COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matters of:

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

**SOUTHERN RENEWABLE ENERGY ASSOCIATION
WRITTEN COMMENTS UPON LOUISVILLE GAS AND ELECTRIC
COMPANY'S AND KENTUCKY UTILITIES COMPANYS'
JOINT INTEGRATED RESOURCE PLAN**

(PUBLIC VERSION – REDACTED)

WITH

NOTICE CONCERNING CONFIDENTIAL INFORMATION

Comes now the Southern Renewable Energy Association (also "SREA"), by and through counsel, and files its Written Comments upon Louisville Gas and Electric Company's ("LG&E") and Kentucky Utilities Company's ("KU" collectively "Companies") Joint Integrated Resource Plan ("IRP") into the record in the instant case. SREA submits its comment through separate reports prepared by Miriam Makhyoun (Attachment A) and Dr. Jennifer Chen (Attachment B).

SREA is very grateful to the Kentucky Public Service Commission for allowing it the opportunity to provide these written comments into the record of the Commission's forward-looking, cooperative resource planning process. The objective of these written comments is to exchange information and ideas in a less adversarial manner to best serve the interests of the parties, the stakeholders, and the Commonwealth of Kentucky in resource planning.

MIRIAM MAKHYOUN

Miriam Makhyoun is the Chief Executive Officer of EQ Research, a national energy consulting firm known for Policy Vista™, an online platform tracking and analyzing state regulatory proposals, state legislation, general rate cases, RPS and resource planning market data, electric vehicle regulation, and low carbon fuel policy. EQ Research's IRP as a Data Service™ tool keeps users up-to-date on utility energy procurement schedules from their Integrated Resource Plans (IRPs). EQ Research consultants also provide regulatory compliance support to clients and serve as expert witnesses at utility commissions on topics related to resource planning and rate design.

MS. MAKHYOUN'S BACKGROUND

Miriam Makhyoun was a Power Supply Contracts Manager at MCE, California's first Community Choice Aggregation Program, where she managed MCE's 2018 Energy Storage Request for Offer process. Other experience includes portfolio management for Pacific Gas & Electric (PG&E) procuring Resource Adequacy capacity and carbon compliance instruments. Before PG&E, Miriam provided customized research to members of the Smart Electric Power Alliance. Ms. Makhyoun also published numerous energy industry reports while at North Carolina Sustainable Energy Association. Ms. Makhyoun holds a Master of Business Administration and a Master of Science in Appropriate Technology (Renewable Energy) from Appalachian State University.

FOCUS OF MS. MAKHYOUN'S REPORT

Ms. Makhyoun, on behalf of SREA, presents written comments pertaining to the necessity of an improved stakeholder process for the development of the Companies' IRP, an improved RFP process that can inform IRP resource cost assumptions, modeling assumptions for load planning and resource planning, and the characterization of baseload and dispatchable resources as it informs the Companies' resource planning methodology.

DR. JENNIFER CHEN

Dr. Jennifer Chen is the President of ReGrid, a research and policy analysis consultancy with expertise in power markets and infrastructure.

DR. CHEN'S BACKGROUND

Dr. Chen has previously testified on electricity, transmission, and governance topics, including before the U.S. Congress and the U.S. Federal Energy Regulatory Commission (FERC). Prior to consulting, Dr. Chen led federal electricity policy work at the Nicholas Institute, a think tank for policy solutions at Duke University. She was previously an attorney with the Natural Resources Defense Council and began her energy career at FERC. Dr. Chen earned a J.D. from New York University and a Physics Ph.D. from the University of Chicago. She has affiliations with R Street, World Resources Institute, New Energy Economics, Americans for a Clean Energy Grid, and the U.S. Department of Energy Electricity Advisory Committee; however, her comments are solely her own and should not be attributed in any way to these entities.

FOCUS OF DR. CHEN'S REPORT

Dr. Chen, on behalf of SREA, presents written comments pertaining to her review of LG&E/KU's 2021 Regional Transmission Organization Membership Analysis and the necessity of an RTO membership evaluation framework containing clear goals as well as criteria and metrics for evaluating the costs, benefits, and risks of membership.

<u>**NOTICE CONCERNING CONFIDENTIAL INFORMATION**</u>

SREA provides notice that Ms. Makhyoun's Report includes information for which the Companies have, by motions, sought confidential protection and is therefore, per 807 KAR 5:001, Section 13(4), accorded confidential treatment pending action by the Commission.

The subject information, the source of which is referenced in each instance in Ms. Makhyoun's Report, pertains to the following: Vol. I, Table 5-5 of the Companies' IRP (motion for confidential protection filed on October 19, 2021); the Companies' response to the first request for information submitted by the Sierra Club, Item 5, and the Companies' response to the first request for information submitted by SREA, Item 1(b), and corresponding attachment (motion for confidential protection filed on February 11, 2022). The subject information is redacted in the public version of the report.

WHEREFORE, SREA respectfully submits its Written Comments.

Respectfully submitted,

<u>/s/ David E. Spenard</u>

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Notice And Certification for Filing

Undersigned counsel provides notice that the electronic version of the redacted paper has been submitted to the Commission by uploading it using the Commission's E-Filing System on this 22nd day of April 2022. Pursuant to the Commission's Order in Case No. 2020-00085, *Electronic Emergency Docket Related to Novel Coronavirus Covid-19*, the paper, in paper medium, is not required to be filed. The electronic version of the non-redacted (confidential) paper has been submitted to the Executive Director of the Commission in compliance with instructions from Commission Staff on this 22nd day of April 2022.

/s/ David E. Spenard

Notice Concerning Service

The Commission has not yet excused any party from electronic filing procedures for this case.

/s/ David E. Spenard

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

ATTACHMENT A

REPORT OF MIRIAM MAKHYOUN UPON THE 2021 JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY

Miriam Makhyoun, on behalf of Southern Renewable Energy Association (SREA), presents this report pertaining to the 2021 Joint Integrated Resource Plan (IRP) of Louisville Gas and Electric Company (LG&E) and Kentucky Utility Company (KU – collectively "Companies").

Filed: April 21, 2022

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Summary and Recommendations

SREA recommends the following:

1. In all future IRPs, the Companies should provide a robust stakeholder engagement process, including holding public meetings and technical conferences as it develops its IRP, responding to stakeholder requests for information, sharing modeling files, and not opposing interested stakeholders from intervening in their IRP proceeding to provide comments.
2. 807 KAR 5:058 was promulgated for the purpose of providing "a solid foundation for a forward-looking, cooperative, resource planning process."[1] The Commission should consider amending this regulation to include additional detail concerning the stakeholder engagement process, and the Companies should, in future IRPs, fully describe the efforts by the Companies to, among other things, meet the objective of a cooperative, non-adversarial, process.
3. To the extent the Companies refuse to engage in a forward-looking resource planning process and consider the risk of climate policy or regulations on carbon dioxide emissions in their IRP, such as by refusing to model a price on carbon dioxide emissions in any scenarios, the Commission should remind the Companies that they should have no expectation to recover any costs that are unjust or unreasonable such that the financial risk will be borne by the Companies' shareholders and not ratepayers should such a policy be enacted in the future and that their actions are based upon scenarios that are not adequate and realistic forward-looking planning scenarios.
4. The Companies' IRP does not provide a reasonable basis for determining that it should build new natural gas peaker plants. The Companies should conduct additional modeling and analysis on renewable resources paired with energy storage, among other solutions, to examine opportunities to avoid the construction of additional natural gas generation. The Companies should model both 2-hour and 4-hour solar plus storage and stand-alone storage as alternatives to the additional planned natural gas-fired capacity.
5. Given the high cost of generation identified by the Companies at a number of their existing coal and natural gas generation, the Companies should conduct a robust and transparent

[1] Adm. Case 308, Order, (Ky. P.S.C. Aug. 8, 1990), p. 11.

retirement analysis to identify which, if any, legacy generating plants could be retired early to save ratepayers money.

6. In all future IRPs, the Companies should conduct substantially more robust reliability modeling suitable for analyzing scenarios featuring high deployment of renewable energy and battery storage.
7. In all future IRPs, solar paired with battery storage should be modeled as a distinct, separate resource, and batteries utilizing durations other than 4 hours, including shorter durations, should also be considered (both paired and standalone), and the Companies should not preclude these resources from participating in resource solicitations.
8. The PSC should remind the Companies that the Commission may investigate, in all pertinent dockets involving the Companies, including an investigation initiated by the Commission, the reasonableness of the Companies' continued reliance on expensive existing generating plants that are substantially above the cost of constructing new clean alternatives *today*. The Companies should have no expectation of collecting in rates any costs that are unjust and unreasonable.
9. LG&E/KU should conduct another RFP in 2022 to pursue additional renewable energy over the next three years, or use its 2021 RFP results to select additional renewable energy and battery storage projects in the near term to take advantage of federal tax credits that will be phased out in future years.

Overview of IRP

The Companies developed resource plans over three energy requirement or load forecast scenarios (low, base, high) and three fuel price scenarios (low, base, high). These scenarios produce nine possible combinations, but the Companies state that they do not have a 'preferred' plan."[2] However, since they provided more details and analysis only with respect to their Base Load, Base Fuel Price scenario, these comments treat this as the *de facto* resource plan for the Companies. The Companies concluded that "[s]olar and SCCTs [simple cycle combustion turbines] are the predominant resource technology choices," with 500 MW of solar and 440 MW (summer capacity) of SCCTs selected for 2026-2030, and 1,600 MW of solar and 880 MW of

[2] Responses to OAG Initial Data Requests (filed Feb. 11, 2022), Item 8(a).

SCCTs selected for 2031-2036 under the Companies' Base Load, Base Fuel Price scenario.[3] No changes or additions to the Companies' generation resources are planned for the next three years, aside from the planned addition of Rhudes Creek solar and the retirement of Mill Creek 1 and Zorn 1.[4]

The Companies claim in their 2021 IRP that it experiences both summer and winter peaks that must be planned for to ensure customer demand is always met. To determine a reliable portfolio of resources, the Companies conducted a reserve margin analysis that, for the first time, was communicated in the context of both a summer and a winter peak reserve margin. The Companies claim they evaluated (a) annual capacity costs and (b) annual reliability and generation production costs for 2025 over a range of generation portfolios with different reserve margins to identify the optimal generation mix for customers. They concluded that their existing resources are economically optimal for meeting system reliability needs in 2025 and that "it is not cost-effective to alter annual or summer peak hour reliability by either retiring existing resources or adding new resources; the reliability and generation production cost benefit for each of the Companies' marginal resources exceeds the costs that would be saved by retiring these units."[5]

General Comments on IRP Format

The IRP format used by the Companies appears to be expressly organized to demonstrate that the Companies are "checking the box" on meeting the minimum compliance requirements specified in the Commission's IRP regulations, 807 KAR 5:058, including using the Section and Subsection numbers found in the Administrative Regulation. While SREA understands the Companies' desire to comply with the Commission's regulations, this format, while appropriate for perfunctory and more limited compliance filings and reporting, is ill-suited for a major public-facing document analyzing issues of great import to the residents of Kentucky. As such, IRPs should strive to be as accessible and understandable as possible, notwithstanding the technical nature of the underlying analyses. To that end, SREA encourages the Commission and the Companies to consider improvements to the IRP format, including organizing IRPs narratives in a more natural manner to the reader, rather than as a compliance checklist.

[3] IRP, Vol. I, p. 5-43.
[4] IRP, Vol. I, p. 5-44.
[5] IRP, Vol. III, Generation Planning & Analysis, dated Oct. 2021, Executive Summary, p. 3 [PDF 26 of 140].

IRP Stakeholder Process

KU and LG&E failed to conduct a transparent and robust stakeholder engagement process prior to finalizing and submitting their 2021 IRP. The Companies confirmed that they "did not have a 2021 IRP stakeholder engagement process and have not had such a pre-filing process for any previous IRP."[6] The Companies did not hold a single public meeting, open house, technical conference, or solicit input from stakeholders on the inputs and assumptions related to their modeling approach, scenarios, load forecast, generating resource options, or non-generating alternatives. The only stakeholder engagement they appear to have done prior to filing their IRP relates to communications with their largest customers to collect information for developing their sales forecasts.[7] They justify the lack of public engagement by explaining that "the regulation does not require or even suggest a pre-filing public or stakeholder process."[8]

The Commission's current rules provide that a utility's IRP "shall include the utility's resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost. The plan shall consider the potential impacts of selected, key uncertainties and shall include assessment of potentially cost-effective resource options available to the utility."[9] All of these issues affect the public interest and should be subject to public engagement from the *beginning* of the process. Stakeholder engagement early in the IRP process is also critical for building consensus on key issues; providing early feedback to utilities; identifying deficiencies in the utility's modeling approach, inputs, and assumptions; and ensuring that stakeholders have a deeper understanding of the utility's IRP, enabling them to provide more informed and insightful comments in response to the final IRP. Involving impacted communities through a robust stakeholder engagement process can help achieve win-win outcomes in the public interest,[10] which itself is a cornerstone to energy justice and ensuring a just transition as the Commonwealth's electric generation resource portfolio changes in the future. The residents of Kentucky deserve to have a say in how their energy needs are met.

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[6] Responses to SREA Initial Requests for Information (filed Feb. 11, 2022), Item 4(a).
[7] *Id.* at Item 4(b).
[8] *Id.* at Item 4(a).
[9] 807 KAR 5:058(8)(a).
[10] National Association of Regulatory Utility Commissioners (2021, January), p. 2. Public Utility Commission Stakeholder Engagement: A Decision-Making Framework. https://pubs naruc.org/pub/7A519871-155D-0A36-3117-96A8D0ECB5DA

Many other states require that investor-owned utilities conduct a stakeholder engagement process. Robust stakeholder engagement processes are part of the IRP process in Indiana,[11] North Carolina and South Carolina,[12] Arkansas,[13] Louisiana,[14] Mississippi,[15] and for Tennessee Valley Authority (TVA).[16] For instance, TVA conducted a robust IRP stakeholder process when developing its most recent IRP that included proactively reaching out to stakeholders, developing a stakeholder working group to meet regularly throughout the IRP development process, and soliciting multiple rounds of public comment, which it said were "critical in shaping the IRP."[17] Likewise, in Indiana, investor-owned utilities must conduct at least three meetings prior to submitting a final IRP, publish agendas and relevant information on their IRP webpages, and respond to stakeholder information requests within fifteen days.[18] Notably, the rules require the utility to "solicit, consider, and timely respond to relevant input relating to the development of the utility's IRP"[19] and to "provide an opportunity for public participation in a timely manner so that it may affect the outcome of the IRP,"[20] which acknowledges the important role stakeholders can have in providing valuable information and influencing IRP outcomes when they are allowed to meaningfully participate. For instance, Duke Energy Kentucky's sister utility, Duke Energy Indiana, conducted eight stakeholder workshops in Indiana when developing its 2021 IRP,[21] and

[11] *See* https://www.in.gov/iurc/energy-division/electricity-industry/integrated-resource-plans/.
[12] *See* https://www.duke-energy.com/our-company/about-us/irp-carolinas.
[13] *See* https://www.entergy-arkansas.com/integrated_resource_planning/.
[14] *See* https://www.cleco.com/about/regulatory/integrated-resource-plan.
[15] *See* https://lpdd.org/resources/mississippi-irp-process/.
[16] *See* https://www.tva.com/environment/environmental-stewardship/integrated-resource-plan/2019-irp-background
[17] TVA 2019 IRP, p. ES-8, https://bit.ly/3vMMeaH (Stating that "Throughout the IRP process, TVA engaged external stakeholders to understand diverse opinions and to challenge assumptions. TVA established the IRP Working Group, whose 20 members represent diverse interests in the Valley. The IRP Working Group met approximately monthly to review input assumptions and preliminary results and to enable its members to provide their respective views to TVA. TVA also presented IRP progress updates to the Regional Energy Resource Council (RERC), a federal advisory committee that provides advice to the TVA Board of Directors on a range of energy-related matters, including the IRP. During a 60-day scoping period from February 15 through April 16, 2018, TVA obtained public comments on the scope of the effort to develop this IRP, which helped shape the draft IRP and EIS. After the release of the draft IRP and EIS on February 15, 2019, TVA provided a public comment period through April 8, 2019. TVA held meetings across the Tennessee Valley and an online webinar, and accepted public comments via mail, email, online and in-person at the meetings. Input was critical in shaping the IRP and EIS, and many of the sensitivity analyses that were performed were informed by stakeholder and public input.")
[18] 170 IAC 4-7-2.6.
[19] 170 IAC 4-7-2.6(c).
[20] 170 IAC 4-7-2.6(e)(3)(C).
[21] https://www.duke-energy.com/home/products/in-2021-irp-stakeholder

Kentucky Power's sister utility, Indiana Michigan Power, conducted five workshops when developing its 2021 IRP.[22]

Finally, not only did the Companies prevent stakeholders from having any meaningful participation in the creation of its IRP, but they also actively opposed SREA intervening in this proceeding after its final IRP was filed.[23] Collectively, these actions demonstrate the Companies' aversion, if not outright hostility, to a transparent, cooperative, and robust IRP process that is necessary to ensuring the best possible least-cost outcomes for the Commonwealth and the Companies' ratepayers. Fortunately, the Commission denied the Companies' attempt to stifle SREA's constructive participation in this non-adversarial case and granted SREA's intervention.[24] However, given the Companies' actions in this case, SREA remains concerned about the Companies' commitment to an open and cooperative IRP process in the future, and how its actions here could work to stifle participation by other stakeholders in the future, absent additional Commission direction.

Accordingly, the Commission should take immediate steps to modify its IRP process to address these shortcomings, including requiring a robust and transparent stakeholder process from the beginning of the IRP process and ensuring interested parties can participate without being singled out by the Companies with burdensome legal challenges seeking to prevent them from providing comments on their IRP. Because utilities like the Companies are not meaningfully involving and engaging with stakeholders as they develop their IRPs, the current IRP process is inadequate and insufficient for ensuring the Commonwealth's energy goals are achieved. As a result, and as detailed in the following sections, there are major errors and omissions in the Companies' IRP, and it relies on dubious assumptions and methods to justify its ultimate conclusion that it should not procure any additional low-cost clean energy resources in the next three years beyond its Rhudes Creek solar project and renewable energy that will only be available for select large customers. This has produced a deficient IRP in which the Companies have failed to demonstrate that their current resources, and plan for future resources, will provide an adequate

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[22] https://www.indianamichiganpower.com/community/projects/irp/

[23] LG&E's and KU's Objection To Motion To Intervene Of Southern Renewable Energy Association, (filed Nov. 3, 2021), https://psc.ky.gov/pscecf/2021-00393/kendrick.riggs%40skofirm.com/11032021025615/LGE-KU_Objection_to_Southern_Renewable_Energy_Assoc_Mtn_to_Intervene.pdf.

[24] Order, (Ky. P.S.C. Jan. 11, 2022), https://psc.ky.gov/pscscf/2021%20Cases/2021-00393//20220111_PSC_ORDER05.pdf.

and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost.

