COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC 2021 JOINT INTEGRATED	**)**	
RESOURCE PLAN OF LOUISVILLE GAS	**)**	**CASE NO. 2021-00393**
AND ELECTRIC COMPANY AND	**)**	
KENTUCKY UTILITIES COMPANY	**)**	

RESPONSIVE COMMENTS OF
LOUISVILLE GAS AND ELECTRIC COMPANY
AND KENTUCKY UTILITIES COMPANY

Filed: May 20, 2022

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I. INTRODUCTION

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, the "Companies") respectfully submit these comments in response to the comments filed by the Attorney General of the Commonwealth of Kentucky, through his Office of Rate Intervention ("AG"); Sierra Club ("Sierra"); Southern Renewable Energy Association, ("SREA"); Louisville/Jefferson County Metro Government ("Lou Metro"); and Metropolitan Housing Coalition, Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association (collectively, "Joint Intervenors") regarding the Companies' 2021 Joint Integrated Resource Plan ("2021 IRP") filed with this Commission on October 19, 2021.

At the outset, the Companies believe it is helpful to recognize what an IRP is and what it is not, and to remain focused on the prescribed purpose and scope of an IRP proceeding. As the Commission Staff recently stated in its report on Duke Energy Kentucky's IRP, "[T]he IRP is simply a triennial snapshot in time …."[1] The text and history of the Commission's IRP regulation show that Commission Staff is exactly right: far from being a binding resource plan that a utility must execute, an IRP is a triennial planning exercise that results not in a Commission order or other determination of any kind, but rather a Commission Staff report with guidance to be considered in the next triennial IRP planning exercise.[2] For that very reason the text and history of the IRP regulation are clear that an IRP proceeding is intended to be informal, constructive, and non-adversarial. Relatedly and as the Companies discuss at length herein, the IRP does not require a pre-filing stakeholder process precisely because each IRP proceeding *is* a stakeholder process, and the collection of IRP proceedings are an ongoing stakeholder process that extends across

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[1] *Electronic 2021 Integrated Resource Plan of Duke Energy Kentucky, Inc.*, Case No. 2021-00245, Order Appx. at 32 (Ky. PSC May 10, 2022).

[2] *See, e.g.*, 807 KAR 5:058 Sec. 11(3).

decades. Keeping that perspective is vital to making these informal, non-binding proceedings as constructive and productive as possible and to carry out the letter and objective of the IRP regulation.

In that spirit, the Companies would note that their current IRP is consistent with their best past practices and Commission Staff guidance from past IRPs *and is nonetheless entirely transformative*. Far from overlooking or ignoring possible regulations on carbon emissions, the Companies accounted for what appears to be the most likely CO_2 regulatory path by assuming that new natural gas combined cycle ("NGCC") units would require carbon capture and sequestration systems rather than assume a CO_2 emissions pricing regime. Coupling that assumption with favorable assumptions about battery storage and solar resource pricing, the Companies' IRP retires almost 2,000 MW of coal-fired generation and adds 2,100 MW of solar generation.[3] Beginning in 2034, the IRP's generation portfolio would serve customers' energy requirements with 18% utility-scale solar energy—more than six times the percentage of solar energy serving America today—and would reduce the Companies' CO_2 emissions 26% from 2021 levels.[4] The Companies understand that others might desire to see 100% renewable resources in the IRP, but the Companies' IRP is nonetheless both transformative relative to the Companies' and America's current generation portfolios *and* is consistent with the IRP's regulation's directive to pursue "an adequate and reliable supply of electricity at the lowest possible cost for all customers" based on reasonable assumptions about the future.[5]

Regarding possible RTO membership, as the Companies discuss at length herein, it is important to understand that such membership is not a panacea. The Companies are not oblivious

[3] IRP Vol. I at 8-28. Note that the 2,100 MW of new solar capacity does not include the Companies' existing 10 MW Brown Solar Facility, the Companies' Solar Share Facility, the Rhudes Creek solar PPA, or the Ragland solar PPA.
[4] IRP Vol. I at 8-30.
[5] 807 KAR 5:058 Necessity, Function, and Conformity.

concerning RTOs; they already transact routinely in RTO markets, almost exclusively as sellers into those markets because the Companies nearly always have lower energy costs than RTOs' market prices. With respect to capacity and the notion that the Companies might be able to reduce their capacity needs as RTO members, recent reports from RTOs such as MISO indicate those markets are short on capacity and are publicly stating they might have to resort to localized load shedding as early as this summer to preserve overall grid stability.[6] This is not entirely surprising considering that RTOs, unlike the Companies, do *not* have a load serving obligation, but rather seek only to incentivize needed investment purely financially. That is not to say that RTO membership could never be beneficial to the Companies' customers, but it does suggest that an entity with load-serving obligations should approach such membership with caution and only when the benefits—including reliability benefits—are clear and durable.

The Companies address these and other issues in their comments below, but because the comments in this proceeding are unusually voluminous, the Companies have not attempted herein to respond to all of the intervenors' comments; rather, the Companies are responding only to issues they believe are important to address before the hearing in this proceeding, particularly if Commission Staff desires to issue its report on the Companies' IRP before the hearing. Therefore, these comments are not intended to be exhaustive, and no party or the Commission should assume that the Companies agree with any criticism or recommendation the Companies do not address in these comments. The Commission's procedural schedule includes a final set of responsive comments from the Companies, in which the Companies will address any issues that require comment at that time.

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[6] MISO 2022/2023 Planning Resource Auction (PRA) Results, April 14, 2022, at slide 9, available at https://cdn.misoenergy.org/2022%20PRA%20Results624053.pdf.

II. THE HISTORY AND PLAIN TEXT OF THE IRP REGULATION DEMONSTRATE THAT IRP PROCEEDINGS ARE LIMITED IN SCOPE AND DESIGNED TO BE INFORMAL, NON-ADVERSARIAL PROCEEDINGS LACKING FORMAL EVIDENTIARY HEARINGS, COMMISSION FINDINGS, AND BINDING RESOURCE PLANS

Before addressing the substantive observations, criticisms, and recommendations made in the intervenors' comments, it is important to revisit the text of the IRP regulation and its history to establish the correct context for and scope of this proceeding. It is necessary to do this because the intervenors' comments raise a host of issues and recommendations, some of which are pertinent to an IRP proceeding but many of which are not or are in direct conflict with the IRP regulation. Understanding which is which requires understanding the Commission's IRP regulation and its history. And it appears from the tone and content of several intervenors' comments that they appear to believe this proceeding will establish a binding resource plan for the Companies, which it emphatically cannot precisely because that is not what the IRP regulation or its history have established as the proper purpose of this proceeding.

A. The History of the IRP Regulation Shows that an IRP proceeding Is an Informal Process that Does Not Result in a Binding Resource Plan.

Over 35 years ago, legislation was introduced in the Kentucky Senate during the 1986 general session to prescribe integrated resource planning for Kentucky (SB 226). The bill would have created a new section of KRS Chapter 278 authorizing the Commission to investigate and implement statewide electric planning and coordination options. It would also have required the Commission to conduct an investigation at least every four years and to submit a report to the governor every four years, concerning load forecasts and forecasting methods, generation and transmission planning, and conservation programs to ensure the most efficient and economic provision of electric service to ratepayers. The bill further specified certain IRP investigation topics, and it allowed participation and comment by utilities and intervenors. Most notably, SB

226 would have required the results of the investigation to be considered by the Commission in any application for construction or rate case before it.

The bill did not become law.

After SB 226 failed to become law, the Commission initiated Administrative Case No. 308 to examine resource planning options then available to serve Kentucky customers and "to develop a regulation that provides for the regular review of resource planning issues."[7] The regulation that resulted from that proceeding is in large part the IRP regulation that remains in force today.

1. The order initiating Administrative Case No. 308 focused on resource planning for the purpose of maintaining low-cost, reliable service.

In the Order that initiated Admin. Case No. 308, the Commission demonstrated a primary concern for the cost of electric service:

> Although electric rates in Kentucky are relatively low when compared with other regions, two important questions remain. First, are rates as low as they can be? Secondly, are the electric utilities making appropriate plans to keep rates as low as possible?[8]

The Commission noted also the importance of reliable electric supply, stating, "[I]t is vital for the utilities, the Commission, and other interested parties to work together to … determine which options will continue to provide the ratepayers of Kentucky with a reliable, low-cost supply of electricity."[9] The Commission further observed that seeking to engage in a process to help ensure ongoing low-cost, reliable electric supply would benefit everyone involved: "Ratepayers—from the retired person on a fixed income to the largest industrial customer—benefit from reasonable rates."[10]

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[7] *An Inquiry into Kentucky's Present and Future Electric Needs and the Alternatives for Meeting those Needs*, Admin. Case No. 308, Order at 2 (Ky. PSC Oct. 9, 1986).
[8] *Id.* at 2-3.
[9] *Id.* at 3.
[10] *Id.*

The Commission concluded its initiating Order by stating its "belie[f] that for this investigation to be most productive it should be carried out in as constructive and cooperative a spirit as possible."[11] As shown below, the Commission's desire to foster a "constructive and cooperative … spirit" is evident throughout the Commission's later orders in Admin. Case 308 and the final IRP regulation.

2. The Commission's draft IRP regulation contemplated formal evidentiary hearings, Commission findings, and binding resource plans.

Following two and half years of discussions with utilities and interested parties, the Commission issued its draft IRP regulation. At the outset, the Commission noted that it had initiated the proceeding to "assur[e] ratepayers that all reasonable alternatives for the provision of a reliable, low-cost supply of electricity are being carefully considered."[12] In that order and the draft IRP regulation, the Commission contemplated a multi-phase formal process that would lead to approval or disapproval of utilities' resource plans, which plans would effectively become binding upon utilities:

> It is the Commission's intent to develop a detailed and formal reporting, review, and approval process regarding the development of electric utility forecasts and resource plans as well as the implementation of the plans.[13]
>
> …
>
> Additionally, the Commission will develop formal procedures for a detailed evaluation leading to approval or disapproval of each electric utility's load forecasts and resource plans. These procedures may involve evidentiary hearings and Commission Orders.[14]
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> …

[11] *Id.* at 4.
[12] Admin. Case No. 308, Order at 1 (Ky. PSC Apr. 28, 1989).
[13] *Id.* at 2.
[14] *Id.* at 4.

> The third phase establishes formal relationships between a utility's approved resource plan and applications for a certificate of public convenience and necessity and for rate changes. This final phase may be characterized by a requirement for a complete description of criteria and justification of the chosen resource plan; sensitivity analyses of the chosen resource plan; formalized criteria for Commission approval of the plan; and the requirement that any application of a certificate of public convenience and necessity or a rate change be consistent with a utility's most recently approved plan.[15]

In short, at the time the Commission issued its *draft* IRP regulation, it clearly intended for the IRP process to be formal, driven by evidentiary hearings, and resulting in binding utility resource plans.

3. The Commission's order issuing its final IRP regulation explicitly rejected formal evidentiary hearings, Commission findings, and binding resource plans in favor of informal, non-adversarial processes and non-binding resource plans.

When the Commission issued its order promulgating its final IRP regulation, it *entirely changed* its approach to IRP proceedings and their outcomes. After again noting at the outset that the purpose of the proceeding was to "assur[e] the ratepayers of Kentucky that all alternatives for a reliable, low-cost supply of electricity were being considered,"[16] the Commission went on to discuss how its final IRP regulation removed essentially all formality and finality from the IRP process:

> 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. … 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

[15] *Id.* at 5.
[16] Admin. Case No. 308, Order at 1 (Aug. 8, 1990).

> or disapproval of utility plans. … However, without an approval process, there is little need for evaluation criteria. Utilities' plans will be judged on the basis of their adequacy in meeting the filing requirements of the regulation.
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> … 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. Further, the Staff report will contain recommendations and suggestions on the utility's filing to be addressed in its next filing.
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> 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.[17]

Thus, far from IRP proceedings resulting in formal Commission findings or approvals or disapprovals of resource plans that would then become binding in later CPCN or rate proceedings, the Commission's order issuing the final version of the IRP regulation goes to lengths to point out that IRP proceedings are to be informal and non-binding. As the Commission noted, it pursued this approach in part to enable "parties … [to] exchange information and ideas in a less adversarial manner."[18]

4. The 1995 amendments to the IRP regulation affirmed the informality of IRP proceedings.

In 1995, the Commission conducted a rulemaking under KRS Chapter 13A to amend the IRP regulation.[19] In its amended regulation, the Commission moved from a biennial IRP in which all utilities filed their IRPs essentially simultaneously to a triennial, staggered IRP schedule. It further eliminated the statewide report that Commission Staff had previously been required to file after reviewing all utilities' IRPs. Although the Commission was clear that it did not intend to

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[17] *Id.* at 13-14.
[18] *Id.* at 13.
[19] *See, e.g.,* Statement of Consideration Relating to 807 KAR 5:058 (Ky. PSC Apr. 6, 1995).

diminish the importance of the IRP process by its amendments, neither did it attempt to increase the formality of the process or introduce binding resource plans or substantive Commission findings or orders into IRP proceedings. In short, when the Commission sought to amend the IRP regulation, it sought to make the process less frequent and burdensome on all parties involved, not more so.

