COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC JOINT APPLICATION OF KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND SITE COMPATIBILITY CERTIFICATES AND APPROVAL OF A DEMAND SIDE MANAGEMENT PLAN AND APPROVAL OF FOSSIL FUEL-FIRED GENERATING UNIT RETIREMENTS	))))))))))	**CASE NO. 2022-00402**

POST-HEARING BRIEF OF KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

Dated: September 22, 2023

PUBLIC - REDACTED VERSION

TABLE OF CONTENTS

PUBLIC - REDACTED VERSION

INTRODUCTION

The single most salient point to emerge from the voluminous and complex evidence in this case is this: The time to act is *now*. The Companies' aging coal units at issue in this proceeding, which have served customers for decades, are now at the end of their useful lives due to increasingly stringent environmental constraints and the growing capital investments that would be needed to keep the units functioning reliably and in compliance with environmental requirements. Moreover, the U.S. Environmental Protection Agency's ("EPA") recently proposed greenhouse gas standards for new and existing electric generating units under Clean Air Act Sections 111(b) and (d) show that the headwinds are strong against continuing to operate coal units beyond the early 2030s. The simple reality is that investing additional hundreds of millions of dollars to continue to operate Mill Creek Units 1 and 2, E.W. Brown Unit 3, and Ghent Unit 2 would almost certainly result in only a handful of years of additional service life and would soon prove to be a regrettable mistake.

In the meantime, the door is rapidly closing with regard to economic replacement capacity for these retiring units. As global energy production transitions away from higher-carbon generating resources like coal toward renewable energy, storage resources, simple-cycle combustion turbines, and high-efficiency natural gas combined cycle ("NGCC") units like those the Companies have proposed, it will become increasingly difficult and costly to acquire such resources. [redacted][1] [redacted]

[1] Companies' Response to Joint Intervenors' Post Hearing Request for Information No. 1, Attachment 1 at 4.

[redacted][2] As the Companies have shown, it is possible today to acquire firm gas transportation on the gas pipelines needed to ensure reliable gas supply to the Companies' proposed NGCC units, but acquiring the same firm gas transportation might not be possible in twelve months' time.[3] Thus, it is clear that the time to move forward with the Companies' supply-side resource proposals, particularly the Companies' two proposed NGCC units, is *now*. Any delay will result in higher costs to customers.

It is equally clear that the Commission should approve the Companies' expanded demand-side management and energy efficiency ("DSM-EE") portfolio as proposed. If approved, the Companies project that their DSM-EE portfolio will achieve peak cumulative demand savings of approximately 377 MW in 2030 from energy efficiency and demand response programs and energy savings of 878 GWh and 170,000 Mcf by 2030.[4] Including customer-initiated energy efficiency improvements, the Companies have assumed total energy efficiency savings exceeding 1,100 GWh in 2030 and over 2,000 GWh by 2050.[5] The Companies believe, and the record reflects, that the DSM-EE Plan captures all cost-effective DSM-EE that can reasonably be achieved at this time, and approving the proposed DSM-EE portfolio will provide significant benefits to customers.

Moreover, if the Commission does act now to approve the Companies' total proposed supply- and demand-side resource portfolio, it will provide significant benefits to customers,

---

[2] *Id.* at Attachment 2.
[3] Companies' Response to Joint Intervenors' Post Hearing Request for Information No. 1(a); 8/23/23 Hearing, VR 13:06:40-13:07:45 (Bellar); 8/24/23 Hearing, VR 16:21:10-16:22:01, 16:43:35-16:44:21, and 17:54:42-17:56:21 (Schram).
[4] Direct Testimony of John Bevington at 23.
[5] Direct Testimony of Tim A. Jones, Exhibit TAJ-1 at 22, Figure 21.

resulting in net present value of revenue requirements ("NPVRR") savings of [redacted] compared to spending hundreds of millions of dollars to maintain the status quo generating portfolio, which additional investments would be stranded if the proposed greenhouse gas rules for existing generating units become final. Indeed, the economics of the Companies' proposed resource portfolio *improves* if non-zero carbon costs occur, which now seems likely in the form of increased costs to operate high-carbon emitting resources like coal units.[6] Moreover, assuming carbon costs of at least $15/ton would be consistent with the carbon cost component the Commission included in the Companies' NMS-2 rates.[7]

In addition to providing savings, the Companies' proposed portfolio would provide excellent reliability and meet all of the requirements of Senate Bill 4.[8] It would also reduce the Companies' carbon emissions,[9] thereby reducing future carbon cost risk, and would give the Companies experience at utility scale with battery storage technology through the Brown Battery Energy Storage System ("BESS"), further preparing the Companies for increasing amounts of renewable resources in a carbon-constrained world.

In short, there is every reason to approve the Companies' requested supply- and demand-side resource portfolio *now* to avoid the ever-increasing costs and reliability risks of delay.

---

[6] *See, e.g.,* Companies' Responses to Commission Staff's Fifth Request for Information, No. 2; Companies' Responses to Commission Staff's Sixth Request for Information, No. 2; Companies' Response to Commission Staff's Post Hearing Request for Information, Nos. 20, 22, 23, and 24.

[7] *See, e.g., Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Meter Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit,* Case No. 2020-00350, Order at 56 (Ky. PSC Sept. 24, 2021); Case No. 2020-00350, LG&E Response to Commission Staff's Eighth Request for Information, No. 21, Attachment (Ky. PSC filed Aug. 13, 2021) (showing nominal carbon prices increasing from $17.00 per ton in 2026 to $48.56 per ton in 2046).

[8] For clarity in the text and ease of reference, "Senate Bill 4" throughout this brief refers collectively to KRS 278.262 and 278.264.

[9] The Companies' proposed resource portfolio results in the lowest CO_2 emissions of any of the portfolios the Companies analyzed. *See* Companies' Response to Joint Intervenors' Second Request for Information, No. 60(a); Updated Exhibit SAW-1 at 32, Table 14.

ARGUMENT

I. The Companies' Proposed NGCC Units, Owned Solar Projects, and Brown BESS Satisfy the Commission's CPCN Standard by Meeting the Need Created by the Companies' Proposed Unit Retirements with an Optimal Blend of Low Cost, Reliability, and Positioning the Companies Fleet for a Carbon-Constrained Future.

The statutory requirement for certificates of public convenience and necessity is contained in KRS 278.020(1), which states:

> No person, partnership, public or private corporation, or any combination thereof shall . . . begin the construction of any plant, equipment, property or facility for furnishing to the public any of the services enumerated in KRS 278.010 . . . until that person has obtained from the Public Service Commission a certificate that public convenience and necessity require the service or construction . . . .

Kentucky's highest court has construed "public convenience and necessity" to mean: (1) there is a need for the proposed facility or service; and (2) the new facility or service will not create wasteful duplication.[10]

A finding of "need" is supported where there has been a showing of "a substantial inadequacy of existing service" due to a deficiency of service facilities beyond what could be supplied by normal improvements in the ordinary course of business.[11] "Substantial inadequacy of existing service" is not required to be a currently existing deficiency, but rather may be a deficiency expected a number of years into the future "in view of the long range planning necessary in the public utility field."[12] The prevention of "wasteful duplication" has been interpreted to mean not only a physical multiplicity of facilities, but also an avoidance of "excessive investment in relation to productivity or efficiency."[13] To demonstrate that a proposed facility does not result in wasteful duplication, a thorough review of all reasonable alternatives needs to be performed. The

[10] *Kentucky Utilities Co. v. Public Service Commission*, 252 S.W.2d 885, 890 (Ky. 1952).
[11] *Id.*
[12] *Kentucky Utilities Co. v. Public Service Commission*, 390 S.W.2d 168, 171 (Ky. 1965).
[13] *Kentucky Utilities Co.*, 252 S.W.2d at 890.

fundamental principle of a reasonable, least cost alternative is embedded in that review.[14] "Selection of a proposal that ultimately costs more than an alternative does not necessarily result in wasteful duplication. All relevant factors must be balanced."[15] Although cost is an important factor, it is not the only factor to be considered. As long as the project is reasonable and feasible, it meets that standard set forth in 278.020(1).[16] The standard has been succinctly described as follows:

> As we view it, if the . . . proposal is feasible (capable of supplying adequate service at reasonable rates) and will not result in wasteful duplication, the Public Service Commission is authorized to grant a certificate . . . .[17]

As public utilities in the Commonwealth of Kentucky that are regulated by the Commission, the Companies are obligated under KRS 278.030(2) to serve their customers: "Every utility shall furnish adequate, efficient and reasonable service . . . ." The Commission has further explicated this requirement in the following regulation, with which the Companies must comply:

> 807 KAR 5:041, Section 2 -- "Every utility shall furnish adequate service and facilities at rates filed with the commission, and in accordance with administrative regulations of the commission and applicable rules of the utility. Energy shall be generated, transmitted, converted and distributed by the utility, and utilized, whether by the utility or the customer, in such manner as to obviate undesirable effects upon the operation of standard services or equipment on the utility, its customers and other utilities."

With those statutory and regulatory requirements in place, the Companies had to decide how to best meet their customers' needs in a least-cost fashion given the required retirements. Their decision-making process included dozens of modeling scenarios before this case was filed

---

[14] *Electronic Application of Big Rivers Electric Corporation for a Certificate of Public Convenience and Necessity to Construct a 161 KV Transmission Line in Henderson County, Kentucky*, Case No. 2022-00012, Order at 8 (Ky. PSC June 6, 2022).
[15] *Id.* at 8-9.
[16] *Kentucky Utilities Co.*, 390 S.W.2d at 172-173.
[17] *Id.* at 175.

(and has included dozens more during progression of this case) as the Companies reviewed all reasonable alternatives. In the end, the Companies' proposed portfolio is the least cost reasonable solution. Further, the requested CPCNs are needed now to position the Companies in a manner that will make the proposed NGCCs available to them in light of increased worldwide demand for NGCC units.

A. The Companies Have Established Need.

1. The Companies' Load Forecast and Economic Retirements, Including Those Driven by Environmental Requirements, Establish Need.

Tables 1 and 2 below, which were provided in the Companies' December 15, 2022 Joint Application, reflect the capacity need beginning in 2028 based on minimum reserve margins of 17% in the summer and 24% in the winter[18] and which included the coal-fired generating retirements that were later the subject of the Companies' May 10, 2023 Senate Bill 4 Joint Application in Case No. 2023-00122. While those retirements are addressed in more detail below, assuming they occur, the capacity need arises in 2028:

[18] Note the following for Tables 1 and 2:

1. Mill Creek 1 and 2 cannot be operated simultaneously during ozone season due to NOx limits, which results in a reduction of available summer capacity through 2024. Mill Creek 1 will be retired by the end of 2024. OVEC's contract term ends in 2040. The Companies' recommendations include retiring Mill Creek 2 and having the Mill Creek NGCC operational in 2027.
2. "Small-Frame SCCTs" assumes Haefling 1-2 and Paddy's Run 12 will be retired in 2025.
3. Existing dispatchable DSM ("Existing Disp. DSM") reflects expected load reductions on an average peak day.
4. "Solar PPAs" assumes 100 MW of solar capacity is added in 2024 (Rhudes Creek), and an additional 125 MW of solar capacity is added in 2025 (Ragland). Capacity values reflect 78.6% expected contribution to summer peak capacity and 0% expected contribution to winter peak capacity.
5. "Coal" includes assumed retirements of Mill Creek 2, Ghent 2, and Brown 3 in 2028.

Table 1 – Summer Peak Demand and Resource Summary (MW)

	2023	2024	2025	2026	2027	2028	2030	2040	2050
Peak Load	**6,162**	**6,197**	**6,248**	**6,253**	**6,347**	**6,319**	**6,305**	**6,262**	**6,218**
Intermittent/Limited-Duration Resources									
Existing Resources	105	105	105	105	105	105	105	105	105
Existing CSR	128	128	128	128	128	128	128	128	128
Existing Disp. DSM	62	60	56	52	49	46	42	28	24
Retirements/Additions									
Solar PPAs	0	79	177	177	177	177	177	177	177
Total	294	371	466	462	459	456	451	438	434
Dispatchable Generation Resources with Assumed Unit Retirements									
Existing Resources	7,583	7,612	7,612	7,612	7,612	7,612	7,612	7,612	7,612
Retirements/Additions									
Coal	-300	-300	-300	-300	-300	-1,494	-1,494	-1,646	-1,646
Large-Frame SCCTs	0	0	0	0	0	0	0	0	0
Small-Frame SCCTs	0	0	-47	-47	-47	-47	-47	-47	-47
Total	7,283	7,312	7,265	7,265	7,265	6,071	6,071	5,919	5,919
Reserve Margin	18.2%	18.0%	16.3%	16.2%	14.5%	-3.9%	-3.7%	-5.5%	-4.8%
Total Supply	**7,577**	**7,683**	**7,730**	**7,727**	**7,724**	**6,527**	**6,522**	**6,357**	**6,353**
Total Reserve Margin	**23.0%**	**24.0%**	**23.7%**	**23.6%**	**21.7%**	**3.3%**	**3.4%**	**1.5%**	**2.2%**

Table 2 – Winter Peak Demand and Resource Summary (MW)

