operation beyond 2031 will have RACT/RACM. The only units without RACT/RACM in the fleet at the time of the IRP submittal were Mill Creek 1, Mill Creek 2, and Ghent 2. As contemplated in the IRP, both Mill Creek 1 & 2 would be retired by 2031, and the Companies included a Ghent 2 SCR in the IRP Recommended Resource Plan, which would ensure Ghent 2 would also have RACT/RACM.

b. The Companies have implemented what is arguably Best or Maximum Achievable Control Technology for particulate matter, Pulse Jet Fabric Filters. The NAAQS process relies on Reasonably Achievable Control technology for existing units. Thus, additional control upgrade considerations are not warranted.

20. Attachment JI-1 page 28 (30 of 58): "To comply with Commission Staff's 2021 instructions, the Companies should fully evaluate carbon risk in their scenario modeling by assigning a cost to carbon emissions. This scenario analysis should be directly and transparently included in the selection of a Recommended Resource Plan. Even though the fate of the current GHG Rule is uncertain, Commission Staff have instructed the Companies to consider carbon prices and climate regulations."

a. This comment misrepresents Commission Staff's recommendations (not "instructions") in the 2021 IRP Report, as well as the Companies' IRP. See responses 17a and b above.

21. Attachment JI-1 page 28 (30 of 58): "A future without limits to greenhouse gas emissions is unlikely. By failing to take full consideration of expected regulatory and financial risk related to climate change, the Companies are exposing themselves to over-investment in new gas resources (including gas co-firing modifications) that may become stranded assets when environmental regulations are strengthened. Stranded assets are a serious financial risk to the Companies long-term viability and could result in increased customer rates to pay for unused infrastructure."

a. The Companies fully modeled the effects of the final Greenhouse Gas Rules, and the IRP Recommended Resource Plan includes resources that would be needed in the GHG Rule scenarios, particularly in the near term. Thus, this "omission" does not exist, and the near-term resources in the IRP Recommended Resource Plan are robust across a broad range of environmental regulatory scenarios, including one that includes the Greenhouse Gas Rules.

b. According to the U.S. Energy Information Administration, "Natural gas is the single-largest source of energy used to generate electricity in the United States, making up 43% of electricity generation in 2023."[10] Electric utilities and others are currently adding large amounts of gas-fired capacity: "In 2023, operators added

[10] U.S. Energy Information Administration, "Use of natural gas-fired generation differs in the United States by technology and region," *Today in Energy* (Feb. 22, 2024), *available at* https://www.eia.gov/todayinenergy/detail.php?id=61444.

9,274 megawatts (MW) of new natural gas turbine generating capacity to the power grid in the United States."[11]

c. According to the National Renewable Energy Laboratory's *2023 Standard Scenarios Report: A U.S. Electricity Sector Outlook*, "*Natural gas capacity continues to expand.* In the Mid-case with current policies, natural gas capacity increases by 200 GW through 2050, whereas it increases by 130 GW in the Mid-case with 95% net decarbonization imposed."[12]

d. According to the U.S. National Power Demand Study performed by S&P Global Commodity Insights for the American Clean Power Association, "[N]atural gas-fired capacity and other firm resources like batteries will be critical to provide capacity and balancing support[.] … By 2040, the US will require *net additions* of between 60 and 100 GW of gas …."[13]

e. Federal Energy Regulatory Commission ("FERC") Chairman Mark Christie stated earlier this month, "When you run a roll call, it doesn't take long to get to combined cycle gas as a baseload generating resource of choice. … Saying that it takes seven years to build combined cycle natural gas is not an argument not to do it, we have to do it."[14]

f. None of this suggests a high stranded asset risk for investing in gas-fired generation.

22. Attachment JI-1 at 28 – 31 (30 – 33 of 58): "Best Practice B.4. Fuel prices"

a. AEC criticizes the Companies' coal price forecasts. AEC notes that the MGMR prices conform to the AEO but argues that all other coal price scenarios are either too high or too low, based on the AEO's very narrow range of coal price forecasts. AEO's fuel price suggests coal and gas prices are not related and, for example, coal prices would be unimpacted by a switch to sustained high gas prices. Suggesting that the Companies should only consider the EIA's narrow coal price range is dubious. The Companies intentionally consider a much wider range of coal prices to capture a reasonably broad range of uncertain futures.

23. Attachment JI-1 at 31 – 34 (33 – 36 of 58): "Best Practice B.5. Technology costs"

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[11] U.S. Energy Information Administration, "Use of natural gas-fired generation differs in the United States by technology and region," *Today in Energy* (Feb. 22, 2024), *available at* https://www.eia.gov/todayinenergy/detail.php?id=61444.

[12] National Renewable Energy Laboratory, "2023 Standard Scenarios Report: A U.S. Electricity Sector Outlook" at vi (Jan. 2024) (emphasis original), available at https://www.nrel.gov/docs/fy24osti/87724.pdf.

[13] S&P Global Commodity Insights, "U.S. National Power Demand Study, Executive Summary" at 2 (Mar. 2025), available at https://cleanpower.org/wp-content/uploads/gateway/2025/03/US_National_Power_Demand_Study_2025_ExecSummary_FINAL-v2.pdf.

