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	)	

JOINT INTERVENORS' SUPPLEMENTAL COMMENT ON LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY'S JOINT 2021 INTEGRATED RESOURCE PLAN

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Metropolitan Housing Coalition, Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association (collectively, "Joint Intervenors") offer these Supplemental Comments on the 2021 Joint Integrated Resource Plan ("IRP") of Louisville Gas and Electric Company and Kentucky Utilities Company ("LG&E/KU" or "the Companies"). These Supplemental Comments reply to the Companies' May 20, 2022 Responsive Comment and the evidence developed over the course of the administrative hearing, held before the Public Service Commission ("Commission" or "PSC") on July 12–13, 2022, in Frankfort, Kentucky.

INTRODUCTION

Joint Intervenors provide these supplemental comments in light of the additional facts and argument adduced in LG&E/KU's Responsive Comment and through cross-examination from the administrative hearing. Beginning with LG&E's Responsive Comment, Joint Intervenors note that, for all the pages of argument, LG&E/KU did not give a strong sense of collaboration. Notwithingstanding, there is substantial common ground here. Joint Intervenors agree with LG&E/KU in a number of respects: the "IRP proceeding is intended to be informal, constructive, and non-adversarial"[1]; "renewable resources can contribute to reliable and economical service."[2]; an IRP should not be treated as "a binding resource plan that a utility must execute."[3]

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[1] Responsive Comments of Louisville Gas and Electric Company and Kentucky Utilities Company ("LG&E/KU Response Comment") at 1 (May 20, 2022).

[2] *Id.*, Heading IV.D. Renewable Resources Can Contribute to Reliable and Economical Service.

[3] *Id.* at 1.

Those commonalities notwithstanding, there are also significant differences in opinion and interests: for example, Joint Intervenors maintain that informal, non-adversarial proceedings can be enriched through pre-filing stakeholder meetings; that all resources capable of contributing to reliable and economical service should be modeled in the course of long-range resource planning; and that Integrated Resource Plans should result in a long-range plan, that particularly in the near-term, transparently discloses and guides real-world utility resource decisions.

In the following sections, Joint Intervenors offer additional fact and argument on a variety of topics, delving into details developed since our Initial Comments. The topics prioritized by Joint Intervenors might be called "low-hanging fruit," each coming down to practical adjustments to make the Companies' modeling exercises and planning processes more robust using the resources and foundation that the Companies already have in place.

Section I furthers dialogue on the history of Kentucky's Integrated Resource Planning regulation, noting LG&E's particular history of misjudgments in generation planning, and makes the unremarkable case for expecting "integrated resource planning" to result in an actual plan. Section II summarizes foundational weaknesses and subsequent developments rendering the Companies' 2021 IRP unreliable, with recast modeling necessary before undertaking any action. Section III revisits Joint Intervenors' critiques of the Companies' approach to demand-side resources, surveys the hearing testimony confirming those critiques, and offers suggestions to correct the Companies' apparent disregard for cost-effective demand-side resources. Section IV responds to the Companies' disregard for customer impacts and environmental risks. Section V revisits potentially cost-effective resource options that were excluded from the analysis entirely or practically, via unrealistic cost assumptions. Sections VI and VII further discussion on two critical methodological choices in IRP modeling: the importance of fully utilizing modeling capabilities to simulate the entire planning period and to estimate production costs of multiple portfolios under a variety of future scenarios. Finally, Section VIII re-emphasizes unanswered critiques of the Companies' solar intermittency study.

Overall, Joint Intervenors urge that the recommendations advanced in their Initial Comment be adopted by the Companies in their next integrated resource plan and that Commission Staff incorporate those recommendations to guide development of the next plan.

DISCUSSION

I. Integrated Resource Planning Should Be a Real-World Planning Exercise, Enabling Least-Cost Decisions, Enhancing Transparency, and Providing the Foundation for Future Action.

Joint Intervenors appreciate the Companies' survey of the history and plain text of the IRP regulation,[4] yet find it incomplete. In this section, Joint Intervenors will further develop the regulation's animating history, and further clarify our normative position on what good integrated resource planning is and why it is essential to effective utility management. Fundamentally, Joint Intervenors urge the Companies to treat IRPs as real-world planning exercises that transparently report a utilities' long-term resource plan in the face of unavoidable uncertainty and subjectivity.

A. LG&E's inconvenient history of long-range resource planning

LG&E/KU provided a ten-page discussion of the regulatory history underlying the Commission regulation,[5] but neglected to mention how LG&E's own planning foibles in the late

[4] *Id.*, Section II., at 4–15.

[5] *Id.*, Section II., at 4–15.

1970s and 80s catalyzed it all.[6] Joint Intervenors offer that LG&E's role was significant and should not be forgotten—lest those mistakes be repeated.

Decades ago, before there were any regulatory requirements for long-range resource planning in Kentucky, LG&E demonstrated the staggering costs of poor planning with its plan for two new coal-fired units in Trimble County. LG&E obtained a certificate in October 1978, for two 495 MW-nameplate coal-fired generating units at a cost of $542,600,000, or roughly $548,080/MW.[7] It was not long before LG&E cancelled one of the two units, cutting the project capacity in half, and delayed the remaining unit several years:

> On October 19, 1978, Louisville Gas and Electric Company ("LG&E") was granted a [CPCN] to construct two 495 megawatt ("MW") coal-fired steam turbine generating units in Trimble County. LG&E's plan at the time the certificates were granted was to complete construction of Trimble County Unit No. 1 by 1983 and the second unit by 1985. In 1978 the projected cost for the completed construction of both units was approximately $542.6 million. Since receiving the certificates LG&E has cancelled the second unit at Trimble County, delayed the completion of the first unit to 1988 and raised the cost estimate for Trimble County No. 1 to $737.9 million.[8]

Delayed construction had been costly, but there was such a glut of capacity that even after cancelling the second unit, LG&E was uncertain that construction on even a single unit still made sense.[9] Several parties in LG&E's then-recent rate case, scrutinized and "challenged

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[6] *An Investigation and Review of Louisville Gas and Electric Company's Capacity Expansion Study and the Need for Trimble County Unit No. 1*, Case No. 9243, Order (Ky. PSC Oct. 14, 1985).

[7] *Id.* at 1.

[8] *Id.*

[9] *General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company*, Case No. 8924, Order at 32–33 (KY. PSC May 16, 1984) ("More fundamental than the issue of allowing CWIP or accruing AFUDC is whether Trimble County should be built at all . . . . The Commission believes that the management of LG&E is responsible for deciding the fate of Trimble County and the record in this case clearly reflects that LG&E would prefer to perform additional studies before deciding the proper course to follow.").

continuation of a cash return on LG&E's construction work in progress balance . . . ."[10] That, in turn, prompted LG&E to restudy the need for even a single Trimble County unit, through a new capacity expansion study.[11]

Meaning, six years *after* issuance of the certificate, LG&E was back to the drawing board, with millions already down the drain and more at risk. At best, customers were looking at a half-sized project with nearly tripled costs on a per megawatt basis ($1,490,707/MW), and the need for the project—even at half-size—remained unclear. Called to address LG&E's situation, the Commission ordered a further three-year construction delay for the single unit.[12]

But the Commission did not stop there. The Commission lamented the considerable glut of capacity in the state, reflecting utilities' failures to plan better than their own self-interest required, and resolved to systematically address electric utilities' generation planning:

> The Commission intends, as soon as possible, to develop, analyze, and implement statewide options that will be beneficial to Kentucky ratepayers. This will be accomplished through a cooperative effort with all interested parties, including the utilities, and through the services of an independent consultant. These options include targeted conservation, aggressive load management, additional bilateral exchanges among the state's utility companies, marketing the state's generation capacity to other regions of the country, joint ownership of generating capacity, installing alternative types of capacity, refurbishing older generating units, and establishing a centrally dispatched pooling arrangement.[13]

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[10] *An Investigation and Review of Louisville Gas and Electric Company's Capacity Expansion Study and the Need for Trimble County Unit No. 1*, Case No. 9243, Order at 2 (Ky. PSC Oct. 14, 1985).

[11] *Id.* at 1–2.

[12] *Id.* at 24–25.

[13] *Id.* at 23 ("A total of 51 plans are used in the S&W study originally filed. In order to compare the various plans, the present worth revenue requirements associated with each plan are calculated."); *see also General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company*, Case No. 8924, Order at 33 (KY. PSC May 16, 1984).

The Commission was unmistakably concerned about poor generation planning generally, and in LG&E's particular case.[14] LG&E became the spark igniting the Commission's generation planning investigation docket.[15]

B. The IRP regulation and common-sense call for examination of all potentially cost-effective resources, if the aim is lowest-cost planning.

As reflected in the Commission response to LG&E's wasteful Trimble County episode, examining all alternatives, including the "no action" alternative, is the tried-and-true method to ensure prudent, low-cost generation choices. That expectation was there when the Commission first wrote of its resolve to open an investigation docket concerned with generation planning[16] and it infuses the final regulation:

> **807 KAR 5:058 Section 5. Plan Summary** . . . . The [plan] summary shall include at a minimum: . . . (4) Summary of the utility's planned resource acquisitions including improvements in operating efficiency of existing facilities, demand-side programs, nonutility sources of generation, new power plants, transmission improvements, bulk power purchases and sales, and interconnections with other utilities;

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[14] *See, e.g.*, *General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company*, Case No. 8924, Order at 33 (KY. PSC May 16, 1984) (announcing in LG&E rate case order, that "[t]he Commission intends to move forward with Case No. 8666, Statewide Planning for the Efficient Provisions of Electric Generation and Transmission Facilities, to review not only the need for Trimble County, but also the future generation needs and construction plans of other electric utilities regulations by this Commission. Case No. 8666 will provide the opportunity for LG&E and other interested parties to present evidence of the need, or lack thereof, for Trimble County. The options to be considered will include, but not necessarily be limited to, further deferrals of Trimble County, cancellation of Trimble County, the installation of alternative types of generating units, purchasing capacity, refurbishing older generating units, joint ownership of generation capacity, power pooling, and other options. The Commission will consider these same options when reviewing the generation requirements and construction plans of all electric utilities.").