5. The statutory authority for the IRP regulation could not support Commission findings or binding resource plans.

Notably, the Commission's explicitly chosen and long-established IRP regulation and approach are fully consistent with the statutory authority upon which it depends; indeed, that statutory authority could not support another purpose for or outcome of an IRP proceeding. The IRP regulation cites only two statutes for its support: KRS 278.040(3) and 278.230(3). The regulation cites KRS 278.040(3) solely to support the Commission's authority to issue regulations: "KRS 278.040(3) provides that the commission may adopt reasonable administrative regulations to implement the provisions of KRS Chapter 278."[20] The only other statutory support, KRS 278.230(3), states in relevant part, "Every utility, when required by the commission, shall file with it any reports, schedules, classifications or other information that the commission reasonably requires." This is so because KRS Chapter 278 contains no statutory authority for such proceedings to result in substantive Commission findings or orders; rather, in accordance with statute, IRP proceedings exist only to review and receive comment upon information the Commission requires utilities to provide.

In sum, the IRP process that the Commission enacted in its IRP regulation and has served the Commonwealth well for more than 30 years is an informal process that by design and consistent with statutory requirements does not result in a Commission determination or the approval of

[20] 807 KAR 5:058 Necessity, Function, and Conformity.

resource plans. Instead, it exists to assure utility customers that planning methods of their utilities ensure ongoing safe and reliable service at the lowest reasonable cost.[21] And as the Commission has repeatedly stated, it is a process that should, at least ideally, be more constructive and less adversarial than some other proceedings can be.[22]

6. The current IRP regulation continues to focus on low-cost, reliable service, informal proceedings, and non-binding resource plans.

The Commission's continual concern that IRPs be focused on low-cost and reliable service, as well as its shift to informal IRP proceedings, remain clear in the IRP regulation in force today. Concerning the former point, the regulation's Necessity, Function, and Conformity clause states that it provides for "regular reporting and commission review of load forecasts and resource plans …to meet future demand with an adequate and reliable supply of electricity at the lowest possible cost for all customers …."[23] Regarding the informality of IRP proceedings, the entirety of the "Procedures for Review of the Integrated Resource Plan" section of the regulation states:

> (1) Upon receipt of a utility's integrated resource plan, the commission shall develop a procedural schedule which allows for submission of written interrogatories to the utility by staff and intervenors, written comments by staff and intervenors, and responses to interrogatories and comments by the utility.
>
> (2) The commission may convene conferences to discuss the filed plan and all other matters relative to review of the plan.
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> (3) Based upon its review of a utility's plan and all related information, the commission staff shall issue a report summarizing its review and offering suggestions and recommendations to the utility for subsequent filings.

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[21] Admin Case No. 308, Order at 1 (Ky. PSC Aug. 8, 1990). *See* also 807 KAR 5:058 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 customers within their service areas, and satisfy all related state and federal laws and regulations.").

[22] *See* Admin Case No. 308, Order at 13 (Ky. PSC Aug. 8, 1990); Admin Case No. 308, Order at 4 (Ky. PSC Oct. 9, 1986).

[23] 807 KAR 5:058 Necessity, Function, and Conformity.

> (4) A utility shall respond to the staff's comments and recommendations in its next integrated resource plan filing.[24]

Consistent with the Commission's final order in Admin. Case 308, all that the IRP regulation permits is review of and comment upon a utility's IRP, followed by a Commission Staff report "offering suggestions and recommendations to the utility for subsequent filings."

B. Use of the Informal and Non-Adversarial IRP Proceedings Limited to the Subject Matter Set Out in the IRP Regulation Will Benefit All Parties.

Reviewing the history and text of the IRP regulation, as well as the regulation's underlying statutory authority, is important for several reasons. First, with regard to the Commission's intention that IRP proceedings be as informal, constructive, and non-adversarial as reasonably possible, the Companies agree entirely with that approach and will make their best efforts to make this proceeding constructive and cooperative. The Companies have a genuine desire to improve their processes and strive to do so continually, not only during IRP filings and proceedings. To the extent intervenors have constructive comments to offer that advance accomplishing the objectives set out in the Commission's IRP regulation, the Companies welcome them.

But with regard to comments that are primarily policy advocacy or concern matters not germane to an IRP proceeding (or are even outside the Commission's jurisdiction), the Companies believe such comments are appropriate for the General Assembly or other legislative or regulatory authorities, but not for an IRP proceeding. Indeed, the Commission remarked in its order issuing the final IRP regulation in 1990, "Utilities' plans will be judged on the basis of their adequacy in meeting the filing requirements of the regulation,"[25] making comments not pertinent to the issues addressed in the IRP regulation extraneous at best. For example, comments that address how the Companies should account for possible environmental regulations that would affect their costs and

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[24] 807 KAR 5:058 Sec. 11.
[25] Admin. Case No. 308, Order at 13 (Aug. 8, 1990).

operations are entirely germane to this proceeding, but comments suggesting the IRP should account for costs that are externalities, such as environmental impacts generally,[26] are not constructive or germane precisely because they are beyond this Commission's jurisdiction and therefore the scope of this proceeding. Rather, as the Commission observed in its order initiating Admin. Case 308, an IRP should focus on ensuring ongoing low-cost, reliable service, which is good for all customers: "Ratepayers--from the retired person on a fixed income to the largest industrial customer--benefit from reasonable rates."[27]

C. The History and Plain Text of the IRP Regulation Show Definitively that No Substantive Commission Order Will Result from this Proceeding.

Certain intervenors' comments ask the Commission to take substantive action in this proceeding. As shown above, such Commission action would be inconsistent with the Commission's stated determination for IRP proceedings and the plain text of the IRP regulation, and beyond the Commission's authority in KRS Chapter 278. For example, the Sierra Club asks the Commission to "weigh in or at least give direction at this juncture" regarding the Companies' power purchase agreement with the Ohio Valley Electric Corporation, Inc. ("OVEC"),[28] but it is beyond the scope of this proceeding for the Commission to do so. Similarly, SREA argues that the Commission should "remind the Companies" that they should not expect to recover "unjust or unreasonable" costs,[29] yet it is not within the scope of this proceeding to address the justness, reasonableness, or recovery of *any* costs. As the Commission stated in its order promulgating the

[26] *See, e.g.,* Louisville Metro Comments at 10 ("While the PSC has not historically included the external costs of burning fossil fuels, these costs are real and will continue to rise without immediate action. … We implore the PSC and LG&E/KU to consider these costs when evaluating the future of energy in Kentucky."); Sierra Club Comments at 13 ("Coal and gas harm local public health, foul local air and waterways, and exacerbate climate change."); Joint Intervenors Comments at 3 ("Furthermore, fundamentally linked to the utilities' business model, there is now an overarching societal need to rapidly transition our economy to net-zero carbon emissions. The global energy transition is undeniably underway, and its urgency has grown with each passing year.").
[27] Admin. Case No. 308, Order at 3 (Ky. PSC Oct. 9, 1986).
[28] Sierra Club Comments at 3.
[29] SREA Comments Attachment A at 4.

final IRP regulation, no Commission findings, or binding resource plans are to be part of IRP proceedings, much less Commission statements regarding cost recovery.[30]

Relatedly, perhaps because other jurisdictions have IRP-like proceedings that result in resource plans that formally and necessarily affect utilities' subsequent resource decisions, certain commenters appear to argue that the economically optimal portfolio the Companies included in their IRP for the base-load, base-fuel scenario is the resource plan the Companies intend to pursue, and it therefore requires significantly more rigorous analysis.[31] But any such view is mistaken. As the Commission Staff remarked in its recent report in Duke Energy Kentucky's current IRP proceeding, "[T]he IRP is simply a triennial snapshot in time and … changes in technology costs, supply disruptions and especially changing environmental requirements create risks … can greatly alter long-range plans."[32] As demonstrated time and again over the years, the Companies perform more rigorous analyses, including using actual market data obtained through requests for proposals, longer-term forecasts, and more sensitivity analyses, to support their CPCN applications.[33] Any such proceeding involves extensive discovery, testimony, evidentiary hearings, and briefing before the Commission issues its final order, making determinations and approving or denying the requested CPCN. In contrast, the Commission enacted the IRP regulation and instituted IRP proceedings to assure ratepayers that electric utilities' planning methods for low-cost, reliable resources was occurring, not to result in substantive orders or

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[30] Admin. Case No. 308, Order at 13-14 (Ky. PSC Aug. 8, 1990).
[31] *See, e.g.,* SREA Comments at 4-5; Joint Intervenors Comments at 3 ("Integrated Resource Planning is at the core of that compact. Utility resource decisions are a direct and substantial driver of the services available, and the costs paid").
[32] Case No. 2021-00245, Order Appx. at 32 (Ky. PSC May 10, 2022).
[33] *See, e.g., Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity and Site Compatibility Certificate for the Construction of a Combined Cycle Combustion Turbine at the Cane Run Generating Station and the Purchase of Existing Simple Cycle Combustion Turbine Facilities from Bluegrass Generation Company, LLC in LaGrange, Kentucky*, Case No. 2011-00375, Application (Sept. 15, 2011).

binding resource plans. Indeed, precisely because IRP proceedings occur on a triennial basis, regardless of whether a utility has any need or intention of making resource changes, it must file an IRP to present its current planning methods and practices; and because IRP proceedings do not result in substantive Commission orders, binding resource decisions, investment commitments, or ratemaking, it is appropriate that the analysis and effort that goes into an IRP should be proportional to its import and effect.

D. The Commission's IRP Regulation Does Not Require a Pre-Filing IRP Stakeholder Process Because the IRP Proceeding Is a Stakeholder Process.

Fourth and relatedly, the Companies disagree with the commenters who assert a pre-filing IRP stakeholder process is necessary.[34] Neither the history of the IRP regulation nor the IRP regulation itself contemplate such a pre-filing stakeholder process. That is by design, not oversight: as the history of the IRP regulation and the text of the IRP regulation show, the stakeholder process in an IRP proceeding *is the IRP proceeding itself*. Indeed, each utility's IRP proceedings collectively are, in essence, an ongoing, iterative stakeholder process extended across decades; each IRP proceeding involves a utility presenting an analysis illustrating its planning methods for review and comment, receiving comment, and then receiving comments from Commission Staff for how to adjust the analysis the utility will present at the next stakeholder meeting that begins with the next IRP filing. That stakeholder process has been productive over time, resulting in improvements from one IRP to the next. Commission Staff reports on the Companies' previous IRPs that have been generally complimentary and constructive.[35]

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[34] *See, e.g.,* SREA Comments Attachment A at 4; Joint Intervenors Comments Exh. 1 at 7.

[35] *See, e.g., Electronic 2018 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2018-00348, Order Appendix, Commission Staff Report at 46 (Ky. PSC July 20, 2020) ("Staff commends the Companies' effort in developing its Joint 2018 IRP. … Staff is generally satisfied with the Companies' analysis of the many uncertainties and risks LG&E/KU will be facing over the planning period. The improvements in its load forecasting analysis, reserve margin analysis, and its supply-side screening and optimization plan have produced an optimal plan that is cost-effective."); *2014 Joint Integrated Resource Plan of Louisville Gas*

But it is important to note that the IRP process's being essentially a stakeholder process does not mean that every person or entity seeking intervenor status should receive it. Contrary to SREA's recommendation that the Companies not oppose certain intervention requests,[36] it is not true that every party that seeks intervention would necessarily offer useful or relevant commentary. For example, it is not obvious that advocates for a particular kind of generation technology should receive intervention precisely because the IRP regulation is neutral with regard to generation technologies and other energy supply resources, as are the Companies. Therefore, in the interest of administrative efficiency and ensuring stakeholder input that furthers the stated interests of the IRP regulation, the Companies will continue to oppose interventions they believe will not advance the IRP's informal, constructive, and non-adversarial process.

III. THE COMPANIES' IRP IS TRANSFORMATIVE AND DRIVEN BY A COMMITMENT TO SAFE, RELIABLE, AND LOW-COST SERVICE

Though the intervenors in this proceeding with explicit environmental and renewable energy policy goals appear to believe the Companies have given renewable energy short shrift in this IRP, the reality is that the Companies' IRP is transformative from a renewable energy perspective. *The base load, base fuel price portfolio in this IRP includes almost 2,000 MW of coal unit retirements and the addition of 2,100 MW of solar resources and 200 MW of battery capacity by the end of the IRP planning period*.[37] By 2034, nearly 18% of the Companies' annual energy

and Electric Company and Kentucky Utilities Company, Case No. 2014-00131, Order Appendix, Commission Staff Report at 59 (Ky. PSC Mar. 1, 2016) ("The Companies have endeavored to improve their Integration process considering an increasing number of Issues, particularly those that are being driven by environmental compliance rules. … Staff is generally satisfied with LG&E/KU's analysis of the many uncertainties it will be facing over the planning period. … Staff concludes that the overall Integration and optimization approach used by KU/LG&E is thorough, well-documented, and reasonable in all respects.").