[14] Kevin Clark, "FERC Chairman: Build more Combined Cycle," *Power Engineering* (Mar. 13, 2025), available at https://www.power-eng.com/gas/combined-cycle/ferc-chairman-build-more-combined-cycle/.

a. AEC claims the Companies' method for converting NREL technology costs from real to nominal dollars is "erroneous." This claim is incorrect. The Companies' methodology is documented in the 2024 IRP Technology updated and aligns technology costs with recent market-based cost estimates wherever possible.

24. Attachment JI-1 at 35 – 37 (37 – 39 of 58): "Best Practice C.1. Future scenarios"; also Attachment JI-1 at 37 – 38 (39 – 40 of 58): "Best Practice C.2. Scenario assumptions"

    a. AEC criticizes the Companies for only considering a handful of scenarios in their selection of a Recommended Resource Plan, but this criticism reflects a misunderstanding of the purpose of the IRP. The IRP is not a commitment to action. Indeed, the IRP contemplates a number of resource decisions over a 15-year planning horizon that would be imprudent to make today. Therefore, the method used to develop a resource plan for reporting in Sections 8 and 9 of 2024 IRP Volume I is reasonable.

25. Attachment JI-1 at 38 (40 of 58): "Best Practice C.3. Base case"

    a. AEC asserts the Companies should have re-evaluated the "base case" (i.e., Recommended Resource Plan) over all scenarios for better risk assessment. Because the IRP is not a commitment to action and many resource decisions in a 15-year resource plan do not require immediate attention, this analysis is unnecessary. Re-evaluating the fixed 15-year "base case" over all scenarios presumes that the Companies would not adjust their Recommended Resource Plan over time as new information regarding technology pricing, load, environmental regulations, or fuel prices becomes available. For example, if the recent spike in solar costs proves transitory and solar prices decline in the future as NREL projects, the Companies will modify future resource plans to include additional solar generation if those resources are identified as least cost at that time.

26. Attachment JI-1 at 38 – 39 (40 – 41 of 58): "Best Practice C.4. Resource portfolios"

    a. In addition to their PLEXOS modeling, AEC criticized the Companies for not developing and evaluating portfolios to meet other objective functions. But the Companies submit that focusing on developing resource plans to reliably serve customers at the lowest reasonable cost is appropriate.

27. Attachment JI-1 at 39 – 40 (41 – 42 of 58): "Best Practice C.5. Retirement analysis"

    a. The AEC reiterates concerns regarding carbon prices and renewable limits, which the Companies address above. See responses to items 14, 17, and 20 regarding carbon prices. See response to item 13 regarding renewable limits.

28. Attachment JI-1 at 40 – 42 (42 – 44 of 58): "Best Practice C.6. Optimization modeling"; Attachment JI-1 at 53 – 55 (55 – 57 of 58): "Best Practice E.2. Transparency and accessibility"

a. AEC criticizes the Companies for a perceived lack of transparency, saying modeling results were not presented in a way that was easy to understand for non-technical experts, and saying "Direct IRP modeling experience and/or an advanced degree in economics should not be a limiting factor in stakeholders' ability to access and interpret basic IRP findings, including quantitative comparisons of key metrics across resource plans and scenarios." The Companies strive for transparency by thoroughly documenting their work product and making as much information publicly available as reasonably possible. But due to the necessarily complex nature of resource planning, a level of expertise will be required to digest some of the Companies' workpapers and understand whether rules and regulations from other jurisdictions are applicable to the Companies.

b. See also the response provided in the Companies' Responsive Comments.

29. Attachment JI-1 at 42 – 44 (44 – 46 of 58): "Best Practice C.7. Uncertainty analysis"

    a. AEC criticizes the Companies for not performing stochastic modeling for risk analysis, but the Companies' scenario modeling is more than adequate for this purpose. Scenario analysis is a form of stochastic modeling.

30. Attachment JI-1 at 44 – 46 (46 – 48 of 58): "Best Practice D.1. NPV comparison"; Attachment JI-1 at 50 – 51 (52 – 53 of 58): "Best Practice D.4. Recommended plan"

    a. AEC claims the Companies failed to compare PVRR in their workpapers and across all scenarios. The Companies performed PVRR analysis within each load and environmental scenario to determine the optimal resource plans. AEC again misunderstands the purpose of the IRP, expecting a level of evaluation as though the Recommended Resource Plan were a firm commitment to action.

31. Attachment JI-1 at 46 – 48 (48 – 50 of 58): "Best Practice D.2. Scorecard evaluation"; Attachment JI-1 at 49 (51 of 58): "Best Practice D.3. Quantitative assessment"

    a. AEC criticizes the Companies for not having a scorecard evaluation. The Companies objective is to provide reliable service at the lowest reasonable cost. Meeting this objective will properly account for all factors that impact utility revenue requirements.

