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 APPROVAL OF A DEMAND SIDE MANAGEMENT PLAN AND APPROVAL OF FOSSIL FUEL-FIRED GENERATING UNIT RETIREMENTS	**)))))))))**	**CASE NO. 2022-00402**

RESPONSE OF
KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY
TO
THE COMMISSION STAFF'S SIXTH REQUEST FOR INFORMATION
DATED JULY 24, 2023

FILED: AUGUST 4, 2023

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **David S. Sinclair**, being duly sworn, deposes and says that he is Vice President, Energy Supply and Analysis for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, 220 West Main Street, Louisville, KY 40202, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

David S. Sinclair
David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 2nd day of August 2023.

Caroline J. Davison
Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

CAROLINE J. DAVISON
COMM EXPIRES 01/22/2027
NOTARY PUBLIC
ID # KYNP63286
STATE AT LARGE, KENTUCKY

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Stuart A. Wilson**, being duly sworn, deposes and says that he is Director, Energy Planning, Analysis & Forecasting for LG&E and KU Services Company, 220 West Main Street, Louisville, KY 40202, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Stuart A

Stuart A. Wilson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 2nd day of August 2023.

Caroline J. Davison

Notary Public

Notary Public ID No. KYNP63286

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KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Sixth Request for Information
Dated July 24, 2023

Case No. 2022-00402

Question No. 1

Responding Witness: David S. Sinclair / Stuart A. Wilson

Q-1. Refer to LG&E/KU's response to Commission Staff's Fifth Request for Information (Staff's Fifth Request), Item 2, in which LG&E/KU performed analysis to assess the impact of the proposed EPA carbon regulations on the cost-effectiveness of the preferred portfolio. Also, for the following questions, refer to 04- PSC_DR5_LGE_KU_Attach_to_Q02_-_PUBLIC_WORKPAPERS, CONFIDENTIAL_WORKPAPERS, CONFIDENTIAL_PROSYM, out_unityr.csv:

a. In LG&E/KU's response to Staff's Fifth Request, Item 2, LG&E/KU stated that "any analysis of the proposed regulations should include the impact on the Companies' entire generation fleet." Explain why the 50 percent capacity factor limit for natural gas combustion turbines after 2031 was applied to the new NGCC and SCCT units only (CC621 01, 02; SCCT 01, 02, 03, 04), but some existing natural gas units exceeded percent after 2031 (Cane Run 7 2x1; Trimble County 1, 2). If an alternative compliance method, such as CCS or conversion to hydrogen co-firing, was assumed for these units, describe how this was incorporated into the model.

b. Explain why some existing coal units exceeded the 20 percent capacity factor limit after 2031 in some scenarios (Ghent 1, 3, 4; Mill Creek 3, 4). If an alternative compliance method, such as CCS or conversion to natural gas co-firing, was assumed for these units, describe how this was incorporated into the model.

c. On average across all "CaseName" scenarios, the following fossil fuel resources had capacity factors in 2032 exceeding the proposed EPA carbon regulations, 50 percent for natural gas, 20 percent for coal. Identify which resources would provide replacement energy if all of the following units reduced their generation to comply with the regulations, as shown in the below table.

[redacted]

A-1. The seeming non-compliance with the proposed GHG standards for existing generating units noted by these requests was intentional; it was a feature, not a flaw, of the Companies' modeling approach in response to PSC 5-2. The Companies intentionally designed their modeling in that response to do three things simultaneously:

1. **Provide the *least favorable* scenario for the Mill Creek and Brown NGCC units under the proposed GHG standards.** To do so, the Companies modeled compliance with the proposed greenhouse gas new source performance standards by constraining all new gas-fired units' capacity factors to 50% beginning in 2032. The Companies chose to model that constraint because it was straightforward to model, whereas any attempt to model the costs associated with CCS or low-GHG hydrogen would necessarily be speculative because the required technologies and their costs are not commercially available (and in some cases do not exist at all). Modeling the impact of a 50% annual capacity factor limitation is therefore also necessarily modeling a worst-case scenario for the NGCCs; if either CCS or hydrogen co-firing eventually became cost-effective, the Companies would presumably choose to employ the most economical retrofit and improve the NGCCs' economics from the modeled 50% capacity factor constraint.