[15] *An Inquiry into Kentucky's Present and Future Electric Needs and the Alternatives for Meeting Those Needs*, Admin. Case No. 308, Order at 1 (Ky. PSC Oct. 9, 1986) (noting recent orders indicating intention to establish docket to review plans to meet electricity needs, and citing only the Oct. 14, 1985 Order in Case No. 9243, focuses on the need for Trimble County Unit No. 1).

[16] *Id.* at 1.

807 KAR 5:058 Section 8. Resource Assessment and Acquisition Plan.
(1) The plan . . . shall include assessment of potentially cost-effective resource options available to the utility.
(2) The utility shall describe and discuss all options considered for inclusion in the plan including:

> (a) Improvements to and more efficient utilization of existing utility generation, transmission, and distribution facilities;
> (b) Conservation and load management or other demand-side programs not already in place;
> (c) Expansion of generating facilities, including assessment of economic opportunities for coordination with other utilities in constructing and operating new units; and
> (d) Assessment of nonutility generation, including generating capacity provided by cogeneration, technologies relying on renewable resource, and other nonutility sources.

Reasonable minds must agree that the IRP regulation requires electric utilities to make searching inquiries, identifying and testing all potentially cost-effective options, with the aim of determining the optimal least-cost mix. It is common sense, codified.

As a practical matter, it is hard to overstate the significance of this fundamental methodological premise, as the Regulatory Assistance Project's 2013 report, *Best Practices in Electric Utility Integrated Resource Planning* explains:

> Integrated resource planning has many benefits to consumers, and other positive impacts on the environment. This is a planning process that, if correctly implemented, locates the lowest practical costs at which a utility can deliver reliable energy services to its customers. IRP differs from traditional planning in that it requires utilities to use analytical tools that are capable of fairly evaluating and comparing the costs and benefits of both demand- and supply-side resources. The result is an opportunity to achieve lower overall costs than might result from considering only supply-side options. In particular, the inclusion of demand-side options presents more possibilities for saving fuel and reducing negative environmental impacts than might be possible if only supply-side options were considered.[17]

[17] Wilson, Rachel and Bruce Biewald, Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans (June 2013).

Cohesive analyses that put *all* resources on equal footing are unquestionably at the heart of good integrated resource planning. Here, the analytical tools designed for exactly that are at hand.

The Companies have computational modeling software capable of "fairly evaluating and comparing . . . both demand- and supply-side resources,"[18] and they need to take advantage of its full capabilities if they want their integrated resource planning to work.[19] Nothing against the intuitive hunches of a collection of the Companies' employees,[20] but with over $6,000,000,000 of rate base and growing at issue, it is essential to explore how powerful computational models might optimize resource decisions and timing across a long-term horizon.[21]

Joint Intervenors continue to encourage Commission Staff to recommend that LG&E and KU's next IRP rely on resource expansion modeling that fairly characterizes all resources and sets all resources on an even playing field for the software to optimize over the entire planning period.

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[18] *Id.*

[19] *See* EFG Report, Section 1.4 (listing modeling recommendations) *and* Section 3.6 (recommendations to appropriately characterize DSM and DERs in future IRP modeling).

[20] *E.g.*, July 12, 2022 Hearing, Cross-examination of Companies' Witness Wilson ca. 8:23 (confirming, in response to questions from Chairman Chandler, the Companies relied on intuitive knowledge of system rather than modeling economically optimal unit retirements, which the model certainly could have done)); July 12, 2022 Hearing, Cross-examination of Companies' Witness Sinclair ca. 13:31 (explaining Companies did not model out-of-state renewables, and instead assumed based on older analyses that such resources would be categorically uncompetitive).

[21] As raised by Chairman Chandler, "If you know the model can make the appropriate economic choice, qualitative decisions aside, . . .why not just see what the analysis puts out." July 12, 2022 Hearing ca. 8:23:40.

C. *By definition, an Integrated Resource Planning exercise should result in a "plan" that the utility provisionally expects to implement.*

LG&E/KU, it seems, urge that because the IRP regulation does not require a binding resource plan, it must not require a plan at all.[22] With this argument, the Companies reduce the IRP process to an absurdity. However, by definition, the integrated resource planning regulation requires regulated utilities to report a ***plan*** to the Commission and the public.[23]

That much is obvious from the plain language of the regulation, as well as its object and policy. Under Kentucky law, statutory rules of construction and interpretation also guide interpretation of administrative regulations.[24] When interpreting administrative regulations, "it is imperative that we give the words . . . their literal meaning."[25] Meaning must also be derived by "look[ing] to the provisions of the whole statute and its object and policy."[26]

The IRP regulation refers to a "plan" no fewer than twenty-six times. The literal meaning of "plan" in this context would be "a method of achieving an end" or "an orderly arrangement of

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[22] LG&E/KU Response Comment at 13 (explaining that the Companies do not intend to pursue the base-load, base-fuel scenario resource plan, which provided the foundation for the financial information required by section 9 of the IRP regulation).

[23] *E.g.*, 807 KAR 5:058(1)(2) ("Each electric utility shall file triennially with the commission an integrated resource plan."); *id.* § (5)(5) (requiring each electric utility's integrated resource plan to include "[s]teps to be taken during the next three (3) years to implement the plan"). *See e.g.*, *Electronic 2021 Integrated Resource Plan of Duke Energy Kentucky, Inc.*, Case No. 2021-00245, Duke Energy Kentucky 2021 Integrated Resource Plan (public version) at 64–67 (Ky. PSC June 21, 2021). https://psc.ky.gov/pscecf/2021-00245/kristen%40gosssamfordlaw.com/06212021013847/DUKE_ENERGY_KENTUCKY_2021_IRP_-_PUBLIC_VERSION_-_210621.pdf. (providing overview of 2021 IRP's preferred plan).

[24] *Comprehensive Home Health Servs., Inc. v. Prof. Home Health Care Agency, Inc.*, 434 S.W.3d 433, 441 (Ky. 2013) (citing *Revenue Cabinet v. Joy Techs., Inc.*, 838 S.W.2d 406 (Ky. App. 1992)).

[25] *Samons v. Ky. Farm Bureau Mut. Ins. Co.*, 399 S.W.3d 425, 429 (Ky. 2013).

[26] *Id.* (citing *Cosby v. Commonwealth*, 147 S.W.3d 56, 59 (Ky. 2004)).

parts of an overall design or objective."[27] That literal meaning comports with the object and policy of the IRP regulation, namely: "prescrib[ing] rules for regular reporting and commission review of load forecasts and resource plans of the state's electric utilities . . . ."[28] "Each electric utility shall file triennially with the commission an integrated resource plan,"[29] and that plan should propose specific actions: "The plan . . . shall discuss the facts, assumptions, and conclusions upon which the plan is based **and the actions it proposes**."[30] The plan must also discuss "[s]teps to be taken during the next three (3) years **to implement the plan**,"[31] and "key issues or uncertainties that could affect **successful implementation of the plan**."[32]

As the regulation makes plain, while utilities retain the responsibility and flexibility to respond to ever-changing conditions, they are nonetheless expected to regularly report to the Commission an actual plan that they provisionally expect to implement. The Companies seem to dispute this unremarkable conclusion that their integrated resource plan must identify an actual plan, yet never offer any explanation of how that interpretation could possibly square with the plain language of the regulation.

Instead of endeavoring toward a robust, real-world analysis and identification of a preferred resource plan in the 2021 IRP, the Companies' approach was to offer an IRP that illustrates the obvious: the lowest-cost portfolio in the year 2035 will vary based on different

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[27] plan (noun), Merriam-Wester, https://www.merriam-webster.com/dictionary/plan (last visited Aug. 22, 2022).

[28] 807 KAR 5:058

[29] *Id.* § (1)(2).

[30] *Id.* (emphasis added).

[31] *Id.* § (5)(5) (emphasis added).

[32] *Id.* § (5)(6) (emphasis added).

load and fuel price conditions.[33] That obvious fact is where an IRP should begin—not end. The IRP should conclude every three years with reporting and review of a preferred plan, including proposed actions to implement that plan over the next three years and discussion of potential implementation challenges.[34]

But the Companies make plain that one cannot look at their 2021 IRP and discern what portfolio decisions the Companies intend to make. The Companies' Responsive Comment confirms that it would be a mistake to assume they intended to pursue the portfolio identified in the base load, base fuel price scenario—the only resource plan for which they provide required financial information.[35] Then, under questioning from the Commissioners, the Companies' witnesses disclosed for the first time that they intend to submit two 660-MW combined cycle gas plant projects in response to their outstanding RFP (and have already submitted the projects to their Generation Interconnection Queue).[36] Yet on the face of the Companies' 2021 IRP, there is no hint of pursuing a combined cycle plant now or later.[37]

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[33] LG&E/KU Response Comment at 37 ("The Companies developed their IRP to demonstrate how the least-cost generation portfolio varies with load and fuel prices.").

[34] *See e.g.*, *Electronic 2021 Integrated Resource Plan of Duke Energy Kentucky, Inc.*, Case No. 2021-00245, Duke Energy Kentucky 2021 Integrated Resource Plan (public version) at 64–67 (Ky. PSC June 21, 2021). https://psc.ky.gov/pscecf/2021-00245/kristen%40gosssamfordlaw.com/06212021013847/DUKE_ENERGY_KENTUCKY_2021_IRP_-_PUBLIC_VERSION_-_210621.pdf. (providing overview of 2021 IRP's preferred plan).

[35] LG&E/KU Response Comment at 13. *See also* Post-Hearing Comments of Kentucky Industrial Utility Customers, Inc. at 1 (continuing to mistakenly assume that LG&E/KU intends to pursue the base load, base fuel scenario portfolio).

[36] July 13, 2022 Hearing, Cross-Examination of Companies' Witness Schram ca. 14:05.

[37] 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company, Volume I, 2021 IRP Long-Term Resource Planning Analysis at tbl. 5-19 ("2021 IRP, Vol. I") (summarizing least-cost resource portfolios identified in each of nine scenarios, none of which call for combined cycle gas generation).