The Companies' 2021 RFP

On January 7, 2021, the Companies issued a request for proposals (RFP) for 300 MW to 900 MW beginning in 2025 and no later than 2028. Proposals were due March 31, 2021, and the Companies planned to complete their evaluation by July 1, 2021.[25] The Companies filed their 2021 IRP on October 19, 2021 in this proceeding. Despite having access to voluminous data and information about actual projects under development in Kentucky and neighboring states, the Companies inexplicably claim they "did not use or rely upon any RFP responses in their 2021 IRP."[26] However, SREA notes that in a response to Commission Staff's question asking the Companies to provide support for their assumption that the capital cost of constructing two or more SCCTs at an existing site, the Companies provided a seemingly conflicting response, stating "[t]he cost estimate for new generation at an existing facility was provided by a vendor as part of a response to the Companies' 2021 Request for Proposals."[27] This demonstrates a lack of consistency in modeling resource cost assumptions.

Another concern is the sample itself, were it to have been used for information on resource cost, was limited. The Companies' 2021 RFP[28] contained overly restrictive bidding criteria that unduly limited the eligibility of proposals for various types of renewable energy and energy storage technologies. Examples of overly restrictive criteria include:

- The Companies refused to consider resources smaller than 100 MW, meaning potentially cost-effective solar and wind projects, or aggregations of smaller resources, were prevented from competing with alternatives.
- The Companies required that renewables paired with energy storage have a minimum capacity of 100 MW with four-hour battery storage (400 MWh), and in the case of standalone battery storage, a minimum of 100 MW of capacity and 400 MWh of energy, limiting long- and short-duration storage and other types of hybrid resources.

[25] LG&E and KU, "Request for Proposals to Sell Electric Capacity and Energy (RFP)," p. 5 of 10, https://lge-ku.com/sites/default/files/media/files/downloads/RFP-LGE-and-KU-January-2021.pdf
[26] Responses to SREA Initial Request for Information (filed Feb. 11, 2022), Item A-1(j).
[27] Responses to Commission Staff's First Request for Information (filed Feb. 11, 2022), Item 56.
[28] *See* https://lge-ku.com/lge-ku-request-proposals-sell-electric-capacity-energy

Shorter duration energy storage systems have been widely deployed. The four-hour battery energy duration limitation common in certain geographies is nearly always an artifact of existing regulatory constructs, rather than because this is the minimum duration needed to produce meaningful benefits. For example, the biggest driver of four-hour battery storage in the U.S. context is California, where the four-hour duration minimum is a requirement under the state's Resource Adequacy program.[29] In markets outside of California, shorter duration batteries are commonly employed.

Responses the Companies received to its 2021 RFP demonstrate that the Companies were informed by leading U.S. clean energy developers that their arbitrary requirement for a 4-hour battery storage solution would result in higher costs and less desirable outcomes than shorter duration batteries that would still provide valuable winter peaking capacity to the Companies. For instance, **[BEGIN CONFIDENTIAL INFORMATION]** [redacted][30] (emphasis added).**[END CONFIDENTIAL INFORMATION]**. Similarly, **[BEGIN CONFIDENTIAL INFORMATION]** [redacted]

[29] D.21-06-029. (June, 2021). California Public Utilities Decision, p. 26. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.PDF

[30] **[BEGIN CONFIDENTIAL INFORMATION]** [redacted] **.[END CONFDIENTIAL INFORMATION]**[Provided in the Companies' Responses to Sierra Club's Initial Requests for Information (filed Feb. 11, 2022), Item 5.]

[redacted][31] **[END CONFIDENTIAL INFORMATION]**. The Companies ignored or disregarded this and other valuable input from leading clean energy companies that responded to the 2021 RFP, instead choosing to stack the deck against renewable-plus-storage solutions that can flexibly assist the Companies in meeting both summer and winter peak loads today.

Modeling Approach

The Companies' modeling approach reflects an outdated view of resources and resource planning that is insufficient for evaluating a transition to clean energy solutions and for developing a least-cost portfolio.

Summer and Winter Peak

In 2021, the Companies' average peak demand occurred between Hour Ending (HE) 9 AM - HE 10 AM in November through March and HE 3 PM - HE 5 PM in April through October,[32] which are the times solar energy is most productive. The Companies showed that on average in 2021, their current solar portfolio as represented by generation at E.W. Brown only, produced 94% of all solar energy produced between the period, HE 9 AM - 5 PM.[33] The times load was on average greater than 4 GW in 2021 included January at HE 8 AM - 1 PM and HE 7 PM - HE 10 PM; February at HE 6 AM - HE 11 PM; June at HE 11 AM - HE 10 PM; July and August at HE 10 AM - HE 10 PM; and September at HE 1 PM - HE 8 PM.[34] Two-hour and four-hour solar plus storage is a cost-effective hedge for the morning and evening peaks during much of the year and would serve as a hedge against volatile gas prices.

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[31] **[BEGIN CONFIDENTIAL INFORMATION]**[redacted]**[END CONFDIENTIAL INFORMATION]**[Provided in the Companies' Responses to Sierra Club's Initial Requests for Information (filed Feb11, 2022), Item 5.]

[32] Provided in the Companies' Responses SREA's Supplemental Requests for Information (filed Mar. 25, 2022), Item 20(a), Attachment to SREA 2-20.

[33] Provided in the Companies' Responses SREA's Supplemental Requests for Information (filed Mar. 25, 2022), Item 20(d), Attachment to SREA 2-20.

[34] Provided in the Companies' Responses SREA's Supplemental Requests for Information (filed Mar. 25, 2022), Item 20(a), Attachment to SREA 2-20.

Hour Ending	January	February	March	April	May	June	July	August	September	October	November	December
1:00 AM	3,684	3,935	2,948	2,765	2,753	3,218	3,393	3,481	2,964	2,756	3,174	3,109
2:00 AM	3,622	3,884	2,915	2,738	2,665	3,092	3,237	3,318	2,848	2,680	3,142	3,052
3:00 AM	3,601	3,876	2,901	2,734	2,623	2,991	3,141	3,219	2,780	2,635	3,134	3,022
4:00 AM	3,598	3,890	2,930	2,756	2,616	2,951	3,087	3,175	2,765	2,630	3,146	3,015
5:00 AM	3,636	3,942	3,032	2,867	2,683	2,995	3,109	3,210	2,821	2,702	3,231	3,045
6:00 AM	3,757	4,064	3,231	3,077	2,843	3,088	3,199	3,375	3,013	2,897	3,387	3,154
7:00 AM	3,953	4,277	3,446	3,231	2,990	3,262	3,332	3,471	3,146	3,056	3,620	3,356
8:00 AM	4,141	4,450	3,553	3,308	3,129	3,494	3,543	3,684	3,258	3,131	3,766	3,535
9:00 AM	4,225	4,506	3,566	3,338	3,258	3,732	3,797	3,958	3,428	3,238	3,800	3,603
10:00 AM	4,235	4,493	3,534	3,341	3,360	3,961	4,069	4,263	3,598	3,323	3,741	3,614
11:00 AM	4,192	4,441	3,480	3,339	3,433	4,189	4,321	4,525	3,772	3,399	3,659	3,571
12:00 PM	4,135	4,358	3,429	3,338	3,523	4,384	4,560	4,763	3,935	3,482	3,579	3,511
1:00 PM	4,073	4,296	3,377	3,325	3,569	4,520	4,744	4,943	4,072	3,535	3,514	3,449
2:00 PM	3,987	4,213	3,315	3,311	3,619	4,642	4,883	5,055	4,194	3,597	3,447	3,382
3:00 PM	3,915	4,136	3,257	3,291	3,644	4,711	4,972	5,108	4,279	3,618	3,389	3,333
4:00 PM	3,867	4,077	3,209	3,257	3,653	4,738	4,989	5,116	4,319	3,617	3,351	3,304
5:00 PM	3,859	4,059	3,191	3,249	3,657	4,726	4,996	5,098	4,316	3,601	3,358	3,301
6:00 PM	3,971	4,142	3,204	3,252	3,639	4,671	4,905	5,020	4,237	3,550	3,475	3,444
7:00 PM	4,137	4,280	3,260	3,226	3,574	4,541	4,755	4,862	4,084	3,561	3,606	3,534
8:00 PM	4,122	4,325	3,396	3,286	3,513	4,379	4,553	4,708	4,015	3,493	3,595	3,519
9:00 PM	4,100	4,292	3,362	3,266	3,484	4,251	4,402	4,551	3,821	3,360	3,563	3,497
10:00 PM	4,014	4,199	3,261	3,130	3,295	4,033	4,151	4,255	3,572	3,177	3,483	3,436
11:00 PM	3,902	4,096	3,141	2,964	3,071	3,736	3,863	3,959	3,316	3,001	3,382	3,322
12:00 AM	3,784	3,982	3,031	2,840	2,890	3,468	3,596	3,697	3,102	2,851	3,272	3,189

Figure 1. 2021 Average Hourly MW by Month[35]

The Companies' simplistic reserve margin analysis is insufficient for comprehensively analyzing resource portfolios. For example, the Companies' Loss of Load Probability (LOLP) used in its Cost-of-Service Study in their most recent rate case is instructive. As the Companies explained in their most recent Kentucky rate case application:

> LOLP represents the probability that a utility system's total demand will exceed its generation capacity during a given hour. LOLP therefore takes into consideration the magnitude of the load, installed generation capacity, forced outage rates, maintenance schedules, and ramp-up rates of generating units. LOLP can be calculated for any period—an hour, a day, a week, etc. LOLP is a critical measurement the Companies use to plan their generation resources. Specifically, it is used to evaluate the level of reserve margins the Companies target.[36]

The Companies' LOLP methodology utilized in its rate cases used an LOLP calculated for each hour of the year, which was then multiplied by hourly class loads for each class in order to assign weight to each hour. The results were then summed to produce the LOLP allocator.[37] Thus

[35] *Id.* Edited with Conditional Formatting.
[36] *Electronic Application of Kentucky Utilities for an Adjustment to its Electric Rates etc.*, Kentucky Public Service Commission Case No. 2020-0349, Application, Testimony, Vol. 4 of 4, Direct Testimony of William S. Seelye at p. 105 lines 5 through 15, (filed Nov. 25, 2020), available at https://psc.ky.gov/pscecf/2020-00349/rick.lovekamp%40lge-ku.com/112520200847 57/13-KU_Testimony_4of4%28Seelye%29.pdf.
[37] *Id*. at p. 105, line 16 through p. 106, line 15.

in effect, hours with no LOLP were given a zero weight in the allocation of production demand costs, and the greater weight was given to hours with higher LOLPs.

The Companies' LOLP results indicate that the Companies' assertions about its winter peak being an immediate concern are overblown, as nearly 100% of its loss of load would be expected during summer peaking events, and not winter peaks. The figure below provides a 12×24 heat map that shows the percentage of LOLP represented for each daily hour by month based on the hourly LOLP evaluation for July 2021 through June 2022 that the Company presented in Kentucky. LOLP hours are highly concentrated during summer afternoons, with 98.7% of annual LOLP occurring from June to September. Some hours outside of this window show non-zero LOLPs but the amounts are generally small with the highest concentration of the remainder occurring on January mornings from 7 AM to 11 AM (0.6% in total).[38]

Month/ Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	TOTAL
1	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 2%	0 2%	0 1%	0 1%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	**0.9%**
2	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	**0.2%**
3	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	**0.0%**
4	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	**0.0%**
5	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	**0.2%**
6	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 1%	0 2%	0 6%	0 9%	1 5%	1 2%	1 0%	0 7%	0 3%	0 1%	0 0%	0 0%	0 0%	0 0%	**6.6%**
7	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 2%	0 9%	2 7%	5 1%	6 3%	6 3%	4 8%	2 9%	1 2%	0 4%	0 2%	0 1%	0 0%	0 0%	**31.2%**
8	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 2%	0 8%	3 0%	5 9%	10 4%	12 2%	11 5%	7 0%	3 0%	1 1%	0 6%	0 1%	0 0%	0 0%	**55.9%**
9	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 2%	0 6%	1 3%	1 5%	0 9%	0 3%	0 1%	0 1%	0 0%	0 0%	0 0%	0 0%	**5.0%**
10	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	**0.0%**
11	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	**0.0%**
12	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	0 0%	**0.0%**

Figure 2. LOLP Heat Map, July 2021–June 2022[39]

As the Companies transition to more renewable energy and retire existing natural generation, these results could change, and therefore it is prudent for the Companies to model this in the future. Clearly, however, the major threat to grid reliability currently faced by the Companies is its summer peak, for which additional standalone solar is capable of providing substantial capacity benefits.

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[38] Figure derived from *Electronic Application of Kentucky Utilities for an Adjustment to its Electric Rates etc.*, Kentucky Public Service Commission Case No. 2020-0349, Kentucky Utilities' Response to Joint Initial Data Requests of OAG and KIUC (filed Jan. 11, 2021), Item 122(a) Attachment, available at https://psc.ky.gov/pscecf/2020-00349/mike.hornung%40lge-ku.com/01222021020208/2020_AG-KIUC_DR1_KU_LGE_Attach_to_Q122a_-_LOLP_July2021toJune2022.xlsx.

[39] *Id.*

Baseload and Dispatchable Resources

The Companies define "dispatchable resources" as those that "include baseload and peaking resources," and state that baseload resources are low-cost, while implying peaking resources are a higher cost, but "are better-suited for following load during peak periods and for responding to unit outages."[40] The Companies further define "non-dispatchable resources" as renewable resources that "have little to no fuel or emissions costs, but their availability is uncertain during peak load conditions."[41]

The Companies mistakenly assert in their IRP that "baseload" resources are necessary to provide reliable and cost-effective electricity to its customers. For instance, the Companies claim that, "[i]n addition to the ability to serve load during the annual system peak hour, the generation fleet must have the ability to produce low-cost baseload energy, the ability to respond to unit outages and follow load, and the ability to instantaneously produce power when customers want it." When asked to confirm this statement in an information request, the Companies confirmed it.[42]

The Commissions should be highly alarmed by the Companies' delineation of baseload resources and its insistence of the necessity of baseload resources, which reflect an outdated and thoroughly debunked view that has no place in modern utility resource planning. Nearly five years ago, a Brattle Group report comprehensively explained why the term no longer made sense and warned that "[t]he use of the term 'baseload generation' may even distract regulators', planners', and markets administrators' attention from meeting emerging system and public policy needs in the most cost-effective manner," and concluded that "focusing on their status as 'baseload' generation is not a useful perspective for ensuring the cost-effective and reliable supply of electricity."[43] That warning is apt today in the context of the Companies' IRP.

There is no such technical or operational requirement to have "baseload" generation in order to provide safe, reliable, and affordable energy to customers when they demand it. Baseload does not refer to specific or unique services or resource attributes that are needed to reliably serve electricity customers. It is also a misconception that "baseload" generation units (or any resources)

[40] IRP Vol. I, Figure 5-5.
[41] *Id.*
[42] Responses to OAG's Initial Data Requests (filed Feb. 11, 2022), Item 10.
[43] Judy W. Chang, Mariko Geronimo Aydin, Johannes Pfeifenberger, Kathleen Spees, and John Imon Pedtke, "Advancing Past "Baseload" to a Flexible Grid How Grid Planners and Power Markets Are Better Defining System Needs to Achieve a Cost-Effective and Reliable Supply Mix," June 26, 2017, https://www.ourenergypolicy.org/wp-content/uploads/2017/06/document_ew_01.pdf.

are 100% reliable, as the Companies admitted in their IRP.[44] As detailed further below, baseload resources, as well as so-called "dispatchable" resources, have failed to perform as planned during events like the 2014 Polar Vortex, the August 2020 California rolling blackouts, and the February 2021 Texas Winter Storm Uri. System reliability is achieved not by having baseload generation, but rather by using a mix of resources that can collectively meet consumer demand. Simply put, there is no special need for continuous power supply to come from a single unit rather than a mix of resources. The figure below illustrates a generic load curve and how load can be met at all hours both under the traditional supply mix and under a high-renewable-energy resource mix.[45]

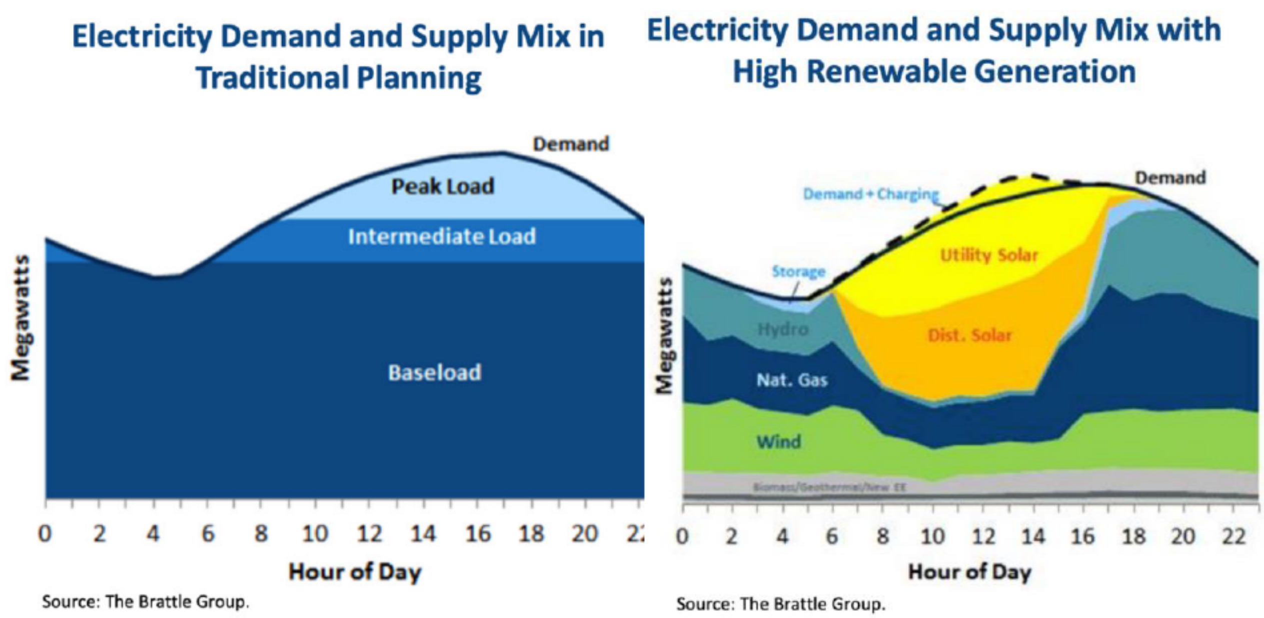

Figure 3. Comparison of Traditional and Modern Resource Planning

The Companies' contention that they need a minimum amount of "baseload" and "peaking" resources is therefore erroneous. System reliability is achieved when the Companies' planning provides for sufficient resource adequacy, regulation and frequency control, and operating reserves—regardless of whether the Companies classify those resources as "baseload," "dispatchable," "peaking," "non-dispatchable," or otherwise. In the future, as more renewable

[44] IRP, Vol. III, Generation Planning & Analysis (Oct. 2021), p. 7 [PDF 30 of 140] (Stating "Customers consume electricity every hour of the year, but no generating resource can be available at all times.").
[45] Figures come from Judy W. Chang, Mariko Geronimo Aydin, Johannes Pfeifenberger, Kathleen Spees, and John Imon Pedtke, "Advancing Past "Baseload" to a Flexible Grid How Grid Planners and Power Markets Are Better Defining System Needs to Achieve a Cost-Effective and Reliable Supply Mix," June 26, 2017, https://www.ourenergypolicy.org/wp-content/uploads/2017/06/document_ew_01.pdf.

energy is added to the grid, *flexible* resources will become increasing critical to allow the utilities to nimbly respond to changes in supply and demand. In contrast, baseload resources that cannot easily or cost-effectively vary their output to respond to changes in demand or the availability of other resources become a hinderance for integrating additional renewable energy onto the system. Therefore, reliance on what have traditionally been called "baseload" resources can ultimately *detract* from overall system reliability in a 21st century grid dominated by rapid renewable energy growth.