[36] SREA Comments Attachment A at 4 ("In all future IRPs, the Companies should … not oppos[e] interested stakeholders from intervening in their IRP proceeding to provide comments.").

[37] IRP Vol. I at 8-28. Note that the 2,100 MW of new solar capacity does not include the Companies' existing 10 MW Brown Solar Facility, the Companies' Solar Share Facility, the Rhudes Creek solar PPA, or the Ragland solar PPA.

requirement would be supplied by utility-scale solar resources using the IRP's resource portfolio.[38] That is an *enormous* shift from 2021, in which less than 20 GWh—about 0.05%—of the Companies' customers' energy requirements were met by utility-scale solar.[39] Likewise, the IRP portfolio would result in a 26% reduction in CO_2 emissions from 2022 levels by 2036.[40] Changes of this magnitude are historic.

To put in context the historic and transformative nature of the Companies' meeting nearly 20 percent of customers' energy needs with solar, it is important to note that in 2021 utility-scale solar met a little under 3 percent and wind around 9 percent of total U.S. electricity sales.[41] Similarly, California's in-state utility-scale solar generation in 2020 was 11 percent of sales.[42] Thus, in just over ten years, it is possible that the Companies' customers would be using over six times the amount of solar electricity as a percent of total generation than the nation did last year and almost twice as much in-state solar generation as California's recent share. It is also important to note that both solar and wind energy nationally are currently mainly generated in some of the best regions in the world for such technologies, which unfortunately does not include Kentucky. To achieve such a large shift in electric generating capacity in a little over a decade would require significant effort and investment, and it would be truly historic.

The Companies recognize that the AG, who is the sole intervenor responsible for representing all customers in this proceeding, has expressed concern that a transition to increasing amounts of renewable resources could increase costs to customers and compromise system

[38] IRP Vol. I at 8-30.
[39] *Id.*
[40] Companies' Response to JI 2-16(c). Notably, these CO_2 emissions reductions would be in addition to PPL-wide CO_2 emissions reductions of 60% from 2010 through 2021.
[41] U.S. Energy Information Administration, *Electric Power Monthly with Data for December 2021*, p. 13, February 2022. *See* https://www.eia.gov/electricity/monthly/archive/february2022.pdf.
[42] California Energy Commission, *2020 Total System Electric Generation*. *See* https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2020-total-system-electric-generation.

reliability.[43] The AG is not alone is his concern. For example, the Wall Street Journal published an article on May 8, 2022, titled, "Electricity Shortage Warnings Grow Across U.S.," which stated that MISO's CEO John Bear "foresees the risk of near-term [capacity] shortages" and noted that MISO "has more frequently resorted to emergency measures to shore up supplies in recent years.[44] The Journal went on to quote Mr. Bear as stating, "I am concerned about it. … As we move forward, we need to know that when you put a solar panel or a wind turbine up, it's not the same as a thermal resource."[45] The Companies appreciate these concerns and can assure all parties that the Companies' objective is always to provide safe and reliable service at the lowest reasonable cost at each and every hour of the day across a broad range of weather conditions, 365 days per year. That goal is consistent with the Commission's IRP regulation, and the Companies believe their IRP, though transformative, reflects a portfolio that could provide safe and reliable service at the lowest reasonable cost given the assumptions included in the analysis.

But intervenors other than the AG have different priorities and objectives than those set forth in the Commission's IRP regulation, and they are evident in their comments in this proceeding. For example, Louisville Metro has certain emissions goals it desires to meet.[46] Sierra Club has an explicit "Beyond Coal" campaign, which publicly states, "America, Let's Move Beyond Coal and Gas," as well as, "The Beyond Coal campaign wants to close all coal plants in the U.S. and replace them entirely with sources of clean energy."[47] The Joint Intervenors desire a rapid transition to net zero emissions and to develop additional DSM-EE programs for low-income customers.[48] SREA likewise desires a rapid transition to net zero emissions, and it asserts that the

[43] *See, e.g.*, AG Comments at 6-10.
[44] Electricity Shortage Warnings Grow Across U.S., https://www.wsj.com/articles/electricity-shortage-warnings-grow-across-u-s-11652002380?mod=hp_trending_now_article_pos1 (accessed May 9, 2022).
[45] *Id.*
[46] *See, e.g.*, Louisville Metro Comments at 1-2.
[47] https://coal.sierraclub.org/ (viewed on May 8, 2022).
[48] *See, e.g.*, Joint Intervenors Comments at 3-4 and 22-31.

Companies' RTO analysis should focus not only on being beneficial to customers but also on meeting state and local policy goals.[49] Whatever the merits of these intervenors' stated objectives, they are not the objectives set out in the Commission's IRP regulation, but they do color these intervenors' comments. For example, understanding these objectives helps explain why, unlike the AG, who is charged by the General Assembly to represent the interest of customers and expresses concern that the Companies' IRP might contain too many renewable resources, these intervenors uniformly argue the Companies have not included enough renewable resources. That does not mean these intervenors' arguments are necessarily invalid, but it is clear that they are operating from a different viewpoint than the one reflected in the Commission's IRP regulation and its history, which are focused on safe, reliable, and low-cost service without regard for generation technology.

To be clear, the Companies are not committing to seek approval for the exact portfolio reflected in the IRP, which is not the proper purpose of this proceeding; rather, when the Companies do seek approval for new resources, they will do so based on rigorous multi-factor, multi-decadal analyses based on actual market prices obtained through requests for proposals. But this particular IRP is nonetheless valuable and historic: using the Companies' traditional resource-neutral approach that does not begin with a preference for one generating technology over another, as well as reasonable, defensible assumptions about future costs and legal requirements, this IRP shows a massive, transformative shift in the projected resource portfolio to serve the Companies'

[49] *See, e.g.*, https://www.southernrenewable.org/ ("The Southern Renewable Energy Association (SREA) is an industry-led initiative that promotes responsible use and development of wind energy, solar energy, energy storage and transmission solutions in the South. Our vision is for renewable energy to become a leading source of energy in the South and our mission is to promote responsible use and development of renewable energy in the South."); SREA Comments Attachment A at 22 ("Even if the Companies believe carbon pricing (e.g., a carbon tax) is unlikely, it should have still modeled, through one or more additional scenarios, the impact of selecting alternative resource portfolios designed to achieve important climate and clean energy goals.").

customers in a relatively short time frame. Importantly, this shift results from the Companies' ongoing commitment to safe and reliable service at the lowest reasonable cost, not ideology.

IV. CERTAIN INTERVENOR CRITICISMS ARISE FROM INAPPROPRIATELY USING LEVELIZED COST OF ENERGY TO COMPARE TECHNOLOGIES WITH DIFFERENT OPERATING CHARACTERISTICS

When confronting a challenging problem—such as how to compare different generating technologies on a consistent, uniform basis—it is understandably tempting to seek a single metric to use, such as levelized cost of energy ("LCOE"). LCOE would seem to be a natural candidate, effectively creating an all-in measure of a generator's cost—capital, operating and maintenance, and fuel cost—spread over the energy the generator produces in a year, resulting in a straightforward $/MWh value that is easy to compare across generating technologies. Thus, if the goal is to create a portfolio with low-cost generation, it would appear that whichever technology has the lowest LCOE would be the technology of choice.

But appearances are often deceiving, and certainly that is true when taking a simplistic view of LCOE. Although LCOE communicates some useful information about the cost of generation, it communicates *nothing* about such vital matters as whether a generator can or will produce energy when customers need it. That is why LCOE alone is a poor means of comparing generating technologies with different production characteristics, such as solar and NGCC: the LCOE of an NGCC unit producing the same production profile as solar is unattractively high, but a solar facility without energy storage simply cannot produce energy at night or during cloudy conditions, which any functioning NGCC unit can do.

This discussion is relevant because several intervenors' comments rely on LCOE in inappropriate ways to suggest that the Companies' IRP is flawed, and even that the Companies intentionally ignored certain low LCOE resources.[50] The Companies respectfully but firmly disagree with these comments. Far from having a predisposition to include particular kinds of technologies in their IRP, the Companies are agnostic regarding generating technologies. Their IRP objective—consistent with the Commission's IRP regulation—is to model a resource portfolio that serves customers reliably at the lowest reasonable cost. To do so appropriately, one cannot compare LCOE on a standalone basis for technologies with different operating characteristics. An appropriate understanding of generation technologies and the considerations for assembling technologies into a generation portfolio that can reliably serve load under a range of weather conditions will make this and future IRP proceedings more productive.

A. Different Generation Technologies Have Different Strengths and Limitations.

The Companies operate a generation portfolio comprising NGCC, coal, simple-cycle combustion turbine ("SCCT"), hydro, and solar resources, all of which have different characteristics and capabilities. For instance, they have different minimum and maximum operating levels. Solar has no fuel cost but can produce energy only when the sun is shining, making its production necessarily intermittent and variable. SCCT resources have higher energy costs than coal or NGCC resources but are designed to start very quickly and operate for shorter periods of hours. NGCC units have higher capital costs but lower energy costs than SCCTs because NGCC units have heat recovery steam generators to use waste heat to produce additional electricity with no incremental fuel input, though they have similar load following capabilities as

[50] *See, e.g.,* SREA Comments Attachment A at 23 ("Solar-plus-storage is already cost-competitive with natural gas peaking plants under baseline assumptions."); *id.* at 32 ("As shown in the figure below, all the Companies' existing resources, except for Cane Run 7 (although this has likely changed due to the higher cost of natural gas currently), are already more expensive on a dollar-per-MWh basis than new solar resources like the Rhudes Creek project, according to the Companies own estimates and contracts."); Louisville Metro Comments at 7 ("The City's understanding is that coal replacement with clean energy portfolios (a combination of renewables, energy efficiency, demand response, and storage) can provide the same services as gas plants at lower costs, and with better public health and environmental outcomes."); Joint Intervenors Comments at 23-25.

SCCTs. One shared feature of coal, SCCT, and NGCC units is that they can produce power in all hours of the year. Economically and reliably serving load at all moments and in all seasons and weather conditions typically requires a mixture of resources, blending their various performance and cost characteristics to offset the weaknesses of one with the strengths of another.

In actual operation, as well as in modeling exercises, the Companies' dispatch their resources subject to load, economic, and operating constraints. To illustrate this, Table 1 contains actual generation and capacity factors in 2019 for the Companies' NGCC unit (Cane Run 7), OVEC, the Trimble County SCCTs, and Brown Solar. As the table shows, these units have a variety of capacity factors, which differ due to the economics of their dispatch and availability; the Companies dispatch units with lower energy costs at higher capacity factors to the extent they are able. Thus, other than Brown Solar, the Companies could have dispatched each of these resources differently to serve load in 2019, but it would have been uneconomical to do so based on natural gas and coal prices in 2019.

Table 1: 2019 Generation and Capacity Factors

Resource	Capacity (MW)[51]	2019 Generation (GWh)	2019 Capacity Factor
Cane Run 7 (NGCC)	662	5,166	85%
OVEC (Coal)	174	878	58%
Trimble County SCCTs (SCCT)	954	887	9%
Brown Solar	10	17	20%

As seen in Table 1, Brown Solar operated at a 20% capacity factor in 2019 due to the solar irradiance at that location that year, as well as the efficiency of the solar panels and inverters. That is not necessarily indicative of the capacity of solar resources today, even in Kentucky, because new solar technology is more efficient than Brown Solar. Therefore, for the discussion below the

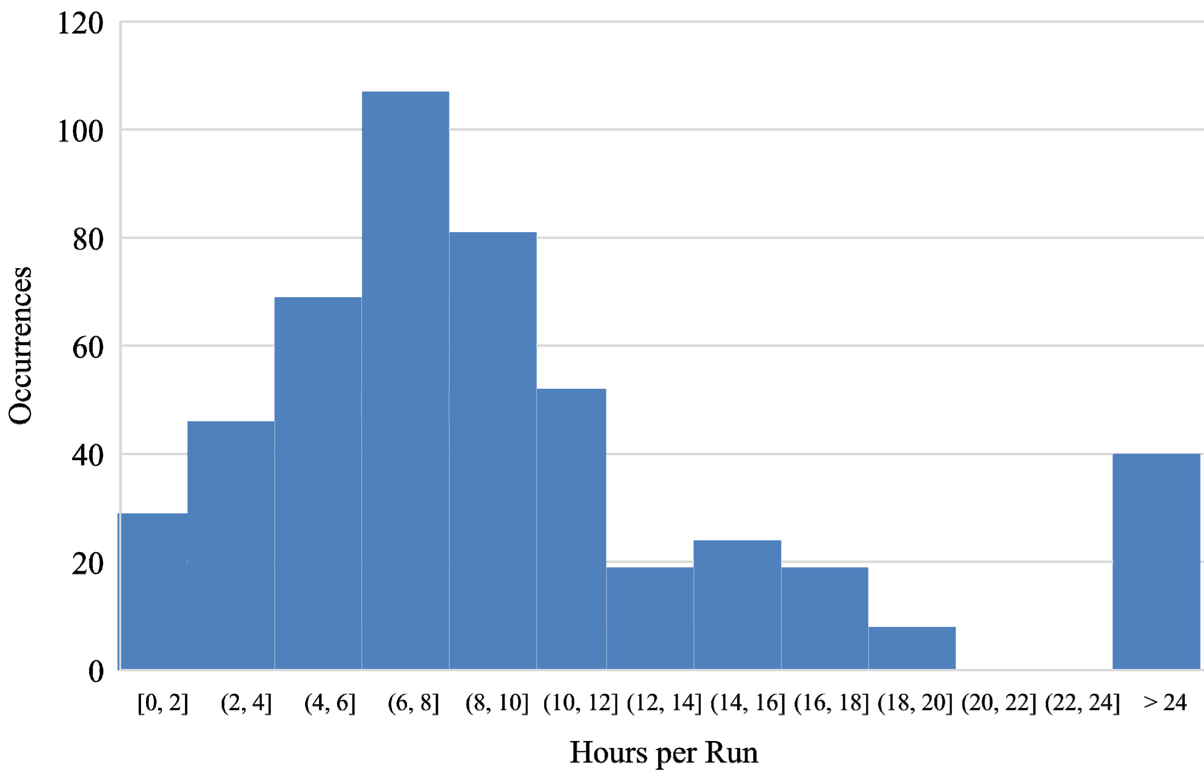
[51] The capacity values reflect net summer ratings for Cane Run 7, OVEC, and the total of the six Trimble County CTs. The renewables' capacity values reflect nameplate AC ratings.