In defense of not transparently reporting a long-range resource plan, the Companies' Responsive Comment cites Commission Staff comments on Duke Energy Kentucky's latest 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 that can greatly alter long-range plans."[38] Joint Intervenors could not agree more with Commission Staff. The planning process must be iterative and ongoing: each triennial integrated resource plan is reported at a specific time, ideally based on the most recent information then-available, and it is essential to respond to new information, opportunities, and risks. In this respect, the Companies are absolutely right to perform additional analyses before seeking any CPCN.[39] The Companies, however, are wrong to conclude from this that they are not required by the IRP regulation to report a **plan**, reflecting the resource decisions the Companies would make, and why, based on what was known at the time.[40]

The Companies are similarly wrong to suggest that there should be a difference between "doing things for real versus the planning."[41] In order to provide a sound foundation for "doing things for real," planning must be based in robust, real-world assessments of all reasonable

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[38] LG&E/KU Response Comment at 13 (quoting Case No. 2021-00245, Order Appx. at 32 (Ky. PSC Aug. 8, 1990)).

[39] *Id.*

[40] *E.g.*, *Electronic 2021 Integrated Resource Plan of Duke Energy Kentucky, Inc.*, Case No. 2021-00245, Duke Energy Kentucky 2021 Integrated Resource Plan (public version) at 64–67 (Ky. PSC June 21, 2021) https://psc.ky.gov/pscecf/2021-00245/kristen%40gosssamfordlaw.com/06212021013847/DUKE_ENERGY_KENTUCKY_2021_IRP_-_PUBLIC_VERSION_-_210621.pdf (providing overview of 2021 IRP's preferred plan and explaining basis for subjective judgments and balancing of risk in resource plan); *Electronic 2022 Integrated Resource Plan of East Kentucky Power Cooperative, Inc.*, Case No. 2022-00098, East Kentucky Power Cooperative 2022 Integrated Resource Plan (public version) at 166 (Ky. PSC June 21, 2021) https://psc.ky.gov/pscecf/2022-00098/Jessica.Fitch-Snedegar%40ekpc.coop/04012022085400/2022-00098_-_REDACTED_EKPC_2022_IRP.pdf (reporting plan for resource additions).

[41] July 12, 2022 Hearing, Cross-Examination of Companies' Witness Sinclair ca. 17:39.

alternatives. When it comes to the quality and rigor of analysis, there should be very little difference between "what goes on in the planning world versus the CPCN real world,"[42] with planning providing the necessary foundation for real-world decisions.

The Commission, its Staff, and all stakeholders should be able to pick up the Companies' IRP and have some sense of the Companies' near-term plans, subject to further analysis in light of changing circumstances, until superseded by the next iteration of the triennial resource plan. The regulation requires nothing less. Joint Intervenors maintain that the Companies are required to present their preferred resource plan in each and every IRP filing.

D. The Companies' integrated resource planning exercise could be improved with early and substantive stakeholder engagement.

The Companies' Responsive Comment includes a section opposing the pre-filing IRP stakeholder processes,[43] recommended by Joint Intervenors.[44] According to the Companies, that degree of collaboration is unnecessary, with the IRP proceeding itself amounting to a stakeholder process.[45] Joint Intervenors respectfully disagree, and maintain that the Companies' integrated resource planning would benefit from early, ongoing, and substantive stakeholder engagement.

Pre-filing engagement with stakeholders is consistent with the Companies' view of integrated resource planning as informal, constructive and non-adversarial. As summarized in the EFG Report, pre-filing engagement with stakeholders has materially improved the planning processes of other utilities and lessened the disputed issues in IRP proceedings.[46] Joint

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[42] July 12, 2022 Hearing, Cross-Examination of Companies' Witness Sinclair ca. 13:18.

[43] LG&E/KU Response Comment at 14–15.

[44] EFG Report, Section 3.1 at 12–13.

[45] LG&E/KU Response Comment at 14–15.

[46] EFG Report, Section 3.1.

Intervenors' experts have reviewed over 100 integrated resource plans in their combined twenty-five years of experience, finding pre-filing stakeholder meetings typical.[47] Joint Intervenors' experts summarized the benefits of such processes:

> In our experience, this process allows the utility to adjust its IRP to accommodate stakeholder concerns, better understand the perspectives of stakeholders, and allows stakeholders to understand the Companies' thought process and concerns. This can help narrow the issues the staff must consider as well as improve the ability of the IRP to address stakeholder concerns. It's our experience that only involving stakeholders after the IRP is filed results in little meaningful engagement and tends to delay improvements that would otherwise be made in subsequent IRPs.[48]

The Companies nowhere dispute these advantages to a pre-filing stakeholder process and do not complain that it would be inconvenient or burdensome to pursue pre-filing stakeholder engagement.

The IRP regulation neither requires nor precludes this sort of pre-filing engagement, leaving the Companies free to pursue it, the Staff free to recommend it, and the Commission free to order it pursuant to general authority.[49] Joint Intervenors maintain that pre-filing stakeholder discussions could greatly improve the Companies' iterative integrated resource planning. For example, in the current proceeding, had there been pre-filing stakeholder meetings, Joint Intervenors' modeling experts could have informed the Companies on the variety of ways their modeling software is capable of modeling demand-response resources on equal footing with their supply-side counterparts; and perhaps Commission Staff would have encouraged more consistent application of carbon risk assumptions earlier in the modeling process. Those are but two

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[47] EFG Report at 13.

[48] *Id.*

[49] KRS 278.040(3); KRS 278.230(3).

examples of issues that could have been discussed with the Companies in advance of their modeling, and would have made that modeling more robust and useful in decision-making.

To their credit, upon request, the Companies allowed their modeling team to confer directly with Joint Intervenors' modeling experts following the Companies' initial responses to data requests. Joint Intervenors' laud the Companies' willingness to collaborate in that non-adversarial manner, which assuredly helped provide mutual understanding of a common set of facts. Joint Intervenors' sincere interest in non-adversarial collaboration animated that early outreach and the recommendation to convene pre-filing stakeholder processes.

For these reasons, Joint Intervenors continue to recommend to the Commission Staff that their Report should "[e]ncourage the Companies to establish an ongoing IRP stakeholder process for the purpose of considering and inviting stakeholder input and review on certain potentially complex changes to the Companies' IRP methodology, inputs, and assumptions including, but not limited to:

a. The Companies' reserve margin study;
b. The development and modeling of the portfolios considered in the IRP;
c. The manner in which unit retirement is evaluated;
d. The RTO membership analysis;
e. The source of and manner in which new resource costs and supply are developed, e.g., demand-side management ("DSM") and other distributed energy resources (DERs); and
f. The modeling tools used in the development of the IRP."[50]

[50] EFG Report at 8.

II. The Companies' 2021 IRP has Little Value Based on Several Critical Factors and Subsequent Developments.

Joint Intervenors' Initial Comment noted that, due to flaws in the Companies' integrated resource planning exercise, the 2021 IRP does not and cannot not provide sound evidentiary support for selection of new generation resources or assumed retirement dates for existing units.[51] While never suggesting that a substantive Commission order would result from this IRP proceeding,[52] Joint Intervenors maintain that IRPs should advance utilities' "real-world" planning efforts, and that robust analyses of resource options cannot and *should* not be deferred until the Companies are ready to imminently file a CPCN application.[53] Rather, the triennial IRPs should reflect robust analyses resulting in an actual plan, and those analyses should be reexamined and updated at times when the utility acts on their integrated resource plan with a CPCN application.

Since those Initial Comments, the limited value and validity of the Companies' 2021 IRP has become even more plain. Joint Intervenors' April modeling critiques have been largely confirmed: the Companies modeled only a single year of the planning period, rather than using the model's full capability to optimize the timing of resource retirements and additions; the Companies nowhere identify a preferred portfolio or plan they provisionally intend to implement in the near-term; the Companies performed production cost modeling on a single portfolio in a single scenario, making portfolio performance in different conditions unknowable and

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[51] Joint Intervenors' Initial Comment at 1.

[52] The Companies' Response Comment, Section II, argues at length against non-binding resource plans, without providing citation to any particular intervenor comment. Joint Intervenors' Initial Comment did not urge a construction of the IRP regulation including a binding resource plan, and to the extent Section II of the Companies' Response is directed to Joint Intervenors, the Companies argue against a figment.

[53] *Contra* LG&E/KU Response Comment at 13.

comparison between portfolios impossible; the Companies neglected analysis of the potential cost-effectiveness of continuing or expanding DSM-EE programs and DERs, thus entirely marginalizing demand-side potential; the Companies paid no heed to the needs of their low- and fixed-income customers and made no effort to assess customer impacts flowing from different resource decisions; and the Companies neither consistently nor comprehensively evaluated risks associated with greenhouse gas emissions.

In addition to those critiques, it is also now clear that the Companies did not appreciate or evaluate the potential risks of future methane emission constraints or pricing. These risks disfavor coal- and gas resources, with both fuel types causing significant levels of climate-harming methane emissions.[54] Overlooking methane risks for gas generation appears particularly shortsighted, with recent passage of the Inflation Reduction Act ("IRA"). In the IRA, Congress authorizes a methane reduction program,[55] applying to, *inter alia*, on- and off-shore natural gas production; onshore natural gas processing; gathering and boosting of natural gas; natural gas transmission; underground natural gas storage; and liquified natural gas storage.[56] The program

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[54] *See, e.g.*, Tom Rickey, *News Release: Methane Emissions from Coal Mines Are Higher Than Previously Thought*, Pacific Northwest National Laboratory (Jan. 27, 2021) https://www.pnnl.gov/news-media/methane-emissions-coal-mines-are-higher-previously-thought (announcing new study presented by Pacific Northwest National Laboratory, the EPA and others finding higher methane emissions from coal mining than previously estimated); Jonathan L. Ramseur, *Inflation Reduction Act Methane Emissions Charge: In Brief*, Congressional Research Service (Aug. 4, 2022) https://crsreports.congress.gov/product/pdf/R/R47206 ("Methane (or CH4) is the primary component of natural gas.").

[55] Inflation Reduction Act of 2022, H.R. 5376, 117th Cong. § 60113 (2022) https://www.democrats.senate.gov/imo/media/doc/inflation_reduction_act_of_2022.pdf.

[56] *Id.* § 60113(d) (listing applicable facilities by industry segments).

requires emissions reporting and imposes a charge on methane emissions, beginning at $900 per ton in 2024, and increasing annually to $1,500 per ton by 2026.[57]

Further disfavoring coal- and gas-fired resources in the real world, actual fuel prices have remained higher than even the "high" price scenarios used in the IRP analysis.[58] Joint Intervenors acknowledge that fuel and energy prices have been uniquely difficult to forecast in recent years for a number of reasons, making it not especially surprising that the Companies' IRP forecasts are already so stale and understated. But the fact remains that the modeled fuel price forecasts made the costs of coal- and gas-fired resources appear artificially low, inaccurately favoring those resources in the planning exercise.