The Companies are not fully valuing renewables and storage in their resource planning. Inverter-based resources including solar can rapidly, accurately, and comprehensively respond to grid operator signals by ramping up or down their output. In fact, resources like solar can respond to grid operator signals to increase or decrease output much faster, more accurately, and across a wider spectrum of power output than coal or natural gas resources.[46] And battery energy storage can rapidly charge or discharge in a fraction of a second, faster than conventional thermal plants, which take about ten seconds to respond[47] and 15 minutes to start,[48] making battery energy storage a suitable resource for short-term reliability services, such as Primary Frequency Response and Regulation.[49]

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[46] U.S. Department of Energy Solar Energy Technologies Office. (Apr. 4, 2022). Solar Integration: Inverters and Grid Services Basics. Systems Integration Basics. Retrieved April 4, 2022, from https://www.energy.gov/eere/solar/solar-integration-inverters-and-grid-services-basics

[47] North American Electric Reliability Corporation (NERC). (Apr. 2015). Frequency Response Initiative Industry Advisory – Generator Governor Frequency Response (No. 5). https://www.nerc.com/pa/rrm/Webinars%20DL/Generator_Governor_Frequency_Response_Webinar_April_2015.pdf

[48] Australia's Clean Energy Council. (Apr. 2021). Battery Storage The New Clean Peaker. 3. https://assets.cleanenergycouncil.org.au/documents/resources/reports/battery-storage-the-new-clean-peaker.pdf

[49] Bowen, T., Chernyakhovskiy, I., Denholm, P. (Sept. 2019). Grid-Scale Battery Storage Frequently Asked Questions. National Renewable Energy Laboratory.

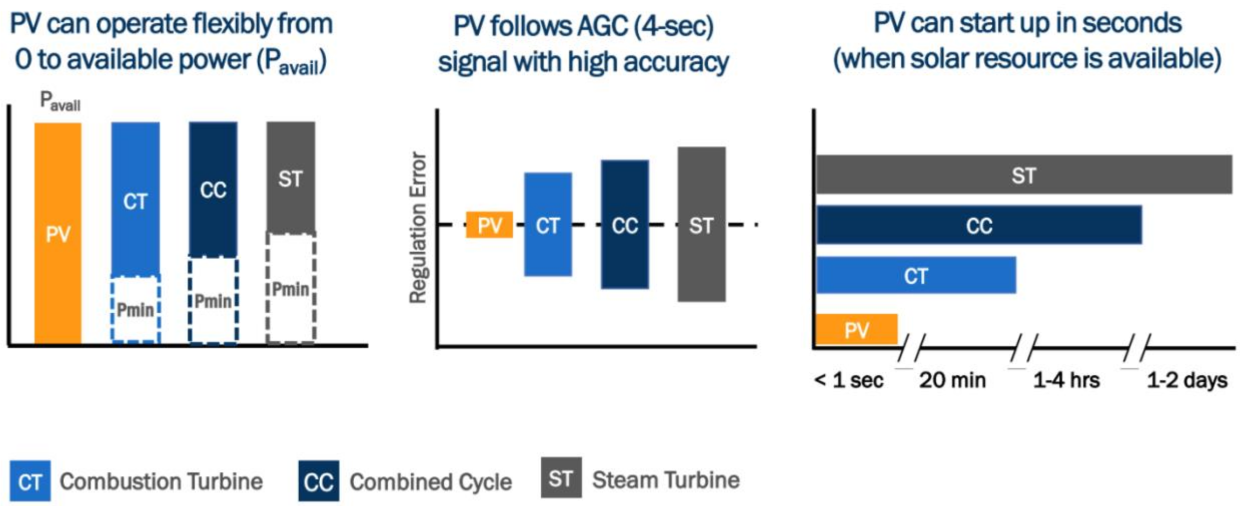

Figure 4. Solar PV Is More Flexible, Accurate at Following Grid Signal, and Has Faster Start Up Times Than Conventional Fossil Fuel Generation[50]

Additionally, renewable resources like solar do not have a minimum level of generation required (i.e., a "pmin") like coal and natural gas plants that constrain the ability of those resources to reduce their output when needed. The main limitation of solar and wind is the availability of their primary "fuel" source (sunlight and wind, respectively), and not their dispatchability, which is actually far superior to conventional resources. Thanks to substantial cost reductions in battery storage technologies, renewables paired with battery storage offer an immediate solution for mitigating a significant portion of variable fuel availability for these resources that can help address this issue. By adding additional SCCTs and prolonging the coal-fired portfolio, renewable resources would need to be curtailed, jeopardizing the success of the Companies' carbon goals of a 70% reduction from 2010 levels by 2035 and an 80% reduction by 2040.

[50] Figure is from Mahesh Morjaria, "The Role of Solar in Clean Energy Transition," IEEE PES Meeting, January 16, 2020, https://site.ieee.org/phoenix-pes/files/2020/01/The-Role-of-Solar-in-Clean-Energy-Transition-Morjaria.pdf.

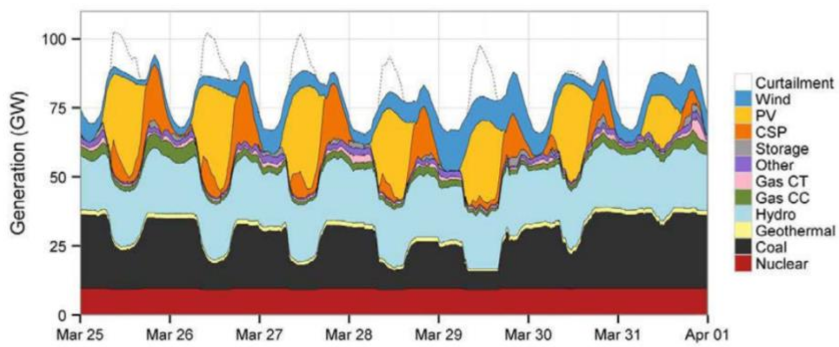

Figure 5. Minimum Generation Levels Resulting in Renewable Curtailment[51]

The Companies also repeatedly demonstrate an outdated and inaccurate understanding of the ability of renewable energy resources to contribute to grid reliability that unfairly diminishes the value of these resources. For instance, they state that "[a]s the Companies evaluate integrating more renewables into their generation portfolio, they must consider the fact that renewables lack many of the characteristics required to serve customers in every moment."[52] This is incorrect. Renewable energy, along with a portfolio of other solutions such as energy storage, energy efficiency, demand response, additional transmission, and access to markets (e.g., through membership in an ISO/RTO) can provide sufficient resource adequacy, regulation and frequency control, and operating reserves to ensure grid reliability.

Weather and Climate

The Companies relied exclusively on historical weather data and assumed that weather would be average or "normal" in every year.[53] In the face of overwhelming evidence that the climate is rapidly warming, driving more extreme weather, this is no longer a reasonable assumption for the Companies' long-term resource plan. The Companies should be evaluating their resource plan not based on what the weather of the past was, but rather on what Kentuckians are likely to experience in the future, during the planning years covered by the IRP. This includes consideration of higher average and nighttime ambient air temperatures, as well as increased

[51] Lew, D., Brinkman, G., Ibanez, E., Florita, A., Heaney, M., Hodge, B.-M., Hummon, M., Stark, G., King, J., Lefton, S. A., Kumar, N., Agan, D., Jordan, G., Venkataraman, S., 2013. The Western Wind and Solar Integration Study Phase 2. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5500-55588. https://www.nrel.gov/docs/fy13osti/55588.pdf.
[52] IRP, Vol. I, p. 5-19.
[53] IRP, Vol. I, p. 5-15.

frequency and severity of extreme weather events. Failure by the Companies to take the warming climate into consideration could lead to overestimating the winter peak demand, and under-forecasting the summer peak demand. As a result, it could result in future outages due to the Companies procuring insufficient resource capacity, either due to significantly higher-than-expected summer temperatures relative to historical temperatures or due to correlated outages among generating units during peak periods.

Correlated Forced Outages

The Companies noted that "A key aspect in developing a target reserve margin is properly considering the likelihood of unit outages during extreme weather events."[54] However, although the Companies say they analyzed outage scenarios where multiple units are unavailable at the same time, they assumed that forced unit outages are not correlated.[55] This assumption is unreasonable and flies in the face of recent events across the U.S. in which correlated plant outages contributed to blackouts.

Correlated generation unit outages occur when a common exogenous cause (e.g., the weather) simultaneously impacts multiple generation units. Although system planners have long assumed that generation units fail independently of one another and at the same probability throughout the year, large generator outages, where many generators are simultaneously unavailable, occur much more frequently than system planners expect. For instance, empirical research has found PJM's generator fleet is substantially less available at both very cold and very hot temperatures.[56]

Several recent events highlight the importance of planning for correlated outages. For example, during Winter Storm Uri in February 2021, outages of 30 GW of electricity occurred, leaving more than 4.5 million Texas customers (more than 10 million people) without electricity, some for several days. Economic losses from reduced economic output and storm damage are estimated to be $130 billion in Texas alone. Texas failed to sufficiently winterize its electricity and gas systems, and when water and other liquids in the raw natural gas stream froze at the wellhead and in natural gas gathering lines near production activities, gas production declined by

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[54] IRP, Vol. I, p. 5-18.
[55] Responses to SREA's Initial Requests for Information (filed Feb. 11, 2022), Item 8.
[56] Sinnott J. Murphy, "Correlated Generator Failures and Power System Reliability," p. 2, https://www.cmu.edu/ceic/assets/docs/publications/phd-dissertations/2019/sinnott-murphy-phd-thesis-2019.pdf.

nearly 50%,[57] which lowered pressure in the pipelines, making it harder for power plants fueled by natural gas to operate. Other sources of electricity also suffered from supply disruptions but these were smaller than the loss of generating capacity from gas power plants.[58] Likewise, rolling blackouts in California in August 2020 were driven in part from higher-than-expected temperatures as a result of the climate crisis.[59] Finally, the Polar Vortex in January 2014 increased demand for natural gas, which resulted in 3,716 hours of cumulative generator outages in the first quarter of 2014 and over 80 GW of cumulative net dependable capacity lost due to curtailments of gas.[60]

Scenarios

The Companies only considered a narrow set of scenarios as part of their IRP, limiting alternative scenarios to high and low load forecasts and high and low fuel prices. The lack of additional scenario analyses is a major limitation of the Companies' IRP that significantly hampers its value as a planning tool because it fails to meaningfully consider how a range of additional key variables could profoundly impact the best resource portfolio. In the future, the Companies should expand the range of scenarios it considers and proactively engage with stakeholders early in its IRP process to identify alternative scenarios that should be considered. Failure to consider potentially likely scenarios that will substantially impact the Companies could result in a plan being selected that is not a least-cost portfolio of resources.

Perhaps the most glaring omission in the Companies' IRP is the lack of any scenario that, through federal or state legislation or regulation, constrains or increases the costs of generation that produces carbon dioxide emissions. The Companies instead took a combative stance against modeling *any* price on carbon dioxide emissions. For example, the Companies asserted they have

[57] U.S. Energy Information Administration (EIA), "Texas natural gas production fell by almost half during recent cold snap - Today in Energy," Feb. 25, 2021. https://www.eia.gov/todayinenergy/detail.php?id=46896 (accessed Apr. 4, 2022).
[58] Busby, J. W., Baker, K., Bazilian, M. D., Gilbert, A. Q., Grubert, E., Rai, V., Rhodes, J. D., Shidore, S., Smith, C. A., & Webber, M. E. (2021). Cascading risks: Understanding the 2021 winter blackout in Texas. Energy Research & Social Science, 77, 102106. https://doi.org/10.1016/j.erss.2021.102106
[59] California Independent System Operator. (2021, January). Root Cause Analysis Mid-August 2020 Extreme Heat Wave. http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf
[60] NERC. (2014, September). Polar Vortex Review (No. 47). https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf

"no basis for assuming that a price on [carbon dioxide] emissions will or will not be part of part of any such regulations"[61] and that "the most reasonable [carbon dioxide] price for the Companies is currently $0."[62] Simply because no final regulations have been promulgated does not suggest that they are not likely to be adopted in the future, and within the forecast period of the Companies' IRP. The Companies' refusal to consider limitations on future carbon dioxide emissions is also internally inconsistent, as elsewhere in its IRP it appeared to assume such regulations are indeed imminent. For instance, the Companies claimed that "[b]ased on the Biden administration's energy policy and the national focus on moving to clean energy, the current environment does not support the installation of [natural gas combined cycle] without [carbon capture and sequestration] due to its [carbon dioxide] emissions."[63] The Companies cannot claim such regulations are imminent, but then object to modeling the policy tools (i.e., carbon dioxide pricing or regulations) that would likely be used to implement this policy preference.

Even if the Companies believe carbon *pricing* (e.g., a carbon tax) is unlikely, it should have still modeled, through one or more additional scenarios, the impact of selecting alternative resource portfolios designed to achieve important climate and clean energy goals. For instance, the Companies failed to include a scenario in which it selected a resource plan that is fully aligned with the climate goals of their parent company, PPL. PPL has established a goal of net-zero carbon emissions by 2050, with interim reduction targets of 80% from 2010 levels by 2040 and 70% by 2035.[64] The Companies also did not include a scenario aligning the utilities' resources with President Biden's stated climate and clean energy goals that include achieving carbon pollution-free electricity sector by 2035, and net zero emissions economy-wide by no later than 2050. Instead, the utilities' IRP shows them continuing to rely on coal generation through 2066 and building new natural gas power plants in the late 2020s and 2030s that would be expected to operate through the late 2050s or the 2060s.

While reasonable people can and do disagree on the specifics of what the most likely future policy will be in this respect, it is difficult to find anyone who believes there will be *no* policy constraining or discouraging these emissions for the decades to come. Therefore, this assumption

[61] IRP, Vol. I, p. 5-20.
[62] Response to Commission Staff's First Request for Information (filed Feb. 11, 2022), Item 9.
[63] IRP, Vol. I, pp. 5-39 and 5-40.
[64] PPL, "Energy Forward: PPL's 2021 Climate Assessment Report," https://www.pplweb.com/wp-content/uploads/2021/11/PPL_Corp-2021-Climate-Assessment-FINAL.pdf.

by the Companies is unreasonable and is likely to produce a resource plan that underestimates the risk of a federal climate policy being imposed on Kentucky and could therefore fail to achieve the requirement that it be a least-cost mix of resources. It is a particularly dubious assumption given the high priority the current administration has place on reducing emissions and other pollution. For instance, U.S. Environmental Protection Agency Administrator Michael Regan recently announced that the federal government is preparing to issue a series of proposals covering air, water and waste pollution from power generators, especially coal-fired power plants.[65] The Companies' ratepayers will bear the risk of higher costs if the Companies act on an IRP that underestimates the costs of continued reliance on a fossil fuel-heavy portfolio under the current regulatory environment and existing political realities. It is inexplicable that the Companies not only failed to include such a policy, they also failed to model the possibility in a single scenario (i.e., outside of the Base Load, Base Fuel Prices scenario), which would have been a valuable sensitivity analysis for determining the potential risk of maintaining and extending the lives of the Companies' fossil fuel plants, as well as that of building new fossil fuel resources, as proposed by the Companies in their IRP.

Resources

Solar-Plus-Storage

One of the most substantial shortcomings of the Companies' IRP is the Companies' failure to consider solar resources paired with battery storage, choosing to only model these resources separately instead.[66] According to the U.S. Energy Information Administration, 60% (51 GW) of planned new generating capacity in America in 2022 and 2023 will be made up of solar power and battery storage projects, and more than 60% of the battery storage capacity will be paired with solar facilities.[67] There are currently more than 13,650 MW of active solar-plus-storage hybrid facilities in MISO's interconnection queue, and more than 10,500 MW in PJM's queue.[68] An even

[65] Ethan Howland, "EPA Plans Sweeping Regulatory Strategy for Power Plants Covering Air, Water and Land Pollution," Utility Dive, March 11, 2022, https://www.utilitydive.com/news/epa-plans-coal-power-plant-actions-air-water-waste-rules/620238/.
[66] Responses to SREA's Initial Requests for Information (filed Feb. 11,, 2022), Item 7(a).
[67] U.S. EIA, "Solar power and batteries account for 60% of planned new U.S. electric generation capacity," March 7, 2022, https://www.eia.gov/todayinenergy/detail.php?id=51518.
[68] Data obtained from https://www misoenergy.org/planning/generator-interconnection/GI_Queue/gi-interactive-queue/ (MISO) and https://www.pjm.com/planning/services-requests/interconnection-queues.aspx (PJM). Totals reflect projects marked as "Active" in the queue as of March 10, 2022. Capacity additions were totaled for projects in the dataset that were labeled "Solar/Battery" in MISO and "Solar; Storage" or "Storage; Solar" in the PJM queue.

greater proportion of solar projects are paired with battery storage in western markets, including more than 90% of the solar capacity in CAISO's queue paired with battery energy storage,[69] further solidifying that this trend is likely to continue into the future and become even more pronounced as renewable energy deployment increases.