32. Attachment JI-1 at 52 – 53 (54 – 55 of 58): "Best Practice E.1. Stakeholder process"

    a. AEC criticizes the asserted lack of a stakeholder process. As the Companies stated in response to JI 2-35:

    > The Companies did not have a pre-filing IRP stakeholder engagement process and have not had such a process for any previous IRP. Unlike demand-side management plan filings for which there is a statutory requirement to consider the involvement of "customer representatives and the Office of the Attorney … in

developing the plan,"[15] the Commission's IRP regulation neither requires nor contemplates a pre-filing stakeholder process.[16] Rather, the IRP regulation provides a process by which the Commission Staff and intervenors may issue discovery requests and submit comments about an IRP after a utility files it.[17] Likewise, the Commission may schedule conferences to discuss an IRP after a utility files it.[18] But the regulation does not require or even suggest a pre-filing public or stakeholder process; rather, the post-filing IRP process prescribed by the Commission's regulation is the stakeholder process.

That notwithstanding, the Companies did engage with their DSM Advisory Group, including residential customer representatives, in two meetings prior to the IRP filing (June 3 and July 16, 2024). The topic of the IRP arose in both meetings.[19]

[15] KRS 278.285(1)(f).
[16] 807 KAR 5:058.
[17] *See, e.g.*, 807 KAR 5:058 Sec. 11(1).
[18] *See, e.g.*, 807 KAR 5:058 Sec. 11(2).
[19] The meeting minutes and other meeting documents are available at https://lge-ku.com/dsm.

<u>Responses to Comments of the Kentucky Coal Association, Inc.</u>

1. Page 4: "The Commission should require the Companies to ensure all data center contracts properly address the cost of service, provide financial assurances in case of a default by the customer, and will not result in any increased electricity rates to existing ratepayers."

    a. As explained at length in the Companies' Responsive Comments and Motion to Amend Procedural Schedule, the Commission cannot take substantive action in this proceeding, and such contract and rate issues are outside the scope of an IRP proceeding.

    b. Also, the interest from data centers and data center developers in connecting to the LG&E/KU Transmission System is unprecedented. As such, an internal process was developed in late December 2024 to require data centers and data center developers ("customers") to enter into an Engineering, Procurement and Construction ("EP&C") Agreement before the Companies incur expenses in the effort of interconnecting the load. This EP&C Agreement requires the customers to provide security in the amount of the estimate(s) contained in the EP&C Agreement; further, the EP&C Agreement stipulates that if customers ultimately fail to take electric service under an executed contract for the provision of electric service, they will reimburse the Companies for any and all costs incurred.

2. Page 4: "[T]here is a general belief that the new Administration will work towards relaxing or removing many of the rules that had been expected to go into effect. To the extent this happens, it affects the need to retrofit new pollution control technologies and/or replace existing generation."

    a. By necessity, every IRP is an analysis conducted at a moment in time. The Companies performed their IRP analysis and filed the IRP before the recent federal election. To account for future uncertainty, the Companies modeled a wide range of possible future fuel, environmental, and load scenarios to understand which kinds of resources are most robust across a broad array of possible future scenarios.

3. Pages 4-5 (footnotes omitted): "It is worth noting that the Companies requested, and the Commission approved the retirement of Mill Creek 2 based predominately on stagnant load growth and the cost to comply with environmental regulations in Case 2022-00402. The key environmental regulation, the Good Neighbor Plan, used to justify the retirement of Mill Creek 2 has been stayed by the SCOTUS and will likely be overturned. If the same assumptions used in this IRP had been used in Case 2022-00402, the continued operation of Mill Creek 2 would have been part of the least-cost option generation portfolio, providing an example of the importance of regulatory certainty."

    a. The assertion that "the Companies requested, and the Commission approved the retirement of Mill Creek 2 based predominately on stagnant load growth" is incorrect. The 2022 CPCN Load Forecast assumed the addition of more than 250

MW of BlueOval SK Battery Park load, which significantly increased the load forecast.

b. As the Companies have shown in this IRP, the demise of the Good Neighbor Plan as applied to Kentucky does not remove the EPA's obligation to drive attainment of the 2015 Ozone NAAQS. Notably, the 2015 Ozone NAAQS standard of 70 ppb is not under attack in Executive Orders issued or regulatory actions taken subsequent to the filing of the IRP.

c. KCA cites nothing to support its assertion that "[i]f the same assumptions used in this IRP had been used in Case 2022-00402, the continued operation of Mill Creek 2 would have been part of the least-cost option generation portfolio …." Moreover, three of the four environmental scenarios modeled in the 2024 IRP included equivalent ozone (and therefore NOx) constraints as those in the Good Neighbor Plan, which was reasonable due to the EPA's obligation to drive attainment of the 2015 Ozone NAAQS. Thus, it is incorrect to say IRP assumptions would undermine Mill Creek 2's planned retirement.

4. Pages 5-6, "Coal and natural gas have different markets. …"

    a. The Companies agree that coal and gas have different markets, and the coal-to-gas ("CTG") methodology acknowledges these differences,[20] but these differences do not invalidate the CTG methodology.

    b. Contrary to the KCA's assertions, the natural gas industry has large amounts of storage that, like coal inventories, play a significant role in the natural gas market.

    c. The fact (cited by the KCA) that the power market accounts for 90% of domestic coal production supports the CTG methodology. Coal and NGCC energy are economic substitutes. With limited markets for coal and fewer coal suppliers than 10 years ago, coal prices over long periods of time will continue to be tied to natural gas prices. Furthermore, contrary to the KCA's forecast, the share of natural gas generation in the power market is expected in increase, not decrease.