Companies developed and modeled solar and wind profiles for 2019 based on actual solar irradiance and wind speeds that year, coupled with the improved efficiencies of newer technology. In 2019, the newer solar technology would have had a 26% capacity factor. New wind would have operated at a 28% capacity factor, slightly higher than solar and with generation in different hours. The modeled solar and wind profiles each reflect 1,000 MW systems comprising ten 100 MW systems located throughout the state.

With regard to battery storage, the Companies have relevant experience concerning such technology and its performance characteristics because they currently operate a battery storage test facility at the E.W. Brown station. Importantly, battery storage is not a generation source per se; rather, it allows previously generated energy to be used at other times, albeit a reduced amount of energy as discussed below. The cost of battery storage is a function of its charging capacity (i.e., the maximum amount of electricity that can be charged or discharged at any given time) and its duration (i.e., the number of hours it can be charged or discharged at its charging capacity). A battery's storage capacity is the product of its charging capacity and duration. For example, a 1 MW, 4-hour battery can store up to 4 MWh. But not all of a battery's storage capacity is usable; maintaining a battery's charge between 5% and 95% of its maximum charge helps preserve battery life. With these limits, a 4 MWh battery can store up to 3.8 MWh (95% of 4 MWh) and discharge to 0.2 MWh (5% of 4 MWh). Therefore, a 1 MW, 4-hour battery can charge or discharge up to 1 MW at any given time subject to these upper and lower charging limits. In addition to the cost of the batteries, the cost of battery storage includes energy losses associated with charging and discharging the battery. Round-trip energy losses for battery storage are approximately 15% (i.e., for every MWh charged in a battery, 0.85 MWh can be discharged).

Understanding these constraints on battery performance helps explain why simply pairing solar with relatively small amounts of battery storage cannot produce the same production profile as conventional, fossil-fueled resources. To illustrate further, Figure 1 below shows the distribution of run times for the Trimble County SCCTs in 2019 (excluding test runs). When the Companies dispatched the Trimble County SCCTs economically to serve load in 2019, 85% of runs were greater than four hours and 71% of the runs were greater than eight hours. To achieve that kind of performance and operational flexibility with battery storage would require significant amounts batteries, as well as the resources to charge them so they could be available when needed. Obviously, pairing a battery only with intermittent resources such as solar would reduce charging flexibility and capability, meaning that a greater quantity of batteries or intermittent resources (or both) would be required to be as dispatchable as SCCTs.

Figure 1: Distribution of Run Times for Trimble County SCCTs in 2019



Although this is by no means an exhaustive generation technology overview, a common understanding of generation technologies and their operating characteristics is critical for making this and future IRP conversations more productive.

B. Replacing Dispatchable Resources with Renewables and Battery Storage Can Be Costly, Especially When Serving Nighttime Energy Requirements.

Several intervenors suggested that fossil resources are economically interchangeable with renewables and battery storage or just solar and battery storage.[52] Because solar resources can produce energy only during the day, serving load at night requires energy storage. The 2021 IRP assumed a solar energy cost $28.05/MWh. With the added cost of battery storage and 15% energy losses, a solar-plus-battery-storage system dedicated to serving nighttime energy would cost $126.66/MWh. Because in this example the battery can be charged only by the solar array, the battery's availability is limited on nights following cloudy days. The nameplate capacity of solar required to serve load around-the-clock is significantly greater than the load being served because solar is needed during the day to not only serve load but charge batteries for serving load during nighttime or cloudy hours.

For the purposes of the discussion and analysis presented in this section (using the same modeling approaches and tools the Companies used to develop their IRP filing), the Companies computed the cost of replacing each of the fossil resources in Table 1 with renewables and battery storage. To do this, the Companies used PLEXOS to develop least-cost renewable portfolios for replacing the fossil resources' actual 2019 generation profile. The first renewable portfolio

[52] *See, e.g.,* SREA Comments Attachment A at 23 ("Solar-plus-storage is already cost-competitive with natural gas peaking plants under baseline assumptions."); *id.* at 32 ("As shown in the figure below, all the Companies' existing resources, except for Cane Run 7 (although this has likely changed due to the higher cost of natural gas currently), are already more expensive on a dollar-per-MWh basis than new solar resources like the Rhudes Creek project, according to the Companies own estimates and contracts."); Louisville Metro Comments at 7 ("The City's understanding is that coal replacement with clean energy portfolios (a combination of renewables, energy efficiency, demand response, and storage) can provide the same services as gas plants at lower costs, and with better public health and environmental outcomes.").

included only solar and battery storage as resource options; the second renewable portfolio included solar, wind, and battery storage as resource options. In addition to the fossil generation profiles, the Companies developed renewable portfolios to replace the modeled solar and wind generation profiles.

Table 2 below summarizes the results of this analysis. The large amounts of solar, wind, and batteries required to completely replace dispatchable coal and natural gas resources may be surprising at first glance. But Kentucky's poor wind conditions generally and the prevalence of clouds in the winter when the availability of sunlight is already low due to fewer daylight hours exacerbate the cost of replacing fossil generation with renewables and battery storage. Indeed, approximately 50 percent of the energy produced by the Cane Run 7 generation profile is during nighttime hours. For a renewable portfolio, that energy must be concurrently produced by wind or by additional solar resources during daylight hours and stored in batteries for nighttime use. Approximately 19.9 MW of solar and 6.3 MW of 8-hour battery storage are needed to replace 1 MW of a high capacity factor generation profile. When wind is included as a resource option, 4.9 MW of solar, 3.4 MW of wind, and 4.1 MW of 8-hour battery storage are needed. As the need for overnight generation decreases, the quantities of renewables and battery storage needed to replace the generation profile decreases.

Table 2: Renewable Replacement Portfolios

Generation Resource	Generation Profile				
	NGCC (Cane Run 7; 662 MW)	**Coal (OVEC; 174 MW)**	**SCCT (Trimble County SCCTs; 954 MW)**	**Modeled Solar (1,000 MW)**	**Modeled Wind (1,000 MW)**
	Renewable Portfolio Needed to Replace Generation Profile				
Renewable Portfolio 1: Solar + Battery Storage[53]	13,168 MW Solar; 4,145 MW Battery	2,437 MW Solar; 872 MW Battery	2,589 MW Solar; 1,826 MW Battery	*1,000 MW Solar*	4,228 MW Solar; 5,734 MW Battery
Renewable Portfolio 2: Solar + Wind + Battery Storage	3,259 MW Solar; 2,283 MW Wind; 2,709 MW Battery	676 MW Solar; 624 MW Wind; 585 MW Battery	2,731 MW Solar; 224 MW Wind; 1,451 MW Battery	*1,000 MW Solar*	*1,000 MW Wind*
	Normalized Portfolio (per MW of Generation Replaced)				
Renewable Portfolio 1: Solar + Battery Storage	19.9 MW Solar; 6.3 MW Battery	14.0 MW Solar; 5.0 MW Battery	2.7 MW Solar; 1.9 MW Battery	*1 MW Solar*	4.2 MW Solar; 5.7 MW Battery
Renewable Portfolio 2: Solar + Wind + Battery Storage	4.9 MW Solar; 3.4 MW Wind; 4.1 MW Battery	3.9 MW Solar; 3.6 MW Wind; 3.4 MW Battery	2.9 MW Solar; 0.2 MW Wind; 1.5 MW Battery	*1 MW Solar*	*1 MW Wind*

Table 3 below lists the assumed cost of resources used in this analysis, which are the same as the costs used in the 2021 IRP. For comparison, Table 3 also contains the assumed costs of NGCC with CCS, NGCC without CCS, and SCCT resources. Although the cost of fuel (i.e., sunlight and wind) is free for a solar and wind, a power purchase agreement for renewable energy is often structured such that the seller's capital and other costs are recovered through a fixed or escalating energy charge. Based on the inputs in Table 3, the IRP assumed a level cost of $28.05/MWh for solar energy and $43.10/MWh for wind energy. On a $/MWh basis, wind is much more expensive in Kentucky than solar. The cost of a wind turbine in Kentucky is no

[53] Battery storage resources are of 8-hour durations.

different than in other states, but the generation output is much lower due to Kentucky's poor wind conditions.

Table 3: Cost of New Resources (2031 Dollars)

Capital	Capital ($/kW)	Fixed Costs[54] ($/kW-year)	Energy Cost ($/MWh)
Solar	955*	21	0
Wind	1,143**	49	0
8-Hour Battery Storage	1,715*	43	N/A
4-Hour Battery Storage	982*	25	N/A
NGCC	1,152	56	15-30
NGCC with CCS	2,477	104	22-38
SCCT	635	51	26-48

*Assumed eligible for 26% ITC.
**Assumed eligible for $15/MWh production tax credit in first ten years of operation.

C. LCOE for an Individual Technology Varies Greatly Depending on the Load Profile Being Served.

Table 4 shows the LCOE for the renewable portfolios needed to replace each of the generation profiles as well as the LCOE for replacing the profiles with NGCC, NGCC with CCS, and SCCT units. The LCOE for replacing fossil resources with renewables and battery storage varies significantly depending on the generation profile needed to serve customers' load. A portfolio of solar, wind, and battery storage is less expensive than just solar and battery storage, but the cost of either renewable portfolio is significantly more expensive than new fossil resources.

[54] Fixed costs include fixed operating and maintenance expenses and firm gas transportation for gas-fired units.

Table 4: LCOE ($/MWh)

	Generation Profile				
	Dispatchable			Non-Dispatchable	
Generation Resource	**NGCC 85% Capacity Factor**	**Coal 58% Capacity Factor**	**SCCT 9% Capacity Factor**	**Solar 26% Capacity Factor**	**Wind 28% Capacity Factor**
Renewable Portfolio 1	310	360	562	28	533
Renewable Portfolio 2	183	246	522	28	43
NGCC	35-52	43-60	187-204	77-94	73-90
NGCC with CCS	63-82	81-101	390-409	153-172	145-164
SCCT	42-68	49-75	162-188	75-101	72-98
OVEC[55]	48-49	56-61	198-259	89-105	84-100

As seen in Table 4, NGCC is the least-cost resource for providing a dispatchable, high capacity factor generation profile ($35-52/MWh based on the range of natural gas prices assumed in the 2021 IRP). The LCOE for the solar, wind, and battery storage portfolio (i.e., Renewable Portfolio 2) needed to provide the same generation profile is $183/MWh. OVEC provides a sound example of why it is important to consider <u>when</u> energy is needed in comparing LCOEs. Using renewables to provide the OVEC energy profile is four to six times more expensive than OVEC. Similarly, using OVEC to serve a solar or wind generation profile would make OVEC approximately two to four times costlier than the solar or wind resource, respectively. Due to its lower capital cost, SCCT is the least-cost resource for providing a peaking, load-following generation profile. The LCOE for the renewable portfolios needed to replace the Trimble County SCCTs is more than $500/MWh. Depending on the generation profile needed to serve load, a given technology will have multiple LCOEs. This is why it is critical to evaluate and deploy technologies based on their technological and economic strengths, not just their weaknesses.

In any given year, the system load factor ranges between 56 and 62 percent, depending on weather, and approximately 46 percent of energy is consumed during nighttime hours. Like the

[55] OVEC's costs are based on OVEC's most recent demand and energy charge forecasts for 2022-2035.

cost of replacing dispatchable resources with renewables, the cost of serving total load exclusively with renewables is high.

D. Renewable Resources Can Contribute to Reliable and Economical Service.

These results demonstrate that the Companies' IRP plays to the strengths of the available technology options. When NGCC is assumed to require CCS, 2,100 MW of new solar is added in the Companies' base load, base fuel scenario through 2036 because of its low energy cost. Peaking capacity is provided primarily by SCCT units and the Companies' existing NGCC and coal units serve nighttime energy requirements. When NGCC without CCS is included as a resource option, it is selected to replace the capacity and energy of the coal units that are assumed to retire.