Solar-plus-storage is already cost-competitive with natural gas peaking plants under baseline assumptions. For instance, Lazard estimates the levelized cost of energy (LCOE) from solar-plus-storage to be $85/MWh to $158/MWh,[70] whereas the levelized cost of energy from gas peakers is $151/MWh to $196/MWh[71] (or $124/MWh to $159/MWh in the U.S.[72]). Under higher gas prices assumptions, solar-plus-storage becomes even more favorable, as the levelized cost of gas peaker plants jumps to a high of $204/MWh.[73] Likewise, solar-plus-storage is also more favorable under carbon pricing scenarios, with the estimated levelized cost of gas peaker plants ranging from $164/MWh to $218/MWh when a $20/ton and $40/ton, respectively, price on carbon emissions is included.[74] See the figure below for a comparison of the LCOEs presented by the Companies as they compare to industry LCOEs. As a reminder, LG&E and KU are planning 440 MW of new SCCTs to come online in 2028 and another 880 MW of SCCT capacity in 2034 and are also planning for 2,360 MW of solar PV without battery storage between 2023 and 2034.[75] The figure below shows that prices for the same online years are more expensive for natural gas combustion turbines (NGCTs) and less expensive than the IRP's solar price forecast of $28.05/MWh during the whole planning period.[76] It is certainly not the industry expectation that

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[69] LBNL, "Utility-Scale Solar, 2021 Edition," http://utilityscalesolar.lbl.gov.
[70] Lazard, "Levelized Cost of Storage Analysis Version 7.0," October 2021, p. 6, https://www.lazard.com/media/451882/lazards-levelized-cost-of-storage-version-70-vf.pdf. Assumes a 4-hour 50 MW (200 MWh) battery.
[71] Lazard, "Levelized Cost of Energy Analysis Version 15.0," October 2021, p. 5, https://www.lazard.com/media/451881/lazards-levelized-cost-of-energy-version-150-vf.pdf. Assumes natural gas prices of $3.45 per MMBTU for the U.S. Assumes a capacity factor of 10% for all geographies.
[72] Lazard, "Levelized Cost of Energy Analysis Version 15.0," October 2021, p. 10, https://www.lazard.com/media/451881/lazards-levelized-cost-of-energy-version-150-vf.pdf. Assumes natural gas prices of $3.45 per MMBTU for the U.S. Assumes a capacity factor of 10% for all geographies.
[73] Lazard, "Levelized Cost of Energy Analysis Version 15.0, October 2021, p. 4, https://www.lazard.com/media/451881/lazards-levelized-cost-of-energy-version-150-vf.pdf. Assumes a fuel cost range for gas-fired generation resources of $2.59/MMBTU – $4.31/MMBTU (representing a range of ± 25% of the standard assumption of $3.45/MMBTU).
[74] Lazard, "Levelized Cost of Energy Analysis Version 15.0," October 2021, p. 5, https://www.lazard.com/media/451881/lazards-levelized-cost-of-energy-version-150-vf.pdf. Assumes natural gas prices of $3.45 per MMBTU for the U.S. Assumes a capacity factor of 10% for all geographies.
[75] IRP Vol. I, Table 8-1, page 8-1 [PDF 76 of 118].
[76] IRP Vol. III, Generation Planning & Analysis (dated Oct. 2021), p. 10 [PDF 20 of 140].

the NGCT LCOE is "$23/MWh and lower than the assumed cost of solar" and the Companies reported.[77]

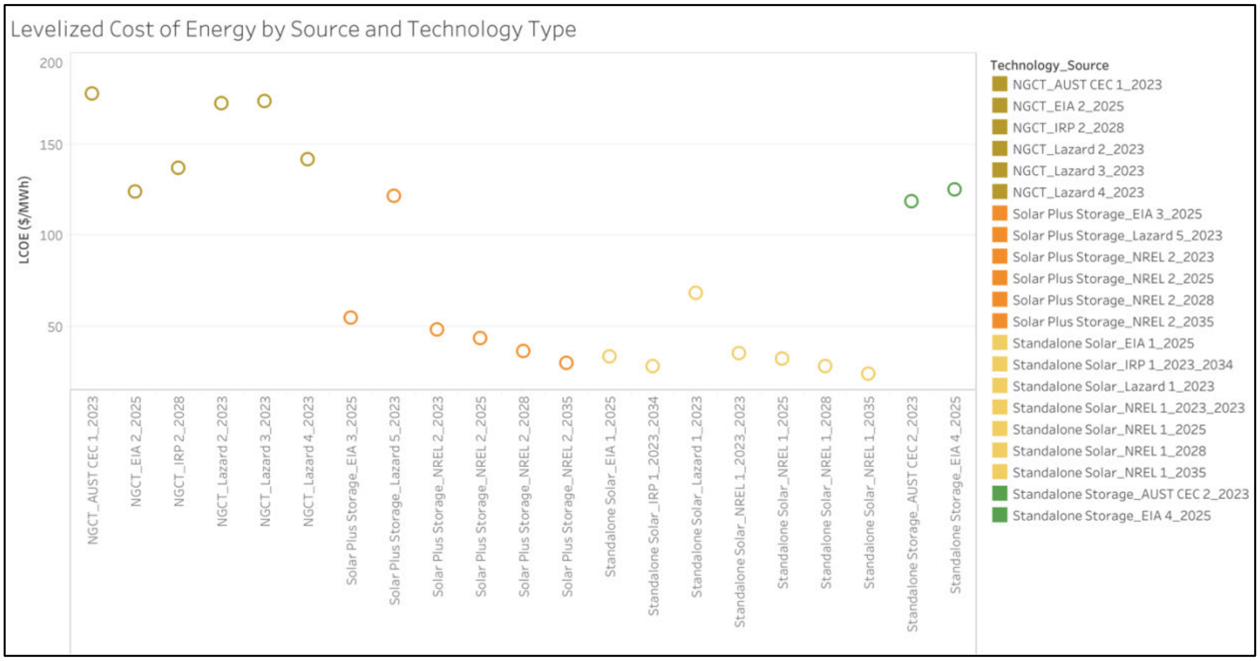

Figure 6. Levelized Cost of Energy by Source and Technology Type[78]

As highlighted in the figure below, there are significant cost advantages of co-locating solar and battery energy facilities together relative to locating them separately, so modeling these technologies separately as done by the Companies will significantly overstate their cost. For instance, solar-plus-storage projects are eligible for the federal investment tax credit (ITC), currently 26% of installed costs, whereas standalone battery energy storage facilities are ineligible for the ITC. They also benefit from additional efficiencies that further reduce costs, such as by being able to share the same site and point of interconnection.

[77] Responses to Commission Staff's Second Request for Information, (filed Mar. 25, 2022), Item 1.
[78] EQ Research. (2022, April). Levelized Cost of Energy by Source and Technology Type – Full Citations and Assumptions. https://eq-research.sharefile.com/d-sf9ca180468ca48c08dbd84a911995ac2

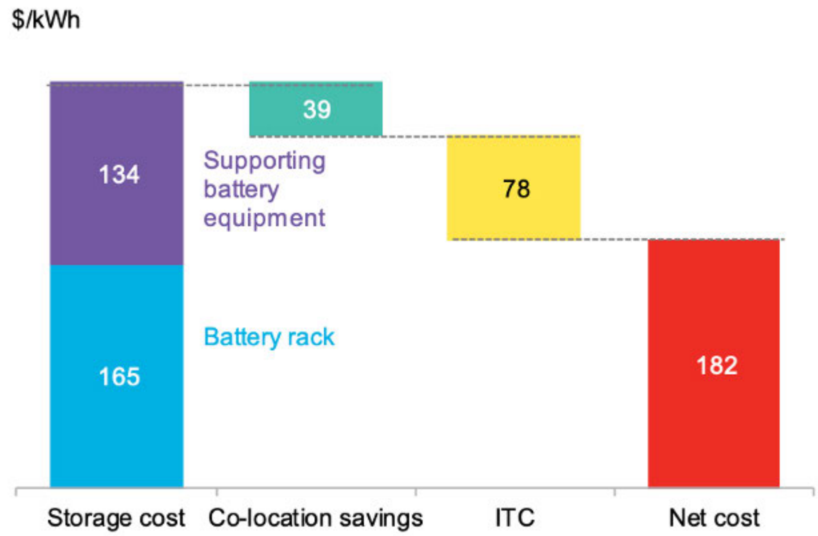

Figure 7. Cost Advantage to Co-Locating Storage with Solar[79]

The Companies justified this approach by stating that they assumed the federal investment tax credit would be available for standalone storage "by the end of the IRP study period," and as a result, they "evaluated battery storage in a favorable light and obviated the need to the model charging restrictions associated with pairing a battery only with solar."[80] They also asserted that "batteries have the most value if they can be charged when the portfolio's marginal cost is lowest (i.e., during nighttime hours on most days). Because solar produces energy during the day, solar is not an ideal resource for charging a battery. Furthermore, pairing a battery with an intermittent resource reduces the value of the battery because it reduces the likelihood that the battery will be charged when needed."[81]

These are misleading or incorrect assumptions about the merits of solar-plus-storage resources. First, while modeling eligibility of standalone battery storage by the end of the IRP study period is reasonable, it does nothing to obviate the need for modeling solar-plus-storage resources that *today*, in the *first year of the IRP*, are already eligible for the ITC. It is unsurprising the Companies did not select any battery energy storage additions until the end of the IRP period given that they incorrectly assumed that battery energy storage was ineligible for the ITC today even when paired with solar.

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[79] BloombergNEF, "Sustainable Energy in America 2022 Factbook," 2022, https://bcse.org/factbook/.
[80] Responses to SREA's Initial Requests for Information (filed Feb. 11, 2022), Item 7(a).
[81] Responses to SREA's Initial Requests for Information (filed Feb. 11, 2022), Item 7(b)(i).

Second, the Companies conflate the value of batteries with their cost. While they are correct insofar as they seem to suggest that charging a battery when the marginal cost is lowest will result in the lowest average cost, that does not necessarily mean that will result in the most value. For instance, charging a battery from solar may not be (although likely is) the lowest cost resource, but it means the battery is eligible for the ITC, which provides substantial offsetting value.

Finally, the Companies suggest that charging a battery from solar generation during the daytime is not ideal. This is incorrect on several levels. During the summer, batteries could be efficiently charged by low-cost solar generation occurring earlier in the day before the peak demand hours in late afternoon. Furthermore, throughout the Companies' IRP, they repeatedly claim that a substantial concern is meeting the Companies' winter peak that occurs in the nighttime or early morning hours, indicating daytime solar in the winter actually is the lowest marginal cost hours. Solar-plus-storage is therefore a logical solution to helping meet these winter peaks, as it is nighttime and early morning hours in which the Companies will have the greatest demand on their system, and therefore likely experience the highest generating costs.

Battery Storage

The Companies stated that they evaluated 4-hour battery storage instead of a 2-hour battery storage because 4-hour batteries have a lower levelized cost of energy.[82] While a 4-hour battery does have a lower levelized cost of energy, a 2-hour battery storge could actually provide a lower-cost of capacity for meeting peak period demand. This dynamic is illustrated in the figure below, which shows that while the installed cost of lithium-ion battery energy storage decreases with duration as an *energy* resource (in terms of $/kWh), it increases with duration as a *capacity* resource (in terms of $/kW). (Note that the costs depicted are for 2019 and are illustrative of the dynamic, but not reflective of the current battery storage costs that have further declined in the past three years.) In other words, a 2-hour battery storage device will have a significantly lower installed cost than the 4-hour battery storage device modeled by the Companies on a $/kW basis. Since the Companies expressed a need for battery energy storage to provide capacity during peaks, the Companies should model both 2-hour and 4-hour solar plus storage and stand-alone storage.

[82] Responses to Commission Staff's Initial Request for Information (filed Feb. 11, 2022), Item 43 [PDF 331 of 356].

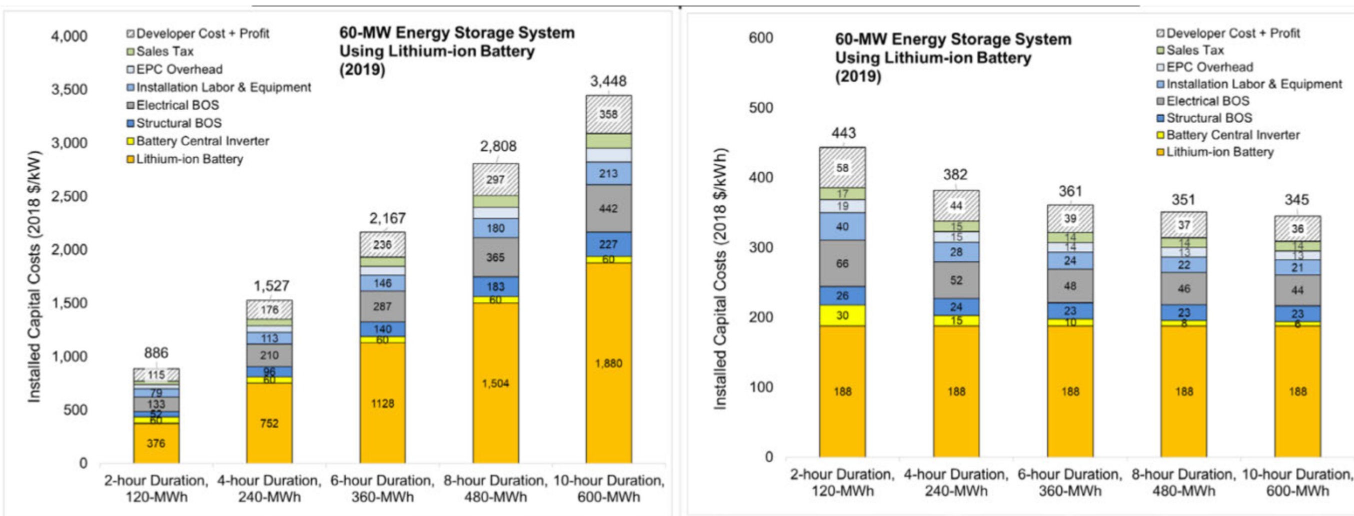

Figure 8. Installed Capital Costs of Battery Energy Storage in Energy Capacity ($/kWh) and Power Capacity ($/kW)[83]

Demand-Side Management

The Companies failed to evaluate any new demand-side management programs as part of its IRP.[84] Their existing demand response capabilities are also extremely limited, [85] suggesting that this could be a substantial additional resource for which the Companies have failed to develop a successful strategy. Demand-side management programs targeting electric heating and electric vehicle charging during the winter months could be a significant resource for helping to meet the Companies' winter peak demand in combination with resources like solar-plus-storage and wind energy.

Natural Gas and Coal

Natural gas prices have increased significantly following an ongoing military conflict between Russia and Ukraine, and rising energy demand as countries resume normal activities after two years of COVID-19 restrictions. But the Companies' current natural gas forecasts range between $2.18 to $4.66 per MMBtu on a levelized basis through 2050.[86] In a response, the Companies stated, "With a $3.60/mmBtu natural gas price, the cost of energy from a NGCC unit

[83] NREL ATB, https://atb nrel.gov/electricity/2021/utility-scale battery storage
[84] IRP, Vol. I, p. 5-11.
[85] IRP, Vol. I, p. 5-19 (Noting that the Companies' Curtailable Service Rider limits the ability to curtail participating customers to hours when all available units have been dispatched, and as a result, the Companies only utilize this resource "a handful of hours each year.").
[86] Response to Commission Staff's First Request for Information (filed Feb. 11, 2022), Item 52 [PDF 344 of 356].

is approximately $23/MWh and lower than the assumed cost of solar."[87] The Companies' natural gas price forecast for its "Mid" or base case ranges from **[BEGIN CONFIDENTIAL INFORMATION]** [redacted] **[END CONFIDENTIAL INFORMATION]** in 2022 to **[BEGIN CONFIDENTIAL INFORMATION]** [redacted] **[END CONFIDENTIAL INFORMATION]** in 2036.[88] The "High" natural gas price for 2022 was **[BEGIN CONFIDENTIAL INFORMATION]** [redacted] **[END CONFIDENTIAL INFORMATION]**.[89] For comparison, for the one-year period between March 9, 2021, and March 8, 2022, Henry Hub natural gas spot market prices averaged $4.02/MMBtu and exceeded $4.66/MMBtu—the upper bound of the Companies' forecast—27% of the time. Natural gas spot prices were well above $5/MMBtu when the Companies filed their IRP and reached as high as $6.70/MMBtu on February 2, 2022. As of March 31, 2022, Trading Economics estimated Henry Hub to trade at $6.70 by March 2023.[90]

Based on the observed natural gas prices, it is clear the Companies' forecast of natural gas prices used as inputs in its IRP are unrealistically low under current market conditions. As a result of this unrealistic assumption, the Companies' modeling will be biased towards adding new natural gas generation and are likely to significantly overstate the economic attractiveness of gas generation relative to alternative resources. The Companies' customers will bear the risk of highly volatile natural gas prices, **[BEGIN CONFIDENTIAL INFORMATION]** [redacted] **[END CONFIDENTIAL INFORMATION]**.[91] It is possible that natural gas prices could further increase in the coming months and years given recent geopolitical events, particularly in Europe, as well as the general economic recovery in the wake of the COVID-19 pandemic and rising inflation, that have resulted in high demand, constrained supply, and skyrocketing prices.

The Companies' new natural gas peaker plants would operate at a low capacity factor, as shown in the figure below. The Companies aggregated the capacity factors of the planned gas

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87 Responses to Commission Staff's Second Request for Information (filed Mar. 25, 2022), Item 1.
88 IRP, Vol. I, Table 5-5 [CONFIDENTIAL version].
89 IRP, Vol. I, Table 5-5 [CONFIDENTIAL version].
90 Trading Economics. (Apr. 3, 2022). Natural gas - 2022 Data - 1990–2021 Historical - 2023 Forecast - Price - Quote - Chart. Retrieved April 3, 2022, from https://tradingeconomics.com/commodity/natural-gas
91 Responses to SREA's Initial Requests for Information, (filed Feb. 11, 2022), SREA DR1 KU LGE Attach to Q01(b) - CONFIDENTIAL Tables.xlsx.

peaking units rather than providing information on each unit, suggesting that one or more planned units could actually operate at an even lower capacity factor, which would further erode its economics. Although the Companies justify the need for new natural gas peaker plants based on needing resources that will be available to meet winter peak demand, the Companies actually plan to operate these new plants much less frequently in the winter than the summer. Indeed, for the 2028-2033 time period, the new gas peaker units would only average a capacity factor of 8% in the winter, compared to 30% in the summer.

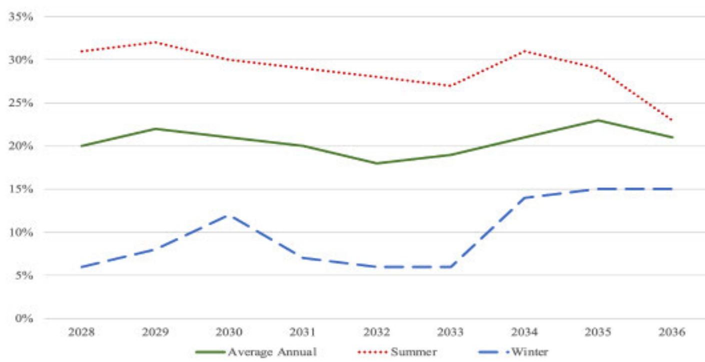

Figure 9. Capacity Factor of New Natural Gas Peaker Plants[92]

Finally, the Companies' assumed capacity values of natural gas and coal generating units overstates those resources' ability to serve load during peak demand periods, as discussed above in the context of correlated forced outages. The Companies implausibly assume coal and natural gas supply will not be negatively impacted during peak events. Furthermore, procuring firm natural gas pipeline capacity increases gas costs (to ensure higher capacity values during peak periods). Overstating the capacity value of natural gas, while underestimating the cost to make those resources firm underestimate the total costs.

Resource Retirements

While the Companies claimed that "existing resources are economically optimal for meeting system reliability needs in 2025,"[93] their 2021 analysis[94] did not comprehensively examine the potential costs and benefits of retiring existing units ahead of schedule. The

[92] Responses to SREA's Initial Requests for Information, (filed Feb. 11, 2022), Item 7(d).
[93] IRP, Vol. I, p. 5-41.
[94] *Id.*

Companies confirmed that "[u]nit retirements[…] are fixed as a simplifying assumption in the 2021 IRP analysis. The analysis did not consider scenarios where units retired earlier or later than the specified years."[95] The Companies' reserve margin analysis instead focused on the impact to reliability under various retirement scenarios, or by adding SCCTs,[96] rather than what the optimal portfolio of resources was to achieve the desired reserve margin. When it did analyze the impacts of adding 260 MW of solar to its portfolio, it found that it could retire Brown 3, resulting in lower costs for customers.[97] However, it then hurriedly moved past those results to suggest more study of solar was needed before it acted on these results.[98] At no time did it evaluate battery storage, or solar-plus-storage, or a combination of other clean energy resources (other than standalone solar) as part of this analysis.