5. Page 7: "Natural gas demand from the power sector has varied over the last four (4) years between 20 and 40 BCFD. Due to lower natural gas demand from the residential/commercial sectors in the summer, the power sector accounts for a higher share of demand during this period."

    a. Contrary to the KCA's assertions, the CTG methodology accounts for seasonal variations in coal and gas prices.

[20] *See, e.g.*, the Companies' 2024 IRP Resource Assessment at 59 ("Coal and gas prices generally move together, but coal markets are slower to respond to changing market fundamentals than gas.").

   b. The seasonal pattern in the Companies' gas price forecast is consistent with history, and the daily pattern in each month is aligned with load.

6. Pages 7-8: "Utility procurement of coal and natural gas are typically handled in different ways. …"

   a. The Companies agree that coal and natural gas are procured in different ways, but this does not invalidate the CTG methodology.

   b. Contrary to the KCA's assertion, the CTG methodology does not presume that coal inventory costs are "tied" to the prompt market. Rather, the CTG methodology presumes that ratio of coal and natural gas prices over a long period of time will fall within a particular range.

   c. Resource planning contemplates long-term investments in resources that are typically commissioned 3-5 years into the future. The aspects of coal and natural gas prices that materially impact long-term resource planning decisions are the average level and average ratio of coal and natural gas prices over a long period of time. Therefore, the Companies develop fuel forecasts that appropriately consider the uncertainty in these factors.

7. Page 8: "The reported delivered prices of coal and natural gas to the Companies over the years 2021 through 2024 are poorly correlated despite the representation that pricing is highly correlated. More importantly, the coal prices are more stable during the four-year period and a fraction of the delivered natural gas prices. This is, in part, a result of the Companies' well planned and implemented coal procurement strategy."

   a. Contrary to the KCA's assertions, the fact that Ghent coal prices and Cane Run gas prices are poorly correlated from 2021 to 2024 does not invalidate the CTG methodology. As noted above, the CTG methodology is focused on the ratio of coal and gas prices, not the correlation.

   b. The KCA provided delivered coal and natural gas prices for Ghent and Cane Run for the period 2021-2024. Although the CTG ratio is not a ratio of delivered prices and the Companies do not consider four years to be a long period of time, the Companies note that the ratio of delivered coal and natural gas prices over this period is 0.58, which is very close to the mid CTG of 0.57.

8. Page 8: "Natural gas prices are considerably more volatile than coal prices. The volatility is not captured in the utilized forecasts."

   a. The Companies agree that daily gas prices are more volatile than coal prices, and the CTG methodology accounts for this volatility.

      i. The Companies reduce the gas price volatility that impacts customer bills by purchasing a portion of natural gas on a forward basis.

b. The evaluated range of CTGs is based on annual CTGs from 2012-2021. Each annual value is computed as the average of weekly "prompt quarter ILB coal" prices divided by the average of daily gas prices. Thus, the annual values on which the CTG range is based fully account for the volatility in both coal and gas prices.

<u>Responses to Comments of the Kentucky Industrial Utility Customers, Inc.</u>

1. Page 1: "Before spending $775 million for the 400 MW, 4-hour Cane Run battery energy storage system ("BESS") and $1.415 billion for the 645 MW Mill Creek 6 natural gas combined cycle ("NGCC") (total cost $2.19 billion) primarily to serve 1,750 MW of potential data center load in 2032, the Commission should require long-term contracts with strong minimum bill provisions to ensure that the potential data center load and revenue actually materializes. The long-term data center contracts should be signed before construction of the new generation or storage begins."

    a. First and foremost, none of this is within the scope of an IRP proceeding for the reasons discussed at length in the Companies' Responsive Comments and Motion to Amend Procedural Schedule.

    b. Second, with regard to IRP load forecasting, the Companies' approach was reasonable. To the extent KIUC is arguing the Companies should include in their load forecasts only for announced economic development projects or those under contract, only the Companies' Low IRP load forecast (zero economic development load) would have been reasonable because, for example, the Camp Ground Road data center project was not announced when the IRP was filed. But an IRP load forecast with zero economic development load would clearly have been too low.

       On the other hand, planning for all possible projects in the economic development queue (more than 8,000 MW) would almost certainly result in overbuilding generation.

       The level of economic development load in the Companies' Mid and High load forecasts was reasonable when the Companies developed the IRP and appropriately reflected information available at the time .

2. Pages 5-9, KIUC's revenue requirements analysis

    a. KIUC's revenue requirement analysis is not based on the optimal resource plans for each load scenario, and as a result overstates the incremental capital costs associated with data center load.

        i. In their analysis, KIUC referenced the "E02" resource plan for all load scenarios. The E02 resource plan is the PLEXOS resource plan developed for the Mid Gas Mid CTG fuel price scenario and is the optimal resource plan for the mid load scenario with the solar cost sensitivity.

        ii. The E04 resource plan is the optimal resource plan for the low load scenario, and the E01 resource plan is the optimal resource plan for the high load scenario.

        iii. Updating the KIUC analysis with the correct resource plans reduces the difference in capital revenue requirements between the mid and low load scenarios from $271 million to $223 million, and the difference between the high and low scenarios reduces from $545 million to $491 million (see corrected tables below). This update has a favorable impact on the KIUC's rate impact calculation (incremental revenue less incremental cost) and causes the incremental revenues to exceed incremental costs by $19 million in the high load scenario with full expected data center load (KIUC Table 5). Previously, the KIUC's analysis reflected incremental costs exceeding incremental revenues for this scenario.