	2023	2024	2025	2026	2027	2028	2030	2040	2050
Peak Load	**5,910**	**5,908**	**6,011**	**6,003**	**6,107**	**6,104**	**6,102**	**6,113**	**6,127**
Intermittent/Limited-Duration Resources									
Existing Resources	72	72	72	72	72	72	72	72	72
Existing CSR	128	128	128	128	128	128	128	128	128
Existing Disp. DSM	22	22	22	22	22	22	22	22	22
Retirements/Additions									
Solar PPAs	0	0	0	0	0	0	0	0	0
Total	221	221	221	221	221	221	221	221	221
Dispatchable Generation Resources with Assumed Unit Retirements									
Existing Resources	7,901	7,909	7,909	7,909	7,909	7,909	7,909	7,909	7,909
Retirements/Additions									
Coal	-300	-300	-300	-300	-300	-1,499	-1,499	-1,657	-1,657
Large-Frame SCCTs	0	0	0	0	0	0	0	0	0
Small-Frame SCCTs	0	0	-55	-55	-55	-55	-55	-55	-55
Total	7,601	7,609	7,554	7,554	7,554	6,355	6,355	6,197	6,197
Reserve Margin	28.6%	28.8%	25.7%	25.8%	23.7%	4.1%	4.1%	1.4%	1.1%
Total Supply	**7,822**	**7,830**	**7,774**	**7,774**	**7,774**	**6,575**	**6,575**	**6,417**	**6,417**
Total Reserve Margin	**32.3%**	**32.5%**	**29.3%**	**29.5%**	**27.3%**	**7.7%**	**7.8%**	**5.0%**	**4.7%**

The Companies' witness Tim Jones testified to the Companies' load forecast that supports the reserve margins conclusions expressed above. Mr. Jones has explained[19] how the Companies'

[19] Direct Testimony of Tim A. Jones at 3.

electric load forecast is developed by using historical data to develop models that relate electricity usage, demand, sales, and number of customers by rate classes to exogenous factors such as economic activity, appliance efficiencies and adoption, demographic trends, and weather conditions. He also explained how the load forecast is developed using historical load shapes for each of KU and LG&E to convert sales forecasts into 30-year hourly forecasts that can be used for generation planning purposes, including forecasting peak demands.[20]

Mr. Jones explained how the Companies ensure that their electric load is reasonable by: (1) building and rigorously testing statistically and economically sound models of the load forecast variables; (2) anticipating future macroeconomic events that affect load forecast variables; and (3) reviewing and analyzing model outputs to ensure they are reasonable based on historical trends and the Companies' experience.[21] Finally, he noted that the Commission Staff has stated, "LG&E/KU's assumptions and methodologies for load forecasting are generally reasonable" and that the Companies sought to follow several recommendations Commission Staff has made to further improve the load forecasting process.[22] Thus, the load forecast is reasonable and the Commission should rely on it. As noted, Tables 1 and 2 above assume coal-fired retirements that are addressed below in the Senate Bill 4 section of this brief.

2. Brown 3 Should be Retired.

At the hearing in this matter, there were some questions about the continued operation of Brown Unit 3 in addition to or instead of Brown Unit 12 (one of the proposed NGCCs). Continued operation of Brown Unit 3 is not in the best interests of customers. Built in 1971, Brown Unit 3 will be 57 years old in 2028 when it is proposed to be retired. While it is environmentally

[20] *Id.*; *see also* Direct Testimony of Tim A. Jones, Exhibit TAJ-2.
[21] Direct Testimony of Tim A. Jones at 3-4.
[22] *Id.* at 4-5.

compliant (for now), it does not burn Kentucky coal, and, more importantly, the Companies have shown that it is uneconomical to continue to operate it beyond 2028 as it will require a major overhaul in 2027. In fact, it is the most uneconomical of the coal units the Companies propose to retire[23] and its operating cost is approximately double that of Ghent 2.[24] Keeping Brown 3 operational would simply cost customers more. When there is a more economical solution, keeping Brown 3 operational with no reliability benefit would run afoul of the requirement to pursue the least cost reasonable solution and would eventually run afoul of the fundamental principle that the Companies' rates must be "fair, just, and reasonable."[25]

Continued operation of Brown 3 will mean the same significant fuel transportation costs and challenges as exist today.[26] It would also present additional investment at the Brown site to accommodate both Brown 3 and the Brown NGCC. Just as important, continued operation of Brown 3 would prevent the Companies from utilizing emission netting in the air permitting process for the Brown NGCC, which would greatly complicate Brown NGCC permitting.[27] On the other hand, the Brown NGCC will have less emissions, contribute to a more reliable system as measured by LOLE, and be more resilient as measured by start-up times and ramp rates.[28] Further, [redacted][29] [redacted]

---

[23] *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Approval of Seven Fossil Fuel-Fired Generating Unit Retirements*, Case No. 2023-00122, Direct Testimony of Lonnie E. Bellar at 7 (Ky. PSC filed May 10, 2023).
[24] *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Approval of Seven Fossil Fuel-Fired Generating Unit Retirements*, Case No. 2023-00122, Direct Testimony of Stuart A. Wilson, Exhibit SB4-1, Table 11 (Ky. PSC filed May 10, 2023).
[25] KRS 278.030(1).
[26] 8/22/23 Hearing, VR 13:39:40.
[27] Companies' Response to KIUC's Post Hearing Request for Information, No. 2.
[28] *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Approval of Seven Fossil Fuel-Fired Generating Unit Retirements*, Case No. 2023-00122, Direct Testimony of Lonnie E. Bellar at 16 (Ky. PSC filed May 10, 2023).
[29] [redacted]

[redacted]

3. The Good Neighbor Plan, Local Ozone Compliance, and ELG Requirements Are Not Going Away, Necessitating Either Inefficient Retrofit or Cost-Effective Replacement of MC 1-2 and GH2.

The Kentucky Coal Association has questioned whether the Companies' consideration of various environmental compliance requirements is appropriate under the notion that those requirements may change or disappear as a result of legal challenges. But that questioning is misguided as it would place the Companies' customers at risk of not having reliable service if the Companies were to just "hope" that looming environmental compliance requirements will somehow evaporate. Assuming environmental compliance with the Good Neighbor Plan, local ozone compliance in Jefferson County, and Effluent Limitations Guidelines will be required, the Companies must either pursue: (1) an uneconomic retrofit of Mill Creek Unit 1,[30] Mill Creek Unit 2, and Ghent Unit 2; or (2) the Companies will need to retire those units and replace them with the cost-effective proposed NGCCs which will be Mill Creek Unit 5 and Brown Unit 12.

The Companies' witness Phillip Imber addressed this environmental compliance issue in detail in his August 9, 2023 rebuttal testimony. First, he explained the development, status, and legal challenges being made to the Good Neighbor Plan and concluded that the Companies must

[30] Although Mill Creek Unit 1 would need to comply with the Good Neighbor Plan, the more immediate reason for its retirement by the end of 2024 is for Effluent Limitation Guidelines compliance by installing process water equipment and a cooling tower as soon as possible in compliance with Clean Water Act regulations. Based on this, in Case No. 2020-00061, the Commission found LG&E ECR Project 31, which explicitly excluded ELG compliance equipment for Mill Creek Unit 1, to be the lowest reasonable cost alternative in that ECR case. *Electronic Application of Louisville Gas and Electric Company for Approval of an Amended Environmental Compliance Plan and a Revised Environmental Surcharge*, Case No. 2020-00061, Order (Ky. PSC Sep. 29, 2020).

act now to achieve compliance.[31] He then explained that, regardless of the status of the Good Neighbor Plan, Mill Creek Unit 2 in Jefferson County has an entirely independent and sufficient basis for retirement in that emissions from Mill Creek Unit 2 are also subject to local ozone compliance in Jefferson County that also requires the Companies to act now to replace that unit.

The Good Neighbor Plan was proposed when the Companies filed their December 15, 2022 Application and it was finalized in March 2023, with some differences from the proposed rule. However, with respect to the Companies, those differences do not affect the Companies' retirements and proposed portfolio because: (1) the major differences between the proposed and final rule were already factored into the Companies' resource modeling; and (2) the final rule makes it clear that the Companies will have to rely on the allocation market beginning in 2027 absent SCRs at Mill Creek Unit 2 and Ghent Unit 2; yet the Companies cannot expect to rely on allocations as a means of compliance.[32]

Mr. Imber also explained that litigation concerning the Good Neighbor Plan is ongoing[33] and that, despite that litigation, EPA remains firmly committed to it and will defend it vigorously, as evidenced by the fact that the new requirements have already gone into effect as scheduled in those states that have not been affected by court-ordered stays. Moreover, the outcome of the litigation is unlikely to have any effect on the Companies' generation decisions,[34] and, even if it does, EPA has existing authority under the Clean Air Act to require the same sort of emissions reductions it seeks under the Good Neighbor Plan.[35] Therefore, under any reasonable consideration of the Good Neighbor Plan, the time to act is now.

---

[31] Rebuttal Testimony of Philip A. Imber at 2-12.
[32] *Id.* at 4; Companies' Response to Attorney General's Third Request for Information, No. 3.
[33] For relation to Kentucky, the litigation is pending in the United States Court of Appeals for the Sixth Circuit.
[34] Rebuttal Testimony of Philip A. Imber at 7.
[35] *Id.* at 9-10.

As for the local ozone compliance issues with Mill Creek Unit 2 in Jefferson County, emissions from that unit are subject to 2015 NAAQS local attainment standards determined by EPA and implemented by the Louisville Metro Air Pollution Control District ("LMAPCD"), an air pollution control district created under KRS Chapter 77. Mill Creek Unit 2 operates pursuant to an LMAPCD air permit and, as Mr. Imber has explained, Mill Creek Unit 2 is the largest source of NOx in the Greater Louisville "attainment area." That area is not likely to be in attainment for NOx emissions by August 2024, which means the Companies fully expect LMAPCD to require further substantial emission reductions from Mill Creek Unit 2 in order to achieve attainment (and Mill Creek Unit 1 if it were to remain operational). LMAPCD and EPA have the authority to enforce those reductions no later than 2026; so, again, the time to act is now.

4. Contrary to Sierra Club's assertions, the Companies' need cannot be met by neighboring systems, which would also be contrary to Commission Orders requiring utilities to have sufficient resources to meet their customers' needs.

Contrary to the assertions of the Sierra Club,[36] the need supporting the Companies' CPCN proposals cannot be avoided by simply relying on the Companies' neighbors to have adequate resources to serve the Companies' customers. The Commission recently stated that Kentucky's electric utilities have an ongoing legal obligation to ensure they have adequate capacity to serve their customers: "Kentucky law requires retail electric suppliers … to have sufficient capacity to meet maximum estimated customer demand, including sufficient generation capacity."[37] Being an RTO member does not suffice to satisfy that requirement; in a related Order, the Commission denied recovery of extraordinary fuel and energy costs because the requesting utility—an RTO

[36] For brevity, because Louisville Metro Government and Lexington-Fayette Urban County Government (collectively, "Cities") did not present their own witness but rather co-presented the testimony of one of Sierra Club's witnesses, namely Andrew Levitt, references to "Sierra Club" throughout refer also to the Cities except when referring only to the testimony of Sierra Club witness Michael Goggin, which the Cities did not co-present.
[37] *Electronic Investigation of the Service, Rates, and Facilities of Kentucky Power Company,* Case No. 2021-00370, Order at 7 (Ky. PSC June 23, 2023).

member—had not planned to have adequate capacity resources available to serve its customers.[38] Yet just three weeks after the Commission issued those Orders, Sierra Club's witnesses testified that the Companies could simply retire seven thermal generating units without arranging for replacement capacity,[39] which would leave the Companies unable to meet projected energy requirements under normal, much less extraordinary, weather.[40] Putting aside other disqualifying flaws in Sierra Club's proposals—including non-compliance with Senate Bill 4,[41] no supporting modeling or complete cost-benefit analysis,[42] use of incorrect data to support Sierra Club's claims,[43] and the capacity concerns of neighboring systems—Sierra Club's "retire without replacement" strategy would be in obvious conflict with the Commission's Orders cited above and would be contrary to the Commission's 2021 statement in an Order concerning another RTO member that "[t]his Commission has no interest in allowing our regulated, vertically-integrated utilities to effectively depend on the market for generation or capacity for any sustained period of time."[44]

None of this means RTO membership would be inconsistent with the Companies' obligation under KRS 278.030(2) to provide adequate service as defined in KRS 278.010(14),

[38] *Electronic Application of Kentucky Power Company for an Order Approving Accounting Practices to Establish a Regulatory Asset Related to the Extraordinary Fuel Charges Incurred by Kentucky Power Company in Connection with Winter Storm Elliott in December 2022*, Case No. 2023-00145, Order (Ky. PSC June 23, 2023).
[39] *See, e.g.,* Direct Testimony of Michael Goggin at 4-6, 47.
[40] Rebuttal Testimony of David S. Sinclair, Rebuttal Exhibit DSS-2 at 8-10.
[41] *See* KRS 278.264(2)(a) ("The utility will replace the retired electric generating unit *with new electric generating capacity* . . . .") (emphasis added).
[42] *See, e.g.,* 8/29/23 Hearing, VR 10:31:23-10:31:29 (Levitt conceding he did not include PJM membership cost in his calculations); Sierra Club's Response to Companies' Request for Information, No. 4 (confirming Goggin did not "conduct[] an analysis to determine whether importation of power during peak periods is a less costly alternative to the Companies' proposal to meet future demand").
[43] Sierra Club's Response to Companies' Request for Information, No. 3.
[44] *Electronic Tariff Filing of East Kentucky Power Cooperative, Inc. and Its Member Distribution Cooperatives for Approval of Proposed Changes to their Qualified Cogeneration and Small Power Production Facilities Tariffs*, Case No. 2021-00198, Order at 5, n. 10 (Ky. PSC Oct. 26, 2021).

namely to have "sufficient capacity to meet [customers'] … maximum estimated requirements."[45] But it *would* be inconsistent with that obligation for the Companies to retire large amounts of thermal capacity and join an RTO without making provision for the easily foreseeable capacity and energy shortfall. Yet that is *exactly* what Sierra Club witness Andrew Levitt proposed;[46] Sierra Club witness Michael Goggin proposed even less, namely retiring the units irrespective of RTO membership.[47] Both proposals are inadequate to satisfy the Companies' legal obligation to serve their customers as articulated by the Commission earlier this year. Thus, nothing about Sierra Club's proposals obviates the need the Companies have shown for their proposed CPCN resources.