The IRA's impacts on coal- and gas-supply prices necessitates recasting of the Companies' fuel price forecasts, and that is just one of the provisions driving economic changes in the energy sector. In total, the IRA commits roughly $369 billion toward energy and climate measures over ten years, including modification and extensions of the production tax credit and investment tax credit; $27 billion toward a Greenhouse Gas Reduction Fund; $10 billion toward a revised and extended advanced energy project credit; modifying, expanding, and extending energy efficiency credits for homes and businesses; an additional $10 billion to DOE building efficiency programs. Joint Intervenors acknowledge that LG&E/KU could not have foreseen passage of the IRA, much less the specific contours of the enacted bill. And still, it is a

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[57] *Id.* § 60113(e) (establishing methane charge amount) https://www.democrats.senate.gov/imo/media/doc/inflation_reduction_act_of_2022.pdf.

[58] *Compare* 2021 IRP, Vol. I at tbl. 5-5 CONF. *and* U.S. Energy Information Administration Coal Markets data (showing current prices above $7/mmbtu for Central Appalachian and Illinois Basin coal supply and above $5/mmbtu for Northern Appalachian coal supply) (https://www.eia.gov/coal/markets/#tabs-prices-2); *and* U.S. Energy Information Administration Natural Gas date (showing current Henry Hub Natural Gas prices above $5/mmbtu) (https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm).

subsequent development so significant and so at odds with the assumptions in the original IRP analyses, that it renders the earlier modeling even more inaccurate and unhelpful.[59]

Based on PPL's public statements, as summarized in this recent article, it appears the Companies would agree that the IRA significantly changes the economics of generation decisions:

> The ability to make use of the PTC instead of the solar ITC will improve the economics of PPL's self-build options as the company looks at renewables as a potential source of replacement generation for its Kentucky utilities, according to Vince Sorgi, PPL president and CEO.
>
> "That will be good for not only our [request for proposals] process in Kentucky, but also our customers in Rhode Island as we procure clean energy to meet the 100% renewable energy by 2033 requirement that was just enacted into law," Sorgi said Aug. 3 in an earnings call. "The transferability provisions around tax credits also makes it more likely that renewables will be built. And that will also be good in general for the industry and for accelerating our clean energy transition. [It] simplifies the structure of the deals significantly."[60]

The IRA is significant, and it is appropriate that PPL is already analyzing the Act and communicating to their investors. Customers of PPL's Kentucky utilities deserve at least that same level of transparency and information, and should not have to wait three years until the Companies' next IRP filing.

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[59] As the Companies' themselves caveat, in bold, ahead of the 2021 IRP's Table of Contents:

> This Integrated Resource Plan represents a snapshot of an ongoing resource planning process using current business assumptions. The planning process is constantly evolving and **may be revised as conditions change and as new information becomes available**. **Before embarking on any final strategic decisions or physical actions**, the Companies will continue to evaluate alternatives for providing reliable energy while complying with all regulations in a least-cost manner.

2021 IRP, Vol. I at 1 (emphasis changed).

[60] Ethan Howland, *Utility leaders hail clean energy tax incentives as House sends historic climate bill to Biden's desk*, UtilityDive (Aug. 15, 2022) https://www.utilitydive.com/news/Congress-clean-energy-tax-climate-inflation-reduction-act/629643/?utm_source=Sailthru&utm_medium=email&utm_campaign=Issue:%202022-08-15%20Utility%20Dive%20Newsletter%20%5Bissue:43817%5D&utm_term=Utility%20Dive.

Joint Intervenors encourage Commission Staff to address an additional information request to LG&E/KU *before* issuing a draft report, to ask what effects PPL, LG&E and KU have identified or project that the IRA may have on their near-term and long-term resource planning, including on (1) the conclusions in the 2021 IRP, (2) the Companies' evaluation of responses to the outstanding request for proposals, (3) the optimal timing of coal-fired unit retirements, and (4) the timeline and costs for development of more renewable resources. In the alternative, Commission Staff might request an informal conference, pursuant to 807 KAR 5:058(11)(2), to consider those impacts.

III. The Companies' Approach to Demand-Side Resources is Arbitrary, Inadequate, and Antithetical to Least-Cost Planning.

Throughout this proceeding, Joint Intervenors have expressed concern with the Companies' neglect of demand-side resources.[61] The Companies arbitrarily and unreasonably excluded analysis of expanded DSM resources in this IRP, particularly considering the potential cost-effectiveness of those resources,[62] as well as the Commission's recent reminder that the Companies are required "to begin evaluating possible DSM programs that will add low-cost value and assist in avoiding the high cost of building new generation.[63] Companies' Witness Wilson offered on cross-examination that LG&E/KU's "CPCN filing will thoughtfully consider DSM," but that is cold comfort and comes far too late in the process to allow a determination of

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[61] Joint Intervenors' Initial Comment at 22–31 (Section III); EFG Report, Section 3.2.2 and 3.6.1.

[62] 807 KAR 5:058(8)(1) ("The plan . . . shall include assessment of potentially cost-effective resource options available to the utility.").

[63] *In the Matter of Elec. Application of Ky. Util. Co. for an adjustment of Its Elec. Rates*, Case No. 2020-00349, Order at 61 (June 30, 2021), https://psc.ky.gov/pscscf/2020%20Cases/2020-00349//20210630_PSC_ORDER.pdf; *In the Matter of Elec. 2018 Joint Integrated Resource Plan of Louisville Gas and Elec. Co. and Ky. Util. Co.*, Case No. 2018-00348, Order at 22–23 (July 20, 2020), https://psc.ky.gov/pscscf/2018%20Cases/2018-00348//20200720_PSC_ORDER.pdf.

whether and to what extent use of robust DSM measures can defer or affect the scope of CPCN filing.

Instead of proactively using the IRP to optimize supply- and demand-side resources, the Companies apparently are only interested in DSM when they file a Certificate of Need request. As the Companies explain in post-hearing data responses, it is only accompanying that CPCN filing that the Companies would expect to perform "a full analysis of cost-effective DSM-EE programs":

> [I]f the Companies file an application for a CPCN or PPA (or some combination of the two) based on the results of the current RFP, they anticipate doing so toward the end of this year or early next year. As the Companies further stated during the hearing in this proceeding, any such application would include a full analysis of cost-effective DSM-EE programs . . . .[64]

That approach to analysis and planning for DSM-EE is unlikely "to ensure that customers' projected needs are met with a cost-effective balance of supply and demand side resources."[65] It is too little, too late. If least-cost planning is indeed the Companies' goal,[66] analyzing DSM-EE resources on equal footing with supply-side resources is essential.[67]

Although required by regulation and supported by common sense and basic prudency, the Companies continue to insist that they need not include DSM/EE in their resource optimization modeling. According to the Companies, by assuming 6% savings as a result of end-use

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[64] Companies' Response to Joint Intervenors Post-Hearing Request No. 1.b.

[65] *Id.*; *see also* Wilson, Rachel and Bruce Biewald, Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans (June 2013) (explaining importance of evaluating demand-side resources in IRP, resulting in "an opportunity to achieve lower overall costs than might result from considering only supply-side options.").

[66] *Id.*

[67] *Supra* Section I.B.

efficiency gains by the end of the planning period, they did enough to include DSM/EE programmatic decisions in their IRP.[68] Joint Intervenors disagree.

First, every load forecast must make some assumption about end-use efficiency gains that organically reduce customer usage without utility engagement, e.g., naturally occurring savings because of factors like improvements in building codes and appliance standards. These savings occur separate and apart from accounting for savings from utility-sponsored demand response or energy efficiency programs. The Companies' load forecast includes assumptions related to both naturally occurring savings as well as the lingering effects of efficiency measures it previously incentivized. The cumulative effect of the two is 6% savings at the end of the planning period, which tends toward the conservative.[69]

The DSM potential studies of several utilities near the Companies' service territory predict that DSM programs *alone* can reasonably achieve about 6% or more cumulative savings in periods shorter than 15 years.

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[68] *E.g.*, LG&E/KU Response Comment at 45.

[69] *E.g.*, Amory B. Lovins, *Energy End-Use Efficiency* (Sept. 19, 2005) https://rmi.org/insight/energy-end-use-efficiency/#:~:text=Energy%20end%2Duse%20efficiency%20is,way%20to%20provide%20energy%20services ("U.S. energy intensity has lately fallen by ~2.5% per year . . .", which over 15 years, would far exceed LG&E/KU's assumed 6% savings).

Table 1. Regional DSM Potential Study Findings

Utility	Cumulative Realistic Savings
Vectren 2019-2020 IRP	9.0% (5-year)
EKPC 2022 IRP	5.9% (5-year)
Northern Indiana Public Service Company 2021 IRP	11.3% (10-year)
Indiana Michigan Power Company 2021 IRP (Indiana only)	13% (10-year)

Second, the Companies' 6% assumption over 15 years understates their combined end-use efficiency gains and programmatic savings over the last ten years, which reached 9%.[70] That does not make the 6% assumption per se unreasonable, but again suggests it may be unreasonable in light of past savings. The Companies nowhere discuss any reasons their savings into the 2020s and 2030s would not be so great as the savings realized in the 2010s. In fact, the significant federal investments in energy efficiency through the Infrastructure Act and the recently-enacted Inflation Reduction Act support the contrary assumption.

Third, and most importantly, LG&E/KU's assumed 6% savings in its load forecast by the end of the planning period does not make up for what the Companies should have done: optimize EE/DR as part of the IRP resource assessment process and on equal footing with supply-side resource options. Not only did the Companies skip analysis of continuing or expanded EE/DR programs beyond 2025, they assumed zero new programmatic savings after 2025.[71]

[70] Companies' Post-Hearing Response to Joint Intervenors No. 2.c. ("Compared to 2010, annual weather-normalized residential use-per-customer in 2021 was 9% lower in the LG&E service territory and 5.5% lower in the KU service territory. These decreases reflect the impacts of customer-initiated energy efficiency improvements as well as past and current DSM-EE programs.").