Corrected KIUC Table 3

03_ELG; E04/E02(SolarSens)/E01, MGMR	**Low-Load**	**Mid-Load**	**High-Load**	**Low-Load to Mid-Load**	**Low-Load to High-Load**
Annual Capital Cost Revenue Requirement	$1,127	$1,394	$1,762	$268	$636
Data Center Percent of Winter Peak Load Increase				83%	77%
Data Center Share of Annual Capital Cost Revenue Requirement				$223	$491

Corrected KIUC Table 4

Mid-Load (1,050 MW data center) 03_ELG; E02, MGMR, 2032	**Capital Costs $ million**	**RTS Revenue $ million**	**Delta $ million**
Full Expected Data Center Load	$223	$306	$83
Partial Data Center Load (50% Load Ramp)	$223	$153	($70)
No Data Center Load	$223	$0	($223)

Corrected KIUC Table 5

Low-Load to High-Load (1,750 MW data center) 03_ELG; E02, MGMR, 2032	**Capital Costs $ million**	**RTS Revenue $ million**	**Delta $ million**
Full Expected Data Center Load	$491	$510	$19
Partial Data Center Load (50% Load Ramp)	$491	$255	($236)
No Data Center Load	$491	$0	($491)

b. On page 9, KIUC references the capital cost for Cane Run BESS ($775 million) and asserts that the first-year capital revenue requirement for the resource will be $124 million, but this capital revenue requirement figure does not account for the investment tax credit. With the investment tax credit, the first-year capital cost revenue requirement is approximately $60 million.

Responses to Comments of the Sierra Club

1. Page 4: "The Companies should have evaluated whether it was a 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 NOx emissions rates at or below the targeted emission rate that the Companies hope to achieve at Ghent 2 during ozone season with an SCR, so the Companies should have considered conversion as an alternative."

    a. The Companies have historically evaluated conversion of coal fired boilers in their fleet to co-firing and full-firing natural gas. The Companies' previous engineering studies for gas conversion of Trimble County Unit 1, which is a large tangentially-fired coal electric generating unit similar to Ghent 2, indicates NOx emissions from a such a converted unit would likely to be in the range of 0.10-0.15 lb./ MMBtu, not in the range of 0.04 lb./ MMBtu and 0.09 lb./MMBtu EFG claims for units not in the Companies' fleet.[21] According to the Good Neighbor Plan, the Reasonably Achievable Control Technology emission rate for new SCR is 0.04 lb./ MMBtu and 0.08 lb./MMBtu for existing SCR. Therefore, the conversion of Ghent 2 to natural gas does not eliminate the need for a SCR.

    b. EFG significantly understates the cost of gas service for converting only Ghent 2 to burn gas. The Ghent Station does not have existing gas service, and as noted in footnote 65 in the Resource Assessment, "Station costs for pipeline capital are allocated across units as a simplifying assumption, so costs may be understated if some units at a station are retrofitted and others are not." If the full pipeline cost had to be borne by Ghent 2 for gas conversion, the capital cost of that option would increase by over $80 million. While EFG attempted to account for this added cost in their workpapers, their end result only accounted for a fraction of this incremental cost increase. The Companies cannot comment further on EFG's analysis because they did not provide formulas in their workpapers, only pasted values.

2. Page 5: "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."

    a. The Companies follow NERC Reliability Standards ("Reliability Standards") and the FERC approved Open Access Transmission Tariff ("OATT"). The Reliability Standards and the processes outlined in the OATT are designed to ensure seamless integration of load and generation resources into the LG&E/KU Balancing Authority Area while maintaining the reliability of the grid. Transmission Service Request studies are performed independently by the Companies' Independent

[21] EFG Comments at 30.

Transmission Organization, and any constraints resulting from the integration of the load must be mitigated.

3. Page 5: "The Companies should provide an analysis around the costs and benefits of securing ATC access with neighboring regions."

    a. As EFG notes, the Companies have provided high-level cost estimates of increasing ATC to allow for greater imports from surrounding systems. But there is little reason to conduct additional analyses around ATC in future IRPs, at least in the near term, for several reasons.

    b. First, the cost of constructing a transmission facility is only part of the total transmission cost. The Companies would then need to secure and pay annually for firm transmission to any needed resource in a neighboring system.

    c. Second and perhaps most importantly, there must be one or more resources available to serve the Companies on the other side of the hypothetical transmission project(s). With regard to existing resources in neighboring systems, that is far from certain. For example, NERC's 2024 Long-Term Reliability Assessment indicates MISO is at "high risk" beginning in 2025, meaning "shortfalls may occur at normal peak conditions," and PJM is at "elevates risk" beginning in 2026, meaning "shortfalls may occur in extreme conditions."[22] Thus, for any reliable, long-term supply to be available in neighboring regions would likely require building new resources. With the possible exception of certain renewable resources (particularly wind), there is no reason to expect the costs of new resources to be lower in other geographies than they would be if the Companies constructed them. Thus, adding transmission costs to the costs of such hypothetical new facilities in neighboring systems would tend to make their total cost *less* economical than if the Companies constructed the same resources locally.