The Companies' refusal to consider earlier retirement dates for existing generation resources—and ignore its own findings that adding solar can reduce costs to ratepayers—contradicts the Commission's regulation requiring utility IRPs to "include the utility's resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost."[99] By failing to examine scenarios where expensive existing generation units could be retired early and replaced with a portfolio of lower-cost resource options, the Companies have failed to show that their plan will provide adequate and reliable supply of electricity at the lowest possible cost. By "baking in" existing retirement dates, rather than by letting the modeling economically retire units, the Companies have stacked the deck in favor of their current resources and stymied any competition from alternatives, even though it is highly likely those alternatives could lower costs for ratepayers.

The figure below identifies the planned operating lives of the Companies' current and planned fossil fuel generating resources. It illustrates that the Companies' plan to continue using both coal and natural gas generating resources well into the 2060s based on current anticipated lives.[100]

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[95] Responses to SREA's Initial Requests for Information (filed Feb. 11, 2022), Item 5.
[96] IRP, Vol. III, PDF pp. 43-50.
[97] IRP, Vol. III, PDF pp. 49-50.
[98] IRP, Vol. III, PDF p. 50.
[99] 807 KAR 5:058, Section 8(1).
[100] The New SCCTs shown in the Figure correspond to the six new SCCT additions include in the Companies' Base Load, Base Fuel Price scenario.

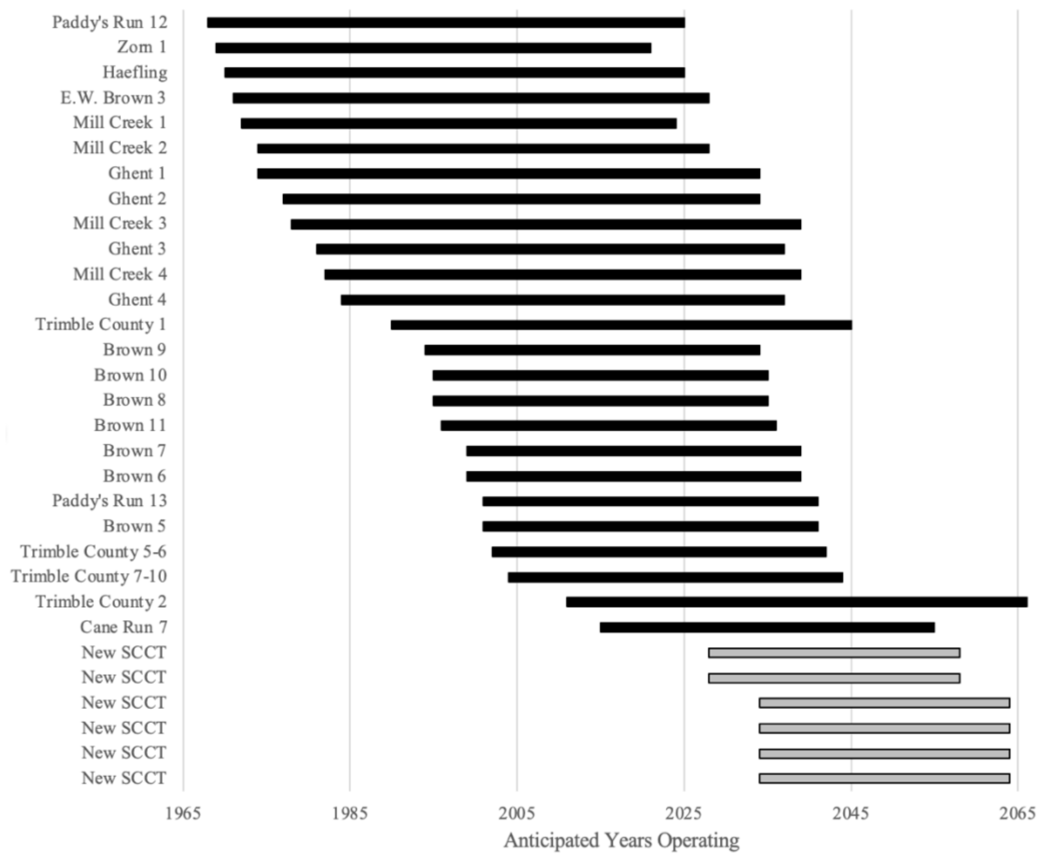

Figure 10. Anticipated Operating Years of LG&E/KU Existing and Planned Fossil Fuel Resources[101]

As shown in the figure below, all the Companies' existing resources, except for Cane Run 7 (although this has likely changed due to the higher cost of natural gas currently), are already more expensive on a dollar-per-MWh basis than new solar resources like the Rhudes Creek project, *according to the Companies own estimates and contracts*. (Not shown in the figure are Mill Creek 1, retiring in 2024, and Haefling 1-2 and Paddy's Run 12, retiring in 2025.) Yet, rather than invest in additional low-cost solar resources, the Companies' IRP continues to lean heavily on existing, expensive generation options and does not include any additional solar resources over the next three years when the Companies and its ratepayers would benefit from the federal ITC.

[101] Figure created using data from IRP, Vol. I, Table 8-3 (existing units), Table 8-1 (new unit start year), and Responses to REA's Initial Requests for Information (Feb. 11, 2022), Item 7(e) (identifying the anticipated operating life of new natural gas units).

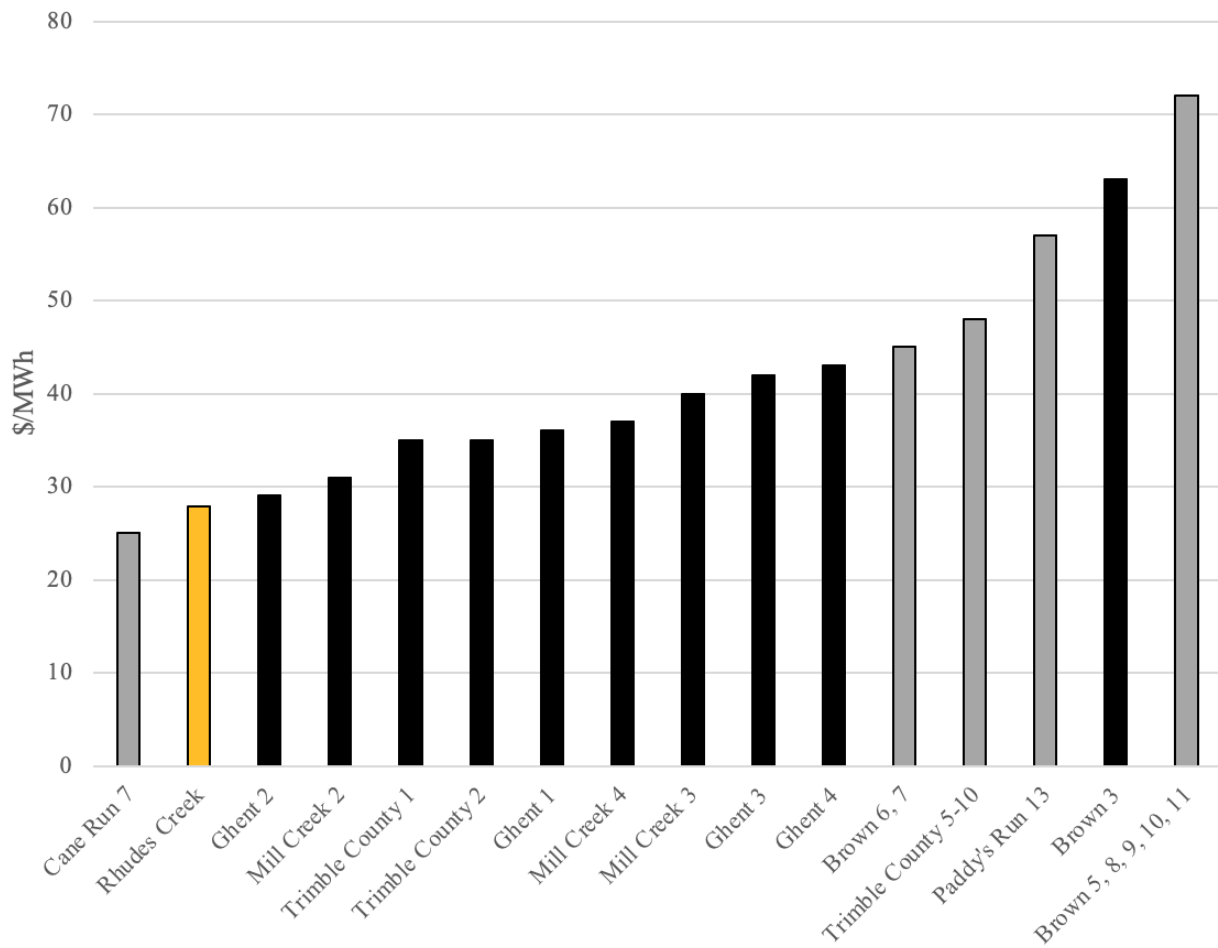

Figure 11. Costs of Electricity Generation of LG&E/KU Units[102]

OVEC Contract

Among the existing resources that were not robustly analyzed for early retirement are the Ohio- and Indiana-based coal plants operated by the Ohio Valley Electric Corporation (OVEC). The Companies have a contract through 2040 with the OVEC coal plants totaling 8.13% of the output from the Ohio Valley Electric Corporation (OVEC), which equates to a summer rating of 172 MW, or 152 MW at the time of summer peak, on average, when accounting for potential outages.[103] The Companies stated they did not have the data and refused to provide it when asked

[102] Figure created from data in IRP, Vol. III, Table 10, and Responses to SREA's Initial Requests for Information (filed Feb. 11, 2022), Item 10. Solar resources are in yellow, natural gas resources are shaded grey, and coal resources are shaded black. The cost of electricity generation for fossil fuel power plants is the stay-open costs plus average energy costs. The cost of electricity generation for Rhudes Creek is the PPA price paid by the Companies.
[103] Responses to OAG's First Request for Information (filed Feb. 11, 2022), Item 1(b)(ii).

to identify the stay-open cost and average energy cost for the OVEC units,[104] but stated that OVEC's position in dispatch order typically falls after Cane Run 7 and the coal units at Trimble County, Mill Creek, and Ghent, but before Brown 3 and the simple-cycle combustion turbines,[105] which confirms these resources are more expensive than many existing resources owned by the Companies and far more expensive than alternatives available to the Companies to procure today. The Companies modeled the OVEC plants as "must run" for unit commitment and dispatch, using the minimum take portion of the Companies' contract with OVEC (typically about 50 MW of the Companies' share).[106]

The Companies' continued reliance on OVEC is troubling and contrary to the principle of least-cost resource planning. Evidence continues to mount that the agreement the Companies have to procure OVEC output is substantially higher cost than the value of the products and services provided by the OVEC to the Companies and therefore, the OVEC contract is not reasonable or prudent under current market conditions. The Companies have provided no evidence in its IRP that the costs of its OVEC contracts are reasonable, let alone lowest cost resources, or demonstrated that they have taken steps to minimize costs, including efforts to renegotiate contracts.

The Companies point to Commission final decisions in Case Nos. 2011-00099 and 2011-00100, as approving the Companies' request to extend their contract with OVEC through 2040 through an Inter-Company Power Agreement (ICPA). However, the Commission's decision expressly specified that, "[t]he effectiveness of the amended ICPA is contingent upon all owners receiving the necessary regulatory approvals of the states in which they operate, if applicable," with the footnote for this sentence noting that "[i]n addition to other state commissions, the investor-owned OVEC owners must also receive consent, or approval, of the Federal Energy Regulatory Commission."[107] The Michigan Public Service Commission recently issued an Order finding that "[t]he ICPA has […] not been approved at the state level by the [Michigan Public Service] Commission nor at the federal level by [the Federal Energy Regulatory Commission]."[108]

[104] Responses to SREA's Initial Requests for Information (filed Feb. 11, 2022), Item 13(d).
[105] Responses to OAG's First Request for Information (filed Feb. 11, 2022), Item 1(b)(iii).
[106] Responses to SREA's Initial Requests for Information (filed Feb. 11, 2022), Item 5.
[107] Kentucky Public Service Commission Cases No. 2011-00099 and 2011-00100, Order, (Ky. P.S.C. Aug. 11, 2011), http://psc ky.gov/pscscf/2011%20cases/2011-00099/20110811 PSC ORDER.pdf
[108] Michigan Public Service Commission, Order, November 18, 2021, p. 19, Docket No. U-20804, https://mi-psc force.com/sfc/servlet.shepherd/version/download/0688y000001Cgb0AAC

Furthermore, Ordering Paragraph 2 stated that "[a]fter the Amended Inter-Company Power Agreement has received all necessary regulatory approvals, LG&E and KU shall, within 20 days of the finalization of the Amended Inter-Company Power Agreement, file a copy of the agreement with the Commission." These conditions have not been met. The Companies seem to recognize this fact, as they have not filed the ICPA in Case Nos. 2011-00099 and 2011-00100, as directed under Ordering Paragraph 2.

Accordingly, it is unreasonable to include the OVEC plants as "must run" units in the IRP. As the Michigan Public Service Commission aptly summarized with respect to Indiana Michigan Power's ICPA costs, "[t]he Commission does not control the business judgment or decisions of utilities, but the Commission has a duty to customers to assure utilities are not subsidizing uneconomic, unreasonable, and imprudent decisions through customer rates."[109]

Short Term Action Plan

The Companies short-term action was summarized as follows: "[a]side from the planned addition of Rhudes Creek solar and the retirement of Mill Creek 1 and Zorn 1, no changes or additions to the Companies' generation resources are planned for the next three years."[110] The Companies' plan to essentially maintain the status quo despite lower-cost resources being available today does not reflect a least-cost plan, and therefore does not comply with the Commission's IRP regulations. As highlighted in these comments, the Companies' IRP contains substantial flaws in the inputs, assumptions, and modeling. Taken together, these shortcomings reflect a bad information in/bad information out exercise rather than a fair, robust, and comprehensive analysis. Furthermore, the Companies' own analysis demonstrated that adding additional solar resources would reduce overall costs, and yet the Companies summarily brushed aside this finding. Therefore, the Companies' IRP is likely to produce unjust and unreasonable rates for the Companies' customers.

Rather than continuing to delay a transition to low-cost, clean energy resources, the Companies should seize this opportunity to align its resource planning with its parent company's ambitious climate goals and begin a substantial build-out of clean energy solutions, including renewable energy, battery storage resources, and hybrid resources like solar-plus-storage. As

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[109] Michigan Public Service Commission, Order, November 18, 2021, p. 19, Docket No. U-20804, https://mi-psc force.com/sfc/servlet.shepherd/version/download/0688y000001Cgb0AAC.
[110] IRP, Vol. I., p. 5-44.

responses to the Companies' 2021 RFP make clear, there are numerous low-cost clean energy resources available to the Companies. It is important for the Companies to begin this build-out now in order to take advantage of federal tax credits that are being phased out, reduce their risk of federal carbon regulation, gain additional experience with clean energy solutions, retain and attract businesses to Kentucky, reduce pollution from fossil fuel generation that is harmful to the public health and welfare, and mitigate carbon dioxide emissions. It should also consider cost-effective complementary solutions that will aid in meeting demand during peak periods, including transmission expansion, new demand-side management programs (including those targeting demand reduction during winter peak periods), and RTO membership.[111]

Finally, the Companies should take steps in the near-term to improve its modeling and analytical capabilities so it can provide a more rigorous evaluation of clean energy solutions in the future, including in its next IRP. It is paramount that the Companies identify and evaluate additional opportunities to avoid, or at least minimize, the build-out of additional fossil fuel generation, including new SCCTs, that would lock-in the Commonwealth to decades of additional carbon dioxide emissions, while imposing substantial risks onto its customers of high natural gas prices and potentially costly federal carbon dioxide regulations. At the minimum, this should include expanded modeling of solar-plus-storage resources and standalone batteries on a more granular time scale to determine the viability of these resources for aiding in meeting peak demand and avoiding the need for risky and costly new SCCTs.

Recommendations and Conclusion

SREA thanks the Commission for the opportunity to provide comments in this case and respectfully requests the Commission take into consideration the following recommendations:

1. In all future IRPs, the Companies should provide a robust stakeholder engagement process, including holding public meetings and technical conferences as it develops its IRP, responding to stakeholder requests for information, sharing modeling files, and not

[111] See IRP, Vol. III, p. 96 of 140 (Stating "As many entities with fossil fuel fired generation resources contemplate a transition to increased renewable resources, RTOs could be an attractive option for supporting this transition. The diverse geography, resources, and loads in an RTO allow for the integration of higher penetration of intermittent resources than what the Companies could likely achieve on a standalone basis and potentially at lower cost.").

opposing interested stakeholders from intervening in their IRP proceeding to provide comments.

2. 807 KRA 5:058 was promulgated for the purpose of providing "a solid foundation for a forward-looking, cooperative, resource planning process."[112] The Commission should consider amending this regulation to include additional detail concerning the stakeholder engagement process, and the Companies should, in future IRPs, fully describe the efforts by the Companies to, among other things, meet the objective of a cooperative, non-adversarial, process.
3. To the extent the Companies refuse to engage in a forward-looking resource planning process and consider the risk of climate policy or regulations on carbon dioxide emissions in their IRP, such as by refusing to model a price on carbon dioxide emissions in any scenarios, the Commission should remind the Companies that they should have no expectation to recover any costs that are unjust or unreasonable such that the financial risk will be borne by the Companies' shareholders and not ratepayers should such a policy be enacted in the future and their actions are based upon scenarios that are not adequate and realistic forward-looking planning scenarios.
4. The Companies' IRP does not provide a reasonable basis for determining that it should build new natural gas peaker plants. The Companies should conduct additional modeling and analysis on renewable resources paired with energy storage, among other solutions, to examine opportunities to avoid the construction of additional natural gas generation. The Companies should model both 2-hour and 4-hour solar plus storage and stand-alone storage as alternatives to the additional planned natural gas-fired capacity.
5. Given the high cost of generation identified by the Companies at a number of their existing coal and natural gas generation, the Companies should conduct a robust and transparent retirement analysis to identify which, if any, legacy generating plants could be retired early to save ratepayers money.
6. In all future IRPs, the Companies should conduct substantially more robust reliability modeling suitable for analyzing scenarios featuring high deployment of renewable energy and battery storage.

[112] Adm. Case 308, Order (Ky. P.S.C. Aug. 8, 1990), p. 11.

7. In all future IRPs, solar paired with battery storage should be modeled as a distinct, separate resource, and batteries utilizing durations other than 4 hours, including shorter durations, should also be considered (both paired and standalone), and the Companies should not preclude these resources from participating in resource solicitations.
8. The PSC should remind the Companies that the Commission may investigate, in all pertinent dockets involving the Companies, including an investigation initiated by the Commission, the reasonableness of the Companies' continued reliance on expensive existing generating plants that are substantially above the cost of constructing new clean alternatives *today*. The Companies should have no expectation of collecting in rates any costs that are unjust and unreasonable.
9. LG&E/KU should conduct another RFP in 2022 to pursue additional renewable energy over the next three years, or use its 2021 RFP results to select additional renewable energy and battery storage projects in the near term to take advantage of federal tax credits that will be phased out in future years.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

ATTACHMENT B

COMMENTS ON LG&E KU'S 2021 RTO MEMBERSHIP ANALYSIS
DR. JENNIFER CHEN, REGRID

These comments are being filed by Dr. Jennifer Chen, on behalf of Southern Renewable Energy Association (SREA), pertaining to the 2021 Joint Integrated Resource Plan (IRP) of Louisville Gas and Electric Company (LG&E) and Kentucky Utility Company (KU – collectively "Companies"). The following contains comments and recommendations related to the Companies' 2021 RTO Membership Analysis. We appreciate the opportunity to submit these comments.