[71] 2021 IRP, Vol. I at tbl. 8-12 (showing zero incremental DSM energy and demand impacts after 2025).

LG&E/KU take pride in their DSM-EE programs,[72] and should be rigorously evaluating continuing and expanding DSM potential in every integrated resource plan. When compared to only Kentucky utilities, perhaps one could call the Companies occasional leaders in DSM/EE.[73] But compared to national leaders in utility-DSM programs, the Companies remain laggards, achieving substantially less savings than leading utilities.[74] National research reports consistently rank Kentucky below-average in energy efficiency,[75] and the Companies' reported savings as a percentage of sales from their DSM programs (0.3%)[76] is markedly below what other utilities are cost-effectively achieving, as reflected in the following table, excerpted from ACEEE's 2020 Utility Energy Efficiency Scorecard.[77] Integrated resource planning is precisely the context in which the Companies should begin exploring the cost-effectiveness of expanded efficiency and demand response programs.

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[72] LG&E/KU Response Comment at 46–47; Companies' Response to Joint Intervenors' Post-Hearing Request No. 2.

[73] Companies' Response to Joint Intervenors' Post-Hearing Request No. 2.

[74] *See, e.g.*, Grace Relf, et al, *2020 Utility Energy Efficiency Scorecard*, American Council for an Energy-Efficient Economy ("ACEEE") (Feb. 2020) https://www.aceee.org/sites/default/files/pdfs/u2004%20rev_0.pdf (identifying at least 25 utilities from across the country achieving annual net savings as a percentage of sales of 1% to above 3%).

[75] *See, e.g.*, Weston Berg, et. al., *2020 State Energy Efficiency Scorecard* at tbl. 2, ACEEE (Dec. 2020) https://www.aceee.org/sites/default/files/pdfs/u2011.pdf (ranking Kentucky 33 out of 50 states overall).

[76] Companies' Response to Joint Intervenors' Post-Hearing Request No. 2.

[77] *E.g.*, Grace Relf, et al, *2020 Utility Energy Efficiency Scorecard*, American Council for an Energy-Efficient Economy ("ACEEE") (Feb. 2020) https://www.aceee.org/sites/default/files/pdfs/u2004%20rev_0.pdf (identifying at least 25 utilities from across the country achieving net savings as a percentage of sales of 1% to above 3%).

Table 8. Scores for net savings as a percentage of retail sales in 2018

Utility	Net incremental savings (MWh)	Savings as % of sales	Points
NG MA	782,838	3.73%	8.5*
Eversource MA	760,750	3.15%	8
SDG&E	463,260	2.35%	6
ComEd	2,064,720	2.08%	5.5
SRP	624,658	2.05%	5.5
BGE	616,559	1.96%	5
Xcel MN	565,220	1.73%	4.5
LADWP	395,609	1.63%	4.5
PG&E	1,352,387	1.61%	4.5
SCE	1,415,400	1.55%	4
Consumers	641,648	1.55%	4
Eversource CT	346,200	1.54%	4
DTE	777,405	1.50%	4
Xcel CO	453,854	1.45%	4
PGE [a]	303,416	1.45%	4
LIPA	293,161	1.41%	4
Duke OH	292,107	1.32%	3.5
MidAm IA	322,760	1.27%	3.5
OH Edison	286,819	1.12%	3
PSE	261,586	1.10%	3
Entergy AR	255,930	1.08%	3
NG NY [a]	397,304	1.07%	3
Ameren MO	364,080	1.03%	3
Duke SC	233,774	1.01%	3
AEP OH	467,385	1.00%	2.5
Duke NC	624,322	0.99%	2.5
Ameren IL	404,725	0.98%	2.5

Utility	Net incremental savings (MWh)	Savings as % of sales	Points
PacifiCorp UT	230,839	0.87%	2.5
PECO	349,889	0.84%	2.5
PPL	326,966	0.82%	2.5
We Energies [a]	202,487	0.77%	2
Duke Progress	305,066	0.76%	2
West Penn	162,428	0.75%	2
APS	212,752	0.71%	2
ConEd [a]	425,521	0.71%	2
OG&E	187,414	0.68%	2
Duke IN	199,640	0.65%	2
Nevada Power	134,609	0.56%	1.5
CPS	126,985	0.54%	1.5
GA Power	413,919	0.46%	1.5
PSE&G [a]	175,192	0.40%	1
JCP&L [a]	64,189	0.29%	1
SCE&G	58,635	0.25%	1
TECO	40,696	0.20%	0.5
AEP TC	53,294	0.19%	0.5
Duke FL	68,377	0.16%	0.5
CenterPoint	140,997	0.15%	0.5
Oncor	182,620	0.13%	0.5
Dominion	70,097	0.08%	0
FP&L	72,652	0.06%	0
AL Power [b]	10,127	0.02%	0
Entergy LA	5,963	0.01%	0
Average		**1.03%**	

Savings are net at the generator level. We adjusted EIA retail sales data (shown in table 1, above) for line loss factors to be consistent with the generator-level reporting of savings. See Appendix B for meter-level savings and loss factors. * We awarded a half-point bonus to NG MA for far exceeding the top threshold of 3% savings as a percentage of sales. [a] Includes savings separately allocated from a third-party program administrator. [b] Savings from EIA 2019b.

Joint Intervenors maintain that Commission Staff should remind the Companies of the expectation that they follow the regulatory requirements in how load impacts of existing and future demand-side management programs are reported in the IRP.[78] The Companies should also be directed, as the Commission has previously admonished them, to include demand- and supply-side resource alternatives on equal footing in the next IRP's resource optimization modeling. If the Companies' goal is least cost planning, nothing less will do.

IV. Initial Comments Addressing the Significance of Customer Impacts and Climate Risks are Germane and within the Commission's jurisdiction.

Joint Intervenors' Initial Comments addressed at length the value of grounding resource planning in an understanding of customer needs and customer impacts resulting from resource decisions—particularly those impacts on low- and fixed-income customers—including a robust explanation of the supporting regulatory authority and source of jurisdiction.[79] The Companies' Responsive Comment, however, offers no direct response. From this, Joint Intervenors assume that the Companies judged impacts to all customers as unimportant to their resource planning,[80] possibly implying that, in the Companies' view, consideration of customer impacts is not "constructive or germane."[81] The Companies appear to dismiss environmental or climate risk discussions using similar logic.[82] Respectfully, the Companies response on each issue is wanting.

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[78] 807 KAR 5:058(7)(3).

[79] Joint Intervenors' Initial Comment, Section II, at 8–22.

[80] LG&E/KU Response Comment at 3 ("the Companies are responding only to issues they believe are important to address before the hearing in this proceeding").

[81] *Id.* at 12.

[82] *Id.* at 12 (citing Initial Comments from Louisville Metro, Sierra Club, and Joint Intervenors).

Silence in the face of legitimate concern is neither collaborative nor constructive. If the Companies sincerely desire informal, collaborative, non-adversarial processes, one might expect that they would welcome the unique depth and breadth of input from all intervenors and make a better effort to engage on issues that each intervenor deemed important enough to invest time, resources, and expertise bringing it to the Companies' and the Commission's attention.

Specific to customer impacts, Joint Intervenors remain disappointed that the Companies have not engaged in any discussion furthering consideration of customer impacts, particularly given growing recognition of the intersections between energy, affordability, and housing security. As recently as last week, ACEEE published a first-of-its-kind state survey comparing programs and policies aimed at "reducing pollution and improving a building's healthfulness through energy efficiency, electrification, and renewable energy."[83] Examining linkages between energy and affordable housing, the authors found incredible need in Kentucky, and also a notable lack of programs and policies. Out of 50 states and the District of Columbia, Kentucky ranks 49th, scoring just marginally better than Mississippi[84] and earning the unfortunate distinction of being a state with high need and poor performance:

> Examining the ranking of state efforts to support healthy, affordable housing alongside state poverty rates, we find that of the 10 lowest-ranked states, 6 lead the nation for the percentage of their populations living in poverty. Mississippi and Louisiana have the highest and second highest poverty rates in the nation, respectively, and both scored in the bottom five in our assessment of state efforts to provide healthy, affordable housing. In addition to these two states, West Virginia, Arkansas, Alabama, and Kentucky all rank in the top 10 for most impoverished populations and in the bottom 10 for efforts to provide those families with healthy, affordable housing. This combination of high poverty rates

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[83] Sara Hayes, et al., *Pathways to Healthy, Affordable, Decarbonized Housing: A State Scorecard* at v, ACEEE (Aug. 18, 2022) www.aceee.org/research-report/h2201.

[84] *Id.* at 10.

> and early stages of policy adoption mean that efforts by these states to implement the approaches outlined in the Scorecard could be particularly impactful.[85]

The Companies can proactively be part of the solution here, and they need not wait to be ordered into action. Acknowledging that resource decisions directly impact customers, and that those impacts should be considered in long-range planning, would be a good start.[86]

From there, the Companies can bring to bear internal and public data to better understand customer needs and evaluate how different resource decisions might contribute to meeting those needs.[87] For example, following the Greater Louisville Project's 2015 multidimensional poverty study,[88] which identified eleven disproportionately impacted zip codes, Metropolitan Housing Coalition layered disconnections data from LG&E to test the prevalence of disconnections. MHC's analysis found a pattern, with residential disconnections for non-payment from July 2016 to June 2018 showing a disparate impact on the same 11 zip codes identified by the Greater Louisville Project. Such data, had it been considered by the Companies during their planning process, would have highlighted significant customer need for energy security assistance, which could take the form of targeted DSM programs, including Pay-As-You-Save Programs discussed by Joint Intervenors' expert James Owen.[89]

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[85] *Id.* at 11.

[86] *See e.g.*, Joint Intervenors' Initial Comment at 8–22 (addressing legal basis for considering customer impacts in IRP proceeding, providing examples of resource decisions with direct customer impacts, and offering recommended data and analysis to assist Companies in developing greater understanding of customer needs and impacts).

[87] Joint Intervenors' Initial Comment, Sec. II.D, at 20–21.

[88] Greater Louisville Project, *Louisville: A Focus on Poverty* (2015) https://greaterlouisvilleproject.org/content/uploads/2016/11/Final-PDF_GLP-2015-Poverty-Report.pdf.

[89] Joint Intervenors' Initial Comment, Ex. 2, PAYS Programs Report, James Owen.