5. Even assuming the Joint Intervenors' proposed DSM-EE savings could be economically achieved, it would not offset the Companies' need for replacement generation.

Setting aside the reasonableness of the Joint Intervenors' claims about the amount and cost of the DSM-EE savings Mr. Grevatt asserts the Companies could achieve, even they have not suggested that the Companies' need for capacity and energy resulting from the proposed unit retirements could be fully or even significantly satisfied by DSM-EE programs.[48] Indeed, none of the portfolios the Joint Intervenors themselves constructed assumed efficiency and other distributed energy resources alone would be sufficient replacement resources to reliably and economically serve customers.[49] Rather, the Joint Intervenors modeled two portfolios assuming Grevatt-level DSM-EE savings, each of which included a new gas-fired generating resource and a

---

[45] KRS 278.010(14): "'Adequate service' means having sufficient capacity to meet the maximum estimated requirements of the customer to be served during the year following the commencement of permanent service and to meet the maximum estimated requirements of other actual customers to be supplied from the same lines or facilities during such year and to assure such customers of reasonable continuity of service[.]"

[46] *See, e.g.*, Direct Testimony of Andrew Levitt at 6.

[47] Direct Testimony of Michael Goggin at 4-6, 47.

[48] *See, e.g.*, Corrected Direct Testimony of Andrew McDonald at 4-5 (recommending expanded DSM-EE and additional solar facilities and Brown BESS); *see generally* Direct Testimony of Anna Sommer (analyzing two portfolios created by Ms. Sommer that included Grevatt-level DSM-EE savings *and* a new gas-fired resource and new renewable resources).

[49] Direct Testimony of Anna Sommer (analyzing two portfolios created by Ms. Sommer that included Grevatt-level DSM-EE savings *and* a new gas-fired resource and new renewable resources).

suite of additional renewable and battery resources.[50] Thus, there is no evidence that DSM-EE and distributed energy resources alone could satisfy the need created by retiring the generating units the Companies have proposed to retire, which retirements the Joint Intervenors support.[51]

B. The Companies Have Demonstrated that their Proposed NGCCs, Owned Solar Facilities, and Brown BESS Would Provide Significant Benefits and Would Not Result in Wasteful Duplication.

In satisfaction of the Commission's longstanding "wasteful duplication" prong of its CPCN analysis, the Companies have shown that their proposed CPCN facilities will not result in excessive capacity, excessive investment relative to production and efficiency, or an unnecessary multiplicity of physical properties. Rather, the Companies have shown that their proposed resource portfolio results in the lowest reasonable cost with excellent reliability across numerous possible future fuel cost and environmental compliance cost scenarios, all while making the most productive use of existing physical properties by locating the two proposed NGCC units and the Brown BESS at existing generating stations, which also makes the most efficient use of existing transmission facilities and existing environmental permitting. In short, far from being wastefully duplicative, the Companies' CPCN proposals will make the best use of existing and new resources.

1. The Companies' proposed portfolio is lowest reasonable cost and achieves excellent reliability.

In its Order approving the Companies' Cane Run 7 NGCC facility, the Commission stated, "To demonstrate that a proposed facility does not result in wasteful duplication … [an] applicant must demonstrate that a thorough review of all reasonable alternatives has been performed. Selection of a proposal that ultimately costs more than an alternative does not necessarily result in

---

[50] *Id.*

[51] Corrected Direct Testimony of Andrew McDonald at 4-5.

wasteful duplication. All relevant factors must be balanced."[52] In this case, the Companies issued a wide-ranging RFP to gather actually available supply-side resource options to consider, resulting in more than 100 proposals from 22 respondents.[53] Through the most extensive and sophisticated resource modeling and cost-benefit analysis the Companies have ever undertaken (and likely any Kentucky utility has ever undertaken) in a CPCN proceeding, the Companies evaluated those proposals across thousands of possible combinations in PLEXOS and then dozens of additional portfolio, fuel cost, carbon cost, and capacity factor scenarios. The Companies' analysis shows that their proposed CPCN resources and solar PPAs will provide NPVRR savings and provide excellent reliability across a wide range of possible future scenarios.

a. No party has modeled a more economical portfolio.

No intervenor has modeled in this proceeding a more economical or reliable portfolio than the Companies' proposed portfolio. Indeed, no other party has even attempted to model the complete cost or reliability of their own proposals.

Beginning with the Sierra Club, Messrs. Goggin and Levitt support the Companies' proposed unit retirements and propose to replace them with *nothing*.[54] This would entirely fail to satisfy Senate Bill 4's requirement that retiring thermal units *be replaced* with "new electric generating capacity that: 1. Is dispatchable …; 2. Maintains or improves the reliability and resilience of the electric transmission grid; and 3. Maintains the minimum reserve capacity requirement …."[55] Moreover, Mr. Levitt did not model either the complete cost or reliability

---

[52] *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Construction of a Combined Cycle Combustion Turbine at the Cane Run Generating Station and the Purchase of Existing Simple Cycle Combustion Turbine Facilities from Bluegrass Generation Company, LLC in LaGrange, Kentucky*, Case No. 2011-00375, Order at 14-15 (Ky. PSC May 3, 2012).
[53] Direct Testimony of Charles R. Schram at 4.
[54] Direct Testimony of Michael Goggin at 4-6, 47; Direct Testimony of Andrew Levitt at 6.
[55] KRS 278.264(2)(a).

impacts of his proposal that the Companies simply retire the generating units and join PJM.[56] This makes the Companies' Guidehouse analysis the only evidence in the record on this issue, which shows both that PJM membership is not currently economical and that the Companies' optimal resource portfolio as PJM members would include adding NGCC capacity in the same timeframe the Companies have proposed in this proceeding.[57]

Mr. Goggin's proposal that the Companies retire the seven thermal units at issue, replace them with nothing, and rely on imported power similarly does not comply with Senate Bill 4's requirements and lacks any modeling or cost-benefit analysis support.[58] Moreover, Mr. Goggin's import capability analysis is fundamentally flawed because he used balancing area data rather than the Companies' own demand and import data.[59] Using the correct data—i.e., the Companies' actual demand and import data—would have demonstrated both that the Companies have far less import capability than Mr. Goggin claimed and that the Companies typically do *not* depend on non-firm external resources to supply their customers' needs at times of peak demand.[60] Moreover, the Companies' actual data shows that it would be risky at best to depend on neighboring systems to serve customers because there is routinely *zero* import capability during the Companies' peaks.[61] In addition, the neighboring systems upon which Mr. Goggin asserts the Companies can rely are also expressing concerns about their own resource adequacy in the same timeframe at issue in this proceeding.[62]

---

[56] *See generally* Direct Testimony of Andrew Levitt.
[57] *See* Companies' Response to Sierra Club's Second Request for Information, No. 26(b), Attachments 1-3.
[58] Sierra Club's Response to Companies' Request for Information, No. 4.
[59] Sierra Club's Response to Companies' Request for Information, No. 3.
[60] Rebuttal Testimony of David S. Sinclair at 23-26.
[61] *See, e.g., Id.* at 26-27 and Rebuttal Exhibit DSS-4.
[62] *Id.* at 3 (quoting PJM Vice President for State and Member Services Asim Haque stating, "We are concerned about being in a supply crunch by the end of this decade."); Companies' Hearing Exhibit 1, Joint Comments of ERCOT, MISO, PJM, and SPP to the EPA dated Aug. 8, 2023 (subject to Companies' Motion to Take Administrative Notice dated Sept. 1, 2023).

The Joint Intervenors also did not model their own recommendations, which were to: (1) approve the Companies' DSM-EE portfolio and requiring the Companies to expand it to achieve Grevatt-level savings, (2) "[d]irect the Companies to seriously encourage customer-sited resources," (3) approve CPCNs for the Companies' proposed owned solar facilities and the Brown BESS, (4) approve the Companies' proposed unit retirements, and (5) deny CPCNs for the Companies' two proposed NGCC units.[63] The Joint Intervenors modeled two alternative portfolios, but neither encompassed all of the Joint Intervenors' recommendations;[64] indeed, the Joint Intervenors stated they did not intend either portfolio they modeled to be treated as a viable alternative to the Companies' proposed portfolio.[65] Thus, Joint Intervenors' witness Anna Sommer acknowledged at hearing that she modeled neither the cost nor the reliability of the totality of the Joint Intervenors' proposals.[66] The Companies *did* model the totality of the Joint Intervenors' proposals, which are substantively identical to the Sierra Club's proposals, and showed that it would result in significant amounts of unserved energy in all seasons and all hours that would have to be acquired from neighboring systems.[67] This result, in addition to being indeterminately costly and imperiling reliability, flies in the face of the Commission's statement that it "has no interest in allowing our regulated, vertically integrated utilities to effectively depend on the market for generation or capacity for any sustained period of time."[68]

---

[63] Corrected Direct Testimony of Andrew McDonald at 4-5.
[64] 8/26/23 Hearing, VR 15:27:13-15:29:46; *see generally* Direct Testimony of Anna Sommer at 25-35.
[65] Joint Intervenors' Response to Companies' Request for Information, No. 6 ("The portfolios developed by Ms. Sommer are not intended as alterative portfolios that should be pursued.").
[66] 8/26/23 Hearing, VR 15:27:13-15:29:46.
[67] Rebuttal Testimony of David S. Sinclair, Rebuttal Exhibit DSS-2 at 8-10.
[68] *Electronic Tariff Filing of East Kentucky Power Cooperative, Inc. and Its Member Distribution Cooperatives for Approval of Proposed Changes to their Qualified Cogeneration and Small Power Production Facilities Tariffs*, Case No. 2021-00198, Order at 5, n. 10 (Ky. PSC Oct. 26, 2021).

KCA, which opposes all of the Companies' proposed unit retirements, also failed to perform any comprehensive modeling or cost-benefit analysis of their "do nothing" approach.[69] The Companies have modeled KCA's "do nothing" portfolio, and it is more than [redacted] costlier than the Companies' proposed resource portfolio—assuming zero cost to comply with EPA's recently proposed greenhouse gas regulations for existing electric generating units *and* assuming zero cost to comply with any additional future environmental constraints through 2050.[70] On the much more plausible assumption that there will be non-zero costs of greenhouse gas and other environmental compliance through 2050, the benefits of the Companies' proposed portfolio will far exceed [redacted] savings compared to KCA's "do nothing" approach.[71]

KIUC also has not modeled either the cost or reliability of its proposal. Again, the Companies have modeled the KIUC portfolio, and it is higher cost than the Companies' proposed portfolio.[72]

b. Criticisms of the Companies' fuel-price and CO_2 cost modeling are misplaced because both account for important variables across a range of possible futures.

There is no doubt that coal and gas prices and their relationship to each other are vitally important to the economics of the resource decisions in this proceeding. That is why the Companies did not depend on a single forecast of coal or gas prices, but rather used a range of publicly available gas price forecasts created by the U.S. Department of Energy's Energy Information Administration ("EIA") and a range of well-established, historical relationships between coal and gas prices to evaluate alternative portfolios. This approach has the advantage of

---

[69] *See generally* Direct Testimony of Emily Medine.
[70] Companies' Response to Joint Intervenors' Post Hearing Request for Information, No. 1.
[71] *See, e.g.*, Companies' Response to Commission Staff's Fifth Request for Information, No. 2; Companies' Response to Commission Staff's Sixth Request for Information, No. 2; Companies' Response to Commission Staff's Post Hearing Request for Information, Nos. 20, 22, 23, and 24.
[72] Rebuttal Testimony of David S. Sinclair, Rebuttal Exhibit DSS-2 at 1-2.

testing alternative portfolios across a wide range of possible fuel cost levels and relationships to determine how robust any given portfolio's economics are. Also, the Companies' fuel cost forecasting approach is actually favorable to coal by ensuring that gas prices are *always* higher than coal prices on a cost per MMBtu basis,[73] and the coal-to-gas ratios the Companies used in this proceeding (0.52, 0.57, and 0.84) provide a broader range of, but still align closely with, the coal-to-gas ratios derived from the fuel price forecasts the Companies used in their 2021 IRP study (0.49, 0.58, and 0.75).[74] Moreover, though KCA argues the Companies should have used different fuel forecasts, it provided no fuel forecast recommendations or any analysis of what using different forecasts would have shown. In reality, nobody knows precisely what coal and gas market prices will be next year, much less in 20 years. But the likely range of such prices is more readily knowable, as are the historical relationships between coal and gas prices, making the Companies' approach to modeling alternative portfolios using a broad range of gas prices and coal-to-gas price relationships reasonable and reliable for making the resource decisions at issue in this proceeding.

As with modeling a range of fuel prices, modeling a range of possible CO_2 costs is reasonable to address an important and potentially costly uncertainty. With the EPA's recent proposal of greenhouse gas rules for new and existing electric generating units under Clean Air Act Sections 111(b) and (d), respectively, there remains no room for reasonable doubt: greenhouse gas constraints will become more restrictive for power generation—soon. Though it is uncertain exactly what form those restrictions will take in the final rules and whether those restrictions will remain fully intact after the litigation that will inevitably result from the final rules' promulgation, it is reasonable to assume that greenhouse gas constraints will result in increased costs to operate fossil fuel fired generating units, particularly coal-fired units.

---

[73] *See, e.g.*, Companies' Response to Commission Staff's Post Hearing Request for Information, No. 17.
[74] Companies' Response to Commission Staff's Post Hearing Request for Information, No. 18.