Filed: April 21, 2022

Table of Contents

I. Evolving grid needs and regionalization

Since FERC issued Order 2000 encouraging the formation of Regional Transmission Organizations ("RTOs"),[1] more than two-thirds of U.S. load is now in an RTO. Many of the utilities in the non-RTO West have voluntarily joined an energy imbalance market or service ("EIM" or "EIS"), which is an extension of an RTO's energy market allowing non-RTO utilities to participate. There are active discussions about forming an RTO in the West,[2] and Southeastern lawmakers and stakeholders are expressing interest in RTOs as well.[3]

The resource mix is evolving and extreme weather is becoming more frequent, which adds variability that is more difficult for smaller power systems to handle.[4] RTOs have brought savings from economies of scale and transparent and efficient markets. RTOs have independent market monitors and experts who can provide information and educate stakeholders and regulators, and RTO regional states committees provide a forum for states to coordinate or collaborate.[5]

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[1] Federal Energy Regulatory Commission, Order No. 2000: Regional Transmission Organizations, Docket No. RM99-2-000, Dec. 20, 1999, p. 7, https://www.ferc.gov/sites/default/files/2020-06/RM99-2-00K_1.pdf.

[2] See, e.g., https://www.energy.gov/eere/articles/new-doe-report-shows-how-continued-western-state-collaboration-can-support-affordable

[3] Options on a Continuum of Competition for the Southeastern Electricity Sector, September 2020, https://nicholasinstitute.duke.edu/sites/default/files/publications/Options-on-a-Continuum-of-Competition-for-the-Southeastern-Electricity-Sector.pdf pp 1-3.

[4] LG&E and KU, ("the Companies") acknowledge that "being a member of a larger generation footprint could be beneficial if the nation's and the Companies' future generation resources consist of large quantities of intermittent renewable technology, as RTO membership may support higher levels of renewable penetration with lower integration costs." 2021 RTO Membership Analysis at p. 9.

[5] See generally, Evaluating Options for Enhancing Wholesale Competition and Implications for the Southeastern United States, March 2020 https://nicholasinstitute.duke.edu/sites/default/files/publications/Evaluating%20Options%20for%20Enhancing-Wholesale-Competition-and-Implications-for-the-Southeastern-United-States-Final_0.pdf; Engagement between States and Regional Transmission Organizations,

National Association of Regulatory Utility Commissioners Center for Partnerships & Innovation, March 2022, https://pubs.naruc.org/pub/6C1AA0FC-1866-DAAC-99FB-993D01E9FDA5

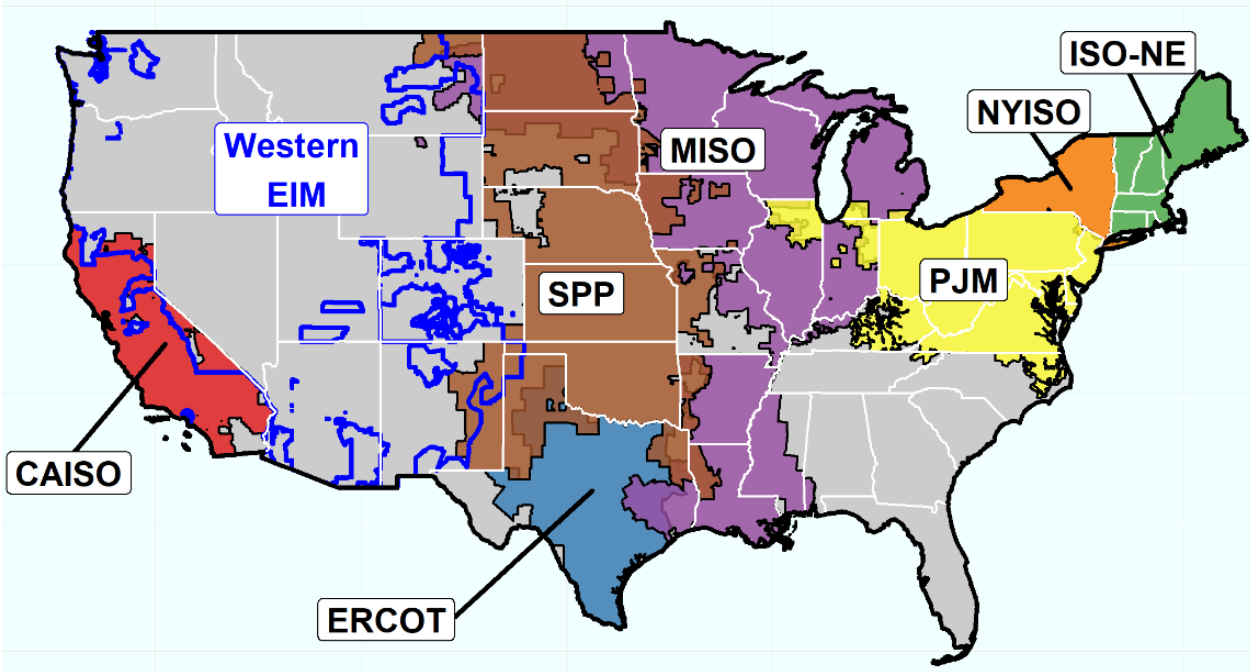

Figure 1: Schematic map of RTO and EIM/EIS markets. Source: An Energy Imbalance Market in the Southeastern United States, September 2020, Matt Butner, at p. 6.

LG&E KU were founding members of MISO in 1998 but later wanted to withdraw as MISO developed additional functions, such as independently and transparently operating the transmission system and energy markets.[6] In a split decision, the Commission allowed LG&E KU to leave MISO in 2006, with two commissioners believing that exit would provide the utilities with greater control and savings while a dissenting commissioner expressed concern that the move would isolate the utilities from the inevitable regionalization in transmission infrastructure and markets.[7] No public or independent retrospective analyses were performed to confirm that the exit actually saved customers money.

[6] LG&E KU Response to SREA Initial Requests for Information (filed Feb. 10, 2022), Item 18(l)

[7] https://psc.ky.gov/agencies/psc/press/052006/0531_r02.pdf

Currently, LG&E KU are required to conduct annual RTO membership cost-benefit studies,[8] the latest being the 2021 RTO Membership Analysis.[9] LG&E KU includes three scenarios for joining RTOs–a high, mid and low case. While the analysis includes uncertain but significant costs, the Companies completely omitted large quantifiable benefits that would not be zero under any realistic scenario. Including these benefits reverses the conclusions. The Companies have not worked with the RTOs to develop more realistic assumptions[10] or asked to leverage the RTOs' more sophisticated modeling software to obtain more accurate results.[11]

The implicit question that the RTO Membership Analysis is meant to answer is whether it is beneficial to the utilities' customers and to state and local policy goals for the Companies to join an RTO. However, they did not offer a clear set of explicit criteria or an evaluation framework to determine when that should happen. In a response to SREA's questions, the Companies state that the "criteria [for joining an RTO] would be lower revenue requirements for customers over a broad range of possible futures compared to remaining outside an RTO"[12] and a clear demonstration of "permanent cost savings."[13]

At the same time, the Companies have joined the Southeast Energy Exchange Market (SEEM), a platform for bilaterally matching counterparties interested in voluntary energy

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[8] "The Commission finds that KU [and LG&E] should continue to separately evaluate and assess the benefits and costs associated with membership in a Regional Transmission Organization…The Commission finds that LG&E should update these studies annually and file such updates with the Commission as part of its annual report. The RTO study should include detailed qualitative and quantitative analysis regarding benefits and costs associated with LG&E joining an RTO along with the company's efforts to reduce any excess reserve margin." Case No. 2018-00294, Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates, Order (Ky. P.S.C. Apr. 30, 2019), pp. 29 and 30; also see Case No. 2018-00295, Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, Order (Ky. P.S.C. Apr. 30, 2019), p. 30. "In the next IRP, the Companies should provide updated comprehensive and detailed cost/benefit studies comparing the full costs of joining MISO or PJM and all potential benefits such as increased revenues, lower reserve margin requirements, and improved reliability versus operating under its existing operating construct." Case No. 2018-00348, The 2018 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company, Order (Ky. P.S.C. July 20, 2020), Appendix (Staff Report), p. 41.

[9] 2021 RTO Membership Analysis, LG&E KU October 2021, https://psc.ky.gov/pscecf/2020-00349/rick.lovekamp%40lge-ku.com/10192021013538/2-2021_RTO_Membership_Analysis.pdf.

[10] LG&E KU Response to SREA Initial Requests for Information (filed Feb. 10, 2022), Item 21.

[11] The Companies use PROSYM and not a more sophisticated program like PROMOD used by RTOs and consultants. LG&E KU Response to SREA Supplemental Requests For Information (filed Mar. 25, 2022), Item 1(g)(i)(citing to Section 8.2 of the 2021 RTO Membership Analysis).

[12] LG&E KU Response to SREA Supplemental Requests For Information (filed Mar. 25, 2022), Item 6(a).

[13] LG&E KU Response to SREA Initial Requests for Information (filed Feb. 11, 2022), Item 28.

exchange.[14] The Companies "expect SEEM implementation costs to be approximately $600,000 and ongoing costs to be approximately $200,000 annually. These estimates could change because SEEM systems are still under development."[15] "Although the Companies do not have volumes associated with the purchases and sales in SEEM, it is anticipated the benefits from SEEM participation will range from approximately $1 million to $4 million per year."[16] This showing is arguably less stringent than a clear demonstration of permanent cost savings for customers under a broad range of possible futures–the standard Companies require in order to join an RTO.

II. RTO membership evaluation framework needed

In deciding whether a utility should join an RTO, there needs to be clear goals as well as criteria and metrics for evaluating the costs, benefits, and risks of membership. Obtaining reliable service at lowest cost to customers, enabling the grid to flexibly adapt to the evolving power system, transparency of processes and information provided, along with other aspects of good governance are usually top priorities. Two papers, one from Duke University,[17] and another from an effort led by eleven Western states and funded by the Department of Energy, offer some example evaluation frameworks.[18] Both contain evaluation scorecards useful for RTO membership evaluation, and the content of the scorecards can be for the Commission, utilities, and stakeholders to determine. Benefit-cost analyses are an important component to these evaluations, but consistency in how uncertainty is treated–between both benefits and costs–and thoroughness in accounting matters.

Quantitative benefits should at least include the ability to:

- Optimize existing generation and demand-side resources. This could be estimated with production cost modeling of energy market savings.

[14] Louisville Gas and Electric Company and Kentucky Utilities Company, Southeast Energy Exchange Market Quarterly Status Report No. 3, Case Nos. 2020-00349 and 2020-00350, March 31, 2022, https://psc.ky.gov/pscecf/2020-00349/rick.lovekamp@lge-ku.com/03312022095220/Closed/2-LGE_KU_SEEM_Qtr_Status_Rpt_3.pdf.

[15] LG&E KU Response to SREA Supplemental Requests For Information (filed Mar. 25, 2022), Item 1(k)(ii).

[16] LG&E KU Response to SREA Supplemental Requests For Information (filed Mar. 25, 2022), Item 1(k)(iii).

[17] See generally, Evaluating Options for Enhancing Wholesale Competition and Implications for the Southeastern United States, March 2020,

https://nicholasinstitute.duke.edu/sites/default/files/publications/Evaluating%20Options%20for%20Enhancing-Wholesale-Competition-and-Implications-for-the-Southeastern-United-States-Final.pdf

[18] New DOE Report Shows How Continued Western State Collaboration Can Support Affordable, Reliable, Clean Energy, 2021, https://www.energy.gov/eere/articles/new-doe-report-shows-how-continued-western-state-collaboration-can-support-affordable

- Right size and efficiently invest in new assets and demand-side resources. This could be captured through resource adequacy analysis, capacity expansion models, and avoided capacity cost estimates.

- Cost-effectively procure other grid services. Ancillary service market benefits of competitively procuring and pooling reserves, regulation, and frequency response will result in lower prices and lower overall requirements.

- Optimize existing transmission: Increase in transmission availability, decrease in transmission congestion and associated costs.

- Plan for efficient new infrastructure: Adjusted production cost savings from regional transmission enhancements as well as other quantifiable transmission benefits.

- Leverage economies of scale for fulfilling compliance obligations.

Qualitative considerations should at least include:

- Independent market monitoring

- Transparent prices and decision-making processes, data and information access

- Training, education, outreach, and technical assistance for stakeholder engagement

- Coordination across states on policy and grid issues[19]

- Improved reliability and emergency planning

- Facilitating adoption of cost-efficient innovative technologies and cost and risk containment mechanisms

- Facilitating robust engagement from customers

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[19] See generally Engagement between States and Regional Transmission Organizations,

National Association of Regulatory Utility Commissioners Center for Partnerships & Innovation, March 2022.

https://pubs.naruc.org/pub/6C1AA0FC-1866-DAAC-99FB-993D01E9FDA5

III. RTO benefits are broader in scope and greater in magnitude than what LG&E KU accounted for in its RTO Membership Analysis

RTO savings largely come from more efficient use of existing resource fleets and reduced need for additional long-lived assets. RTOs have documented their benefit-cost estimates,[20] and retrospective academic studies confirm that RTO cost savings are substantial. Independent studies have also offered frameworks for evaluating RTO membership benefits that include categories beyond those listed in the Companies' RTO Membership Analysis.

The Companies' RTO Study incompletely captures the benefits of RTO membership. Supplementing that study with a more thorough accounting of energy and capacity savings, as explained in the sections further below, show that total benefits outweigh the costs in nearly all cases. (The exception is the Companies' "Low Case" scenario for MISO, where hypothetical MISO transmission expansion costs allocated to the Companies are assumed to run into the hundred millions of dollars per year.) Other benefits may be added to the mix, but even working within the Companies' limited assessment and holding all else equal, the missing energy and capacity savings from using existing assets more efficiently and avoiding costs of new power plants already tip the scale. The two tables below compare what the Companies have included, and what a more thorough accounting would look like for energy and capacity market benefits.

[20] See generally the value propositions from MISO, PJM, and SPP: MISO Value Proposition 2021 Detailed Calculation Description, https://cdn.misoenergy.org/20220309%20Item%2003%202021%20MISO%20Value%20Proposition%20Calculation%20Details623347.pdf; PJM Value Proposition, 2019, https://www.pjm.com/about-pjm/~/media/about-pjm/pjm-value-proposition.ashx; 2020 MEMBER VALUE SPP'S MEMBER VALUE STATEMENT AND METHODOLOGY Apr. 15, 2021 https://www.spp.org/documents/64491/2020%20spp%20mvs%20methodology.pdf.

Table 1: Reproduction of the Companies' mid-case cost benefit analysis for MISO

MISO Membership Cost Analysis - Mid Case ($M)

Costs	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MISO Admin Cost	-14.8	-15.4	-15.9	-16.5	-17.1	-17.7	-18.4	-19.0	-19.8	-20.6	-21.4	-22.2	-23.1	-24.1
MISO Uplift Cost - Revenue Neutrality Uplift	-7.7	-7.7	-7.6	-7.6	-7.6	-7.6	-7.5	-7.5	-7.5	-7.5	-7.5	-7.5	-7.5	-7.5
MISO Transmission Expansion Cost (MVP)	-53.0	-52.3	-51.4	-50.6	-49.9	-49.3	-48.5	-47.9	-47.3	-46.8	-46.2	-45.6	-45.1	-44.8
LG&E/KU Internal Staffing & Implementation	-0.8	-0.8	-0.7	-0.7	-0.7	-0.7	-0.7	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6
LG&E/KU Lost XM Revenue	-1.3	-1.3	-1.3	-1.2	-1.2	-1.2	-1.2	-1.5	-1.6	-1.6	-1.7	-2.5	-2.2	-2.7
LG&E/KU Lost Joint Party Settlement Revenue	-1.4	-1.5	-1.5	-1.5	-1.6	-1.6	-1.6	-1.7	-1.7	-1.7	-1.8	-1.8	-1.8	-1.9
	-79.0	**-79.0**	**-78.5**	**-78.1**	**-78.0**	**-78.0**	**-77.9**	**-78.2**	**-78.5**	**-78.9**	**-79.1**	**-80.2**	**-80.4**	**-81.5**
Benefits	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
MISO Energy Market Benefits/(Costs)	11.8	11.7	13.5	15.6	15.4	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
MISO Capacity Market Benefits/(Costs)	1.2	1.3	1.3	1.4	1.5	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
LG&E/KU Avoided Fees (FERC, TVA RC, ITO, TEE)	6.6	6.6	6.7	6.8	6.9	7.0	7.1	7.3	7.4	7.4	7.4	7.4	7.5	7.5
LKE Elimination of De-Pancaking	24.1	23.6	23.4	23.8	14.1	14.4	5.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	43.7	**43.2**	**45.0**	**47.6**	**38.0**	**21.4**	**12.3**	**7.6**	**7.8**	**7.8**	**7.8**	**7.8**	**7.9**	**7.9**
Net Benefits/(Costs)	**-35.3**	**-35.7**	**-33.5**	**-30.5**	**-40.0**	**-56.6**	**-65.6**	**-70.5**	**-70.8**	**-71.1**	**-71.3**	**-72.3**	**-72.5**	**-73.7**

Source: 2021 RTO membership analysis Appendix B p. 47 of 57 (*highlight added*).

Table 2: The Companies' mid-case cost benefit analysis for MISO but with scaled benefits from MISO

MISO Membership Cost Analysis - Mid Case ($M)

Costs	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MISO Admin Cost	-14.8	-15.4	-15.9	-16.5	-17.1	-17.7	-18.4	-19.0	-19.8	-20.6	-21.4	-22.2	-23.1	-24.1
MISO Uplift Cost - Revenue Neutrality Uplift	-7.7	-7.7	-7.6	-7.6	-7.6	-7.6	-7.5	-7.5	-7.5	-7.5	-7.5	-7.5	-7.5	-7.5
MISO Transmission Expansion Cost (MVP)	-53.0	-52.3	-51.4	-50.6	-49.9	-49.3	-48.5	-47.9	-47.3	-46.8	-46.2	-45.6	-45.1	-44.8
LG&E/KU Internal Staffing & Implementation	-0.8	-0.8	-0.7	-0.7	-0.7	-0.7	-0.7	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6
MISO Congestion Cost/ARR/FTR ($M)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MISO Ancillary Services - charges to load ($M)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LG&E/KU Lost XM Revenue	-1.3	-1.3	-1.3	-1.2	-1.2	-1.2	-1.2	-1.5	-1.6	-1.6	-1.7	-2.5	-2.2	-2.7
LG&E/KU Lost Joint Party Settlement Revenue	-1.4	-1.5	-1.5	-1.5	-1.6	-1.6	-1.6	-1.7	-1.7	-1.7	-1.8	-1.8	-1.8	-1.9
	-79.0	**-79.0**	**-78.5**	**-78.1**	**-78.0**	**-78.0**	**-77.9**	**-78.2**	**-78.5**	**-78.9**	**-79.1**	**-80.2**	**-80.4**	**-81.5**
Benefits	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
MISO Energy Market Benefits/(Costs)	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
MISO Capacity Market Benefits/(Costs)	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
LG&E/KU Avoided Fees (FERC, TVA RC, ITO, TEE	6.6	6.6	6.7	6.8	6.9	7.0	7.1	7.3	7.4	7.4	7.4	7.4	7.5	7.5
LKE Elimination of De-Pancaking	24.1	23.6	23.4	23.8	14.1	14.4	5.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4
LG&E/KU Elimination of Compliance Cost														
	155.7	**155.2**	**155.1**	**155.6**	**146.1**	**146.4**	**137.3**	**132.6**	**132.8**	**132.8**	**132.8**	**132.8**	**132.9**	**132.9**
Net Benefits/(Costs)	**76.7**	**76.3**	**76.6**	**77.6**	**68.1**	**68.4**	**59.4**	**54.5**	**54.2**	**53.9**	**53.7**	**52.7**	**52.5**	**51.3**

Source: LG&E KU RTO Membership Analysis Workpapers with modifications to the highlighted cells with midpoint energy market and footprint diversity savings from MISO scaled to LG&E KU, as described in the text below. An improved approximation of these benefits would not be constant across the years, but could potentially see benefits increase over time.