Specific to the potential for climate impacts to drive costs to the Companies and their customers, the Companies appear to dismiss these cost risks as "externalities."[90] Joint Intervenors submit that the Companies' resistance to evaluating all significant risks is irresponsible and short-sighted. Long-range planning is the right place for that evaluation because today's externalities may become internalized costs over the coming fifteen years.

The Companies cannot dispute that reliance on fossil-fuel fired generating units, as noted by the Sierra Club, will "harm local public health, foul local air and waterways, and exacerbate climate change."[91] The Companies dispute only whether those costs to public health, air, water, and the planet are relevant to their long-range planning. History and experience support the positions of Louisville Metro, Sierra Club, and Joint Intervenors in this regard. So do the IRP regulations' requirements for discussion of changes in law and policy[92]—each capable of requiring the Companies to newly grapple with harms they previously externalized to society generally.

In truth, the Companies must recognize that prudent business practices include forward-looking assessments of costs and risks, including environmental liability risks. That is reflected in their discussions of anticipated statutory and regulatory changes.[93] And it is reflected in their agreement that "the Companies should account for possible environmental regulations that would affect their costs and operations," which "are entirely germane to this proceeding."[94] With

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[90] LG&E/KU Response Comment at 12.

[91] Sierra Club's Initial Comment at 13.

[92] 807 KAR 5:058(8)(5) (requiring description and discussion of anticipated environmental compliance and planning).

[93] 2021 IRP, Vol. I at 8-35 to 8-42.

[94] LG&E/KU Response Comment at 11–12.

that, the Companies position appears to be little more than arbitrary line drawing, designed to avoid collaboration or genuine dialogue on and analysis of issues that could dramatically impact their ability to provide low-cost, reliable service into the 2030s.

V. LG&E/KU's 2021 IRP is Inadequate, and the Next IRP Should Evaluate a More Robust Set of Potentially Cost-Effective Resources.

Joint Intervenors' Initial Comments, as well as those by other intervenors, noted a variety of potentially cost-effective resources ignored or superficially discounted in the Companies' IRP exercise. As summarized below, LG&E/KU's Responsive Comment, testimony, and post-hearing data responses confirm those critiques. Because potentially cost-effective resource options were not analyzed, the Companies' 2021 IRP is fundamentally inadequate and unreliable as a planning tool. Joint Intervenors continue to recommend that Staff encourage the Companies to model all potentially cost-effective resources in their next IRP.

A. The next IRP should include potential contributions from generation resources outside the Companies' balancing area.

The Companies' IRP analysis is inadequate for failing to evaluate wind or solar resources from outside Kentucky. The Companies' decision assumed without empirical evidence that transmission costs would render out-of-state wind or solar non-economical, unacceptably discounting potential resources on a basis that could and should have been empirically tested.

The Companies confirmed, via cross-examination[95] and post-hearing data requests,[96] that they are capable of accounting for transmission costs for resources outside their balancing area. Accounting for transmission is so doable that, in a recent request for proposals, the Companies

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[95] July 12, 2022 Hearing, Cross-Examination of Companies' Witness Sinclair ca. 13:30 (explaining how Companies are "better positioned" to evaluate transmission costs than an RFP project bidder).

[96] Companies' Post-Hearing Response to Joint Intervenors No. 4.b.

did not require bidders to provide all costs of getting power to LG&E/KU's territory, instead preferring to perform that assessment in-house:

> Q–4.b Did any of the responding bids include all costs of getting the power to KULGE? Please explain in full.
>
> A–4.b No. The RFP specified that the Companies would apply to use the applicable tariff(s) for firm point-to-point transmission to account for costs related to delivering the energy to the Companies.[97]

The Companies can account for transmission costs, and they should use that capability to consider out-of-state wind and solar resources. Additionally, the planning should consider the effect of membership in an RTO in access to such resources and costs associated with transmission of such power.

If the aim is lowest cost planning, the Companies' Integrated Resource Plan should be based on empirical analysis of all potentially cost-effective resource options, including resources located outside Kentucky. Joint Intervenors ask Commission Staff to recommend that in the Companies' next IRP, they include analysis of wind and solar resources from both within and outside of Kentucky. This analysis should include a clear accounting of the transmission costs, using real-world data.

B. The Companies' Scarcity Pricing Curve is out-of-line with actual prices, biasing the model against available imported energy.

Following the Companies' response comments and testimony at the hearing, Joint Intervenors offer brief additional comments addressing the scarcity pricing curve applied in the Companies' SERVM modeling.[98] Scarcity pricing assumptions have a significant impact on how

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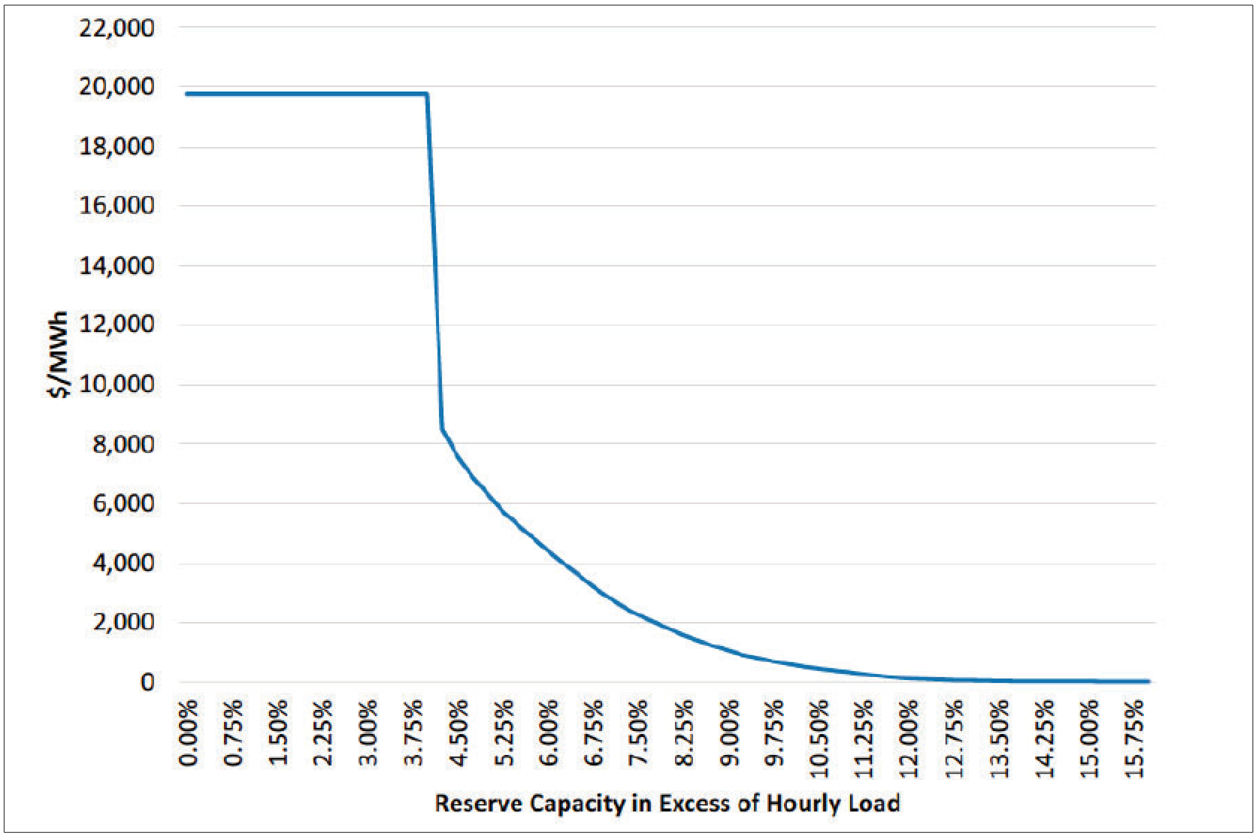
[97] *Id.*; *see also* July 12, 2022, Cross-Examination of Companies' Witness Sinclair ca. 13:30 to 13:33.

[98] EFG Report, Section 4.3 (addressing the scarcity pricing curve).

the model treats transfers of power between a neighboring region and the Companies' service territory.[99] During any hour in which the amount of capacity in excess of load falls below 15.25%, the SERVM simulation assessed a corresponding scarcity price on any transfers from neighboring areas: from $20 per MWh at 15.25%, to $226 per MWh at 11.5%, and topping out just shy of $20,000 per MWh at 3.5% or less.



The EFG Report commented briefly on the unreasonableness of the Companies' scarcity price curve, expressing skepticism that the price increases reflected in the scarcity price curve are realistic or warranted.[100] That skepticism is based on a review of hourly real-time pricing over

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[99] EFG Report at 28.

[100] *Id.* at 28.

the last four years, showing that the actual hourly price never exceeded $1,000 over that time period, and was only rarely as high as $226.[101]

Table 2. Count of Real-Time Prices in Excess of Selected Scarcity Prices in SERVM Modeling, April 2018 – April 2022 (reproduced from EFG Report, tbl. 6 at 28).

Real-time Price per MWh	MISO-LG&E (number of hours)	PJM-EKPC (number of hours)
>$20	27,265	25,690
>$226	63	49
>$1000	0	0

The Companies do not dispute that data or observation, yet somehow claimed that the prices they used were nonetheless realistic and based on historical data.[102] At best, that claim is mistaken.

First, the reserve margin analysis makes plain that, at reserve capacities below 4.0% of hourly load, "the scarcity price is equal to the Companies' value of unserved energy ($19,800/MWh; see Section 4.7)."[103] Section 4.7 explains how the Companies derived that value of unserved energy: "For this study, unserved energy costs were derived based on information from four publicly available studies."[104] Those four studies date to 2000 to 2009, making them rather out-of-date, and not one mentions relying on data from LG&E/KU or any other Kentucky

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[101] *Id.* at 28 (providing count of real-time prices at the MISO-LG&E interface and PJM-EKPC interface from April 2018 through April 2022).

[102] LG&E/KU Response Comment at 41 (citing IRP Vol. III, 2021 IRP Reserve Margin Analysis at 22-23, which the Companies say shows their scarcity pricing curve was based on historical data).

[103] 2021 IRP, Vol. III, Reserve Margin Analysis at 22.