Recognizing the high likelihood of greenhouse gas ("GHG") constraints in the near term as well as the uncertainty about precisely what form those constraints will take, the Companies' approach of using a proxy price per ton of carbon emissions is reasonable. Speculating about the future cost and performance characteristics of technologies that are not currently available, such as carbon capture and storage ("CCS") and low-GHG hydrogen, would serve little purpose in making resource decisions today. Rather, in conditions of considerable price uncertainty, it is helpful to evaluate a range of possible cost impacts independent of any particular technology to understand the relative economics of resource decisions that must be made today. That is why the Companies evaluated possible resource portfolios with CO_2 prices ranging from \$0 to \$25 per ton to account for the effects of future greenhouse gas regulation even before the EPA proposed its greenhouse gas rules for new and existing electric generating units. Notably, the non-zero portion of that range is consistent with the carbon cost component the Commission included in the Companies' NMS-2 rates, which was based on the then-present value of nominal carbon prices increasing from \$17.00 per ton in 2026 to \$48.56 per ton in 2046.[75]

After the EPA proposed its greenhouse gas rules, the Companies further analyzed their proposed portfolios making assumptions that were as unfavorable to their proposed NGCC units as possible, including assuming that Section 45Q tax credits for carbon capture and sequestration ("CCS") would persist undiminished through 2050 to reduce CCS costs for existing units to \$0, \$15, or \$25 per ton net cost, and further assuming no derate for CCS-equipped units. Even with those generous assumptions for the Companies' existing coal units, the Companies' analysis still

[75] *See, e.g.*, *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Meter Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*, Case No. 2020-00350, Order at 56 (Ky. PSC Sept. 24, 2021); Case No. 2020-00350, LG&E's Response to Commission Staff's Eighth Request for Information, No. 21, Attachment (Ky. PSC filed Aug. 13, 2021) (showing nominal carbon prices increasing from \$17.00 per ton in 2026 to \$48.56 per ton in 2046).

demonstrated that the Companies' proposed two NGCC and 637 MW of solar PPAs portfolio was lowest cost in non-zero net cost of carbon emissions scenarios.[76] Those results found further support in the modeling the Commission requested the Companies to perform in response to PSC 6-2(b), which showed that retiring coal units was least cost and that NGCC was indeed the preferred technology to replace retiring coal units.

In sum, the Companies' approach to modeling greenhouse gas emission constraints under conditions of uncertainty was reasonable, and it is further reasonable to assume that carbon costs greater than zero are likely given EPA's recent greenhouse gas emissions rule proposals.

c. The Companies' proposed NGCCs make economical use of existing facilities and environmental permitting.

Use of the existing real estate the Companies own at the Brown and Mill Creek Stations for the proposed NGCCs allows for significant cost savings compared to other possible locations. Specifically, as Mr. Bellar has explained,[77] the following advantages will be derived by constructing an NGCC at each station: (1) reliability risk is reduced in that if a complication or problem occurs at one location (such as an equipment failure or other problem unique to that location), the Companies will be in a position to address that problem while keeping the other NGCC operational; (2) reliability risk is also reduced by the fact that gas supply to each station will be diverse;[78] (3) only minimal electric transmission upgrades will be necessary at each station; (4) two NGCCs will reduce project execution risk of the full generating capacity proposed in this case. Once the NGCCs are fully operational, Mill Creek Unit 2 and Brown Unit 3 will be retired.

[76] Companies' Response to Commission Staff's Fifth Request for Information, No, 2.
[77] Direct Testimony of Lonnie E. Bellar at 7-8.
[78] The Brown NGCC will be supplied by either Tennessee Gas or Texas Eastern and the Mill Creek NGCC will be supplied by Texas Gas. *Id.* at 16-17.

Installing the NGCCs at two existing locations allows for the existing air quality emission limits to be used with little to no modification when taking into account retiring Mill Creek Units 1-2 and Brown Unit 3.[79] Although the proposed NGCCs will still require an air permit and compliance with all applicable environmental requirements, the utilization of the existing permitted emissions of Mill Creek Units 1 and 2 and Brown Unit 3 will allow the proposed NGCCs to "net out" of the Prevention of Significant Deterioration ("PSD") air permitting process for all New Source Review pollutants including nitrogen oxides ("NO_x"), sulfur dioxide ("SO_2"), and particulate matter ("PM") that would be required for a new "green field" site. Further, the NGCCs will produce 65% less CO_2 per MWh than the coal-fired units the Companies plan to retire.[80]

d. <u>The Companies' proposed NGCCs are consistent with the resource plan suggested by Guidehouse and EPA modeling</u>.

The reasonableness of the Companies' proposed resource portfolio finds additional directional support in the modeling performed by Guidehouse in the Companies' 2022 RTO Study and the independent modeling EPA has conducted since the enactment of the Inflation Reduction Act (i.e., both pre- and post-Good Neighbor Plan and pre- and post-proposed greenhouse gas rules).[81] The Guidehouse analysis—conducted before the Good Neighbor Plan was final and before the EPA issued proposed greenhouse gas regulations—indicates that adding NGCC capacity in the 2028-2032 timeframe would be favorable for the Companies as standalone utilities and as PJM members.[82] EPA's multiple modeling efforts since the passage of the Inflation Reduction Act—even with a lower reserve margin constraint than both the Companies' seasonal target reserve margins—have included more than 1,700 MW of new NGCC capacity being

---

[79] *Id.* at 8-9.
[80] Direct Testimony of John R. Crocket III at 8.
[81] Companies' Response to Sierra Club's Second Request for Information, No. 26(b), Attachment 1 (Guidehouse RTO Study); Rebuttal Testimony of Stuart A. Wilson at 5-6, 67-72.
[82] Companies' Response to Sierra Club's Second Request for Information, No.26(b), Attachment 1 at 19-21 (Guidehouse RTO Study).

installed in the SERC Central Kentucky regional by 2028, and most have included more than 2,000 MW.[83] Although the Companies are not relying on these analyses as the primary support for their proposed NGCC units, it is noteworthy that these analyses conducted by third parties—particularly the EPA—fully align directionally with the Companies' analyses in this proceeding.

e. <u>The Companies' proposed portfolio positions the Companies well for possible future RTO membership because RTOs are expressing a need for thermal and battery resources with rapid ramping capability</u>.

Although RTO membership could not displace the Companies' need for new dispatchable generating capacity to replace its proposed retiring thermal units, the NGCC and other resources the Companies propose to add in this proceeding would position them well for possible future RTO membership. As noted previously, both PJM and MISO have expressed concerns about capacity needs by the end of this decade, and PJM has expressed a clear desire for thermal resources—like NGCCs—to remain and be added to its footprint to ensure reliability, including needed rapid ramping capabilities.[84] Also, the Companies have shown that under reasonable assumptions NGCCs should be economically advantageous if the Companies were to become RTO members.[85] Therefore, rather than providing a reason not to add the Companies' two proposed NGCC units, possible RTO membership *supports* approving CPCNs for the NGCC units.

2. The Proposed NGCC Units Remain Economical and Must Be Pursued Now to Avoid Additional Cost Increases and Potential Gas Pipeline Constraints.

[83] Rebuttal Testimony of Stuart A. Wilson at 5-6.
[84] Rebuttal Testimony of David S. Sinclair at 3 (quoting PJM Vice President for State and Member Services Asim Haque stating, "We are going to need thermal resources in order to preserve reliability until replacement tech exists to deploy at scale"); *see, e.g.*, Companies' Hearing Exhibit1, Joint Comments of ERCOT, MISO, PJM, and SPP to the EPA dated Aug. 8, 2023 at 11 ("[I]t is crucial for reliability purposes to maintain certain levels of resources with attributes such as quick start-up and ramping capabilities . . . .").
[85] *See, e.g.*, Rebuttal Testimony of David S. Sinclair at 43-46.

The Companies have repeatedly stated that the time to act towards both NGCCs is now. This is true for many reasons, including timely compliance with environmental regulations, but it is also true because acting now ensures reliable service at the lowest cost for customers. Customers, both current and future want and deserve reliable energy at the lowest possible cost.[86] Delay will mean increased prices for the turbines and increased prices for gas supply[87] – to the extent turbines and gas continue to be available. Getting in line for ***both*** NGCCs ***now*** will help ensure best pricing and ability to actually have machines available when needed; delay could result in increased prices or machines' outright unavailability, resulting in higher compliance costs. As explained in response to Joint Intervenors PHDR 1, the pricing the Companies received from machine vendors was higher than estimated, which is a telling sign that the market has gotten tighter and a corresponding reduction in available gas pipeline capacity will necessarily follow. The Companies are still committed to exploring dual fuel capability for reliability and resilience purposes and hydrogen cofiring in an effort to maximize value given pending and possible future GHG regulations. The Companies will do so as they continue to work with vendors to achieve best possible prices.

Although it might seem facially appealing to reduce near-term costs by reducing the size of the proposed investment, e.g., by approving only one NGCC unit, such an approach would likely result in higher, not lower, costs for customers in the long run, and it would result in a significantly less reliable system than what the Companies have proposed, which arguably would not satisfy the requirements of Senate Bill 4.[88] The record shows that even with NGCC bids coming in higher

[86] 8/23/23 Hearing, VR 12:45:00.
[87] 8/23/23 Hearing, VR 13:06:40.
[88] *See, e.g.*, Companies' Responses to Commission Staff's Fifth Request for Information, No. 2; Companies' Response to Commission Staff's Sixth Request for Information, No. 2; Commission Staff's Post Hearing Request for Information, Nos. 20, 22, 23, and 24.

than initially anticipated, the Companies' complete proposed resource portfolio is the most consistently economical portfolio in a non-zero CO_2 cost world, particularly when accounting for solar PPA execution risk.[89] Moreover, [redacted]—and with the very real possibility that firm gas transportation will not be available on existing pipelines in twelve months or less, any "wait and see" approach regarding a second NGCC risks increasing costs for customers at a minimum and possibly imperiling the Companies' ability to provide reliable service in the near future. That is neither alarmist nor hyperbolic: even PJM is "concerned about being in a supply crunch by the end of this decade,"[90] and both MISO and PJM publicly stated to EPA this summer that "there may also be a need to build dispatchable resources such as new natural gas combustion turbines in the coming years to ensure that grid reliability is not jeopardized …."[91] If coal units were retired at a site without replacing the capacity now, environmental permitting challenges may prevent an NGCC unit being built there in the future.[92] In short, there is every reason to approve the Companies' requested supply- and demand-side resource portfolio *now* to avoid the ever-increasing costs and reliability risks of delay.

Finally, the Companies have a proven track record of seeking, obtaining, and exercising CPCN authority appropriately and prudently. For example, in the midst of a CPCN case seeking approval to construct what would have been an NGCC at the Green River Station, the projected load changed with the departure of some of KU's significant wholesale customers. The

---

[89] *See, e.g.*, *Id.*
[90] Rebuttal Testimony of David S. Sinclair at 3 (quoting PJM Vice President for State and Member Services Asim Haque, Interim Joint Committee on Natural Resources and Energy Hearing August 3, 2023, YouTube video at 13:25-13:33, available at https://www.youtube.com/watch?v=Bja3IDPFPMs (accessed August 4, 2023)).
[91] Companies' Hearing Exhibit 1, Joint Comments of ERCOT, MISO, PJM, and SPP to the EPA dated Aug. 8, 2023 at 12 (subject to Companies' Motion to Take Administrative Notice dated Sept. 1, 2023).
[92] *See, e.g.*, Companies' Response to Commission Staff's Post Hearing Request for Information, No. 20.

Companies' response was to promptly withdraw the CPCN request.[93] As Mr. Bellar has testified, if the Commission issues the requested CPCNs, the Companies' evaluation and assessment of whether to proceed with the various projects does not end. Indeed, the Companies will continue to evaluate each project (which will include working with vendors to achieve the best possible price) and proposed retirement to ensure the best decisions are made for customers.[94] Mr. Conroy testified similarly and further explained the Companies' diligence in executing on projects and reporting on progress for significant investments.[95] In fact, the Commission has a history of commending the Companies for their handling and management of significant capital investment projects. In a letter[96] to the Companies after completing significant environmental compliance projects, the Commission stated:

> The original estimated capital cost of the projects totaled $2.301 billion. The final estimated total cost of the projects is $2 billion. The projects, which will be completed well under budget, within original schedules, and with an outstanding safety record, must be considered very successful by any standard. Commission Staff expresses its appreciation for the Companies' efforts in keeping Vantage and Staff informed regarding the progress of the environmental projects, and appreciates the professional manner in which the Companies have assisted this review.

The Commission can therefore approve the Companies' requested NGCC CPCNs with the confidence that the Companies will proceed with the units only if they remain economical and in customers' best interest and keep the Commission informed.

---

[93] *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Construction of a Combined Cycle Combustion Turbine at the Green River Generating Station and a Solar Photovoltaic Facility at the E.W. Brown Generating Station,* Case No. 2014-00002, Companies' Notice of Withdrawal (Ky. PSC filed Aug. 22, 2014).
[94] Rebuttal Testimony of Lonnie E. Bellar at 7.
[95] Rebuttal Testimony of Robert M. Conroy at 6-9.
[96] A copy of the letter is attached as Exhibit RMC-1 to Mr. Conroy's rebuttal testimony.

3. The Proposed Companies-Owned Solar Facilities Merit CPCN Approval Because They Will Help Hedge Fuel and CO_2 Cost Risks.