SREA does not necessarily confirm the accuracy of the numerical estimates in the various RTO value propositions, but their methodologies are comparatively more robust than what the Companies have presented. Our recommendation is, therefore, that the Commission remind the Companies of their current obligation to analyze RTO membership and direct them to approach and work with any RTOs that are interested in assisting the Companies to develop a more accurate membership evaluation. This assistance could include modeling and providing more accurate data and information. The Companies should also solicit stakeholder input on the evaluation, as further discussed in the Recommendations section.

A. Energy market benefits

RTO markets have reduced production costs by increasing trade, better coordinating power plants, and driving efficiency improvements at plants, according to the most cited literature surveyed by U.C. Davis and Dartmouth researchers.[21] A few retrospective academic studies have quantified efficiency gains from wholesale electric energy trading.

- A University of Chicago researcher estimated that wholesale markets nationwide saved about $3 billion per year in production costs, based on data from 1999-2012.[22] The savings accrued from greater use of lower-cost plants and increased trading among utilities.

- A Dartmouth study found that 19 Midwest utilities joining PJM in 2004 produced efficiency gains of over $160 million annually, exceeding the one-time $40 million implementation cost. These Midwestern utilities already had been trading bilaterally with their eastern neighbors. After joining PJM, the energy traded between them tripled, and production shifted to lower-cost facilities as the market identified new trading opportunities.[23]

- An Oberlin study examining Texas' transition from a bilateral market to a centralized auction found improved market efficiency that dominated any change in market power incentives. Following the transition, production shifted to lower-cost generators, leading to annual cost savings of about $59 million.[24]

Security constrained economic dispatch (SCED) over a broader region like in an RTO or EIM has yielded greater efficiencies. Studies indicate utilities joining RTOs may expect to gain

[21] Review of the Economics Literature on US Electricity Restructuring, James Bushnell, Erin T. Mansur, and Kevin Novan, Draft Version: February 23, 2017, https://bushnell.ucdavis.edu/uploads/7/6/9/5/76951361/economics-literature.pdf

[22] NBER WORKING PAPER SERIES, IMPERFECT MARKETS VERSUS IMPERFECT REGULATION IN U.S. ELECTRICITY GENERATION, Steve Cicala, January 2017, https://www.nber.org/system/files/working_papers/w23053/w23053.pdf

[23] Market Organization and Efficiency in Electricity Markets, Erin T. Mansur and Matthew W. White, January 13, 2012, https://mansur.host.dartmouth.edu/papers/mansur_white_pjmaep.pdf

[24] The Efficiency and Environmental Impacts of Market Organization: Evidence from the Texas Electricity Market, Paul A. Brehm and Yiyuan Zhang, November 2019, https://www2.oberlin.edu/faculty/pbrehm/BrehmZhang_Electricity_Mkt_Structure_Submitted.pdf

around 2-11% in production cost savings.[25] LG&E KU's estimates are lower: "In all scenarios, the estimated benefit of additional energy sales margin was greater than the additional cost of purchasing market energy for native load through 2027. These benefits represent about 1-3% of the total native load cost of $670 to $840 million per year in these scenarios."[26] SCED can also increase available transmission capacity, particularly when coupled with eliminating hurdle rates. For example, MISO, using PROMOD, showed that transmission utilization improved by 10%.[27] The Companies' analysis does not include this benefit.

As a side note, SEEM is expected to yield lower savings. Member-hired consultants estimated that SEEM could provide about 0.3% to 0.4% in production cost savings, assuming that all efficient trades would be executed.[28]

If LG&E KU were to join MISO, a rough estimate for production costs savings could be obtained by scaling MISO's benefits to LG&E KU by load, noting that LG&E KU is about 5% of MISO's load. This results in a benefit of approximately $24M-26M per year[29] and is more than twice $11.8M, which is LG&E KU's mid-case estimate of the same.

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[25] Potential Benefits of a Regional Wholesale Power Market to North Carolina's Electricity Customers, Judy Chang, Johannes Pfeifenberger, John Tsoukalis, April 2019, https://www.brattle.com/wp-content/uploads/2021/05/16092_nc_wholesale_power_market_whitepaper_april_2019_final.pdf, p. 7 (9-11% savings if Duke Energy Carolinas and Progress join PJM). Production Cost Savings Offered by Regional Transmission and a Regional Market in the Mountain West Transmission Group Footprint, Judy W. Chang, Johannes P. Pfeifenberger, John Tsoukalis, DECEMBER 1, 2016, https://www.wapa.gov/About/keytopics/Documents/mountain-west-brattle-report.pdf (5-9% savings from RTO formation in Colorado and Wyoming), https://www.wapa.gov/regions/UGP/PowerMarketing/Documents/ISNodalStudyRedacted030813.pdf pp. 34, 36, ("Most analyses of actually-achieved regional market benefits have found production cost savings in the range of 2–8% of total production costs….Mountain West participants would realize annual production cost savings ranging from $53 million/year to $88 million/year by joining a centralized wholesale power market. This range represents a reduction in production costs of 5.7% to 9.4%"), https://www.spp.org/documents/28607/rsc%20materials%2020150427.pdf (8% savings from SPP's first year operation of Integrated marketplace).

[26] 2021 RTO Membership Analysis at p. 34.

[27] 2021 MISO Value Proposition, https://cdn.misoenergy.org/20220309%20Item%2003%202021%20MISO%20Value%20Proposition%20Calculation%20Details623347.pdf at p. 15.

[28] Guidehouse, Southeast Energy Exchange Market: Market Benefits and Non-Centralized Costs Evaluation Prepared for: Participants in Southeast Energy Exchange Market, Updated: November 18, 2020,

https://www.crai.com/engagements/study-of-benefits-for-new-energy-trading-market-in-u-s-southeast/; https://media.crai.com/wp-content/uploads/2020/12/23104641/CRA-SEEM-Report_Public-SNL.pdf at p. vii.

[29] 2021 MISO Value Proposition, https://cdn.misoenergy.org/20220309%20Item%2003%202021%20MISO%20Value%20Proposition%20

Similarly, scaling PJM's production cost savings to LG&E KU (which is about 4% of PJM load) yields an annual savings of $24M.[30] This is more than twice $10.5M, which is LG&E KU's mid-case estimate of the same.

B. LG&E KU analysis on energy market benefits

LG&E KU examined only real-time energy markets (in hourly and not 5-minute intervals) and did not look for savings available through day-ahead energy markets.[31] Day-ahead energy markets account for about 95% of energy market transactions, and not including them can leave out significant benefits.[32]

The Companies confirm that their quantification of the energy market benefits only come from their sales into MISO and PJM markets.[33] They also confirm that they did not calculate production cost savings as a result of dispatching the most efficient resources selected from across the PJM or MISO footprints.[34]

The Companies state that their "entire fleet was economically dispatched based on market prices, except for solar resources and the Ohio Falls run-of-river hydro station."[35] However, this "economic dispatch" on an hourly basis is not the same as RTO security constrained economic dispatch operating in 5 minute increments. The Companies confirm that their model does not consider or otherwise include how security constrained economic dispatch could optimize

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Calculation%20Details623347.pdf at p. 14 (more efficient use of existing assets produce benefits of $471 million to $521 million in MISO annually)

[30] PJM Value Proposition, https://www.pjm.com/about-pjm/~/media/about-pjm/pjm-value-proposition.ashx at p. 3 (energy production cost savings are about $600 million per year).

[31] LG&E KU Response to SREA Supplemental Requests For Information (filed Mar. 25, 2022), Item 1(c).

[32] Evaluating Options for Enhancing Wholesale Competition and Implications for the Southeastern United States, March 2020, https://nicholasinstitute.duke.edu/sites/default/files/publications/Evaluating%20Options%20for%20Enhancing-Wholesale-Competition-and-Implications-for-the-Southeastern-United-States-Final_0.pdf at p. 16 ("For RTOs, about 5% of all energy transactions are scheduled in the real-time market, the rest having already been scheduled in the day-ahead market").

[33] LG&E KU confirms that its accounting of "energy market benefits come only from sales into the MISO and PJM markets and their related expenses." LG&E KU Response to SREA Supplemental Requests For Information (filed Mar. 25, 2022), Item 1(f)(citing to Section 8.2 of the 2021 RTO Membership Analysis).

[34] LG&E KU Response to SREA Supplemental Requests For Information (filed Mar. 25, 2022), Item 1(h)(citing to Section 8.2 of the 2021 RTO Membership Analysis, p. 32 and the responses to PSC 2-8 and 2-10).

[35] LG&E KU Response to SREA Supplemental Requests For Information (filed Mar. 25, 2022), Item 1.b.

available transmission and reduce congestion.[36] This is unsurprising given that the Companies use PROSYM.[37] To get an accurate estimate of the energy market savings, LG&E KU would have to simulate LG&E KU in each market and calculate their adjusted cost of production inside and outside of the RTO.

Note that LG&E KU has transfer capacity to support more flows between itself and PJM or MISO without transmission upgrades to its own system. The 2021 SERTP analysis found no transmission system impact from LG&E KU's study request of 300 MW to/from PJM or MISO.[38] Further, the Companies state: "In 2021, non-firm hourly transmission was unavailable less than six percent and two percent of the time for sales into PJM and MISO, respectively, some of which was due to unavailability of RTO transmission. This affected an estimated 110,000 MWh and 21,000 MWh of energy the Companies could have potentially sold into PJM and MISO, respectively. Non-firm hourly transmission was unavailable less than one tenth of one percent of the time when the Companies could have potentially purchased economy energy from PJM or MISO."[39] As a note to flag for the later section on transmission planning, the Companies' issue with the unavailability of RTO transmission may be addressed through RTO regional transmission planning, which is an issue the Companies could raise as a member of the RTO.

Despite sufficient transmission, trades are fairly limited. In 2021, the Companies purchased 0.004% of its load in non-firm economy energy from PJM, sold 0.5% to PJM, purchased no energy from MISO, and sold 0.6% to MISO.[40]

C. Capacity sharing and trading benefits

Sharing capacity across a larger, often more diverse footprint reduces the amount of total capacity needed to meet demand as well as the amount of additional reserve capacity needed to meet a commonly used reliability target (i.e., to satisfy the 1-in-10 loss of load expectation

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[36] LG&E KU Response to SREA Supplemental Requests For Information (filed Mar. 25, 2022), Item 1.i. Citing to Section 6 of the 2021 RTO Membership Analysis, p. 21.

[37] LG&E KU Response to SREA Supplemental Requests For Information (filed Mar. 25, 2022), Item 1.g.i. For a comparison of PROSYM versus PROMOD functions, see, e.g., Assessing the Electricity System Benefits of Energy Efficiency and Renewable Energy,

https://www.epa.gov/sites/default/files/2018-07/documents/mbg_2-3_electricitysystembenefits.pdf at pp. 3-52 to 3-53.

[38] Southeastern Regional Transmission Planning, 2021 Economic Planning Studies, August 27, 2021 http://www.southeasternrtp.com/docs/general/2021/2021-SERTP-Economic-Study-Results-Final.pdf.

[39] LG&E KU Response to SREA Supplemental Requests For Information (filed Mar. 25, 2022), Item 8.c.i.

[40] See LG&E KU Response to SREA Supplemental Requests For Information (filed Mar. 25, 2022), Item 5. Here, the Companies' Energy Requirement for Load is estimated to be around 32 million MWh.

criterion, or "LOLE"). This requirement is lower because peak demand does not occur at the same time across a larger footprint (i.e., the coincident peak is smaller than combining separate non-coincident peaks). In addition, a greater amount and diversity of resources shared across a broader region benefits from economies of scale while mitigating the risk of correlated failure.

Thus, for example, SPP's target reserve margin has been 12%, PJM's is less than 15%, and MISO's PRM around 18%.[41] In comparison to these RTO targets, LG&E KU's 2021 IRP target reserve margin corresponding to meeting the 1-in-10 LOLE criterion is 24% in the summer and 35% in the winter.[42]

If capacity markets are a concern, MISO does not require utilities to participate in its capacity market, and PJM's Fixed Resource Requirement option makes it possible for a utility to take advantage of PJM's energy and ancillary services markets without participating in the capacity market.[43] Thus, the concern over changing capacity market rules can be mitigated or eliminated.

Avoided capacity cost savings can be an order of magnitude greater than savings from more efficient use of existing resources because of the compounding of savings over time for long-lived assets. Scaling MISO's avoided capacity cost savings from footprint diversity[44] to LG&E KU yields a mid-case annual savings of $100M. LG&E KU's estimate of the same is $1.2M. Scaling PJM's capacity savings results in an annual benefit of $108.M,[45] while LG&E KU's estimate of the same is $4.2M.

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[41] NERC 2021 Summer Reliability Assessment, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20SRA%202021.pdf at p.20 for MISO, p. 28 for PJM, p. 33 for SPP. Note that NERC assumes a reference margin level (target reserve margin) of 15% for regions that have not specified otherwise in its reliability assessments, p. 41.

[42] IRP Vol. I at pp. 47-48 of the PDF has target reserve margins. Available at: https://psc.ky.gov/pscecf/2021-00393/rick.lovekamp%40lge-ku.com/10192021013101/3-LGE_KU_2021_IRP-Volume_I.pdf. These values are in terms of installed capacity (ICAP) and not unforced capacity (UCAP). LG&E KU Response to SREA Supplemental Requests For Information (filed Mar. 25, 2022), Item 4.

[43] PJM, Securing Resources Through the Fixed Resource Requirement, https://www.pjm.com/-/media/about-pjm/newsroom/fact-sheets/securing-resources-through-fixed-resource-requirement-fact-sheet.ashx ("Companies opting out of the capacity market through the election of the FRR alternative … can continue to participate in PJM's energy and ancillary services markets."

[44] 2021 MISO Value Proposition, https://www.misoenergy.org/about/miso-strategy-and-value-proposition/miso-value-proposition/ at p.22 (footprint diversity produces $1,741 million to $2,254 million in savings per year for MISO).

[45] PJM Value Proposition, https://www.pjm.com/about-pjm/~/media/about-pjm/pjm-value-proposition.ashx at pp. 2-3 (lower reserve margin cost savings are about $1.2 billion to $1.8 billion per year and replacement of less efficient resources amount to savings of $1.1 billion to $1.3 billion per year).

D. LG&E KU analysis on RTO capacity benefits

The Companies' estimates are much lower than the RTO estimates because they focus on off-system capacity sales to PJM and MISO capacity markets from their own excess capacity until Mill Creek unit 2 and Brown unit 3 are retired in 2028, at which point there are no estimates of benefits. LG&E KU did not quantify avoided capacity costs associated with RTO membership.[46] They claim to have "included the benefits of a lower target reserve margin by quantifying the amount of the Companies' capacity that could be sold into the RTOs capacity markets net of the capacity required for load as a function of the RTOs' lower target reserve margin requirements."[47] Thus, the Companies recognize that they could sell more capacity into an RTO due to a lower required reserve margin, but did not quantify and include the benefit of having to build less or avoid building new capacity in the near term. The Companies should also consider whether a lower capacity requirement arising from RTO membership could avert or delay potential capacity shortfalls due to planned retirements. There is also the potential to retire inefficient plants even earlier with lower capacity targets. Further, if LG&E KU finds that it needs to replace capacity, they could avoid the new build capacity costs by accessing the larger pool of cheap excess capacity in MISO and PJM. This could be done through bilateral transactions or markets. These are all potential futures with quantifiable benefits that the Companies should study.

Note that the capacity issue is one that deserves enhanced regulatory scrutiny because the cost-of-service business model incentivizes utilities to build more as long as they can justify placing assets in rate base,[48] and RTO membership reduces capacity needs and thus potentially the amount of assets on which a utility can earn a return.

Thus, to properly study the RTO options, the Companies needed to include:

- The lower costs due to reducing their capacity needs by joining an RTO.

- If they need capacity, the costs of procuring capacity from the RTOs under various scenarios reflecting the range in historical prices. They would need to compare the cost impacts of these scenarios against what the Companies would incur to ensure sufficient resources without being a part of an RTO. For example, this could be an estimate of the

[46] LG&E KU Response to SREA Initial Requests for Information (filed Feb. 10, 2022), Item 1-18(j) and LG&E KU Response to SREA Supplemental Requests For Information (filed Mar. 25, 2022), Item 3.

[47] LG&E KU Response to SREA Supplemental Requests For Information (filed Mar. 25, 2022), Item 3, citing Section 8.1, p. 28 of the 2021 RTO Membership Analysis.

[48] Averch, H.A., and L.L. Johnson. 1962. Behavior of the firm under regulatory constraint. American Economic Review 52(5): 1052–1069. https://www.jstor.org/stable/1812181.

costs of building generation, obtaining demand response commitments or improving energy efficiency, and/or obtaining long-term contracts.

- If joining an RTO means that the Companies can retire inefficient power plants early, then the cost savings from having to maintain those plants should be included.

- If the Companies opt to participate in capacity markets, the avoided risk of stranded costs with new generation build should also factor in as environmental and regulatory requirements evolve. Markets are designed to put such investment risks on investors and not ratepayers.

What the Companies did in its RTO Membership Analysis was to assume zero capacity replacement costs after planned unit retirements, missing a critical and large cost under the status quo case and a large avoided cost benefit in the RTO membership case. This assumption is completely unrealistic under any scenario, and the Companies' explanation that uncertain benefits are not included does not explain why completely omitting capacity replacement costs provide for a more realistic analysis.

Specifically, the Companies state that they "did not make an assumption for capacity replacement costs in the RTO analysis, as explained in the RTO Study in the Executive Summary on page 5 and in Appendix B, which notes that the capacity benefits and costs are undetermined after 2027 when the Companies forecast a need for new capacity in the 2021 IRP. Capacity implications would be included in any final decision to join an RTO when more certainty is available regarding the future of the RTOs' capacity markets."[49] This reasoning that "Capacity implications would be included in any final decision to join an RTO" appears to be circular, as the Companies will unlikely come to the conclusion that RTO membership is worthwhile if they do not properly account for its benefits to begin with. Further the Companies are waiting for more certainty, and later state that "More certainty could be achieved in the RTOs' capacity markets through market development and revised market rules."[50] But this is a red herring, as the MISO's capacity market is voluntary, and there is a carve out from having to participate in PJM's capacity market through the Fixed Resource Requirement mechanism. Further, the issue here is whether pooling capacity as part of an RTO would yield cost-saving benefits, a question that can be independently answered from whether and when the Companies should participate in the capacity markets.