When evaluating resources for the purpose of reliably serving load at the lowest cost, the analysis must consider the load being served *and* the operating characteristics of generation alternatives. As the discussion above shows, comparing LCOE for technologies with different operating characteristics is not appropriate because the technologies are not equally capable of serving the same load. As the discussion above also shows, based on current cost estimates, renewables and battery storage cannot replace dispatchable resources at a lower cost, contrary to certain intervenors' assertions.

V. THE COMPANIES' APPROACH TO CO_2 EMISSIONS CONSTRAINTS WAS REASONABLE, AND THE IRP IS CONSISTENT WITH PPL'S CLIMATE GOALS

Certain intervenors argue that the Companies' initial IRP filing is flawed because it did not include a scenario with a broad-based CO_2 price that would, at a minimum, apply to all electricity generation nationwide.[56] But as explained in the Companies' initial IRP filing, the Companies' approach to CO_2 regulation was based on its assessment of the focus of the Biden Administration

[56] *See, e.g.,* Joint Intervenors Comments at 36-37 and Exh. 1 at 21-22; SREA Comments Attachment A at 21-22.

at the time. For example, the Build Back Better legislation had a provision that would have required a growing percentage of load to be served by "clean" generation, but it had no CO_2 emission price. Likewise, there was and is a significant effort at the federal level to constrain the development of new natural gas-fired generation, including work toward establishing New Source Performance Standards ("NSPS") for new NGCC units that would require carbon capture technology. For example, the U.S. Environmental Protection Agency ("EPA") recently released a draft technology white paper that lays the procedural foundation for establishing such a standard later this summer.[57] Also, the White House's national climate advisor, Gina McCarthy, recently stated that U.S. climate policy "is not a fight about coal anymore. It is a challenge about natural gas and infrastructure investments because we don't want to invest in things that are time limited. Because we are time limited."[58] None of these recent developments suggests the implementation of a generally applicable CO_2 pricing regime in the foreseeable future, making the Companies' IRP assumption that any new NGCC unit would require carbon capture and storage ("CCS") a reasonable approach to modeling CO_2 emissions constraints.[59]

Notwithstanding that there is no current carbon pricing to which the Companies are subject, and there is no likely state or federal carbon pricing or cap-and-trade regulation regime being discussed of which the Companies are aware, the Companies assessed the impact of CO_2 prices in discovery in this proceeding.[60] Therefore, if the current or future administrations pursue CO_2

[57] EPA, Office of Air and Radiation, "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units" (April 21, 2022), available at: https://www.epa.gov/system/files/documents/2022-04/epa_ghg-controls-for-combustion-turbine-egus_draft-april-2022.pdf.

[58] Wall Street Journal, "Biden's Great Energy and Climate Contradiction" (Mar. 25, 2022), available at: https://www.wsj.com/articles/joe-bidens-energy-contradiction-lng-europe-gas-companies-russia-ukraine-gina-mccarthy-11648244471.

[59] *See, e.g.*, IRP Vol. I at pgs. 5-20 and 6-11; Companies' Response to PSC 1-9; Companies' Response to JI 1-10.

[60] *See* Companies' Response to PSC 2-1.

pricing, the parties understand the implications of such a regulatory approach on future resource decisions.

Relatedly, several intervenors' comments cite PPL's Climate Assessment Report and its stated carbon-emissions reduction goals to criticize the IRP's generation portfolios, the IRP's approach to accounting for carbon emissions constraints, or both.[61] Of course, the Companies are well aware of PPL's stated goals, just as PPL is well aware of the content of the Companies' IRP. Indeed, the Companies' personnel consulted with PPL personnel as PPL created its corporate carbon-emissions goals. Therefore, the Companies' IRP is not oblivious to nor inconsistent with PPL's carbon-emissions goals, and the Companies' IRP was not a surprise to PPL. Indeed, as the Companies noted in a DR response, "The report [PPL's 'Energy Forward 2021 Climate Assessment Report'] demonstrates a range of forecasted potential PPL-wide CO_2 reductions through 2050, which includes the forecast presented in the Companies' 2021 IRP."[62]

But more importantly, meeting PPL's corporate goals has and should have no bearing on the Companies' IRP. The Commission's IRP regulation contains no criterion regarding meeting a corporate goal of any kind; rather, the prescribed purpose of the IRP, and the objective function toward which the Companies worked in crafting their IRP, is to produce "load forecasts and resource plans … to meet future demand with an adequate and reliable supply of electricity at the lowest possible cost for all customers … and satisfy all related state and federal laws and regulations."[63] Whether such resource plans tend to help achieve corporate goals has no bearing on an IRP and an IRP proceeding, though in this case the Companies can assure all parties with such concerns that the Companies' IRP is indeed consistent with PPL's stated climate goals.

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[61] *See, e.g.*, Louisville Metro Comments at 1-2; Sierra Club Comments at 14; SREA Comments Attachment A at 22; Joint Intervenors Comments Exh. A at 21-22.
[62] Companies' Response to JI 1-11.
[63] 807 KAR 5:058 Necessity, Function, and Conformity.

VI. THE COMPANIES' MODELING PROCESSES ARE REASONABLE AND PRODUCE EXCELLENT REAL-WORLD RESULTS

As previously stated, the Companies are dedicated to continually improving their processes. Therefore, they welcome constructive suggestions about how they might improve the modeling that goes into their IRPs. Such suggestions are part of the iterative stakeholder process that is the IRP process: utilities present their best modeling and assumptions, answer questions from Staff and intervenors (including providing additional data and analysis), receive and respond to intervenor comments, and ensure that their next IRPs are responsive to Commission Staff's recommendations from previous IRPs.

Before responding to certain intervenor criticisms and recommendations regarding the Companies' modeling methodologies and processes, the Companies offer a few overarching observations.

First, it is noteworthy that no party criticized the Companies' load forecast. The AG noted concern about the possibility of increasing electric heating and electric vehicle load,[64] but the AG did not suggest the Companies' load forecast was flawed.

Second, although the Companies provided historically voluminous data in response to data requests, none of the intervenors performed their own resource modeling or reserve margin analyses, notwithstanding assertions by certain intervenors that the Companies' modeling was inadequate in a number of respects.[65] Thus, putting aside disagreements about reasonable assumptions to include in the models about future costs or regulatory requirements, which could affect the output of any model, there is no basis to conclude that the Companies' IRP modeling processes are fundamentally flawed.

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[64] *See* AG Comments at 4-5.
[65] *See, e.g.,* SREA Comments Attachment A; Joint Intervenors Comments Exh. 1.

Third, the effectiveness of the Companies' system planning speaks for itself in real-world outcomes, not just theoretical planning exercises. Unlike other systems in recent years that have had to shed load during severe weather events,[66] particularly severe cold weather events, the Companies have not had to shed load to preserve system stability for all customers; rather, during the 2014 Polar Vortex cited by SREA, the Companies not only served their own load, but they also exported energy to other systems.[67] Thus, the Companies' modeling and planning processes result not only in reasonable IRPs but also in reliable real-world system performance.

Fourth and finally, the Companies have been entirely forthcoming with their data, methods, and analysis as demonstrated in their voluminous discovery responses. The Companies have provided voluminous data in this proceeding, both in the Companies' IRP filing and in responses to data requests. More particularly, though certain comments state otherwise, the Companies have not attempted to withhold information or "stack the deck" against particular generation or storage options;[68] for example, the Companies clearly stated which resources were included as options in their original resource planning analysis and in subsequent analyses provided in responses to data requests.[69] In short, the Companies are open to providing whatever reasonable information the Commission Staff would find helpful in reviewing the IRP, again bearing in mind the informal and non-binding nature of IRPs and IRP proceedings, as well as the stakeholder process of the IRP proceeding itself, in which the Companies routinely provide additional data and analysis as requested.

[66] *See* SREA Comments Attachment A at 16.
[67] *See id.*
[68] *See, e.g.*, SREA Attachment A at 11-12.
[69] *See* IRP Vol. I Sec. 8; Companies' Response to PSC 2-1.

1. The Companies' modeling process is not unnecessarily complex.

The Joint Intervenors recommend using one modeling tool, PLEXOS, for both expansion planning and production cost modeling,[70] and they criticize the Companies for using multiple tools.[71] Although the Joint Intervenors assert that the Companies' use of multiple tools could result in errors, they did not cite one that actually resulted from the Companies' expansion planning and production cost modeling, but rather a small error in calculating the net present value of revenue requirements for the base load, base fuel portfolio.[72] The Companies corrected the error in discovery,[73] which had no effect on the selected portfolio and would not have been prevented by using PLEXOS alone.

The Joint Intervenors further criticize the Companies' use of multiple tools because it makes the Companies' modeling difficult to understand.[74] In particular, the Joint Intervenors claimed they could not verify certain values in a particular spreadsheet.[75] The Companies do not agree that the number of modeling tools is necessarily problematic, but they acknowledge that they have prepared their tools primarily for use by internal personnel familiar with them, making them more challenging for outside parties to understand. But that does not affect the accuracy or usefulness of the tools, and all the costs and values the Companies used are indeed verifiable using the data the Companies provided; in particular, the values the Joint Intervenors cite are indeed verifiable.[76]

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[70] *See* Joint Intervenors Comments Exh. 1 at 10-11.
[71] *See, e.g., id.* at 9-10.
[72] *See id.* at 21.
[73] Companies' Response to JI 2-35.
[74] Joint Intervenors Comments Exh. 1 at 19-20.
[75] *Id.* at 21.
[76] The Joint Intervenors' Comments Exh. 1 at 21 states, "After reviewing the system costs reported in the 'out_stationyr' output file from PROSYM, we were unable to verify that the costs reported in this file were the costs used in the development of the revenue requirement calculation as we could not match the costs from the PROSYM output file with the Companies' workbook creating the revenue requirements." The Joint Intervenors' comments cite

In addition, the Joint Intervenors assert that using a single modeling tool would allow the Companies to conduct a more meaningful analysis, including evaluating the NPVRR of more than one generating portfolio.[77] Contrary to that criticism, the number of modeling tools the Companies used had no bearing on the number of generating portfolios the Companies evaluated; rather, the Companies calculated the NPVRR for a single portfolio in accordance with the IRP regulation's requirements, not due to technical constraints.

That notwithstanding, the Companies are not opposed to using a single tool for expansion planning and production cost modeling, but neither do they favor using a single tool if it does not produce the most reliable results. The Companies are exploring the possibility of using PLEXOS for both processes, but to date they have found their current process, built over the course of years, produces reliable and reasonable results.[78] Moreover, the Companies have developed tools to minimize the chances of errors in their modeling work by checking it at multiple points to ensure their results are accurate and plausible. Therefore, although the Companies' current modeling process involves the use of multiple tools, the Companies' process is not unnecessarily complex, but rather is as complex as is necessary to produce accurate and plausible results.

CONFIDENTIAL_20210928_LAK_Section8Tables_2021IRPD02.xlsx as the "Companies' workbook creating the revenue requirements." *See* Joint Intervenors Comments Exh. 1 at 21 fn. 25. Regarding that workbook, Specifically its "8-9ProdCost" tab:

1. The 2021 values on which the Companies initially focused are a combination of actual and forecasted values. The values for 2022 through 2036 are forecasted PROSYM values.
2. Production costs in the "out_stationyr.csv" file include the following components: fuel costs, start fuel costs, and variable O&M (so start fuel costs ARE included in production costs). The sum of these components in the "8-9ProdCost" tab tie to the values in the "out_stationyr.csv" file for 2022 through 2036.
3. SO2 and NOx costs reflect the assumed market value of SO2 and NOx allowances. These costs are modeled as "shadow" costs in PROSYM.

[77] *Id.* at 20.

[78] The Joint Intervenors assert that one of the Companies' tools, PROSYM, is no longer supported by its vendor. Joint Intervenors Comments Exh. 1 at 10. That observation is both incorrect—the software vendor, ABB, still provides technical support for PROSYM, though it does not plan to develop it further—and has no impact on the legitimacy or effectiveness of PROSYM as a modeling tool for the purposes for which the Companies use it.

The Joint Intervenors had a number of other criticisms regarding the complexity and transparency of the Companies' resource modeling. One group of such criticisms insinuated that the Companies were not being forthcoming with modeling data, failing to provide an appropriate PLEXOS file, changing modeling data without supplying the updated data to the Joint Intervenors, and preparing modeling at Staff's request regarding NGCCs without CCS, meaning that a constraint must have been changed in the modeling that the Joint Intervenors could not see.[79] The Companies categorically reject any insinuation that they are hiding anything. The Companies provided all the data needed to see their modeling in PLEXOS in response to Joint Intervenors' Data Request 1-3. With regard to the modeling the Companies performed at Staff's request, the Companies were abundantly clear in their documentation which resources were included in each set of runs: in response to PSC 2-1, the Companies provided two sets of data and were clear that one set did not consider NGCC without CCS and the other set did. Therefore, the Companies have been transparent and forthcoming concerning their analyses.