    d. Regional and interregional planning continues to evolve around FERC Order 1920. As part of this order, the Companies are required "to measure and use at least the seven specified benefits to evaluate Long-Term Regional Transmission Facilities," among them "either reduced loss of load probability or reduced planning reserve margin" and "production cost savings." The Companies continue to participate and comply with this order, and they are open to regional and interregional projects that provide benefits to themselves and other transmission customers. Notably, though, the SERTP study process has not yet identified a regional or interregional transmission project that impacts the Companies' transmission system that is more cost-effective than any local transmission project that would serve the same purpose.

[22] 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.

4. Page 21: "The Companies perform their modeling in PLEXOS on an installed capacity ("ICAP") basis for meeting the minimum capacity reserve requirement, but do reflect an unforced capacity ("UCAP") basis for modeling dispatch ratings for NGCC and SCCT resources, while all other resources were modeled on an ICAP basis."

    a. This is incorrect. In their response to PSC 2-14, the Companies clarified their response to SC 1-5 to explain that they do not use UCAP for dispatch ratings.

5. Page 21: "An ICAP approach means that thermal outage risk is socialized to load because thermal outage risk is accounted for by increasing the planning reserve margin, which leads to a less optimal selection of resources in the capacity expansion modeling."

    a. The Companies appreciate EFG for recognizing that the use of capacity contributions adjusted for EFOR would require a similar adjustment to reserve requirements, but the Companies disagree with their assertion that an ICAP approach "leads to a less optimal selection of resources in the capacity expansion modeling." It is unclear whether a UCAP approach would be more or less "optimal." Capacity contributions and reserve requirements are simplifying assumptions that make a resource planning optimization problem tractable. These inputs with either approach are subject to change over time as the generation portfolio changes. Therefore, the Companies agree that the reliability of a portfolio should be assessed with proposed resource changes to confirm it is adequate. This is the approach the Companies used in their recent CPCN filing and in their 2022 CPCN filing.

6. Page 28: "Our recommendation is to move the Companies to an approach that directly evaluates additional DSM programs, as this is in fact supported by Kentucky's IRP rules, by the Staff's encouragement to 'LG&E/KU to continue exploring cost-effective DSM-EE as a method to avoid costly capital investments should energy margins diminish over time,' and by the existence of a DSM Advisory Group. Moreover, considering additional DSM in IRPs is typical practice amongst peer utilities; this is on top of the importance of these programs to resiliency, customer affordability, and reliability."

    a. To be clear, the Companies consider possible new DSM-EE programs on an ongoing basis, and they meet with their DSM-EE Advisory Group at least annually.

    b. No party to this proceeding has demonstrated the Companies have overlooked any DSM-EE programs that would be cost-effective *for the Companies' customers, rates, and service territories*. These assertions and recommendations about the supposed benefits of lengthier—and costlier—DSM-EE analyses thus lack substantive support.

    c. That aside, if the Commission Staff recommends the Companies perform additional DSM-EE analyses, the Companies will endeavor to do so and will seek to recover any additional cost.

7. Page 29: “PROSYM is no longer supported by its vendor ….”

    a. This is incorrect. Although PROSYM is no longer being developed, the vendor continues to provide support for the version the Companies use.

8. Page 30, Section 9.2.1, “FUTURE OPERATIONS AT GHENT 2”

    a. See the responses to 1a and b above.

9. Pages 30-31, Section 9.2.2, “COAL RETIREMENT AND REPLACEMENT”

    a. EFG ignores KRS 267.264 by removing the retirement constraint that fossil fuel units must be replaced with dispatchable generation.

10. Pages 32-33, Section 9.3, “ALTERNATIVE RESOURCE PLAN”

    a. Despite the recommendation from the 2021 IRP Staff Report stating that the Companies should allow PLEXOS to determine the economic retirement of existing units (as opposed to fixing retirement dates in the model), EFG forced the conversion of Ghent 2 to natural gas in 2030 and fixed the retirements of Brown 3 in 2031 and Mill Creek 3-4 in 2035 in their analysis.

11. Pages 35-36, Section 9.4.2, “PRESENT VALUE OF REVENUE REQUIREMENT (“PVRR”) OF ALTERNATIVE RESOURCE PLANS”

    a. EFG’s PVRR calculations are either misleading or incorrect and should be ignored.

    b. EFG’s 2024-2039 PVRR omits a terminal value, which is needed to properly evaluate investments with different book lives.

    c. EFG’s 2024-2050 PVRR omits a terminal value and ignores production costs for 2040-2050, which are a significant contributor to PVRR.

    d. EFG’s 2024-2050+Terminal Value PVRR is also nonsensical because 2040-2050 production costs are omitted, and the terminal value does not contemplate production costs.

    e. The Excel workbooks in EFG’s workpapers labeled “financial model” are not updated versions of the Companies’ financial model. Instead, it appears the EFG copied and pasted selected worksheets (with values only and no formulas) from the Companies’ financial model and at least some values (e.g., Ghent 1 terminal value) were copied incorrectly. In addition, as noted above, these workbooks contain additional worksheets created by EFG that also do not contain formulas.