[104] *Id.* at 21.

utility, as the Companies admit via post-hearing responses.[105] Thus, the value of unserved energy, which was applied in the SERVM modeling at reserve capacities tighter than 4%, plainly was not derived from company-specific data.

Joint Intervenors asked the Companies to explain how the rest of the scarcity pricing curve was derived, but the Companies responded only to say it was "developed based on the Companies' actual purchases over a range of reserve conditions and extrapolated to tighter reserve conditions."[106] The Companies, however, produced no workpapers documenting what data was used or what calculations were applied.[107] Lacking in documentation, neither Commission Staff nor stakeholders can confirm the appropriateness or accuracy of the data used to derive the tail of the scarcity pricing curve.

This is of significant concern given the importance of scarcity pricing in the Companies' modeling. Scarcity pricing is applied when the SERVM model expects power to be available—i.e., not in situations where there has been a loss of load. Although the cost of imported power from MISO and PJM exceeded \$226 in fewer than 115 hours over the last four years (or roughly 0.328% of those 35,064 hours) and never exceeded \$1,000 in that time period, the SERVM modeling applied a price of \$226 to \$19,800 per MWh in any hour with an 11.5% or less reserve.[108] This amounts to a dramatically conservative assumption, exaggerating the cost of

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[105] Companies' Response to Joint Intervenors' Post-Hearing Request No. 11.b (confirming that company-specific data from LG&E or KU was not included in any of the four studies used to determine the cost of unserved energy).

[106] Companies' Response to Joint Intervenors' Supplemental Request No. 2.39(b).

[107] *Id.* No. 2.39(f).

[108] Companies' Response to Joint Intervenors' Post-Hearing Request No. 11.c. (confirming that "that "scarcity pricing" was used in the SERVM modeling as an adder to power purchased during any hour in which reserve capacity was 16% or less in excess of load"); *id.* No. 11.d (confirming that "in the SERVM modeling and as reflected by the scarcity price curve shown in Figure 9, when generation exceeds load by

available power from neighboring regions and inefficiently encouraging reliance on the Companies' fossil generation. Such exaggerated and inefficient assumptions are antithetical to least-cost planning.

Joint Intervenors continue to recommend that Commission Staff encourage the Companies' next IRP to use more realistic pricing. Lest this recommendation continues to be unclear to LG&E/KU,[109] Joint Intervenors clarify that more realistic pricing of imported energy can be accomplished by: (1) relying on the most recently available real-time price data from the Companies' interfaces with neighboring regions; and (2) developing and retaining workpapers that adequately document data and calculations relied upon, as would be necessary for regulatory oversight and collaboration with stakeholders.

C. The next IRP should forecast distributed generation additions under different scenarios.

On distributed generation, one gets the sense that Joint Intervenors and the Companies may be talking past one another. In response to Joint Intervenors' discussions of net metering and distributed generation, LG&E/KU continue to emphasize that residential rooftop solar is more expensive than utility-scale solar on an LCOE basis.[110] While Joint Intervenors agree this is factually correct, the fact is relevant only if the distributed generation is developed at the utilities' expense, and in the case of net metering, it is not. Customer-owned distributed

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11.5% or more, a $264 / MWh fee was assessed on any power transfers"); *id.* No. 11.e (confirming that "in the SERVM modeling and as reflected by the scarcity price curve shown in Figure 9, when reserve capacity is 4.0% in excess of hourly load, an approximately $19,800 per MWh fee was assessed on any power transfers").

[109] LG&E/KU Response Comment at 41 ("It is not clear [to the Companies] how the Companies could be more 'realistic' with their pricing . . .").

[110] Companies' Response to Joint Intervenors' Post-Hearing Request No. 7.

generation is fundamentally different than utility-scale solar because the customer makes the investment, not the utility.

In rate cases 2021-00349 and 2021-00350, the Commission established successor rates for net metering for LG&E-KU, known as NMS II, which by definition enable the utilities to recover their costs of serving NMS II customers.[111] Through application of a cost-benefit analysis prescribed by the Commission, NMS II customers are compensated for the value they supply to the utility when they generate excess power onto the grid. For the energy which they self-consume, those NMSII customers provide the grid with load reduction and demand-savings equivalent to the savings derived by conservation and efficiency measures—when a customer's load is reduced, the utility does not know whether it is because they turned off the lights or generated and self-consumed a bit more solar energy on-site. The significance of all this is that customer-owned generation provides recognized value to the utility, in the form of reduced load and demand, with no investment required of the utility. This contrasts with utility-scale solar, in which the utility is making the investment (whether by building the resource or purchasing it from a third party). This distinction renders an LCOE comparison between utility-scale solar and customer-owned distributed solar wholly irrelevant.

LG&E/KU's IRP demonstrates that, with no cap on net metering, adoption of distributed generation resources would increase steeply through the end of the decade.[112] By 2030, with

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[111] *See generally, Electronic Application of Kentucky Utilities Company and Louisville Gas and Electric Company for an Adjustment of Electric Rates and Gas Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit,* Case Nos. 2020-00349 and 2020-00350, Order (Ky. PSC Sept. 24, 2021) https://psc.ky.gov/pscscf/2020%20Cases/2020-00350//20210924_PSC_ORDER.pdf.

[112] 2021 IRP, Vol. I at 5-29, Figure 5-13.

continued access to net metering, the Companies forecast that net-metered, customer-owned distributed resources could provide over 500 MW of capacity—a considerable increase over the base forecast of less than 100 MW.[113] According to the Companies' analysis, the only thing preventing the steeper uptake of distributed generation resources is what the Companies' refer to as "the 1% cap on total installed net metering capacity."[114] However, the idea that net metering growth is "capped" misconstrues the statute.

Under Kentucky law, there is no "cap" on the number of customers free to develop distributed generation alternatives for themselves and no cap on the total capacity of resources participating in net metering.[115] Instead, there is a only a floor—a minimum threshold below which utilities must offer net metering, with discretion to provide net metering above that threshold, to the extent consistent with the utilities' general obligations to provide reliable, low-cost service in their territories. The Companies acknowledge this point, and Joint Intervenors appreciate the acknowledgement of their discretionary ability to offer net metering beyond the 1% threshold mandated by the Kentucky General Assembly.[116]

Next, the Companies should bring that understanding into their Integrated Resource Planning exercise. The value of distributed energy resources should be fully evaluated in the next IRP, including customer-owned distributed energy resources. Using computational modeling, the Companies should test the potential to lower overall system costs by assuring customers of the availability of net metering above the mandatory 1% threshold. Specifically, the Companies

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[113] *Id.*

[114] *Id.* at 5-29.

[115] KRS 278.466.

[116] Companies' Post-Hearing Response to Joint Intervenors No. 7 (acknowledging that the Companies have discretion to offer net metering to customers beyond the required 1% threshold).

should analyze the costs of distributed resources according to who actually pays those costs; which is to say, net metering customers pay the costs for installing these resources, *not* the utility. Strategies to aggregate and make dispatchable those distributed rooftop resources should also be required to be evaluated.

D. The next IRP should optimize unit retirement timelines.

As noted in Joint Intervenors' Initial Comment, the Companies did not evaluate optimal retirement dates as part of this long-range planning exercise.[117] That fact is not in dispute, with LG&E admitting they ignored assessment of optimal retirement horizons for existing generation units as a simplifying assumption.[118] The only remaining dispute is whether, in the regular course of integrated resource planning, the Companies should analyze—rather than assume—economically optimal retirement dates.

LG&E/KU's Responsive Comment continued to insist that the IRP's approach to analysis of unit retirements was reasonable, and asserted that using modeling software to analyze economically optimal retirement dates is not "necessary or advisable."[119] According to the Companies, they do not need computational modeling to optimize retirements because that boils down to basic business knowledge:

> 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

[117] EFG Report, Section 3.2.3; *id.* at 15 ("The lack of capacity need until 2028 is entirely a product of the Companies' discretion. Because the timing of resource additions and retirements was developed without benefit of any optimization, a capacity need in 2028 or any other specific date was not explicitly determined in this IRP.").

[118] *E.g.*, LG&E/KU Response Comment at 37; July 13, 2022 Hearing, Cross-examination of Companies' Witness Wilson ca. 8:20 (confirming that model did not select retirement dates in IRP modeling, which were hardwired planning assumptions).

[119] LG&E/KU Response Comment at 37.

> not necessary to conduct complex modeling to confirm this basic business knowledge.[120]

Here, Joint Intervenors cannot agree. Joint Intervenors continue to recommend that the next IRP should include resource optimization modeling to determine economically optimal unit retirement dates.

To start, the law requires evaluation of optimal retirement dates in an IRP.[121] Fifty years ago, such an evaluation might have consisted of little more than the basic business assumptions of a handful of utility employees. But today, in the information age, we can also test human assumptions against computational modeling of robust datasets.

The Companies have modeling software capable of optimizing unit retirement dates, and its other modeling required input of all the same assumptions and unit characteristics that would be necessary for those retirement optimizations.[122] Meaning, the Companies had everything they needed, yet opted against asking the model to try to optimize unit retirements. That decision wasted already spent resources, reflects considerable hubris, and cannot be remedied by a single modeling run provided late in discovery and without supporting documentation.

Joint Intervenors continue to recommend that Commission Staff's Report urge the Companies to use the full capabilities of their modeling software in the next IRP, particularly including using modeling software to optimize retirement dates. In the very least, doing so could affirm the Companies' intuitively assumed retirement dates, or it could identify potential to reduce overall system cost through better optimized retirement dates.

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[120] LG&E/KU Response Comment at 37.

[121] *See generally* 807 KAR 5:058(8).

[122] July 13, 2022 Hearing, Cross-examination of Companies' Witness Wilson ca. 18:24.

VI. Present Value Revenue Requirements Should Be Presented for All Portfolios in the Next IRP

The Companies' Responsive Comment and hearing testimony confirmed a key critique from the EFG Report: because the Companies only provided net present value revenue requirements ("NPVRR") for a single portfolio, cost comparisons are impossible. Via Responsive Comment, the Companies confirmed that production cost modeling necessary to develop NPVRRs was done for a single portfolio, and the decision to only calculate NPVRR for a single portfolio was LG&E/KU's choice—"not due to technical constraints."[123]

Although LG&E/KU claim that choice was "in accordance with the IRP regulation's requirements,"[124] no citations to the regulation were provided and no logic was offered supporting that contention.[125] Joint Intervenors submit that the Companies' interpretation of the IRP regulation must be mistaken. The IRP regulation requires utilities to provide a "resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost."[126] If the Companies are not comparing the production costs and NPVRR of multiple portfolio options under multiple scenarios, it becomes practically impossible for the Companies themselves, the Commission,

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[123] LG&E/KU Response Comment at 35.