There is clear evidence in the record of this proceeding concerning the value of solar energy as a hedge against fuel price risk and greenhouse gas cost risk.[97] There is also clear evidence that solar PPAs face greater challenges to being constructed.[98] That is why the two solar facilities the Companies propose to own in Marion and Mercer Counties are important components of the Companies' proposed resource portfolio. The stipulation between the Companies and Mercer County addresses the concerns of Mercer County. Moreover, with the sole exception of the Kentucky Coal Association, whose members have a direct financial interest in not displacing coal-fired energy with solar (or any other) energy, all parties to this proceeding have either explicitly expressed support for or not objected to the proposed Companies-owned solar facilities.[99] The Companies therefore respectfully submit that the Commission should approve CPCNs for the proposed Marion and Mercer County solar facilities.

4. The Commission Should Approve a CPCN for the Brown BESS Because It Will Help Facilitate Other Savings and Provide the Companies Valuable Experience at Utility Scale with a Technology Vital to Future Utility Operations.

Approving the proposed Brown BESS would be consistent with the Commission's CPCN precedents because it would provide a number of important benefits to customers. The CPCN "wasteful duplication" standard explicitly permits considering factors other than cost; as the Commission stated in approving the Brown Solar Facility in 2014, "Selection of a proposal that

---

[97] *See, e.g.*, Companies' Response to Joint Intervenors' Second Request for Information, No.60(a); Updated Exhibit SAW-1 at 23, 32, and 35; *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Approval of Seven Fossil Fuel-Fired Generating Unit Retirements*, Case No. 2023-00122, Direct Testimony of Stuart A. Wilson, Exhibit SB4-1 at 20, Table 8, Table 11 (Ky. PSC filed May 10, 2023).
[98] *See, e.g.*, Direct Testimony of David S. Sinclair at 20-21; Companies' Response to Commission Staff's First Request for Information, No. 27(e); Companies' Response to Joint Intervenors' Second Request for Information, No. 61; Companies' Response to LFUCG-Louisville Metro First Request for Information, No. 23.
[99] *See* Rebuttal Testimony of David S. Sinclair at 7.

ultimately costs more than an alternative does not necessarily result in wasteful duplication. All relevant factors must be balanced."[100] In that case, the Commission agreed that "tak[ing] into consideration potential CO_2 compliance costs is reasonable and prudent,"[101] which supported the Commission's finding that the Brown Solar Facility was not wastefully duplicative because its cost would be significantly offset by tax credits, it would have a small impact on revenue requirements, and it would have marginal fuel cost savings and the potential to reduce future CO_2 compliance costs.[102] Most of these same potential benefits and more apply to Brown BESS: (1) it will provide valuable experience at utility scale with a technology that will be vital to accommodating and optimizing increasing penetration of renewables in coming years to hedge fuel costs and potential CO_2 compliance costs;[103] (2) its cost will be significantly offset by tax credits;[104] (3) its nearly instantaneous ramping capability might be particularly valuable if the Companies eventually join an RTO because RTOs are expressing a need for rapid-ramping resources;[105] and (4) it could allow for the eventual retirement of an existing large-frame combustion turbine without thermal replacement (if such were permissible under Senate Bill 4 in the future).[106] In addition, the Joint Intervenors have stated their support for the Brown BESS,[107] Sierra Club witness Levitt assumes its installation in his analyses,[108] and Guidehouse's modeling

---

[100] *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Construction of a Combined Cycle Combustion Turbine at the Green River Generating Station and a Solar Photovoltaic Facility at the E.W. Brown Generating Station,* Case No. 2014-00002, Order at 10 (Ky. PSC Dec. 19, 2014).
[101] *Id.* at 11.
[102] *Id.* at 12.
[103] *See, e.g.*, Rebuttal Testimony of David S. Sinclair at 11; Companies' Response to Commission Staff's First Request for Information, No. 25(b); Companies' Response to Commission Staff's Sixth Request for Information, No. 2(a); Direct Testimony of Stuart A. Wilson at 31.
[104] *See, e.g.*, Companies' Response to Commission Staff's First Request for Information, No. 47(a).
[105] *See, e.g.*, Companies' Hearing Exhibit 1, Joint Comments of ERCOT, MISO, PJM, and SPP to the EPA dated Aug. 8, 2023 at 11 ("[I]t is crucial for reliability purposes to maintain certain levels of resources with attributes such as quick start-up and ramping capabilities . . . .").
[106] Companies' Response to Commission Staff's First Request for Information, No. 25(b).
[107] Corrected Direct Testimony of Andrew McDonald at 4.
[108] Direct Testimony of Andrew Levitt at 24, 26, 27, and 31.

indicated that battery storage would be economical for the Companies by 2036 or earlier regardless of the Companies' RTO membership status.[109] Therefore, approving the requested CPCN for the Brown BESS would be consistent with the "wasteful duplication" standard as articulated and applied by the Commission due to the BESS's considerable known and possible future benefits.

5. The Companies' Proposed Accounting Treatment During the Construction of the Proposed Facilities Is Reasonable

The Companies proposed accounting treatment of their investments in the two NGCCs, Mercer County Solar Facility, and Brown BESS allows the Companies to construct these facilities over the four-year construction period without impacting customers' bills until such time as actual costs are known and the projects are in-service, while accruing the financing costs incurred related to the four projects.[110] KIUC supported this accounting treatment, and no other intervenor opposed it. The requested accounting treatment is reasonable, in accordance with established accounting principles and consistent with the accounting treatment approved for the Companies' investment in the Advanced Metering Infrastructure in the last rate case.[111]

II. The Companies' Proposed Resource Portfolio Fully Complies with Senate Bill 4 by Replacing Retiring Units with Ample Dispatchable New Generating Capacity that Maintains or Improves System Reliability, Resilience, and Reserve Capacity, Provides Savings to Customers, and Is Not Driven by Federal Tax Incentives.

This is a case of first impression for the Commission's application of Senate Bill 4. In applying Senate Bill 4 to the record in this case, the Commission should be guided by the established cannons of construction that any interpretation that leads to an absurdity must be

[109] *See* Companies' Response to Sierra Club's Second Request for Information, No. 26(b), Attachment 1 at 19 and 21.
[110] Direct Testimony of Robert M. Conroy at 4
[111] *Application of Kentucky Utilities Company for an Adjustment of its Electric Rates, A Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of A One-Year Surcredit,* Case No. 2020-00349, Order at 13, 62 (Ky. PSC June 30, 2021); *Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates, A Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of A One-Year Surcredit,* Case No. 2020-00350, Order at 15-16, 69 (Ky. PSC June 30, 2021).

rejected[112] and with respect to matters not express in a statute, "the courts are not at liberty to supply words or insert something or make additions which amount, as sometimes stated, to providing a *casus omissus*, or cure an omission."[113] The Companies' proposed resource portfolio satisfies the plain requirements of Senate Bill 4. The Companies' proposed portfolio replaces retiring thermal units with sufficient dispatchable new generating capacity to maintain or improve system reliability and resilience, maintain adequate reserve margins, and provide net benefits to customers when taking into account all direct and indirect costs of proposed unit retirements and replacement.

Thus, for example, contentions that Senate Bill 4 requires a megawatt of retired capacity to be replaced with an identical megawatt of new capacity violate these fundamental cannons of construction and should be rejected. By adding language that does not exist in the statute, such a construction would create an economically irrational one-way reliability ratchet in times of flat or decreasing demand, creating an absurd result. Other examples include Joint Intervenors' witness Sommer's assertion that the reliability requirement of Senate Bill 4 should include consideration of distribution system reliability and its effect on the value of distributed generation resources and KCA witness Medine's argument that Senate Bill 4 requires onsite fuel storage and a rate impact assessment. But the language of Senate Bill 4 contains no such requirements, and the cannons of construction alone are reason enough to reject these contentions. [114]

---

[112] *Norton Hosps., Inc. v. Peyton*, 381 S.W.3d 286 (Ky. 2012); *Commonwealth v. Holiday*, 33 S.W. 943 (Ky. 1896).
[113] *Travelers Indem. Co. v. Reker*, Ky., 100 S.W.3d 756, 765 (Ky. 2003), *quoting Commonwealth v. Harrelson*, 14 S.W.3d 541, 546 (Ky. 2000).
[114] As explained by Mr. Bellar, the Companies are exploring onsite fuel oil and other options to further enhance the reliability of the two proposed NGCCs. Rebuttal Testimony of Lonnie E. Bellar at 12.

A. The Companies' Proposed Portfolio Contains Sufficient *Dispatchable* Replacement Generating Capacity for Retiring Units

The Companies' proposed supply-side resource portfolio satisfies a key requirement of Senate Bill 4, namely the requirement that "[t]he utility will replace the retired electric generating unit with new electric generating capacity that: 1. Is dispatchable by either the utility or the regional transmission organization or independent system operator responsible for balancing load within the utility's service area[.]"[115]

First, the Companies' proposed resource portfolio includes 1,530 MW of new *dispatchable* generating resources to replace the 1,541 MW (net summer capacity rating) of coal- and gas-fired resources the Companies have proposed to retire in this proceeding.[116] Although Senate Bill 4 does not contain a definition of "dispatchable," based on industry standard definitions, the Companies have proposed to define it as "capable of following dispatch instructions between economic minimum and economic maximum when (i) the generating unit is physically capable of producing electricity and (ii) the unit's power source is available."[117] No party to this proceeding has offered an alternative definition of the term, and Joint Intervenors witness John Wilson has endorsed it with the caveat that it include storage resources such as batteries.[118] Under the Companies' proposed definition, both of the Companies' proposed NGCC units are dispatchable (1,290 MW),[119] and the Companies' proposed owned solar facilities, which the Companies will have the right to dispatch, are also dispatchable (240 MW).[120] Thus, the Companies' proposed

[115] KRS 278.264(2)(a).
[116] Exhibit SB4-1 at 6. The bids received for the NGCC units were for 645 MW units.
[117] Exhibit SB4-1 at 7.
[118] Direct Testimony of John Wilson at 6, lines 5-8.
[119] Exhibit SB4-1 at 7-8; Companies' Response to Joint Intervenors'' Post Hearing Request for Information, No. 1(noting increase in NGCC capacity to 645 MW per unit).
[120] Exhibit SB4-1 at 7-8. Though the Companies do not object to treating the Brown BESS as dispatchable, the Companies do not believe it is appropriate to treat storage resources as "generating capacity," which prevents them as being counted as replacement resources for Senate Bill 4 purposes.

resource portfolio includes a nearly MW-for-MW amount of dispatchable new generating capacity to replace the retiring thermal units, not counting the proposed 637 MW of non-dispatchable new solar PPA capacity, the 125 MW Brown BESS, which is a dispatchable non-generating resource, and 102 MW of dispatchable DSM program capacity.[121]

1. Whether a Utility or an RTO Dispatches Capacity Should Not Affect Whether the Capacity Is Dispatchable, but the Utility Is Responsible for Having or Arranging for Adequate Dispatchable Capacity to Serve Its Customers.

The Chairman requested at hearing that the parties address "the applicability of dispatchability to an RTO or a utility," noting that certain witnesses had equated "balancing authority, utility, and RTO" and asking "whether that makes a difference in terms of the determination and definition of dispatchability."[122] The Companies do not believe the party responsible for dispatching the relevant capacity should affect Senate Bill 4's definition of "dispatchable" per se. The statute treats dispatchability as being distinct from the party with the right or responsibility to dispatch the capacity; it does not state or imply that the requirements of being dispatchable might change depending on the party responsible for making dispatch decisions. But the statute is clear that "[t]he utility will replace the retired electric generating unit with new electric generating capacity that: 1. Is dispatchable by either the utility or the regional transmission organization or independent system operator responsible for balancing load within the utility's service area[.]"[123] Thus, either the utility itself or the RTO or ISO of which it is a member must have dispatch control for the replacement capacity to count for Senate Bill 4 purposes; capacity dispatchable by an entity not listed in the relevant text of Senate Bill 4 cannot count as replacement capacity for a retiring unit. That is why, for example, the Companies have

[121] Exhibit SB4-1 at 8.
[122] 8/29/23 Hearing, VR 16:28:56-16:29:31.
[123] KRS 278.264(2)(a)(1).

excluded capacity associated with their proposed solar PPAs from the resources that would replace the units the Companies have proposed to retire.

Regardless of whether the utility itself or the RTO or ISO of which it is a member has dispatch authority for replacement capacity, it is clear from the plain statutory text that it is the *utility's* responsibility to "replace the retired electric generating unit with *new electric generating capacity*." That is why merely joining an RTO, as Sierra Club witness Mr. Levitt suggests,[124] or retiring 1,500 MW of thermal generation with no replacements or RTO membership at all, as Mr. Goggin suggests,[125] would *not* satisfy Senate Bill 4's requirements for retiring fossil fuel fired generating units: no plausible reading of Senate Bill 4 could support effectively revising the statutory text to say that a utility must "replace the retired electric generating unit with new electric generating capacity *or no new electric generating capacity at all*." The previously cited cannons of construction prohibit such an interpretation. Moreover, any such approach would run afoul of the Commission's clear statement that it "has no interest in allowing our regulated, vertically integrated utilities to effectively depend on the market for generation or capacity for any sustained period of time,"[126] as well as its statement that "Kentucky law requires retail electric suppliers … to have sufficient capacity to meet maximum estimated customer demand, including sufficient generation capacity."[127] Therefore, whether through ownership or contract for firm capacity, a utility seeking to retire existing generating capacity must "replace the retired electric generating unit with new electric generating capacity"; under both Senate Bill 4 and existing Commission

[124] *See, e.g.*, Direct Testimony of Andrew Levitt at 5-7.
[125] *See* Direct Testimony of Michael Goggin at 4-6, 47.
[126] *Electronic Tariff Filing of East Kentucky Power Cooperative, Inc. and Its Member Distribution Cooperatives for Approval of Proposed Changes to their Qualified Cogeneration and Small Power Production Facilities Tariffs*, Case No. 2021-00198, Order at 5, n. 10 (Ky. PSC Oct. 26, 2021).
[127] *Electronic Investigation of the Service, Rates, and Facilities of Kentucky Power Company*, Case No. 2021-00370, Order at 7 (Ky. PSC June 23, 2023).

precedent, such a utility cannot simply retire capacity and depend on an RTO market to have sufficient capacity to serve its customers' needs.