<u>Responses to Comments of the Southern Renewable Energy Association</u>

1. *General observation: Brattle Group's comments reflect a fundamental misunderstanding of the Companies' modeling to assess resource adequacy and develop resource plans. They confuse capacity accreditation in an RTO context with capacity contribution, and they incorrectly assume generation performance in other jurisdictions is relevant to the Companies' planning process.*

2. Brattle Group comments at 2: "Recommendation #7: Integrate improved, proactive local and regional transmission planning to (1) improve access to low-cost capacity and energy purchases that reduce expensive overbuilding of resources within the service territories; (2) improve reliability by leveraging geographic diversity benefits through greater access to neighboring regions, and (3) to perform holistic planning across generation and transmission to develop cost-effective fully integrated generation and transmission plans."

    a. See the response to Sierra Club 3a-d above.

3. Brattle Group comments at 7 (footnotes omitted): "The Companies calculate the reserve margins using the counterfactual resource portfolio that would exist if there were no additional changes to their generating resources beyond those in the approved 2022 CPCN. In evaluating this portfolio, the Companies assign seasonal capacity contributions only to renewable resources. Fully dispatchable and limited-duration resources are assigned flat capacity contributions throughout the year."

    a. Capacity contribution is not a consideration for any resource in this analysis (i.e., capacity contribution is not a SERVM input). Capacity contribution is a consideration only for developing resource plans in PLEXOS.

4. Brattle Group comments at 7-8 (footnotes omitted): "Despite historical evidence indicating that fully dispatchable units are also subject to availability constraints, and recent evidence identifying heightened weather-correlated outage risks of natural gas and coal facilities even in organized markets, including in PJM which administers regional markets in parts of Kentucky, the Companies assumed that thermal resources would be fully available at seasonally rated capacities across all projected seasonal peak conditions. While the Companies appear to acknowledge that their fully dispatchable resources do experience unplanned outages—by modeling the units' equivalent forced outage rate ("EFOR") in their reserve margin estimation analysis—they ignore these average EFORs, and instead assume 100% capacity contribution from such facilities in their capacity expansion analysis to project their future resource needs."

    a. This is incorrect. Seasonal reserve requirements are developed on a net capacity basis and account for resources' unit outage risk (i.e., seasonal reserve requirements are higher than they otherwise would be because they account for unit outage risk). Therefore, using capacity contributions less than 100% for thermal resources would be inconsistent with the development of the Companies' reserve requirements and result in over-building generation.

b. Importantly, the concept of capacity accreditation in an RTO context is ***not*** the same as the concept of capacity contribution.[23]

5. Brattle Group comments at 8-9: Despite evidence the Companies have provided to the contrary, Brattle Group asserts the Companies have failed to account for weather-correlated outage risk in their IRP analysis.

    a. This assertion incorrectly assumes the performance of thermal resources in PJM is relevant to the Companies' thermal resources and ignores the performance of the Companies' resources before and after Winter Storm Elliott.

    b. The Companies' GADS data from 2009 to 2024 shows that there is almost no correlation between forced outages and temperature for the Companies' service territory.

    c. The load shedding event during WSE was caused primarily by low gas pressure on the Texas Gas Transmission interstate pipeline. The Companies and Texas Gas implemented changes after WSE and generation performance during Winter Storms Heather and Enzo was excellent and consistent, for example, with generation performance during the 2014 polar vortex.

6. Brattle Group comments at 10: "When the Companies do account for all available resources by modeling the system with the 758 MW of solar, the required winter reserve margin decreases from 29% to 23%, indicating that these solar facilities would contribute some capacity during winter needs."

    a. This is incorrect. The capacity contribution for solar during the winter peak is zero because the Companies' winter peak demand most commonly occurs at night. The Companies included the referenced analysis to demonstrate why they excluded solar in their analysis to determine reserve margin constraints for PLEXOS. With a focus on annual costs and annual reliability, including solar in this analysis shifts reliability risk from the summer to the winter where the consequences of service curtailments are the greatest. Depending on its cost, solar is a valuable resource for hedging natural gas price volatility and future CO_2 regulation risk, but the Companies would not propose to add solar for the purpose of accepting higher reliability risk in the winter. Therefore, the Companies excluded solar when determining reserve margin constraints for resource planning.

7. Brattle Group comments at 10: "[T]he Companies fail to consider the full value of imports during extreme weather events in calculating their reserve margin requirements, as well as their capacity expansion analysis."

[23] *See, e.g.,* Companies' Response to PSC 2-3.

   a. This is incorrect. The Companies' modeling of inputs is based on their actual experience. Available Transmission Capacity inputs are based on ATC data from 2022 to 2024.

8. Brattle Group comments at 10 (footnotes omitted): "The Companies state that they are uncertain in their ability to rely on neighboring regions to serve load. They note that '[a]pproximately 20 GW of capacity was retired over the past five years in PJM and an additional 3 GW of retirements have been announced for the next five years.' However, this assumption does not account for the vast resources that have come online in parallel with these retirements …."

   a. This is not correct. The Companies' SERVM model properly accounts for retirements and additions of generating resources in neighboring regions (PJM, MISO, and TVA) and assumes neighboring regions' loss of load expectation will be one day in 10 years.