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[49] LG&E KU Response to SREA Initial Requests for Information (filed Feb. 10, 2022), Item 18 j.

[50] LG&E KU Response to SREA Supplemental Requests For Information (filed Mar. 25, 2022), Item 1.p.ii.

E. Ancillary services markets benefits

Most ancillary services may be pooled and doing so reduces the amount of reserves required as well as uncoordinated actions across seams between balancing authorities, so that the amount of needed services are also reduced. Similar to how target capacity reserve margins are reduced in RTOs, other types of reserves needed closer to operational timeframes may be reduced. Some reserves are shared through reserve sharing groups, but aside from the TEE Contingency Reserve Sharing Group, the Companies have not indicated which other reserves are shared and how much would be saved in the RTO analysis. There is no line item in the Companies' RTO cost benefit study on the savings benefits from ancillary services. However, the Companies did note that by reducing the spinning reserve requirement from 327 MW to 220 MW, the Companies estimated that around $2 million would be saved in production costs annually in an RTO.[51]

Ancillary services like ramping and regulation needs may be reduced by eliminating seams between utility footprints. For example, one region may need to dispatch a resource to ramp up while a neighboring region needs a downward ramp. These needs would even out over a broader footprint. The California ISO Energy Imbalance Market ("EIM") has consistently reduced ramping needs by around 50% and above.[52] And MISO has estimated that regulation needs have dropped by a factor of four in its value proposition. Scaling MISO regulation savings to LG&E KU results in annual savings of $7M. A more clear and thorough accounting of ancillary services benefits is needed.

F. Transmission planning benefits

Transmission planning that accurately values benefits and allocates costs to beneficiaries commensurate to their benefits can help optimize the efficiency of the system. This can help ensure that the lowest cost and often lowest emissions resources can reach customers across the footprint. It can also help ensure different utilities are well set up to lend mutual assistance during extreme heat and cold. Regional transmission planning can help find the most efficient or least regrets transmission solutions to satisfy transmission needs arising from reliability, public policy, and market efficiency. While at times broad cost allocation means that one state pays for transmission in other states, the reverse can also be true. Transparent assessment of solutions and

[51] LG&E KU Response to SREA Supplemental Requests For Information (filed Mar. 25, 2022), Item 1.l. Citing to Section 8.2, p. 32, of the 2021 RTO Membership Analysis.

[52] California Independent System Operator, WESTERN EIM BENEFITS REPORT FOURTH QUARTER 2021, January 31, 2022, https://www.westerneim.com/Documents/ISO-EIM-Benefits-Report-Q4-2021.pdf at pp. 23-27.

competitive solicitations mean that more innovative and cost-effective technologies, as well as risk and cost containment, can be part of the winning solution.[53]

For example, PJM notes in its Value of Transmission study that transmission links PJM zones together, allowing them to share capacity, and reducing the need for new generation by $3.78 billion annually. Transmission linking to neighboring regions saved an estimated $1.3 billion (19%) in recent annual capacity auctions. Transmission enhancements in PJM are estimated to reduce costs to customers by more than $288 million a year by alleviating congestion.[54]

Improved regional and interregional transmission planning could help utilities across Kentucky better coordinate, promote efficient use of resources across the state and beyond, and ensure that the utilities are better equipped to help each other during emergencies.

LG&E KU is a member of the Southeastern Regional Transmission Planning Order 1000 Planning Region ("SERTP"), which unlike RTO regions, has not produced regional transmission plans that differ from its individual member utility plans combined. This is unsurprising because there is no independent planner in the region, unlike in an RTO. Further, alternative plans to the rolled-up member utility plans are evaluated based on avoided costs, and this evaluation does not account for other basic, quantifiable benefits, such as the efficiencies these alternatives could bring to the system through adjusted production cost savings. Put differently, there is no entity across the non-RTO Southeast that independently identifies potential transmission needs, solicits inputs on those needs, solicits solutions satisfying those needs, performs production cost modeling to see whether alternatives would result in greater power system efficiencies, or evaluates other benefits of proposed alternatives.

The studies SERTP performs are all requested by the utilities and then restricted so that some requested studies are not performed. For example, SERTP only conducts five transfer studies each year.[55] LG&E KU asked SERTP to do a 500 MW transfer analysis between LG&E KU and PJM/TVA/MISO, but because other utilities also asked for studies this same year, SERTP did not select the LG&E KU requests among its five studies.[56]

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[53] See, e.g., Brattle, Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value, p. 11, https://www.brattle.com/wp-content/uploads/2021/05/16726_cost_savings_offered_by_competition_in_electric_transmission.pdf

[54] The Benefits of the PJM Transmission System (2019) https://www.pjm.com/-/media/library/reports-notices/special-reports/2019/the-benefits-of-the-pjm-transmission-system.pdf at p. 1, 4.

[55] SERTP - 1st Quarter Meeting, First RPSG Meeting & Interactive Training Session, March 22nd, 2022, http://www.southeasternrtp.com/docs/general/2022/2022-SERTP-1st-Qtr-Presentation-FINAL.pdf p. 9.

[56] Regional Planning Stakeholders Group (RPSG) Submitted Economic Planning Studies for 2022, http://www.southeasternrtp.com/docs/general/2022/2022-Selected-Economic-Studies.pdf.

The Companies view RTO transmission planning as a cost and do not recognize its benefits in its RTO Membership Analysis. However, costs allocated prior to the Companies becoming members may not apply to the Companies. For example, MISO did not allocate Multi Value Project ("MVP") costs to Entergy South upon its integration, so LG&E KU may also avoid MVP cost allocation if it negotiates for it.

G. LG&E KU's analysis on reliability

Reliability is a top priority for RTOs, and they typically exceed minimum requirements established by NERC.[57] To address the Companies' concern about the loss of control, each individual utility is free to self schedule their resources and would still have control over their generation assets as part of an RTO.[58]

If the Companies want to compare reliability as an RTO member versus under the status quo, they need an apples-to-apples comparison that uses relevant metrics and captures all relevant data. Thus, comparing reliability metrics with other utilities[59] in RTOs is unhelpful because the correct counterfactual should be what would happen if LG&E KU joined an RTO, not what other utilities experience in RTOs. Further, the Companies do not capture all relevant data with the metrics they use. The Companies' calculation of System Average Interruption Duration Index ("SAIDI") reported in its RTO Study excluded Major Event Days, such as severe storms, which is one of the key reliability benefits to being a part of a larger grid.[60]

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[57] See, e.g., 2021 MISO Value Proposition, https://cdn.misoenergy.org/20220309%20Item%2003%202021%20MISO%20Value%20Proposition%20Calculation%20Details623347.pdf at p. 6.

[58] See generally, Potomac Economics, A REVIEW OF THE COMMITMENT AND DISPATCH OF COAL GENERATORS IN MISO, September 2020, https://www.potomaceconomics.com/wp-content/uploads/2020/09/Coal-Dispatch-Study_9-30-20.pdf; SPP Market Monitoring Unit, Self-committing in SPP markets: Overview, impacts, and recommendations, December 2019, https://spp.org/documents/61118/spp%20mmu%20self-commit%20whitepaper.pdf.

[59] RTO Membership Analysis at p. 19.

[60] RTO Membership Analysis at p. 18 ("This data excludes Major Event Days (MED), each of which includes a severe windstorm or ice storm."). Note that the Companies have offered conflicting information in its responses: "The Companies track System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI), which include Major Event Days." LG&E KU Response to SREA Supplemental Requests For Information (filed Mar. 25, 2022), Item 9.d.

Major Event Days are not insignificant. "The Companies had 24 Major Event Days with transmission outages in the last 5 years" "The initial causes of the outages were either severe weather events or equipment failure. Below is a list of Major Event Days and the causes of the outages" as well as "known and tracked costs associated with these outages":[61]

Year	Weather Events	Equipment Failure	Total Cost ($)
3/1/2017	X		442,117
5/10/2017		X	49,877
5/27/2017	X		56,716
4/4/2018	X		370,339
5/31/2018	X		104,963
6/1/2018		X	24,027
6/13/2018		X	0
6/26/2018	X		27,427
7/20/2018	X		496,089
7/22/2018	X		0
10/20/2018	X		0
11/14/2018	X		0
3/14/2019	X		351,393
6/21/2019	X		127,631
7/2/2019	X		0
8/18/2019		X	25,790
12/12/2019		X	13,970
1/11/2020	X		74,037
4/12/2020	X		364,456
6/10/2020	X		79,541
7/25/2020		X	0
6/5/2021		X	1,477
12/10/2021	X		4,227,402
12/11/2021	X		*
Total	17	7	6,837,252

*Cost included with 12/10/2021

From this table, weather events produced more frequent and the most expensive outages in the past five years compared to equipment failures. Even with the issues on the Companies' system, they state that they exported power during these events. "The Companies did not import any energy from either MISO or PJM during the Major Event Days listed in the days listed in item (e) (ii); rather, the Companies sold over 18,000 MWh of energy to the two RTOs during those days."[62] The point here is not to question the Companies' judgment for doing so, but that in examining reliability metrics for RTO benefits analysis, Major Event Days are a significant cost and can require mutual assistance, and should be included in the data for calculating these metrics.

[61] LG&E KU Response to SREA Supplemental Requests For Information (filed Mar. 25, 2022), Item 9.e.

[62] LG&E KU Response to SREA Supplemental Requests For Information (filed Mar. 25, 2022), Item 9.g.

Similarly, LG&E KU's comparison of Equivalent Forced Outage Rate ("EFOR") and Equivalent Unplanned Outage Rate ("EUOR") for its own fleet and that of Reliability First Corporation ("RFC") does not account for all relevant data. Only certain steam and CC baseload units were included.[63] However, RTOs and their members, when ensuring reliability, use their entire fleets, not only steam and CC units or units designated as "baseload." Thus, it is not accurate to restrict reliability performance of the RFC generation fleet to steam and CC, as member utilities rely on the full fleet and not just what LG&E KU designates as "baseload" for reliability.[64] Baseload resources do not necessarily have a better performance rate in supporting reliability during emergencies, and in fact suffer from fuel supply interruptions and frozen or waterlogged coal piles.[65]

The NERC's Summer Reliability Assessment map included in the Companies' RTO Membership Analysis[66] needs more explanation. The text supporting the NERC map is highlighting recent extreme weather in particular regions in the U.S. and flagging planning reserve margin levels compared to potential demand trends that may not be similar to LG&E KU's situation if they were to join an RTO. The Companies would likely have a significant amount of excess capacity. Further, large planning reserve margins are not necessarily indicative of system reliability. It does not look at how well generators actually perform in a region, how transmission is adequate for emergency sharing of resources, or how markets may help ensure the resources are efficiently allocated when supply is tight. Along those lines, NERC also does

[63] RTO Membership Analysis at p. 16 ("LG&E and KU's EFOR and EUOR compared to the Reliability First Corporation's (RFC) top quartile and average performance for similar sized baseload units. RFC overlaps both MISO and PJM.").

[64] LG&E KU Response to SREA Initial Requests for Information (filed Feb. 10, 2022), Item 34.d. (stating that the Companies restricted analysis to steam and CC units because these are baseload). We were not able to obtain clarity after two rounds of information requests on the point of why the Companies only looked at baseload to ensure reliability. "As stated in the Companies' response to SREA 1-34(e), the Companies do not have this data. As clearly marked in the headers of Figures 6 and 7 of the RTO Analysis, the figures present data for EFOR and EUOR for steam and CC units only, which are the Companies' baseload units. EFOR and EUOR are industry standard metrics for these types of units. Peaking unit reliability metrics include starting, availability, and Equivalent Forced Outage Rate during demand periods (EFORd). See the response to JI 1.22(c) for EFORd for the Companies' primary peaking units." LG&E KU Response to SREA Supplemental Requests For Information (filed Mar. 25, 2022), Item 10.c.

[65] See, e.g., EIA, Extreme winter weather is disrupting energy supply and demand, particularly in Texas, February 19, 2021, https://www.eia.gov/todayinenergy/detail.php?id=46836 ("natural gas-fired power generation fell sharply once ERCOT began implementing rotating outages at midnight on February 15. Output from coal-fired plants, a nuclear facility, and wind farms all fell"); NERC Polar Vortex Review, September 2014, https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf ("Coal plants accounted for 26 percent of the outages. Natural gas represented over 55 percent of the total outages during the polar vortex."), p. 13.

[66] RTO Membership Analysis, Figure 8, at p. 18.

not look at cost-effectiveness, an important limiting factor to building out a large reserve margin.[67]

H. Additional unquantified benefits

There are significant benefits to RTO membership that are not quantifiable. These include increased price and data transparency to the Commission, stakeholders, and investors. The Commission and consumers can better understand what costs are reasonable if they have easy access to transparent and well-formed market prices. Entities seeking to enter into bilateral contracts can also more efficiently do so with a better understanding of what the market would bear. On this point, a transparent marketplace and one where contracting between clean energy developers and customers can thrive could potentially attract businesses to Kentucky, like Google, Meta, Apple, or similar such entities. Importantly, independent market monitors also provide information, analysis, and education to state commissions and to stakeholders.

RTOs have a number of control center features that allow for real time monitoring and more temporally granular and efficient congestion management. They conduct more frequent testing, faster response times for backup capabilities, and a 24/7 staffed backup control center. They also offer more extensive training exceeding NERC requirements.

RTOs could also facilitate coordination across the states as well as further utility renewable goals. For example, PPL, LG&E KU's parent company, "has set an ambitious goal to achieve net-zero carbon emissions by 2050" and "are targeting a 70% reduction from 2010 levels by 2035 and an 80% reduction by 2040."[68] Meeting these targets would likely be more expensive without RTO membership. LG&E KU acknowledges the benefits of RTOs for renewables integration, which is a good start. This provides another significant and material reason for the Companies to more comprehensively study RTO membership.

I. Kentucky utilities have realized net benefits from RTOs

The Companies report on several utilities that are members of PJM or MISO and that have been reaping cost savings and reliability benefits. The Companies provide Duke Energy Kentucky, East Kentucky Power Cooperative, and Kentucky Power Company as examples of utilities benefiting from PJM membership. The Companies' attempt to distinguish themselves from these utilities, but most of their reasoning is based on their flawed cost-benefit estimates.

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[67] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20SRA%202021.pdf at p.4.

[68] Climate Action - PPL Corporation, Clean Energy Transition Strategy and Path to Net-Zero Carbon Emissions, https://www.pplweb.com/sustainability/climate-action/#:~:text=PPL%20has%20set%20an%20ambitious,an%2080%25%20reduction%20by%202040.

- East Kentucky Power Cooperative ("EKPC") provided the Commission with a cost-benefit study by Charles River Associates indicating that joining PJM presented a net expected benefit of $142 million over 2013-2022. These included a decrease in production costs; a decrease in needed planning reserves and cost avoidance as a result of the lower planning reserve margin needed for its winter peaking load; and elimination of the cost of long-term, firm point-to-point transmission service. EKPC noted that fully integrating into PJM also would mitigate challenges of operating as a stand-alone Balancing Authority; transmission costs to the regional markets for the sale of excess capacity or purchase of economic energy; and limited ability to optimize its fleet due to the capacity reserves requirement. EKPC also noted qualitative benefits to joining PJM; namely, that it would be better positioned to respond to future environmental and regulatory requirements and that PJM had structural protections to safeguard the integrity and stability of the market.[69] The Companies similarities with EKPC include that both utilities are wholly in state, long in summer, and short in winter. PJM is a summer peaking RTO, and like EKPC, LG&E KU is winter peaking, which makes both utilities good complements to PJM's profile.

- Kentucky Power Company's cost-benefit study compared a scenario in which AEP and Kentucky Power were not part of PJM to one in which they were fully integrated into PJM. The study found net economic benefits in the period of 2004-2008 of greater off-system sales, net revenues from the sale of financial rights to transmit power on the AEP-East transmission system, and avoided costs associated with contracts for services that would instead be performed by PJM.[70]

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[69] The Companies' counter arguments are: "In contrast to EKPC, the Companies' RTO membership analyses over more than a decade have consistently shown net costs of membership. The Companies are not experiencing difficulties operating as a stand-alone Balancing Authority, nor are there concerns around increasing transmission costs or planning reserve margins. The Companies further believe that they have adequate ability to optimize the Companies' generation fleet outside of an RTO and have plans and processes in place to address current and future environmental and regulatory requirements." LG&E KU Response to SREA Supplemental Requests For Information (filed Mar. 25, 2022), Item 7 citing to Appendix D of Exhibit LEB-2, p. 30, from the Direct Testimony of Lonnie E. Bellar in Case Nos. 2018-00294 and 2018-00295.

[70] The Companies counterargument is simply that: "In contrast to KY Power, the Companies' RTO membership analyses over more than a decade have consistently shown net costs of membership." LG&E KU Response to SREA Supplemental Requests For Information (filed Mar. 25, 2022), Item 7 citing to Appendix D of Exhibit LEB-2, p. 30, from the Direct Testimony of Lonnie E. Bellar in Case Nos. 2018-00294 and 2018-00295.

- In addition, it should be noted that when Entergy performed a retrospective cost-benefit analysis five years after joining MISO, it found $1.3 billion in savings in that first five years as a result of joining the RTO.[71]

IV. Recommendations for the Commission

In conclusion, the Companies have had multiple opportunities to conduct an adequate study satisfying the Commissions directives but have fallen short.[72] The Companies' efforts to date in attempting to produce an RTO membership analysis without input or feedback from the RTOs or stakeholders are not sufficient to serve as a reliable evaluation. The Companies should be working cooperatively with the RTOs to develop a fully informed, accurate, comprehensive, and forward-looking study of RTO benefits and costs using data and modeling tools from the RTOs as well as data from the Companies. The Commission and stakeholders could help develop an evaluation framework and provide input and feedback on the study.

SREA recommends that the Commission remind the Companies of their current obligation to analyze RTO membership in a reasonable manner and direct the Companies to invite MISO, PJM, and SPP to exchange information and data and ask for modeling assistance to evaluate RTO membership because that would serve the best interests of the parties and the resource planning process.[73] SREA further recommends that the Commission invite MISO, PJM, and SPP to conduct membership evaluations.

The Commission may also invite the RTOs to consider assisting in evaluating the benefits and costs of an Energy Imbalance Market or Energy Imbalance Service, which are extensions of RTO energy markets for voluntary participation by non-RTO member utilities. The Commission may request whether an RTO could provide its modeling assistance free of charge, and in the event it cannot, there could be a possibility of requesting funds from DOE's state energy office for the RTO study.[74]

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[71] https://www.prnewswire.com/news-releases/entergy-utility-customers-realize-significant-benefits-after-5-years-as-miso-member-300975438.html

[72] Supra note 8.

[73] *See* Adm. Case No. 308, Order (Ky P.S.C. Aug. 8, 1990), p. 11 (Order predating establishment of RTOs.) Cooperative exchange of information has always been critical resource planning. If the Companies decline to work cooperatively with the RTOs, the failure to exchange information and ideas concerning the Companies' RTO membership should be fully explained in the next IRP.

[74] This was the office funding the Western State-led Study referenced above. State Energy Program Competitive Financial Assistance Program, https://www.energy.gov/eere/wipo/state-energy-program-competitive-financial-assistance-program