The Joint Intervenors further contended that it was not clear how the Companies determined the lowest reasonable cost portfolio.[80] But the Companies stated how they did so in their IRP filing: "For each energy requirements and fuel price case, the Plexos model from Energy Exemplar was used to identify the least-cost generation portfolio for serving customers at the end of the IRP planning period."[81] Again, the Companies have tried throughout this IRP process to be as transparent as possible.

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[79] Joint Intervenors Comments Exh. 1 at 18.
[80] *Id.* at 23.
[81] IRP Vol. I at 5-15.

2. The Companies' approaches to modeling unit retirements and generation replacements in their IRP filing were reasonable.

For the sake of simplicity, the Companies did not model multiple unit retirement scenarios in the current IRP, which SREA and the Joint Intervenors criticized.[82] The Companies' approach was nonetheless reasonable. The Companies are intimately familiar with their systems, cost structures, and applicable and reasonably foreseeable environmental regulations. They therefore know which existing units are most likely to retire early and in what order; it is not necessary to conduct complex modeling to confirm this basic business knowledge. Notably, in discovery the Companies evaluated earlier retirements for coal units assumed to retire after the IRP planning period (i.e., Mill Creek 3 and 4, Ghent 3 and 4, and Trimble County 1 and 2).[83] Assuming no CO_2 pricing, none of these units were retired, confirming the reasonableness of the Companies' retirement assumptions. Therefore, the Companies do not believe that including the modeling of numerous possible retirement scenarios in future IRP filings is necessary or advisable. If parties request reasonable additional analysis of particular retirement scenarios or other changes in input variables, the Companies will provide it as part of the stakeholder process that is the IRP proceeding.

Similarly, the Joint Intervenors recommended that the Companies model generation replacements over each year of the IRP period, not just the last year,[84] though it is not clear what the benefit would be of performing such additional work. The Companies developed their IRP to demonstrate how the least-cost generation portfolio varies with load and fuel prices. Because the range of load and fuel prices is greatest at the end of the planning period, the Companies developed replacement generation portfolios for the end of the IRP planning period to focus the analysis more

[82] *See* SREA Comments Attachment A at 4-5; Joint Intervenors Comments Exh. 1 at 17.
[83] *See* Companies' Response to PSC 2-1.
[84] Joint Intervenors Comments Exh. 1 at 13-14.

on the end-of-period generation portfolio and less on the assumed timing of generation replacements. Evaluating replacement portfolios at the end of the IRP period also allowed the Companies to reflect fully in the analysis the forecasted declines in battery storage costs. Therefore, because modeling generation replacements over the entire IRP period should have no effect on the lowest-cost portfolio in the final year of the planning period, the Companies do not believe that including portfolio modeling for all IRP-period years in future IRP filings is necessary or advisable.

In a more specific criticism, the Joint Intervenors argue that the Companies' erred in applying capacity factor limitations because "there are instances in the run where the SCCTs operate at a capacity factor above 20% between 2028 and 2036" even though the capacity factor limit for such units was 20%.[85] The Companies acknowledge that the capacity factors for new SCCTs range from 18% to 23%, but that range is consistent with an overall 20% capacity factor. Thus, this observation tends to support rather than detract from the reasonableness of the Companies' modeling approach.

In conclusion, if parties request reasonable additional analysis or data in discovery in future IRP proceedings, the Companies will provide it. That is the nature of an informal, constructive, and iterative stakeholder process. But requiring exhaustive and expensive analysis beyond what the Companies already provide is not consistent with such a process or its "triennial snapshot in time" nature.[86]

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[85] *Id.* at 19.
[86] *Electronic 2021 Integrated Resource Plan of Duke Energy Kentucky, Inc.*, Case No. 2021-00245, Order Appx. at 32 (Ky. PSC May 10, 2022).

3. The Companies' use of the term "baseload" in the text of the IRP had no effect on the Companies' modeling or analysis.

SREA contended that the Commission should be "highly alarmed" by the Companies' use of the term "baseload" in its IRP filing, asserting that using such a term "reflect[s] an outdated and thoroughly debunked view that has no place in modern utility resource planning."[87] Notwithstanding this rhetorical assertion, the Companies' use of the term "baseload generation" had no bearing on the Companies' analysis. For example, maintaining a certain level of baseload generation was not a requirement in the Companies' analysis. But the Companies would note that their customers do have a base level of demand at all hours of the day and all seasons of the year, usually about 2 GW. Whatever one wants to call that level of demand, the Companies must serve it reliably at all times. Irrespective of the terminology, the Companies did not artificially constrain their analysis to modeling certain units one way because they were "baseload" and other units another way; rather, the Companies considered all resources according to their unique performance characteristics and sought to create lowest-reasonable-cost portfolios that could safely and reliably serve their customers' load.

[87] SREA Comments Appendix A at 15. The Companies would note that at least one FERC commissioner is still using this terminology as recently as this week. *See* S&P Platts, "'Grim' FERC reliability outlook sees policy failures, extreme weather as threats," May 19, 2022:

> Fellow Republican Commissioner Mark Christie said the nation is "heading for a reliability crisis" as utilities switch too rapidly from baseload energy sources to intermittent renewables. Christie cited a North American Reliability Council summer reliability report released a day earlier.
>
> Further, Christie asserted that state policies, such as renewable energy mandates, are largely driving the pace of this shift in many regions, which the Midcontinent ISO has pointed to as the root cause for potential load shed in its region this summer.
>
> "This is the central issue that we're facing. ... We're replacing baseload generation, dispatchable generation, which can run through all weathers, with generation that's not ready yet to run through all weathers," Christie said. "States have got to pay attention to what resources that you have available to serve your consumers because otherwise, we're heading exactly where NERC says we're heading, and that's a very, very catastrophic situation."

4. The Companies' approach to reliability modeling was appropriate.

The Joint Intervenors assert that the Companies should no longer use the Equivalent Load Duration Curve Model ("ELDCM") in their reliability modeling but should use only the Strategic Energy Risk Valuation Model ("SERVM").[88] The Companies disagree with the criticisms of their reliability modeling. The ELDCM model is an effective tool for evaluating the reliability impacts of variable resources like solar because the Companies developed hourly generation profiles for new solar based primarily on historical solar irradiance to be "chronologically consistent" with the weather conditions underlying each load scenario. Furthermore, the Companies' analysis showed that the addition of solar improves (not erodes) reliability in both the summer and the winter, contrary to the Joint Intervenors' assertion. The Companies agree that the ELDCM model cannot evaluate time-dependent resources like battery storage, but the Companies neither used it for this purpose nor suggested it could be used for this purpose. The Companies' use of the ELDCM model for reliability modeling was appropriate.

Relatedly, Joint Intervenors expressed concern that the Companies were using the ELDCM and SERVM modeling to evaluate the economics and reliability of retiring existing thermal units with limited to no options to replace that capacity. This concern is not valid, and it appears the Joint Intervenors misinterpreted the purpose of the Reserve Margin Analysis. The Companies evaluated a range of generation portfolios with different reserve margins to determine whether altering reliability by either retiring existing resources without replacement or adding new resources was cost-effective. The Companies then evaluated the same generation portfolios to determine the upper and lower limits of the target reserve margin range. The Companies then used

[88] *See, e.g.*, Joint Intervenors Comments Exh. 1 at 24.

this reserve margin range to evaluate optimal replacement generation portfolios in the Long-Term Resource Planning Analysis.

Lastly, Joint Intervenors contend that the Companies should use scarcity pricing in their SERVM modeling that is more "realistic."[89] The Companies respectfully disagree with the Joint Intervenors' characterization of the Companies' scarcity pricing, which the Companies based on historical data.[90] It is not clear how the Companies could be more "realistic" with their pricing than to use actual data from their own experience operating their system and transacting in real markets.

VII. RESPONSES TO CERTAIN SUBSTANTIVE IRP CRITICISMS AND RECOMMENDATIONS

A. The Companies' Assumptions and Approach Regarding Battery Storage Were Favorable to Such Storage, Not Unfavorable.

Contrary to intervenor criticisms, the Companies modeled battery storage as favorably as possible.[91] For example, the Companies did not assume batteries would be charged only by renewable resources, which would have limited their availability and cost-effectiveness.[92] The Companies also assumed favorable tax incentives for battery storage, namely a 26% Investment Tax Credit.[93] Finally, the Companies evaluated battery storage based on NREL's cost projections at the end of the IRP planning period, which are more than 20% lower than NREL's 2022 cost projections. Therefore, far from making assumptions to disfavor battery storage, the Companies treated battery storage favorably in their IRP analysis. But even with such favorable assumptions, the cost of battery storage is higher than SCCT capacity when considering differences in operating characteristics in the context of the Companies' generation portfolio.

[89] *Id.* at 27-29.
[90] *See* IRP Vol. III, 2021 IRP Reserve Margin Analysis at 22-23.
[91] *See, e.g.,* SREA Attachment A at 11-12 and 26.
[92] *See, e.g.,* Companies' Response to SREA 1-7(a) and (b).
[93] *See id.*

B. The Companies Correctly Assumed their Thermal Units Would Not Have Correlated Outages.

SREA and the Joint Intervenors argue that the Companies' assumption that their thermal units would not have correlated outages was flawed.[94] They are mistaken.

Forced outage data for the Companies' generating units during extreme weather events like the 2014 polar vortex does not support a claim that the Companies' generator outages are correlated to seasonal weather. The reliability event evaluations cited by SREA indicate that the California, Texas, and PJM events were caused by a lack of dispatchable resources or the failure to contract for fuel or fuel transport for otherwise available dispatchable resources. This is not equivalent to forced outages in extreme weather conditions due to equipment failure.

After reviewing the reliability events cited by SREA, the Companies conclude that the California, Texas, and PJM events were caused primarily by inadequate resource planning or flawed market design by the respective RTO that failed to incentivize generators to ensure fuel availability and winter preparedness.

Each of SREA's cited reliability events illustrate key differences between the Companies' overall responsibilities and those of individual RTO participants. Unlike RTO participants, the Companies have load serving obligations and cannot simply claim that the capacity contribution of their generation units will be available; rather, it must actually be able to provide energy to reliably meet customers' energy needs. Therefore, fuel and transport services must be available to support energy production. For the Companies, the provision of capacity and production of energy is not merely an economic or financial decision in accordance with RTO rules and tariffs, and their energy production does not depend on an RTO's decision to call upon specific resources. Instead, the Companies plan and execute operationally to ensure that their generating capacity is

[94] SREA Comments Appendix A at 20 and 30; Joint Intervenors Exh. 1 at 29.

available to produce energy as part of the Companies' reliability obligation to customers. In addition to ensuring fuel availability, the Companies are responsible for their maintenance and operating practices, including pre-warming combustion turbines during extreme cold, to ensure generation performance.

All of this demonstrates that, unlike certain utilities or other generators in RTO environments that did not have incentives to ensure they could operate in severe weather conditions because they did not have load-serving obligations, the Companies have appropriately weatherized their units, ensured firm gas transport, ensured adequate coal inventory, and operated their units to ensure they were available when needed to serve their customers when they needed it most. Moreover, precisely because the Companies have taken such steps and know how to operate their units in severe weather conditions—and in advance of severe weather conditions, such as starting peaking units early to ensure they can address any start-up issues before it is too late—it is not appropriate to assume unit outage correlations of the kind Joint Intervenors criticized the Companies for not considering.[95]

C. The Companies Appropriately Included OVEC in their IRP Modeling.

The vast majority of Sierra Club's comments are substantively identical to their previous criticisms of OVEC and the ICPA to which the Companies are parties.[96] As the Companies discussed above, this is unsurprising given Sierra Club's Beyond Coal commitment to "close all coal plants in the U.S."[97] But as the Companies also discussed above at length, notwithstanding that Sierra Club invites the Commission to "weigh[] in or at least giving direction at this

[95] *See* Joint Intervenors Comments Exh. 1 at 29.

[96] *See, e.g., Electronic 2018 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company,* Case No. 2018-00348, Sierra Club Comments (Feb. 17, 2020); *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric* Rates, Case No. 2018-00294, Direct Testimony of Jeremy I. Fisher (Jan. 16, 2019); *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric* Rates, Case No. 2018-00295, Direct Testimony of Jeremy I. Fisher (Jan. 16, 2019).

[97] https://coal.sierraclub.org/

juncture,"[98] it is entirely beyond the scope of this proceeding and would contravene the Commission's IRP regulation for the Commission to do any of what Sierra Club asks of it regarding OVEC in this proceeding.

The Companies observe this not because they seek to avoid discussing OVEC, but rather because, as Sierra Club has presented it, it is entirely outside the scope of this proceeding. The Companies continue to be forthcoming regarding their conduct concerning OVEC. The Companies are acting toward it in ways that are best for their customers in view of existing ICPA commitments and the potential costs of exiting those commitments. The participation of Companies' personnel on OVEC's board has not been inconsistent with Companies' working in their customers' best interests. The Companies' participation in OVEC has been fully above-board and has provided benefits to customers over decades. And the Companies continue to monitor OVEC closely, and they will act timely to take any actions they can for customers' benefit. As true as all these things are, they are all entirely irrelevant to this proceeding, and there is no reason to address them further in this case.