9. Brattle Group comments at 11: "While solar resources typically contribute much less during winter peak hours than summer peak hours, it is still common in other jurisdictions to assign solar a non-zero capacity contribution."

   a. Assigning solar a non-zero capacity contribution would not be a reasonable planning assumption for the Companies' service territories. Capacity contributions should be based on data from the Companies' service territories. The capacity contribution for solar during the winter peak is zero because the Companies' winter peak demand most commonly occurs at night or during early morning hours prior to sunrise. Furthermore, a zero capacity contribution is consistent with the Companies' experience during Winter Storms Elliot, Heather and Enzo.

10. Brattle Group comments at 13: "To have informed price discovery on realistic solar costs the Companies should issue Requests for Proposals ("RFPs") for market bids for solar, wind, and storage Power Purchase Agreements ("PPAs") and Purchase Sale Agreements ("PSAs") that can inform the market costs for such facilities."

    a. As stated in the Companies' Responsive Comments, it is unreasonable to expect that issuing RFPs for an IRP analysis will result in any useful data due to bidders' anticipation that such an RFP is not for any actual need and due to IRP's 15-year planning horizon. It is therefore reasonable to use commercial information in the Companies' possession and data from the U.S. Department of Energy's National Renewable Energy Laboratory in modeling resources to obtain directional insight from the IRP.

    b. Relatedly, Brattle Group's Figure 3 at page 14 is misleading. All cost data in the NREL ATB is provided in real dollars and must be converted to nominal dollars using an estimate of inflation. It is unclear what inflation assumptions Brattle Group used, but their assumptions do not properly account for recent increases in the cost of solar.

11. Brattle Group comments at 17: "The Companies' modeling assumptions favor NGCC units, overlooking the potential reliability and cost advantages of a diversified portfolio that includes renewables and battery storage. Their approach fails to consider the complementary relationship between solar and storage, in which co-located systems can provide more flexible and cost-effective grid support."

    a. This is incorrect. If battery storage has the option of charging from the grid, the location of solar and battery storage has an immaterial impact on hourly production costs. Almost all resource plans developed with high fuel prices include both solar and battery storage for the reasons Brattle Group cites as benefits of co-locating solar and battery storage systems.

12. Brattle Group comments at 19: "The Companies … appear to misunderstand the concept of capacity accreditation (or capacity contribution) within the context of resource adequacy analysis and solutions to mitigate [resource adequacy] risks through robust and sound planning techniques."

    a. This statement confirms the Brattle Group is confusing capacity contribution, a resource planning input in PLEXOS, with UCAP, a concept applicable to an RTO's capacity accreditation process. They are not the same. An RTO uses capacity accreditation to determine the portion of a *UCAP* capacity need for which a particular resource can be credited for meeting. Capacity contribution indicates the portion of the Companies' reserve requirement for which a particular resource can be credited for meeting. As noted repeatedly, the Companies' reserve requirements are appropriately specified on a net capacity basis, not UCAP. The Companies' reserve requirements are developed to account for weather risk and unit availability risk. Thus, they fully account for thermal resources' EFOR, and modeling a capacity contribution less than 100% for thermal resources would cause the Companies to overbuild generation.

    b. Notably, as discussed above in the Sierra Club section, although the Companies do not agree with the recommendations of Energy Futures Group ("EFG") related to reserve requirements and capacity contribution, EFG, unlike Brattle Group, demonstrates an understanding of the differences between capacity *accreditation* (which is an RTO concept) and capacity *contribution*.

13. Brattle Group comments at 20: "The Companies fail to consider market purchases for low-cost energy throughout the entire study window."

    a. The Companies' modeling assumption is intentional. Market purchases account for a very small portion of the Companies' electricity supply, and resource planning ignores market sales and purchases to avoid speculation regarding market electricity prices and ensure the Companies' generation portfolio is optimized for native load customers. The Companies' reserve requirements, which are a resource planning input, account for the Companies' access to market power.

b. Brattle Group overlooks the policy directives of the Kentucky General Assembly and the Commission that Kentucky should be resource sufficient, not reliant on neighboring systems or markets for long-term energy resources.[24]

14. Brattle Group comments at 26: "Recommendation #5: Consider realistic cost savings and resiliency benefits that could be provided by capacity imports from neighboring regions and proactively plan transmission enhancements to increase ATC to leverage greater imports from neighboring regions."

    a. See response 3a to the Sierra Club above.

[24] *See* KRS 164.2807(1)(f) and (j); *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generation Unit Retirements,* Case No. 2022-00402, Order at 177 (Ky. PSC Nov. 6, 2023), quoting *Electronic Tariff Filing of East Kentucky Power Cooperative, Inc. and Its Member Distribution Cooperatives for Approval of Proposed Changes to Their Qualified Cogeneration and Small Power Production Facilities Tariffs*, Case No. 2021-00198, Order at 5 n. 10 (Ky. PSC Oct. 26, 2021).