B. The Companies' Proposed Portfolio - Even Counting Only Dispatchable Generating Resources - Will Maintain or Improve System Reliability and Resilience, and It Will Maintain Sufficient Reserve Capacity

The Companies' proposed resource portfolio will provide more than adequate system reliability and resilience and will maintain sufficient reserve capacity even when accounting for only the two proposed NGCC units, fully satisfying the reliability, resilience, and reserve margin requirements of Senate Bill 4.[128] The Companies' economically optimal seasonal reserve margins, which provide the low ends of the Companies' target reserve margin ranges, are 17% for summer and 24% for winter.[129] Based on those minimum seasonal reserve margins, a loss of load expectation ("LOLE") of 3.57 days in 10 years is consistent with maintaining adequate reliability.[130] The Companies' proposed DSM-EE and supply-side resource portfolio would result in a year-round LOLE of 0.28; even counting only DSM-EE and the Companies' proposed fuel-dispatchable resources (i.e., NGCC units) results in year-round LOLE of 1.22, both of which are superior to the minimum adequate LOLE of 3.57.[131] The Companies' proposed resource portfolio also enhances resilience by providing greater dispatchable range than the retiring resources, and counting only the proposed NGCC units provides comparable dispatchable range to the retiring units.[132] Finally, the Companies' proposed portfolio would maintain sufficient reserve margins, with seasonal reserve margins for the total proposed portfolio of 38.4% in the summer and 32.3%

[128] KRS 278.264(2)(a)(2)-(3).
[129] *See* Companies' Response to Joint Intervenors' Second Request for Information, No. 60(a), Attachment 2, Updated Exhibit SAW-1 at 9, 44, and Appendix D.
[130] Exhibit SB4-1 at 13.
[131] Exhibit SB4-1 at 14.
[132] Exhibit SB4-1 at 16.

in the winter, and with seasonal reserve margins counting only DSM-EE and the proposed NGCCs of 22.7% in the summer and 30.2% in the winter.[133]

Although witnesses for the Joint Intervenors and Sierra Club raised claims concerning correlated outage risk to try to undermine the reliability and resilience of the Companies' proposed portfolio, the correlated outage risk data the intervenors raised was not from any analysis of data for the Companies' system alone.[134] In contrast, the Companies demonstrated conclusively both in Mr. Sinclair's rebuttal testimony and in response to the Commission Staff's PHDR 25 that the Companies do not have *any* statistically significant weather-dependent correlated outage risk.[135] Thus, the issue of correlated outages as applied to the Companies is a red herring, not an evidence-based reliability concern.

Finally, the reality is that the Companies' first-ever load shedding event on December 23, 2022, was an *anomaly*, not an indication of a broader problem. The Companies have demonstrated that they have addressed or are addressing all known fuel security issues and related issues arising from Winter Storm Elliott, including working closely with Texas Gas Transmission to help ensure that the low-pressure condition does not reoccur,[136] adding software updates to allow the Companies' gas-fired units to operate at lower pressures,[137] evaluating adding gas compression equipment at the Companies' generating stations,[138] evaluating onsite fuel oil storage for new NGCCs,[139] and studying possible pipeline diversity for Brown NGCC.[140] In short, the Companies

[133] Exhibit SB4-1 at 18.
[134] *See, e.g.*, Direct Testimony of Michael Goggin Direct Testimony at 29-38; Direct Testimony of Anna Sommer at 8-9.
[135] Rebuttal Testimony of David S. Sinclair at 79-81; Companies' Response to Commission Staff's Post Hearing Request for Information, No. 25.
[136] *See, e.g.*, Rebuttal Testimony of Lonnie E. Bellar at 17 and Rebuttal Exhibit LEB-1; Companies' Response to Commission Staff's First Request for Information, No. 58(a), Attachment.
[137] Rebuttal Testimony of Lonnie E. Bellar at 17.
[138] *Id.*
[139] *See, e.g.*, *id.* at 8.
[140] *See, e.g.*, 8/23/23 Hearing, VR11:23:23-11:23:55.

are taking reasonable steps to reduce the likelihood of another load-shedding event, and the fact of a single, historically anomalous event does not indicate a statistically significant correlated outage risk; indeed, the Companies' actual LOLE history is closer to one loss-of-load event in 100 years than it is to the industry standard of one loss-of-load event in 10 years. Certainly this does not indicate that the Companies' proposed resource portfolio does not satisfy the reliability, resilience, and reserve capacity requirements of Senate Bill 4.

C. The Companies' Proposed Unit Retirements Will Not Harm Customers; Instead, the Retirements and Replacement Portfolio Will Result in Cost Savings for Customers After Accounting for All Known Direct and Indirect Costs of the Retirement

1. NPVRR analysis is both superior to KCA's "residential rate analysis" and consistent with Senate Bill 4's requirements.

KCA witness Medine's claim that Senate Bill 4 requires a rate impact study to assess the cost of the proposed unit retirements and replacements has no support in the plain language of the law. Senate Bill 4 requires only that the proposed retirement will not harm "ratepayers by causing the utility to incur any *net* incremental costs to be recovered from ratepayers that could be avoided by continuing to operate the electric generating unit proposed for retirement in compliance with applicable law."[141] As explained in the Companies' May 10, 2023 Joint Application and Mr. Bellar's and Mr. Wilson's testimony in support thereof, the proposed retirements satisfy the entirety of Senate Bill 4's requirements, including the "harm to ratepayers" requirement. That requirement is met by measuring the net present value revenue requirements of the proposed replacement generation over the life of the investment, not by conducting a rate impact analysis over an arbitrary 10-year period. As pointed out by Mr. Conroy, "Given the fact that the

[141] KRS 278.264(2)(b) (emphasis added)

Companies' rates are cost-based, present value revenue requirements are essentially a rate impact analysis providing appropriate coverage of the life-cycle of the investment."[142]

In making the KCA's argument, witness Medine deliberately ignores the most salient and fundamental fact relating to a possible increase in rates: if the Companies proposed portfolio is approved, any increase in rates will be lower than would otherwise be the case based on the Companies' present value calculations modeling that portfolio as compared to all other reasonable alternatives.[143] In short, customers would benefit by paying a smaller increase under the Companies' portfolio. Witness Medine's contention to the contrary is meritless.

2. The Companies' interpretation of "indirect costs" is appropriate in context of the longstanding scope of Commission authority.

KCA witness Medine's assertion that the absence of an evaluation of the impact of the Companies' portfolio on their service territories, economic development and overall economy of Kentucky is a "significant flaw"[144] is based on language that is not contained in Senate Bill 4 and a complete disregard of the record evidence. In contrast to witness Medine's unsupported rhetoric, the Companies' present value of revenue requirements calculations demonstrate across a broad range of scenarios that the proposed portfolio is more reliable, resilient and less costly than maintaining the status quo for KCA's financial benefit. Indeed recent experience shows economic development prospects desire electricity prices based on a reliable and predictable portfolio. The status quo only presents uncertainty. More exactly, the Companies' present value of revenue requirements calculations were specifically designed to include all known direct and indirect costs of the proposed unit retirements that will be included in customers' rates, including on-site costs

[142] Rebuttal Testimony of Robert M. Conroy at 11; *see* Companies' Response to Kentucky Coal Association's Third Request for Information, No. 3.
[143] *See* Companies' Response to Joint Intervenors' Second Request for Information, No. 60(a), Attachment 2, Updated Exhibit SAW-1 at 32; Companies' Response to Commission Staff's Fifth Request for Information, No. 2 at 14.
[144] Direct Testimony of Emily Medine at 8, 11.

associated with retiring the units (the direct costs) and the cost of replacing their capacity (the indirect costs). Table 7 presented in Mr. Bellar's testimony shows the categories of direct and indirect costs included in the Companies' PVRR calculations.[145] As demonstrated in the Retirement Assessment, and summarized in Mr. Bellar's Table 8, there is no fuel-price scenario modeled in which implementing the CPCN-DSM portfolio results in PVRR detriments relative to incurring the costs to maintain the Companies' existing resource portfolio; rather, in every scenario modeled, the Companies' proposed CPCN-DSM portfolio provides significant PVRR benefit relative to maintaining the existing portfolio when accounting for all known direct and indirect costs of retiring the seven units at issue.[146] Therefore, retiring the seven units at issue and replacing them with the Companies' proposed CPCN-DSM resources will not harm customers in any way. Rather, it will provide significant savings when considering all direct and indirect costs of unit retirements. This fully satisfies the requirements of KRS 278.264(2)(b).

3. All investments in long-lived assets have higher upfront costs through established depreciation practice but result in long-term savings.

To bolster her specious rate impact argument, KCA witness Medine further asserted that because present value revenue requirements are based on levelized costs and utility rates are based on undepreciated capital, the present value revenue requirements do not reflect the ratepayer's perspective, contending the Companies failed to consider the "sunk costs" of the generation units to be retired when customers are expected to pay them.[147] Her argument, like many of her other positions, is based on incorrect or unsupported assumptions or assertions or alleged requirements that simply do not exist in Senate Bill 4 subsection (2)(b) to advocate her client's financial interest. First, the undepreciated capital of the existing units proposed to be retired or the "stranded costs"

[145] Case No. 2023-00122, Direct Testimony of Lonnie E. Bellar at 20.
[146] *Id.* at 21.
[147] Direct Testimony of Emily Medine at 7.

for Mill Creek Units 1 and 2 and Brown Unit 3 were fully presented in the Companies' 2020 rate cases. These balances and their recovery are the result of a unanimous settlement in that case.[148] Equally important is the fact that the balances were fully considered by Mr. Wilson's analyses in this case.[149] When confronted with this fact in discovery, KCA witness Medine simply ignored it.[150]

Secondly, as Mr. Conroy explained, the appropriate analysis in this proceeding is to determine whether the proposed projects constitute the least reasonable cost to customers of meeting their electricity needs and not how much each customer class should pay for the investment in the new facilities to provide each customer service. The financial effect to customers is measured by the present value revenue requirements submitted by the Companies. Revenue requirements are the first phase of a general rate case, used to determine the total amount of revenue required to cover the costs of service provided by a utility. Rate design, or the determination of how costs should be allocated among customer classes and across components of customer rates, which KCA advocates as necessary for this case, in fact is the second phase of a general rate case. The class cost of service and rate design are often products of alternative analyses presented by the Companies and intervening parties, are the subject of significant debate, and are ultimately decided by the Commission based on fair, just and reasonable principles. The Commission has always used the present value revenue requirement to assess the relative cost of

---

[148] *Application of Kentucky Utilities Company for an Adjustment of its Electric Rates, A Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of A One-Year Surcredit,* Case No. 2020-00349, Order at 11, 18-19, 62 (Ky. PSC June 30, 2021); *Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates, A Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of A One-Year Surcredit,* Case No. 2020-00350, Order at 13, 21, 69 (Ky. PSC June 30, 2021).
[149] Case No. 2023-00122, Direct Testimony of Stuart A. Wilson, Exhibit SB4-1, Table 9 at 22.
[150] Companies' Response to Kentucky Coal Association's Second Request for Information, No. 45 ("Revenue requirements for past investments in these units are included in the analysis, but the present value of these revenue requirements is the same in all cases.").

investment alternatives in a CPCN proceeding.[151] KCA's assertion that a class cost of service debate is required for Senate Bill 4 purposes is designed to cause unnecessary delay and confusion – an outcome KCA desires to advance its financial interests.

Finally, the fact that "utility rates are based on undepreciated capital" somehow undermines the use of present value revenue requirement for purposes of evaluating whether the Companies' customers will "incur any net incremental costs" for Senate Bill 4 subsection (2)(b) purposes is a non sequitur. The very purpose of depreciation is to allocate the costs of a fixed asset in a systematic and rational manner over the estimated life of the assets to ensure customers will bear their fair share of the total costs.[152] Ms. Medine bases her assertion that customers' rates are likely to increase over the next ten years on the unrealistic hypothetical of the capital investments proposed in this case, taken alone, without regard to *any* other changes in costs and revenues.[153] The proposed capital investments will be depreciated using the straight-line method of depreciation used for decades by the Companies and repeatedly approved by the Commission.[154] This method allocates the fixed asset costs equitably over the lives of the underlying assets. The resulting depreciation of, and the return on, these capital investments will be reflected with other changes in revenues and expenses over time when the Commission evaluates the financial condition of the Companies and their rates. KCA's contentions are meritless.

---

[151] Companies' Response to Kentucky Coal Association's Second Request for Information, No. 46.
[152] *Public Utility Depreciation Practices*, p.17, National Association of Regulatory Utility Commissioners (August 1996)
[153] Companies' Response to Kentucky Coal Association's Third Request for Information, No. 23.
[154] See e.g., Direct Testimony of John J. Spanos, *Application of Kentucky Utilities Company for an Adjustment of its Electric Rates, A Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of A One-Year Surcredit*, Case No. 2020-00349, Order (Ky. PSC June 30, 2021); Direct Testimony of John J. Spanos, *Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates, A Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of A One-Year Surcredit*, Case No. 2020-00350, (Ky. PSC June 30, 2021).

4. The proposed retirements result from federal environmental requirements and fundamental economics, not federal financial incentives or benefits.