What is relevant is how the Companies modeled OVEC in their IRP, i.e., they assumed OVEC would continue to operate and the Companies would continue to be subject to the ICPA. With regard to that issue, Sierra Club presented nothing to suggest the Companies should have done anything differently in their IRP. Sierra Club did not run any models or perform any analysis to demonstrate OVEC was uneconomical as included in the Companies' IRP. Also, although the Companies have Commission-approved contractual obligations under the OVEC ICPA that they must honor or pay the cost of breaching, Sierra Club did not present a realistic counterfactual situation, i.e., it did not present any analysis of what the actual costs of exiting the ICPA would be

[98] Sierra Club Comments at 3.

or legal basis to support breaching the contractual commitments. In short, Sierra Club has not shown that the Companies should do anything differently regarding OVEC in their next IRP if the Companies remain parties to the ICPA when it is time to perform the next IRP.

D. The Companies Appropriately Addressed and Included DSM, Energy Efficiency, and Other Distributed Energy Resources ("DERs") in their IRP.

The Joint Intervenors incorrectly assert that the Companies did not include DSM programs or savings beyond the end of their current DSM-EE Program Plan, i.e., beyond the end of 2025.[99] To the contrary, although the Companies did not speculate on the nature of DSM programs beyond 2025,[100] the Companies' load forecast implicitly assumes that DSM and other customer-initiated energy efficiency improvements will continue throughout the IRP analysis period.[101] Moreover, DSM and customer-initiated energy efficiency improvements are assumed to achieve savings of over 6% of residential and small commercial sales—more than 800 GWh—by the end of the IRP planning period.[102] The Companies therefore respectfully disagree with any assertion that they have given short shrift to DSM and energy efficiency in their IRP.

In addition, contrary to certain criticisms, it would be inaccurate to model different DSM "levels."[103] DSM programs must target specific end-uses that contribute to reducing the Companies' load when there are benefits associated with reducing load. Only then can the Companies compare the cost of achieving those load savings to other alternatives. In other words, attempting to model levels of DSM savings in the abstract would be inaccurate at best.

It is also noteworthy that when the Commission promulgated the final version of its original IRP regulation in 1990, Kentucky's DSM statute did not exist.[104] Thus, at the time of the IRP

[99] Joint Intervenors Comments at 28.
[100] IRP Vol. I at 8-21 – 8-23; Companies' Response to JI 1-14.
[101] Companies' Response to PSC 1-13(a).
[102] IRP Vol. I at 5-25 to 5-27.
[103] Joint Intervenors Comments Exh. 1 at 22.
[104] *See* KRS 278.285, which became effective on July 15, 1994.

regulation's promulgation, there was not a statutory mechanism or set of evaluation criteria regarding DSM-EE programs. Since the enactment of the DSM statute, the Companies have filed multiple DSM-EE Program Plan applications, including four full DSM-EE applications since 2007. The Companies are currently only three and a half years into their current DSM-EE Program Plan, and just three weeks ago filed an application to increase the budget of their highly successful Non-Residential Rebates Program.[105] Notably, even if the Commission approves the Companies' requested budget enhancements for the Non-Residential Rebates Program, the Companies' WeCare Program, which is available exclusively to low-income customers, will still be the Companies' best-funded DSM-EE program by a substantial margin.[106] Thus, the Companies have in recent decades used the statutory DSM application process to evaluate and seek approval for new DSM-EE programs and then assumed the continuation of those levels of savings in their subsequent IRPs.

Therefore, although certain intervenors might desire a different DSM-EE approach in the Companies' IRPs, the Companies have used the same approach in previous IRPs and have done so consistent with past Commission Staff reports. The facts simply do not bear out any assertion that the Companies have not taken DSM seriously, either in actual practice or in their IRPs.

Finally with regard to DSM-EE, the Joint Intervenors' assertion that the Companies are forgoing cost-effective DSM to increase shareholder profits is incorrect. Kentucky's DSM statute gives utilities strong financial incentives to engage in cost-effective DSM and energy efficiency programs. As implemented by the Commission, those incentives include lost sales recovery,

[105] *Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company to Enhance the Budget of an Existing Demand-Side Management and Energy Efficiency Program*, Case No. 2022-00123, Application (Apr. 29, 2022).
[106] *Id.* at 7 ("Notably, the updated budget for the Nonresidential Rebate Program for 2022-2025 (about $16 million total) is still significantly less than the unchanged Commission-approved budget for the Residential Low-Income Program (WeCare) over the same time period (about $26 million).").

incentives based on operations and maintenance savings (incentives not available in any other context), and an incentive return on equity for capital invested in such programs. The Companies are well aware of these incentives and have traditionally had the most expansive and robust DSM-EE program portfolio in Kentucky. They have every reason to continue to do so, including the financial incentives provided by statute. Therefore, it is simply not true that the Companies are forgoing cost-effective DSM-EE programs to increase their profits; rather, the Companies are currently evaluating potentially cost-effective DSM-EE programs, which take time to analyze carefully and work through the DSM Advisory Group process.[107]

Regarding criticisms that the Companies did not include sufficient amounts of other types of DERs in their IRP analysis,[108] the Companies respectfully disagree for two reasons. First, the Companies adequately accounted for reasonably foreseeable DER scenarios with their low energy requirement forecast scenario, which assumed high DER penetration.[109] Second, given the IRP regulation's requirement that utilities seek to model resource portfolios to provide service reliably and at the lowest reasonable cost, there is no reason to model or include as a utility resource additional DERs. Such resources are not as economical as utility-scale renewable resources of the same kind, making modeling utility-scale resources significantly more favorable to the overall deployment of renewable resources and more consistent with the IRP regulation's focus on low-cost service. The Companies demonstrated this in their IRP filing, for example at IRP Vol. III at pages 9-10, which show that the levelized cost of energy for residential solar is significantly higher than for utility-scale solar. In addition, the current tariff arrangement for compensating net

[107] The Companies have committed to file their next full DSM-EE Program Plan application no later than the end of 2024 to ensure there will be no break in their DSM-EE programs. Notably, the Companies have committed to include an analysis of a PAYS-type program in their next DSM-EE Program Plan filing, which is a program the Joint Intervenors favor and filed comments to address.
[108] *See, e.g.,* Joint Intervenors Comments Exh. 1 at 8, 14-17, and 19-20.
[109] *See* IRP Vol. I at 5-34 – 5-39.

metering customers results in compensation that far exceeds the levelized cost of energy for utility-scale solar, so there is no reason to include additional net metering as a resource if the IRP regulation's goal of serving load at the "lowest possible cost" is indeed the objective of the analysis.[110]

VIII. THE COMPANIES' ANALYSIS OF ACHIEVING ZERO CARBON EMISSIONS BY 2035 AND THE COMPANIES' SOLAR INTERMITTENCY STUDY WERE REASONABLE

The Joint Intervenors devote several pages of comments to criticizing two documents produced in discovery, namely the Companies' analysis of achieving zero carbon emissions by 2035 and the Companies' solar intermittency study.[111] Although the documents were not part of the Companies' IRP filing, the Companies believe it is important to address certain criticisms here.

A. Responses to Criticisms of the Companies' Analysis of Achieving Zero Carbon Emissions by 2035.

An overarching response to the Joint Intervenors' criticisms of the Companies' analysis is that the Joint Intervenors did not attempt to run their own analysis; rather, they pointed to what did not appear reasonable to them. But as the Companies' responses below show, performing the actual analysis helps to understand why the Companies' assumptions and approach were reasonable.

Contrary to the assertion that "[t]he plan to meet a goal of carbon-free electricity by 2035 does not appear to have been optimized and is being compared to a plan that does not seem to include fuel or other non-capital expenditures,"[112] the Companies optimized the plan presented in the analysis over thousands of cases, as described further below. Also, the fuel costs the

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[110] *See* Kentucky Utilities Company, P.S.C. No. 20, First Revision of Original Sheet No. 58; Louisville Gas and Electric Company, P.S.C. No. 13, First Revision of Original Sheet No. 58.
[111] Joint Intervenors Comments Exh. 1 at 31-36. *See* Companies' Response to JI 2-52 Attachments 1 and 2 (Zero Carbon Emissions Analysis); Companies' Response to JI 2-60 Attachment 1 (Solar Intermittency Study).
[112] Joint Intervenors Comments Exh. 1 at 31.

Companies considered are listed in the table shown on slide 27 of the analysis.[113] Notably, the table with the fuel costs is in the Joint Intervenors' comments, though the portion of the table that contained the fuel costs was omitted.[114]

With regard to the criticisms that "[t]he analysis does not seem to be conducted subject to constraints that we would typically see for this analysis, including a reserve margin and operating reserve requirements" and "[t]he Companies modeled a load profile that was based on 2018 data and didn't include additional energy efficiency,"[115] by focusing on only one load scenario (2018 actual load) and by ignoring the need for operating reserves, the analysis provides a *conservative* estimate of the compliance cost, not an exaggerated estimate. Moreover, the analysis effectively assumes increases in load due to space heating and transportation electrification will offset decreases due to incremental energy efficiency savings, both of which assumptions are reasonable if achieving significant carbon emissions reductions in other sectors are to be achieved by 2035.

The Joint Intervenors further assert that "the Biden Scenario appears to be extremely costly because it includes extraordinarily unrealistic levels of capacity, over eight times the Companies' peak load on a nameplate basis."[116] Regardless of the Joint Intervenors' beliefs, these quantities of renewables and battery storage are needed to serve load in the winter during periods of colder than normal weather, low sunlight, and low wind speeds.[117] A smaller amount of renewables could be used, but additional battery storage would be required, which would result in significantly higher costs, not lower costs.

[113] Companies' Response to JI 2-52 Attachment 1, Slide 27.
[114] Compare table on Joint Intervenors Comments Exh. 1 at 33 with the table on Companies' Response to JI 2-52 Attachment 1, Slide 27.
[115] Joint Intervenors Comments Exh. 1 at 31.
[116] *Id.* at 32.
[117] *See* Companies' Response to JI 2-52 Attachment 1 at 20.

With regard to the Joint Intervenors' concern about how the Companies could have analyzed thousands of portfolios without using PLEXOS,[118] it is true that the Companies did not use PLEXOS for this analysis. Instead, the Companies partnered with the University of Kentucky College of Engineering, Department of Electrical and Computer Engineering, to analyze these thousands of portfolios on a high-powered computing cluster. The methodology for the simulations of both the generation and transmission were peer reviewed and published in the open-access journal Energies,[119] which contains all formulas necessary to recreate this analysis. The Companies provided the input data for the analysis in the Companies' response to the Joint Intervenors' data request that included the Companies' zero-carbon-emissions analysis.[120]

With regard to the Joint Intervenors' criticism that the Companies' analysis did not include "technologies widely assumed to be necessary to achieve the highest levels of carbon reduction such as long duration storage,"[121] the Companies modeled technologies that exist in the marketplace today. The Companies did not model technologies that they speculate, and indeed hope, will be available in the future, or that others have "assumed to be necessary" in the future. Rather, the focus of the Companies' analysis was on plausible, currently available means of achieving a certain goal. The Companies respectfully submit that relying on technology that does not yet exist to achieve an aggressive, short-term goal like zero carbon emissions by 2035 is unwise at best.

Concerning the duration of battery storage, the Companies' analysis used data for commercially available lithium-ion energy storage, the most common of which happens to be four

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[118] Joint Intervenors Comments Exh. 1 at 32.
[119] Available at https://www.mdpi.com/1996-1073/14/1/169.
[120] Companies' Response to JI 2-52 Attachment 3, available at https://psc.ky.gov/pscecf/2021-00393/andrea.fackler%40lge-ku.com/03252022110742/JI_DR2_KU_LGE_Attach_to_Q52_-_Att_3_Solar,_Wind,_Load,_Input_Data.xlsx.
[121] Joint Intervenors Comments Exh. 1 at 31 and 32.

hours in duration. But the size of individual lithium-ion battery cells is completely irrelevant in the Companies' analysis because the simulation estimated the total power and energy capacity, i.e., megawatts and megawatt-hours, independently. The duration of the battery is not a significant factor.

Finally, the Joint Intervenors remark, "It is curious that the amount of battery storage capacity more than doubles when moving from the 90% Clean to the 100% Clean scenario, yet the energy from battery storage drops from 11.5 TWh in the 90% Clean scenario down to 10 TWh in the 100% Clean scenario. …[this result] is incongruous and is not the result we would expect to see from a thoughtful optimization exercise."[122] Respectfully, this is exactly the kind of criticism that results from not having conducted one's own analysis and understanding that actually serving load requirements under a 90% clean energy requirement is a vastly different undertaking than meeting a 100% clean energy requirement if the objective is to serve load reliably at all hours of the day and night irrespective of the season or weather. It is not at all incongruous to expect that more battery storage would be needed in a 100% clean energy scenario even if one would anticipate drawing less total energy from that storage than in a 90% clean energy scenario precisely because of the production profiles of the generating units at issue in the two different scenarios. More total battery capacity—having a greater ability to serve instantaneous load with batteries—could easily be required when there are no dispatchable fossil-fueled resources available to serve load on hot nights or cold, cloudy days for relatively limited times even if, on the whole, because of additional renewable resources being added in the 100% clean energy scenario, total energy expected to be drawn from those batteries would be less in a given year than in a 90% clean energy scenario. In other words, the seemingly "incongruous" result is not unusual or unforeseeable at

[122] *Id.*

all, but rather arises from the difference between instantaneous demand and total energy and the differences in the production capabilities of various generating technologies compared to customers' demand patterns.