[124] LG&E/KU Response Comment at 35.

[125] In the absence of supporting citations or logic, Joint Intervenors could guess that the Companies' claim is based on section 9(1), stating that "[t]he integrated resource plan shall, at a minimum, include and discuss the following financial information: (1) Present (base year) value of revenue requirements stated in dollar terms." But that does not withstand scrutiny. First, section 9(1) is assuredly a minimum standard. Second and more fundamentally, unrelated to Financial Information (Section 9's focus), the expectation to identify a least-cost resource plan practically requires production cost modeling and present value of revenue requirement comparisons between portfolios.

[126] 807 KAR 5:058(8)(1).

Staff, and stakeholders to consider which portfolio is most likely to deliver the lowest possible cost.

In this way, as a practical matter, the Companies' interpretation fails to meet the minimum requirements of least-cost planning, which inherently requires cost comparisons. Meaningful least-cost planning requires apples-to-apples comparisons of different portfolio options using NPVRR comparisons based on sound production cost modeling.[127] This is something LG&E understood 35 years ago, when it provided present value revenue requirements for as many as fifty portfolios in support of a single resource decision.[128]

There is no sound reason to have stopped providing robust comparisons of portfolio costs, and Joint Intervenors continue to urge that Staff's Report recommend the LG&E/KU's next IRP include cost data necessary to make comparisons among and between various portfolio options.

VII. The Companies' Decision to Simulate Only the Year 2035 in the Resource Expansion Modeling was a Wasteful and Unnecessary Mistake.

As Joint Intervenors noted in our Initial Comments, and the Companies confirmed at the hearing, the resource expansion modeling capabilities of PLEXOS were used to identify a single least-cost portfolio in each of nine scenarios by simulating just one year of the planning period, 2035. That was a mistake.

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[127] *See* EFG Report, Section 3.3.2.

[128] *An Investigation and Review of Louisville Gas and Electric Company's Capacity Expansion Study and the Need for Trimble County Unit No. 1*, Case No. 9243, Order at 5 (Ky. PSC Oct. 14, 1985) ("A total of 51 plans are used in the S&W study originally filed. In order to compare the various plans, the present worth revenue requirements associated with each plan are calculated.").

That mistake is not justified by technical constraints—the model is perfectly capable of optimizing resource decisions across *each and every* year of a 15-year planning period.[129]

Nor is it justified by convenience. Though the Companies argue against the "additional work" of modeling every year of the planning period,[130] it would have been easy to ask the model to solve for every year of the planning period. Modeling every year of the planning period does not require new or different inputs—it is simply a matter of telling the model to optimize over one time period or another. The "additional work" is remarkably slight, and it adds significant heft to the analysis, which is why modeling the entire planning period is typical. [131]

It is concerning that the Companies profess not to recognize the benefits of utilizing the full capabilities of computational modeling software.[132] In this post-enlightenment information age, we might all agree that more robust computational modeling of complex and large datasets is beneficial. Particularly so where, as here, there is no marginal expense: customers are already paying for the software license, for the computer hardware that the Companies run it on, and for the Staff time and third-party resources relied on to develop all the modeling inputs and

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[129] EFG Report, Section 2; *id.* at Section 3.2.1 at 13–14; July 12, 2022 Hearing, Cross-Examination of Witness Wilson ca. 17:25 (confirming that resource expansion modeling focused on just the final year of the planning period as a "simplifying assumption").

[130] LG&E/KU Response Comment at 37.

[131] EFG Report at 13 ("[The Companies used an atypical approach to capacity expansion modeling for this IRP where only one year of the planning period was modeled for capacity expansion planning."); *e.g.*, *East Kentucky Power Cooperative 2022 Integrated Resource Plan Case*, Case No. 2022-00098, EKPC's Public Response to Joint Intervenors Initial Data Request No. 17(l) (Ky. PSC July 29, 2022) (confirming that EKPC's capacity expansion model "simulates the system one hour at a time over the entire study period, in this case fifteen (15) years").

[132] LG&E/KU Response Comment at 37 ("[T]he Joint Intervenors recommended that the Companies model generation replacements over each year of the IRP period, not just the last year, though it is not clear what the benefit would be of performing such additional work.").

assumptions. With all that sunk cost and effort, it is wasteful and short-sighted not to use the model's full capabilities.

Joint Intervenors continue to strongly recommend that the Companies model the entirety, and not just part, of planning horizons for both IRP and CPCN filings.[133]

VIII. The Companies' Defense of the Solar Intermittency Study Does Not Respond to the Concerns Raised and Clarity Sought in the EFG Report.

The Companies' Responsive Comment attempts to respond to EFG's concerns related to the Solar Intermittency Study, but misses the point.[134] With regard to that study, the EFG Report noted that it is unclear what level of imbalance the Companies would consider acceptable and why, noting that NERC's balancing standards "allow for both positive and negative excursions for specified durations before a violation would occur."[135] Illustrating that fact, reviewing the Companies' historic imbalances, it is clear "that positive and negative imbalances are the norm for system operations": "At no point in 2021 was the Companies' system perfectly in balance on either a 10-minute or 1-minute interval."[136]

The Companies' response, however, does not address the fact that imbalances regularly occur on its system or clarify what level of imbalance the Companies would consider acceptable and why.[137] The Companies do not claim that the forecasted imbalances would violate NERC's balancing standards or provide any additional information forecasting imbalances that would cause violations. Nor do they otherwise present circumstances that would make difficult the

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[133] EFG Report at 14.

[134] LG&E/KU Response Comment at 52–53.

[135] EFG Report at 34.

[136] EFG Report at 34–35.

[137] LG&E/KU Response Comment at 52–53.

possibility of integrating 1000 MW of solar. The Companies do not even claim that the forecasted imbalances are additional to and discrete from current system imbalances.

Joint Intervenors welcome further dialogue on how to model increasing penetration of solar generation. But the Companies' Responsive Comment does not answer Joint Intervenors' principal concerns about the Solar Intermittency Study, which continues to appear out of sync of applicable balancing standards, actual operating conditions, and the reactive power and voltage regulation capabilities of modern renewable and storage resources.[138]

CONCLUSION

Joint Intervenors appreciate this opportunity to provide supplemental comments on LG&E/KU's 2021 IRP, in light of additional facts and argument raised in the Companies' Responsive Comment and testimony. Joint Intervenors' Initial Comment provides numerous constructive suggestions of how the Companies can expand their triennial resource plan to consider impacts to customers—particularly low- and fixed-income customers—and to fully and fairly evaluate all resource options on more equal footing. For the reasons summarized here, as in the Initial Comment, Joint Intervenors respectfully make and restate the following recommendations:

1. Encourage the Companies to establish an ongoing IRP stakeholder process for the purpose of considering and inviting stakeholder input and review on certain potentially complex changes to the Companies' IRP methodology, inputs, and assumptions including, but not limited to:
    a. The Companies' reserve margin study;
    b. The development and modeling of the portfolios considered in the IRP;
    c. The manner in which unit retirement is evaluated;
    d. The RTO membership analysis;

[138] EFG Report at 34–36.

e. The source of and manner in which new resource costs and supply are developed, e.g., demand-side management ("DSM") and other distributed energy resources (DERs); and

f. The modeling tools used in the development of the IRP.

2. Encourage the Companies to negotiate a discounted, project-based licensing fee that permits interested intervenors the ability to perform their own modeling runs in the same software package(s), and encourage the Companies to absorb the cost of these licensing fees.

3. Clarify that upon filing of an IRP, LG&E/KU should make available, on request and ideally simultaneously with filing of the IRP, the modeling inputs (including settings) and outputs, assumptions, any post-processing spreadsheets (e.g. to create the revenue requirements) in electronic spreadsheet format, and the model manual(s).

4. Recommend that the Companies adopt the typical practice of using a single model for capacity expansion and production cost modeling.

5. Direct the Companies to model a full planning period and not just a single year.

6. Recommend that the Companies document their analytical work so that it clearly conveys the steps taken and information relied upon.

7. Encourage the Companies to limit out-of-model adjustments and include as many system costs in the model as is feasible.

8. Direct the Companies to economically evaluate all potentially cost-effective resource options available to it, specifically including a wide range of levels of new and expanded DSM and other DERs such as distributed solar and storage. The DSM levels should be developed through the meaningful and participatory collaboration of the DSM Advisory Group as previously recommended by Staff.

9. Direct the Companies to consider key issues or uncertainties potentially impacting their resource plan, particularly including analysis of the impacts of a carbon price and meeting a significant emission reduction goal, such as PPL's corporate goal, on the Companies' resource plans.

10. Encourage the Companies to cease use of the Equivalent Load Duration Curve Model ("ELDCM") for reliability modeling.

Further, Joint Intervenors continue to encourage the Companies to acknowledge and account for customer impacts in their next IRP, particularly resource decision impacts on their low- and fixed-income customers.

Lastly, as addressed here in Section. II, Joint Intervenors encourage Commission Staff to either set an informal conference or issue additional information requests of LG&E/KU before issuing a draft report, in light of the significant impacts and changes in assumptions likely to flow from recent passage of the Inflation Reduction Act. Joint Intervenors urge Commission Staff to ask what effects the IRA may have on (1) the conclusions in the 2021 IRP, (2) evaluation of responses to the outstanding request for proposals, (3) timing of coal-fired unit retirements, (4) timeline and costs for development of more renewable resources, and (5) any other issues of interest to Staff.

Respectfully submitted,

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CERTIFICATE OF SERVICE

In accordance with the Commission's July 22, 2021 Order in Case No. 2020-00085, Electronic Emergency Docket Related to the Novel Coronavirus COVID-19, this is to certify that the electronic filing was submitted to the Commission on August 22, 2022; that the documents in this electronic filing are a true representations of the materials prepared for the filing; that no hard copy of this filing will be made; and that the Commission has not excused any party from electronic filing procedures for this case at this time.

/s/ Tom FitzGerald

Tom FitzGerald