Finally, the Companies' proposed unit retirements do not result from federal financial incentives or benefits;[155] rather, the Companies are proposing to retire the units at issue due to environmental compliance costs and other significant capital costs.[156] Moreover, even if the Companies' proposed owned solar projects and Brown BESS were excluded from consideration due to the federal tax incentives associated with those projects, the Companies' proposed portfolio would still satisfy all other Senate Bill 4 requirements.[157]

III. The Companies' Proposed Solar PPAs Are Reasonable, and Recovering the Cost of PPA Energy through the KIUC's PPA Rider Proposal Is Preferable to FAC Cost Recovery.

In their applications, the Companies sought declarations related to four Solar Purchased Power Agreements ("Solar PPAs") for the full output of solar PV facilities to be built in Kentucky with a total capacity of 637 MW.[158] The Solar PPAs are for non-firm energy only, not firm energy or capacity, and the Companies will have no capital, operating, or maintenance obligations with respect to the solar facilities, with purchase obligations based only upon actual receipt of output at a specified delivery point at a fixed price per MWh.[159] The Companies are already parties to a

---

[155] KRS 278.264(2)(c).
[156] Rebuttal Testimony of Robert M. Conroy at 10.
[157] *See* Companies' Response to Commission Staff's Post Hearing Request for Information, No. 21(a), Confidential Attachment, "UpdatedBid" tab (showing generally lower cost of Portfolio 5 than Portfolio 0); Exhibit SB4-1 at 14, Table 5 (showing Portfolio 5 maintains adequate reliability with 1.22 annual LOLE); Exhibit SB4-1 at 18, Table 7 (showing Portfolio 5 maintains adequate reserve capacity with 22.7% summer and 30.2% winter reserve margins); Exhibit SB4-1 at 16, Table 6 (showing adequate resilience with comparable dispatchable range counting only new NGCC units).
[158] Joint Application at ¶ 29. The four Solar PPAs are: (1) a 138 MW 30-year PPA with ibV Energy Partners for a project to be built in Hopkins County and named Grays Branch; (2) a 280 MW 30-year PPA with ibV Energy Partners for a project to be built in Hardin County and named Nacke Pike; (3) a 104 MW 20-year PPA with Clearway Energy for a project to be built in Ballard County and named Song Sparrow; and (4) a 115 MW 20-year PPA with BrightNight, LLC for a project to be built in Ballard County and named Gage Solar.
[159] Joint Application at ¶ 31. The energy produced by the projects associated with the Solar PPAs is "must-take" in the sense that the Companies do not have the ability to reduce dispatch of the solar units subject to PPAs unless there

similar non-firm energy-only PPA with Rhudes Creek Solar, LLC for the full output of a 100 MW from that solar facility.[160] The Commission has previously ruled that approval of the Rhudes Creek Solar PPA for service of native load customers was not required under KRS 278.020 or KRS 278.300, and that the Companies could recover the costs of that PPA through their existing FAC mechanisms subject to the "highest cost unit calculation" approach.[161]

After full litigation of the issues and consideration of intervenor testimony, particularly the testimony of Lane Kollen on behalf of KIUC, the Companies now request a declaration that: (1) a PPA rider is an appropriate means for the Companies to seek cost recovery for the Solar PPAs; and (2) that Commission approval of the Solar PPAs is not required.

A. The Commission Should Declare that a PPA Rider Is an Appropriate Means for the Companies to Seek Cost Recovery of the Solar PPAs.

Witness Kollen testified for Intervenor KIUC in this case and has for decades testified in opposition to the Companies and on behalf of customers in rate proceedings.[162] Witness Kollen argues that if the Solar PPAs are authorized,[163] they should be subject to a separate PPA rider similar to the Companies' existing Environmental Cost Recovery ("ECR") and Retired Asset Recovery ("RAR") riders.[164] The Companies agree that Witness Kollen's proposal has merit as an alternate means of cost recovery.[165] In his written testimony and at hearing, Witness Kollen offered three main benefits to his proposal: (1) it would allow the Commission the opportunity to

---

is a Transmission directive for reduction due to grid conditions. This is unlikely to impose operational problems given the capacity of the Solar PPAs and the Companies' minimum load during daylight hours. Companies' Response to Kentucky Coal Association's Second Request for Information, No. 16(d).

[160] *Id.* at ¶ 30.

[161] *See Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of a Solar Power Contract and Two Renewable Power Agreements to Satisfy Customer Requests for a Renewable Energy Source Under Green Tariff Option #3*, Case No. 2020-00016, Order at 9-12 (Ky. PSC May 8, 2020); Case No. 2020-00016, Order at 5-6 (Ky. PSC Dec. 16, 2020).

[162] 8/29/23 Hearing, VR 14:06:50 (Kollen).

[163] Mr. Kollen and KIUC oppose the Solar PPAs on grounds related to SB4, discussed below.

[164] Direct Testimony of Lane Kollen at 22-23.

[165] Rebuttal Testimony of Robert M. Conroy at 2.

assess and approve cost recovery for the PPAs before the cost is incurred rather than after; (2) it would reduce risk to the Companies that their costs are not fully recovered under the FAC; and (3) it would allow for Group 1/Group 2 cost recovery methodology already in use for the ECR and RAR riders that may be better suited to a solar PPA project with high up front fixed costs as opposed to a pure volumetric price per kWh recovery as under the FAC.[166] Mr. Kollen testified that this proposal better reflects that Solar PPAs provide not only energy but also capacity, and result from fixed-cost investments by the developer even though the PPA charges are stated on a purely volumetric (price per kWh) basis.[167]

In response to questioning by the Chairman at hearing, Witness Kollen further confirmed that his proposal does not incentivize utilities to use PPAs by adding return on equity or other economic benefit to the utility, rather it removes the *disincentive* for utilities to use PPAs when it would otherwise be in the best interests of customers due to the risk of not recovering the full cost through the FAC.[168] Witness Kollen further testified that use of a PPA rider as opposed to FAC for the Solar PPAs would have the effect of balancing volatility in pricing through the FAC with certainty of PPA costs on a total bill basis.[169] Under a PPA rider, just like under FAC cost recovery, customers would further derive benefits of the net proceeds from sale of any Renewable Energy Certificates (RECs) attributable to the Solar PPA projects.[170]

The Companies support Witness Kollen's PPA rider proposal.[171] The Companies agree with Kollen and KIUC that a PPA rider may also be preferred by the Commission over FAC recovery because a rider would allow the Commission to review the contracts and the projects

[166] 8/29/23 Hearing, VR 14:10:43 – 14:13:20.
[167] Direct Testimony of Lane Kollen at 20-21.
[168] 8/29/23 Hearing, VR 14:36:18.
[169] 8/29/23 Hearing, VR 14:32:33 – 14:33:34.
[170] 8/28/23 Hearing, VR 9:06:48 p.m. – 9:07:16 p.m. (Conroy).
[171] Rebuttal Testimony of Robert M. Conroy at 3.

before costs are incurred at a time when it has the best information about these long-term commitments, rather than after-the-fact.[172] A rider would also allow for more certain cost recovery and therefore not deter the Companies from pursuing a balanced, least-cost generation portfolio to reliably serve customers. The Companies therefore request a declaratory judgment from the Commission that a PPA rider is appropriate for the four Solar PPAs and that the details of the rider, including proposed cost recovery and impact on FAC, After the Fact Billing, and the Off-System Sales adjustment clause, should be addressed in a separate proceeding to approve that rider.

B. The Commission Should Declare that Commission Approval of the Solar PPAs Is not Required.

The Companies further respectfully request a declaration that no Commission approval is required for the proposed Solar PPAs. The Commission's Orders with respect to the Rhudes Creek Solar PPA for native load customers are clear. Neither KRS 278.020 (CPCN) nor KRS 278.300 (evidence of indebtedness) applies to a long-term purchased power agreement with the following attributes: (1) no minimum obligation or take/pay provision; (2) non-firm energy only, no capacity payments or obligations; and (3) no evidence that financial and operational impact of the agreement on ratepayers is the same as if new generation were being constructed.[173]

The Companies have asserted that all of these attributes of the Rhudes Creek Solar PPA serving native load are shared by the four proposed Solar PPAs here and should be treated similarly.[174] No intervenor has disputed that point. Accordingly, the Companies respectfully

---

[172] *Id.*

[173] *See Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of a Solar Power Contract and Two Renewable Power Agreements to Satisfy Customer Requests for a Renewable Energy Source Under Green Tariff Option #3*, Case No. 2020-00016, Order at 9-12 (Ky. PSC May 8, 2020); Case No. 2020-00016, Order at 5-6 (Ky. PSC Dec. 16, 2020).

[174] Joint Application at ¶ 31; Direct Testimony of Robert M. Conroy at 6-7.

request a declaration applying existing precedent and concluding that the Solar PPAs do not require Commission approval under KRS 278.020 and KRS 278.300.[175]

C. The Parties Generally Support the Solar PPAs and the Arguments Advanced by the Two Objecting Intervenors Do Not Have Merit

Of all the parties in this proceeding, only KIUC and KCA oppose the four Solar PPAs. But these objections miss the mark and do not provide valid grounds for the Commission to deny the Companies' requested relief. For example, KIUC Witness Kollen's criticism of the Solar PPAs is based entirely on his view that the proposals do not meet Senate Bill 4 requirements for replacement of coal-fired generating units because, among other things, they are not "dispatchable" resources as required by Senate Bill 4 and do not improve system reliability and resiliency compared to retiring units.[176] The Companies agree that the Solar PPAs do not meet Senate Bill 4's dispatchability requirements, but strongly disagree that they were ever designed or proposed to do so. As Mr. Bellar's initial testimony filed in these proceedings clearly stated, "the solar PPAs will provide valuable energy to the Companies' system, but . . . are not dispatchable for Senate Bill 4 purposes."[177] Contrary to Witness Kollen's view, the record in this case thoroughly demonstrates that the Companies proposed the Solar PPAs as an important part of a diversified least-cost portfolio that will provide a hedge against fuel price volatility, not as replacement generation for retiring coal-fired units under Senate Bill 4.[178]

KCA's criticisms of the Solar PPAs fare no better. Witness Medine was critical that they did not include buyout provisions, that they feature must-take provisions, and was concerned that they did not allow for ongoing Commission oversight.[179] But as Mr. Sinclair noted in his rebuttal

---

[175] Rebuttal Testimony of Robert M. Conroy at 1-2.
[176] Direct Testimony of Lane Kollen at 18-20.
[177] Case No. 2023-00122, Direct Testimony of Lonnie E. Bellar at 10-11 (Ky. PSC filed May 10, 2023).
[178] *See, e.g.*., Rebuttal Testimony of Lonnie E. Bellar at 13-14.
[179] Direct Testimony of Emily Medine at 50-52.

testimony, the economic feasibility of purchased power agreements depends on must-take provisions and a consistent revenue stream over an extended period of time to repay the significant upfront costs incurred by the developer to build the facilities.[180] Witness Medine's proposal of negotiated buyout provisions for the Solar PPAs would potentially lead to greater flexibility but would also ensure that the projects could never feasibly be built.[181] Finally, Witness Medine's concern about the Solar PPAs not being subject to continual regulatory oversight is unfounded. In all cases but particularly if a PPA rider is approved for cost recovery, the Commission will continue to have jurisdiction, oversight, and regulatory review authority over the contracts and cost recovery to ensure that the PPAs are a reasonable means to serve customers with reliable energy.[182]

IV. The Commission Should Approve the Companies' Proposed DSM-EE Program Plan Because It Will Greatly Expand the Companies' DSM-EE Programs and Offerings, Benefit Customers Across All Rate Classes, and Result in Significant Cost-Effective Demand and Energy Savings.

The Companies are proud of their proposed DSM-EE Plan, which represents the most comprehensive, robust, and ambitious Plan in the Companies' history. If approved, the Companies project that the DSM-EE Plan will achieve peak cumulative demand savings of approximately 377 MW in 2030 from energy efficiency and demand response programs and energy savings of 878 GWh and 170,000 Mcf by 2030 at a total cost of approximately $341 million.[183] Beyond the DSM-EE Plan, the Companies have accounted for a significant amount of energy efficiency in the load forecast. Including customer-initiated DSM-EE, total residential and commercial energy efficiency accounts for a more than 1,000 GWh reduction to the annual load forecast by 2029.[184]

[180] Rebuttal Testimony of David S. Sinclair at 61-62.
[181] *Id.* at 62-63.
[182] Rebuttal Testimony of Robert M. Conroy at 2-3.
[183] Direct Testimony of John Bevington at 23.
[184] Rebuttal Testimony of Tim A. Jones at 3.

The Companies believe, and the record reflects, that the DSM-EE Plan captures all cost-effective DSM-EE that can reasonably be achieved at this time. No intervenor in the case, except for the Joint Intervenors, takes issue with the Companies' proposed DSM-EE Plan. And even the Joint Intervenors do not suggest that the proposed DSM-EE Plan should be denied, but instead simply argue that more savings are achievable without proposing specifics of actual programs that could achieve additional savings or calculating cost-effectiveness. The proposed DSM-EE Plan is reasonable and cost-effective and should be approved pursuant to KRS 278.285.

A. The Companies' DSM Advisory Group Process Was Robust and Provided Ample Engagement and Input.

The Companies began their program development process, as they always do, by engaging with their DSM-EE Advisory Group. The Group consists of representatives from various stakeholders, including representatives from the Kentucky Energy and Environment Cabinet's Office of Energy Policy, the Kentucky Attorney General, the Kentucky Industrial Utility Customers, Inc., the Kentucky School Boards Association, environmental advocacy groups, commercial customers, and low-income advocates.[185] When the Companies became aware of a possible future capacity need, the Companies increased the pace of their program development by updating potential studies and conducting program reviews.[186] The Companies met with their DSM-EE Advisory Group twice in 2021 as they began the DSM-EE program review and development process and on five different occasions in 2022.[187] The minutes from these meetings reflect that the Companies discussed every aspect of program selection and design with the DSM-EE Advisory Group.[188]

[185] Direct Testimony of John Bevington at 4-5.
[186] *Id.* at 6.
[187] *Id.*
[188] *Id.* at Exhibit JB-2; Companies' Response to Commission Staff's Post Hearing Request for Information, No. 5.