B. Responses to Criticisms of the Companies' Solar Intermittency Study.

With regard to the Joint Intervenors' assertions that "[t]he Companies' Solar Intermittency Study is out of sync with applicable balancing standards, current operating conditions, and the capabilities of modern renewable and storage systems" and the reasonableness of the Companies' acceptable imbalance levels,[123] the purpose of the study was to show at what point of solar penetration generation imbalances begin to significantly increase in frequency, duration, and severity, which would require renewable curtailments, energy storage, or other system improvements to maintain the level of reliability customers expect and the law requires. Given the Companies' current generation and transmission portfolio, imbalances increase by all means to measure them after 1,000 MW of solar capacity. To integrate more than 1,000 MW of solar capacity, significant changes to the Companies' generation and transmission systems would be required. The charts provided of imbalances at 5-minute intervals are one of many possible ways to visually analyze imbalances. Regarding applicable balancing standards, the Companies operate a system that complies with NERC Standard BAL-001-2 with overall compliance measured by Control Performance Standard 1. Using 5-minute and 10-minute targets for planning purposes avoids 15-minute imbalances that potentially violate NERC balancing standards, ensuring grid reliability. The Companies also analyzed imbalances at 10-minute and 15-minute intervals, which show the same general results.

[123] *Id.* at 34.

Concerning the Joint Intervenors' assertion that "[t]he Companies failed to consider the impact of applying automatic generation control ("AGC") systems to solar and failed to consider the capabilities of modern inverters …," the Joint Intervenors are simply mistaken.[124] The Companies did not fail to consider AGC. The Companies use AGC to balance load and generation in real time every day. As stated in the analysis, "The option to curtail surplus solar power, even at cost, is critical for increasing solar penetration."[125] The purpose of the analysis was to show at what point generation imbalances begin to significantly increase in frequency, duration, and severity, which would require renewable curtailments, energy storage, or other system improvements.

IX. THE COMPANIES' RTO ANALYSIS IS SUFFICIENT AND ACCURATELY INDICATES THAT RTO MEMBERSHIP IS NOT LIKELY TO BE FAVORABLE TO THE COMPANIES' CUSTOMERS AT THIS TIME

SREA has criticized the Companies' RTO membership analysis in a number of respects.[126] The Companies respectfully disagree with nearly all, if not all, of SREA's criticisms and recommendations.

A. The Companies Have Not Overlooked Large Energy or Capacity Market Benefits of RTOs.

Contrary to SREA's assertion, the Companies have not overlooked large energy and capacity market benefits of RTO membership; indeed, the Companies frequently trade in and interact with those markets, so they are not unknown quantities to the Companies.[127]

Regarding energy market benefits, because all energy trades in RTOs at Locational Marginal Prices ("LMPs"), there are two ways to receive energy market benefits: lower cost energy

[124] *Id.*
[125] Companies' Response to JI 2-60 Attachment 1 at 2.
[126] *See* SREA Comments Attachment B.
[127] *See* SREA Comments Attachment B at 10-16.

to serve the Companies' customers and the opportunity to make off-system sales. Regarding the former, the Companies rarely purchase economy energy from RTOs because the Companies' energy costs are nearly always lower than LMP, meaning there is little reason to expect there would be significant energy market benefits to the Companies and their customers from being in an RTO related to market purchases. Regarding off-system sales, the Companies already routinely sell into the MISO and PJM markets because the Companies' generation costs are routinely lower than LMPs in those markets. Therefore, the Companies have highly credible calculations regarding energy market benefits of RTO membership, and they are not significant.

Also, the Companies' energy pricing advantage is likely to decrease as they retire coal-fired generation and replace it with renewable generation precisely because that is what other utilities and merchant generators are doing. That would tend to reduce the potential energy market benefits of being in an RTO. Indeed, as more and more entities move from fossil-fueled generation to renewable generation, there are increasing chances of negative LMPs at times of peak sun, which have occurred at times in California, Texas, and MISO.[128]

Regarding RTO capacity markets and possible avoided capacity cost savings resulting from the reduced capacity needed to serve load and meet reserve margins due to RTO membership,[129] there are two important reasons to believe the Companies have not underestimated such claimed savings. First, the Commission has repeatedly and recently made it clear that it "has no interest in allowing our jurisdictional utilities to depend on capacity markets for the long-term service of its customers in satisfaction of utilities' obligation to provide adequate, efficient and reasonable

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[128] *See, e.g.,* https://fresh-energy.org/negative-prices-in-the-miso-market-whats-happening-and-why-should-we-care.
[129] SREA Comments Appendix B at 13-14.

service."[130] Second, the reality is that RTOs are facing genuine capacity shortages. This results from RTOs not having load-serving responsibilities and with too many member entities assuming other RTO member entities will have sufficient capacity to supply their needs, particularly as more fossil-fueled resources are retired and more renewable resources come online. To this exact point, MISO recently released documents reporting on their Planning Resource Auction for Planning Year 2022-2023 showing that, even after accounting for imported resources, MISO will be over 1,200 MW *short of capacity* in their north and central zones to meet their reserve margin requirement (the Companies would be in the central zone if they joined MISO) in part because dispatchable fossil-fueled capacity is decreasing while intermittent renewable capacity is increasing.[131] Staggeringly, MISO's solution to this shortfall is its willingness to "implement temporary, controlled load sheds" to prevent "uncontrolled, cascading outage[s]."[132] Therefore, the Companies do not believe that hypothetical capacity market benefits should drive a decision to enter an RTO because such benefits assume the Companies can retire generation, not replace it, and count on RTO markets to provide adequate capacity to serve load. That is a dubious proposition now more than ever. Rather than risk unacceptable "temporary, controlled load sheds," the Companies believe ongoing provision of safe and reliable service must be paramount.

Indeed, noting the capacity problems RTOs are facing brings to the fore the reality that being in an RTO means accepting a "market price" approach to reliability rather than an

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[130] *East Kentucky Power Cooperative, Inc.*, FERC Docket No. EL22-50-000, Protest and Answer of the Kentucky Public Service Commission in Opposition to the Petition of East Kentucky Power Cooperative, Inc. (Apr. 29, 2022). *See also Electronic Tariff Filing of East Kentucky Power Cooperative, Inc. and Its Member Distribution Cooperatives for Approval of Proposed Changes to Their Qualified Cogenerators and Small Power Production Facilities Tariffs*, Case No. 2021-00198, Order at 5 fn. 10 (Ky. PSC Oct. 26, 2021) ("This Commission has no interest in allowing our regulated, vertically-integrated utilities to effectively depend on the market for generation or capacity for any sustained period of time.").

[131] MISO 2022/2023 Planning Resource Auction (PRA) Results, April 14, 2022, at slide 5, available at https://cdn.misoenergy.org/2022%20PRA%20Results624053.pdf.

[132] *Id.* at 9.

engineering and analytical approach used by the Companies as a standalone utility. A utility in an RTO must comply with the RTO's tariffs and market design rules; it does not have an obligation to plan for and serve real-time load, which effectively becomes the role of the RTO *but without the legal obligation to serve*. That is why MISO can report that anticipating being short of capacity is not particularly problematic because it can simply shed load as needed. Such an approach is inconsistent with the load-serving obligation to provide safe and reliable service traditionally borne by Kentucky's utilities. Any decision to join an RTO should be a conscious, informed decision, not one influenced by likely illusory capacity market benefits.

B. Not Modeling Day-Ahead Markets Does Not Make the Companies' RTO Analysis Faulty.

SREA is mistaken in its assertion that not modeling day-ahead markets materially affects the Companies' RTO analysis.[133] There is no material arbitrage value between day-ahead and real-time markets. If there were a disconnect between day-ahead and real-time markets, the functioning of the market should quickly eliminate such arbitrage opportunities, or the market monitor would likely investigate for market manipulation. Thus, though it is true that there can be and are differences between day-ahead and real-time prices, they should be random and not a source of tradeable, sustainable value. Therefore, not including this aspect of RTO operations in the Companies' RTO analysis should not have had any material effect on it, and certainly not one that one should assume would overlook any kind of sustainable RTO market benefit.

[133] SREA Comments Appendix B at 12.

C. Not Modeling CO_2 Pricing in the RTO Analysis Does Not Make the Analysis Faulty.

SREA is mistaken in its assertion that "if there were a carbon price, and being in an RTO provided greater access to low-cost, low-carbon resources, this could very well shift the cost-benefit analysis in favor of joining the RTO."[134] Joining an RTO will not materially impact the Companies' access to renewables. In the Companies' recent RFPs, there has been no shortage of proposals for solar and wind. Moreover, as the Companies have already stated, the Companies are able to transact, and they routinely do transact, in RTO markets. If there were a generally applicable CO_2 price and the Companies found it beneficial for their customers to purchase renewable energy from RTO markets, they could do so even if they were not RTO members. Thus, there is little reason to believe that modeling CO_2 pricing scenarios in the RTO analysis would have any material impact on the conclusion of the analysis.

D. There Is Real Risk that RTO Transmission Cost Sharing Could Harm the Companies' Customers.

With regard to SREA's suggestion that it is possible that RTO membership might result in the Companies' customers benefitting from transmission projects being built with subsidies from other members,[135] the Companies respectfully respond that it is at least as likely that the Companies' customers would be compelled to subsidize other members' projects with little or no benefit to Companies' customers.[136] For example, though SREA suggests that "MISO did not allocate Multi Value Project ("MVP") costs to Entergy South upon its integration, so LG&E KU

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[134] SREA Comments Appendix B at 36.
[135] *Id.* at 17-19.
[136] The Commission recently discussed the significant adverse impact to Kentucky Power that resulted from its involvement in the AEP East zone in PJM, namely that Kentucky Power's customers paid tens of millions of dollars for transmission system improvements that were not for their benefit. *See Electronic Joint Application of American Electric Power Company, Inc. and Liberty Utilities Co. for Approval of the Transfer of Ownership and Control of Kentucky Power Company*, Case No. 2021-00481, Order at 28, 36, 44, and 49-51 (Ky. PSC May 4, 2022).

may also avoid MVP cost allocation if it negotiates for it,"[137] this overlooks the vastly different geographical and electrical situations of the Companies versus Entergy South: Entergy South is electrically isolated from the northern portion of MISO North, where most of the 2011 MVP projects are located, but the Companies are not similarly isolated and therefore would not have the same arguments against MVP cost allocation. Thus, rather than gamble that the Companies' customers would be winners in the transmission ox-goring contest, the Companies believe the better course is not to not make such a speculative assumption in their analysis of possible benefits of RTO membership. The Companies will continue to update their current analysis and report it to the Commission as required.

E. There Is Insufficient Reason at this Time to Engage with RTOs for Further Analysis.

SREA also criticizes the Companies for not engaging RTOs to assist with the RTO analysis.[138] Suffice it to say that there is little reason to believe RTOs would be neutral parties in any such analyses. Moreover, because the Companies' current RTO analysis does not suggest the business case is close enough to merit committing additional resources to it at this time, further engagement with RTOs on this issue is not merited or an effective use of resources.

F. The Companies' SEEM Membership Offers More Concrete Benefits without Compromising Reliable Service.

It is precisely because the RTO construct appears to be creating real reliability problems that a membership arrangement like the Companies' arrangement with SEEM, which SREA criticizes,[139] is more favorable for the Companies' customers, at least at this time. SEEM will allow more trading to occur among members with lower transaction costs but will not compromise

[137] SREA Comments Appendix B at 19.
[138] *See id.* at 5.
[139] *See, e.g.*, SREA Comments Attachment B at 5-6.

any member's obligation to serve its own customers safely and reliably. Therefore, whereas RTO membership benefits are more speculative, SEEM membership offers more concrete cost benefits.

X. CONCLUSION

The Companies respectfully submit that their IRP fully satisfies the letter and objective of the Commission's IRP regulation, as well as the recommendations of past Commission Staff reports on the Companies' previous IRPs. The comments offered by the intervenors do not demonstrate anything to the contrary. Though the Companies desire and seek continually to improve their forecasting and planning processes, few of the intervenors' comments pertain to that topic; rather, most advocate for objectives other than what the Commission's regulation states is the purpose of an IRP, namely to engage in planning that furthers ongoing reliable service at the lowest reasonable cost. Therefore, the Companies believe that many of the intervenors' comments are not constructive.

The Companies believe the Commission should not depart from the established informal, constructive, and non-adversarial IRP process that recognizes that the outcome of an IRP proceeding is not a binding resource plan but rather a Commission Staff report about how to improve future IRPs.

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Respectfully submitted,

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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 May 20, 2022; 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