Regarding program selection, the Companies first solicited input from the DSM-EE Advisory Group in developing a comprehensive list of 39 possible programs.[189] Using a scoring rubric as a filter mechanism, the Companies and their consultant evaluated all 39 possible programs to determine which warranted further consideration and detailed analysis.[190] The Companies discussed this scoring rubric and filtering process with the DSM-EE Advisory Group, specifically soliciting input from the members on which programs they would like to see move on to cost-effectiveness analysis.[191] Based on interest from stakeholders in particular programs, the Companies advanced certain programs that did not score highly on the rubric to cost-effectiveness testing because of this interest.[192]

Next, the Companies shared the results of the initial cost-effectiveness tests with the DSM-EE Advisory Group.[193] On the basis of the preliminary cost-benefit results, the Companies combined certain programs that could have a synergistic effect and an enhanced customer experience prior to performing a second round of cost-benefit analysis. The Companies shared and discussed the results from the second round of cost-benefit analysis with the DSM-EE Advisory Group.[194] Then, based on the results of the final round of cost-benefit analyses and discussions with the DSM-EE Advisory Group, the Companies finalized their proposed DSM-EE Plan.[195] Any assertion that only the Companies and Cadmus participated in the program selection and development process is incorrect; the record clearly reflects that the stakeholders in the DSM-EE Advisory Group had every opportunity to participate—and did participate—in the selection of the programs and development of the Plan.

---

[189] Rebuttal Testimony of Lana Isaacson at 5.
[190] Direct Testimony of John Bevington at 8.
[191] *Id.* at 8-9.
[192] Rebuttal Testimony of Lana Isaacson at 5; 8/28/23 Hearing, VR 19:53:58 – 19:54:52.
[193] Direct Testimony of John Bevington at 8.
[194] *Id.*
[195] *Id.* at 9.

Although Joint Intervenors take issue with the Companies' process for sharing inputs and calculations in the program development process, such claims are without merit and contrary to the evidence in the record. The Companies made every effort to be forthcoming and provide requested information to the Group.[196] In determining the reasonableness of the proposed DSM-EE Plan, the Commission may consider the "extent to which customer representatives and the Office of the Attorney General have been involved in developing the plan, including program design, cost recovery mechanisms, and financial incentives, and if involved, the amount of support for the plan by each participant, provided however, that unanimity among the participants developing the plan shall not be required for the commission to approve the plan."[197] With the exception of Joint Intervenors, all intervenors in this case—most of which participated as members of the DSM-EE Advisory Group—do not oppose the proposed DSM-EE Plan. Joint Intervenors' lack of support for the proposed DSM-EE Plan should not undermine the significant collaborative efforts the Companies undertook through the DSM-EE Advisory Group to develop the Plan.

B. The Proposed DSM-EE Portfolio Is Ambitious and Cost-Effective, and It Did Not Leave Any Clearly Cost-Effective Program on the Drawing Board.

The Companies have demonstrated that their DSM-EE Plan proposes all cost-effective DSM-EE programs that can reasonably be implemented at this time. No intervenor identifies additional cost-effective DSM-EE programs. Should circumstances change, the Companies will file a mid-plan update to propose additional cost-effective DSM-EE.[198] As discussed further below, the Companies have consistently continued to analyze DSM-EE and propose expanded or additional programs based on changed circumstances. For example, as reflected in the DSM-EE Advisory Group meeting minutes, the Companies were considering multiple potential offerings

[196] Companies' Response to Commission Staff's Post Hearing Request for Information, No. 6.
[197] KRS 278.285(1)(f).
[198] *See, e.g.*, Rebuttal Testimony of Lana Isaacson at 12-13.

and pilot programs in 2021.[199] In Case No. 2022-00123, the Companies sought and received an increased budget for the Nonresidential Rebates Program, which was performing beyond forecasted expectations.[200]

C. The Companies Have Long History of Mid-Plan Adjustments and Will Continue to Work with the DSM Advisory Group and Cadmus to Examine Any Additional Possibly Cost-Effective Programs.

Based on the premise that the DSM-EE programs would have been out of date had the Companies not, of their own volition, proposed an update and expansion of DSM-EE programs, Joint Intervenors "recommend the Commission direct [the Companies] to file a [DSM-EE] Plan update early in 2026 to reflect a refreshed program plan that would begin in 2027."[201] The Companies have a proven track record of constantly reviewing current programs, researching new programs, and seeking mid-plan program adjustments as needed. In fact, over the last 15 years, the Companies have filed five DSM-EE Plans[202] and requested modifications to existing programs.[203] Each time, the Companies have completed only approximately three years of a seven-year plan before requesting approval of a new plan because of changing circumstances. Requiring the Companies to present an update at the arbitrary deadline of 2026 when they have

---

[199] Companies' Response to Commission Staff's Post Hearing Request for Information, No. 5.

[200] *Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company to Enhance the Budget of an Existing Demand-Side Management and Energy Efficiency Program,* Case No. 2022-00123, Order (Ky. PSC May 20, 2022).

[201] Direct Testimony of Jim Grevatt at 12.

[202] *Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Certain Existing Demand-Side Management and Energy Efficiency Programs,* Case No. 2017-00441, Order (Ky. PSC Oct. 5, 2018); *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Existing and Addition of New Demand-Side Management and Energy Efficiency Programs,* Case No. 2014-00003, Order (Ky. PSC Nov. 14, 2014); *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Existing and Addition of New Demand-Side Management and Energy Efficiency Programs,* Case No. 2011-00134, Order (Ky. PSC Nov. 9, 2011); *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company Demand-Side Management for the Review, Modification, and Continuation of Energy Efficiency Programs and DSM Cost Recovery Mechanisms,* Case No. 2007-00319, Order (Ky. PSC Mar. 31, 2008).

[203] *See, e.g.*, *Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company to Enhance the Budget of an Existing Demand-Side Management and Energy Efficiency Program,* Case No. 2022-00123, Order (Ky. PSC May 20, 2022).

already shown that they continuously monitor DSM-EE would not be a good use of Commission, Company and customer resources. The Companies will continue to work with their DSM-EE Advisory Group to examine any additional potentially cost-effective programs, which the Companies will propose if and when they are cost-effective.

D. Mr. Grevatt's Minimum Savings Percentage Recommendation Is Contrary to Law.

Kentucky law provides no mandatory savings percentage utilities must achieve for DSM-EE. Instead, KRS 278.285 dictates the factors the Commission should consider in determining the reasonableness of a DSM-EE plan, including the cost-effectiveness of the plan. The Commission has repeatedly held that a utility should analyze DSM-EE programs using the four California Standard Practice Manual tests,[204] which the Companies did. By contrast, Joint Intervenors' witness Mr. Grevatt provides no cost-effectiveness analysis for the programs he recommends and instead bases his savings recommendation on a study titled "Pathways for Energy Efficiency in Virginia." Mr. Grevatt co-authored this study for a group of clean energy non-profits in Virginia "to explore whether, by effectively implementing a suite of energy efficiency programs similar to those currently implemented by other large utilities, Virginia Electric and Power Company . . . can meet or exceed the savings requirements of the Virginia Clean Economy Act."[205] He describes the utilities in his study as "high-achieving"[206] utilities achieving "at least one percent in incremental annual savings."[207] The level of savings other utilities have achieved in other states—particularly in states that mandate reaching certain levels of savings, have significantly higher

[204] *See Joint Application of the Members of the Louisville Gas and Electric Company Demand-Side Management Collaborative for the Review, Modification, and Continuation of the Collaborative, DSM Programs, and Cost Recovery Mechanism*, Case No. 1997-00083, Order at 20 (Ky. PSC Apr. 27, 1998) ("Any new DSM program or change to an existing DSM program shall be supported by . . . [t]he results of the four traditional DSM cost-benefit tests [Participant, Total Resource Cost, Ratepayer Impact, and Utility Cost tests].").
[205] Direct Testimony of Jim Grevatt, Exhibit JG-2 at 4.
[206] Direct Testimony of Jim Grevatt at 36.
[207] Direct Testimony of Jim Grevatt, Exhibit JG-2 at 15.

retail rates than the Companies, or both—have no bearing on the DSM-EE savings the Companies can cost-effectively achieve. The Commission should dismiss Mr. Grevatt's assertions for what they are—rhetoric without analysis to back up his recommendations.

E. Mr. Grevatt's Proposed Additional Savings Are Duplicative and Dubious.

Mr. Grevatt provides no specifics for the amount of savings he argues the Companies can achieve. In fact, with the exception of Residential New Construction,[208] all of the programs Mr. Grevatt proposes are included in some capacity or form in the Companies' proposed DSM-EE Plan.[209] Simply asserting that additional savings can be achieved from a program does not make it so; Mr. Grevatt provides no support for the cost-effectiveness for these additional savings or the specific inputs that would allow the Companies to run cost-benefit tests.

CONCLUSION

For the foregoing reasons, Louisville Gas and Electric Company and Kentucky Utilities Company respectfully request the Commission to issue an order by November 6, 2023:

1. Authorizing the retirement of E. W. Brown Unit 3, Ghent Unit 2, Mill Creek Units 1 and 2, Haefling Units 1 and 2, and Paddy's Run 12;

2. Granting the Companies a Certificate of Public Convenience and Necessity to construct a 645 MW net summer rating natural gas combined cycle combustion turbine at LG&E's Mill Creek Generating Station, including related gas and electric transmission construction at the station;

---

[208] Companies' Response to Commission Staff's First Request for Information, No. 20; Companies' Response to Joint Intervenors' Second Request for Information, No. 19. As the Companies explained in response to discovery, the Companies did not propose a Residential New Construction program because the Companies had previously implemented the program and believed it had achieved maximum results. As stated in response to PSC 1-20, an initial cost-effectiveness analysis indicated that the program is not cost-effective.

[209] *Compare* Direct Testimony of Jim Grevatt, Exhibit JB-1 *with* Direct Testimony of Jim Grevatt at 41, Table 8.

3. Granting the Companies a Certificate of Public Convenience and Necessity to construct a 645 MW net summer rating natural gas combined cycle combustion turbine at KU's E.W. Brown Generating Station, including related gas and electric transmission construction at the station;

4. Granting the Companies a Certificate of Public Convenience and Necessity to construct an approximately or up to 120 MWac solar photovoltaic facility in Mercer County, Kentucky;

5. Contingent upon granting the Certificate of Public Convenience and Necessity to construct an approximately or up to 120 Mwac solar photovoltaic facility in Mercer County, Kentucky, approving the Stipulation between Mercer County and the Companies as a reasonable disposition of their specific issues and granting the Companies the approval to sell the approximately 858 acres to Mercer County and City of Harrodsburg pursuant to KRS 278.218(a);

6. Granting the Companies a Certificate of Public Convenience and Necessity to acquire a 120 Mwac solar photovoltaic facility in Marion County, Kentucky;

7. Granting the Companies a Certificate of Public Convenience and Necessity to construct a 125 MW, 4-hour (500 MWh) battery storage facility at KU's E.W. Brown Generating Station;

8. Granting the Companies Site Compatibility Certificates pursuant to KRS 278.216 for the NGCCs proposed to be constructed at the Mill Creek Generating Station and at the E.W. Brown Generating Station;

9. Approving the regulatory asset treatment for the difference between Allowance for Funds Used During Construction accrued at the Companies' weighted average cost of capital and Allowance for Funds Used During Construction accrued using the methodology approved by the

Federal Energy Regulatory Commission during the construction period of the two NGCCs, Mercer County Solar Facility, and Brown BESS;[210]

10. Approving the Companies' proposed 2024-2030 DSM-EE Program Plan and the proposed revised Demand Side Management cost recovery tariff sheets to be effective for service rendered on and after January 1, 2024; and

11. Declaring that recovery of the costs of solar Purchase Power Agreements should be through a separate solar rider rather than the Fuel Adjustment Clause, subject to Commission approval of the rider and each Purchase Power Agreement before recovering the cost in a future proceeding and declaring that Commission approval of the solar PPAs is not required under KRS KRS 278.020 and KRS 278.300.

---

[210] See section I.B.5. of this Brief.

Dated: September 22, 2023

Respectfully submitted,

Kendrick R. Riggs
Stoll Keenon Ogden PLLC
400 W. Market Street, Suite 2700
Louisville, Kentucky 40202
Telephone: (502) 333-6000
Fax: (502) 627-8722
kendrick.riggs@skofirm.com

Allyson K. Sturgeon
Vice President and Deputy General Counsel
Sara V. Judd
Senior Counsel
PPL Services Corporation
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-2088
Fax: (502) 627-3367
ASturgeon@pplweb.com
SVJudd@pplweb.com

Counsel for Kentucky Utilities Company and Louisville Gas and Electric Company

CERTIFICATE OF COMPLIANCE

In accordance with the Commission's Order of July 22, 2021 in Case No. 2020-00085 (Electronic Emergency Docket Related to the Novel Coronavirus COVID-19), this is to certify that the electronic filing has been transmitted to the Commission on September 22, 2023; and that there are currently no parties in this proceeding that the Commission has excused from participation by electronic means.

Counsel for Kentucky Utilities Company and Louisville Gas and Electric Company

400001/174441:4857-4966-2590v11