2. **Provide *highly favorable* scenarios for existing generation under the proposed GHG standards**. Under the proposed GHG standards for existing generating units, both coal and gas units may operate indefinitely and without capacity factor constraint if they meet the appropriate GHG emission reduction levels. Thus, modeling existing generation without capacity factor constraints in the zero CO_2 price scenario is equivalent to assuming that Section 45Q tax credits would exactly offset the full cost of CCS for coal and gas units (or that other tax arrangements or other incentives would fully offset the cost of low-GHG hydrogen co-firing for gas units). The \$15/short ton and \$25/short ton of CO_2 scenarios thus assume that the net cost of compliance with the proposed GHG standards would be those amounts (for existing units only). Modeling a range of compliance costs has the benefit of not requiring speculation about the exact costs of non-existent technologies or the provisions of the final GHG standards, which could change from their proposed form. Moreover, unless one believes existing coal or gas units would effectively have negative compliance costs (e.g., tax credits that exceeded compliance costs), the Companies' modeling includes the best-case scenario and two highly favorable scenarios for existing coal and gas units under the proposed GHG standards.

3. **Provide *a head-to-head comparison* of the value of other resources under the proposed GHG standards**. The Companies' modeling in response to PSC 5-2 re-ran detailed production cost modeling in PROSYM of the same nine diverse replacement portfolios analyzed in the Companies' original Stage Two, Step Two analysis detailed in Exhibit SAW-1. Those nine portfolios consisted of a variety of resources to be installed by 2028 to replace the Companies' seven retiring coal and gas units. One of the portfolios was a PLEXOS-optimized blend of solar, wind, and battery storage only (Portfolio 8), and another was a PLEXOS-optimized blend of solar and SCCT (Portfolio 9; PLEXOS did not select any wind or battery storage in this portfolio). For PSC 5-2, the Companies re-ran PROSYM for all nine portfolios across eighteen total CO_2 and fuel price scenarios (three CO_2 price scenarios for existing units and six fuel price scenarios for all units) with a 50% capacity factor constraint on new gas-fired units beginning in 2032. Doing so provided a direct PVRR comparison of these different, diverse portfolios under modeling assumptions for the proposed GHG standards that were least favorable for the Companies' proposed NGCC units.

   Even under those unfavorable assumptions for new gas units, the Companies' proposed NGCCs and solar PPAs are least cost in thirteen of the eighteen modeled scenarios (i.e., all twelve scenarios with non-zero

GHG standard compliance costs for existing units and in one scenario with net-zero compliance costs). Therefore, unless one believes that GHG compliance costs for existing coal and gas units will be net zero or negative, the Companies' proposed portfolio will likely be least cost under the proposed GHG standards.

Notably, the Companies' proposed NGCC units plus solar PPAs portfolio (Portfolio 1) was $1.1 billion to $2 billion lower PVRR than the all-renewables and batteries portfolio (Portfolio 8) and $1.2 billion to $2 billion lower PVRR than the solar plus SCCT portfolio (Portfolio 9) across all eighteen CO_2 price and fuel price scenarios. Thus, although the proposed GHG standards improve the relative economics of renewables compared to no GHG compliance cost or constraint for new gas units, they do not support an all-renewables plus batteries portfolio as the least-cost replacement approach for the coal and gas units the Companies propose to retire.

Finally, the Companies would reiterate that their approach to modeling the proposed GHG standards in PSC 5-2 is the best, least speculative means of stress-testing (or providing a "regrets analysis") for their proposed portfolio. The uncertainties and unknowns regarding the proposed GHG standards—including the eventual costs and technological feasibility, much less commercial availability, of the relevant emission reduction technologies, as well as the ultimate requirements of the yet-to-be-final standards—make a resource optimization modeling approach untenable and any results from such a modeling attempt speculative at best. The approach presented in response to PSC 5-2 and described above has the distinct advantage of relying to the greatest possible extent on known quantities and provides reasonable cost forecasts for items like fuel, and it reduces the need for speculation about unknowable costs by modeling boundary cases like the 50% capacity factor limitation on new gas units. It truly is the most reasonable approach to modeling the impacts of the proposed GHG standards on the Companies' proposed NGCCs and solar PPAs in comparison to other possible portfolios of resources to meet the Companies' capacity and energy needs in 2028.

a. See the response above. As discussed at length above, the capacity factor limitation on new gas units was intentional to model the least favorable scenario for such units under the proposed GHG standards. Also, not modeling a capacity factor limitation for existing gas units was intended to model the most favorable scenarios for such units (and to avoid having to speculate about exactly which compliance approach the Companies would take for such units), all in an effort to stress-test the Companies' proposed portfolio.

Also, please note that Trimble County Units 1 and 2 are coal-fired, not gas-fired, units.

b. See the response above. As discussed at length above, not modeling a capacity factor limitation for existing coal units was intended to model the most favorable scenarios for such units (and to avoid having to speculate about exactly which compliance approach the Companies would take for such units), all in an effort to stress-test the Companies' proposed portfolio.

c. See the response above and the responses to parts (a) and (b). This question highlights the usefulness of the Companies' stress-test modeling approach. It is not necessary to speculate about what kinds of future resources might address the Companies' remaining energy needs if the cost of complying with the proposed GHG standards turns out to be greater than zero (costs that would include constraining existing units' capacity factors or retiring them early). Rather, any such cost would only make the proposed NGCCs more valuable and cost effective, not less so.

**KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY**

**Response to Commission Staff's Sixth Request for Information
Dated July 24, 2023**

Case No. 2022-00402

Question No. 2

Responding Witness: David S. Sinclair / Stuart A. Wilson

Q-2. Refer to LG&E/KU's response to Staff's Fifth Request, Item 2, in which LG&E/KU performed analysis to assess the impact of the proposed EPA carbon regulations on the cost-effectiveness of the preferred portfolio.

a. Explain why the final preferred portfolio, including utility-owned solar and storage, was not included in this analysis.

b. Considering the significant energy replacement required to fully comply with the regulations as discussed in Question 1c, re-run the capacity expansion model with the EPA regulations applied to all existing and candidate resources. Using the optimal portfolio from the capacity expansion, provide the Selected Portfolio, Incremental PVRR, LOLE, Reserve Margin, Net Summer/Winter Capacity, and Dispatchable Summer/Winter Range.

A-2

a. The Companies developed the response to PSC 5-2 as an update on the stress-testing analysis performed in Stage Two, Step Two from the Resource Assessment in Exhibit SAW-1, which did not yet include utility-owned solar and storage. Omitting these resources allowed for a direct comparison of Table 13 from Exhibit SAW-1. Furthermore, the utility-owned solar and battery projects were included in the Companies' recommended portfolio to specifically address solar PPA execution risk and gain operational experience with battery storage at utility scale. These resources would only become more valuable in a CO_2 constrained scenario – not less – particularly as the quantity of CO_2 reductions are increased (i.e., there is an increasing marginal cost for reducing the next ton of CO_2).

b. There is no energy replacement required in the Companies' analysis. Please see the response to Question No. 1.

This notwithstanding, in an effort to be as responsive as possible to this request, the Companies modeled the proposed EPA carbon regulations in PLEXOS using the CO_2 price methodology as a proxy for the unknown compliance costs for existing units. This modeling necessarily includes many broad assumptions and does not include costs for new generation sites, incremental transmission or gas pipeline interconnections, and network upgrades associated with the resulting resource retirements and additions because these costs are unknown. Thus, the results are intended to be directional at best; they are not the Companies' final compliance plan for the proposed GHG standards.

Assumptions

The Companies modeled the compliance cost at three levels of CO_2 emissions prices net of 45Q tax credits: \$0 per short ton ("ST"), \$15 per ST, and \$25 per ST. These compliance costs are effective starting in 2030 for existing coal units and in 2035 for new baseload (greater than 50 percent capacity factor) NGCC units. The 45Q tax credits of \$85 per metric ton ("MT") are assumed to expire after twelve years in all three cases (at the end of 2041 for existing coal-fired units and 2046 for new NGCC units). This is modeled by increasing the CO_2 costs by \$85 per metric ton for all three cases.

New and existing NGCC units without CO_2 reduction technology (such as CCS or hydrogen co-firing) are assumed to operate at an intermediate capacity factor of 50 percent or less starting in 2032. New and existing SCCT units are assumed to operate at a 20 percent capacity factor or less. The potential new gas-fired units were modeled with the same characteristics and costs as the responses to the Companies' 2022 RFP for the NGCC and SCCT units proposed at Mill Creek.

In order to develop a tractable model in PLEXOS, new renewables were modeled more generically than new gas-fired units. Each of solar, wind, and battery storage technologies were modeled as one resource that could be selected at any time and constructed at any capacity scale, from 1 MW to 10,000 MW. New solar resources were priced at the average price of the four PPAs the Companies have proposed in this case, with a generation profile reflecting the average of all the solar PPAs modeled from the Companies' 2022 RFP. New wind resources were modeled with the price and generation profile (plus the fixed cost of firm transmission) of the one wind resource proposal from the 2022 RFP. New battery storage resources were modeled with the same costs and characteristics as the lowest-cost 4-hour battery storage PPA proposal from the 2022 RFP.

The Companies also assumed the following:

- Mill Creek 1 is retired in 2024. OVEC is retired at the beginning of 2030 rather than complying with the proposed EPA carbon regulations through CO_2 reductions.[1]
- Mill Creek 2, Ghent 2, and Brown 3 are available to be retired at any time, consistent with the Companies' prior modeling in this case. All other coal units are available to be retired in 2030 or thereafter and are assumed to operate with CO_2 reduction technology (such as CCS or gas co-firing) if they operate beyond 2030 at the aforementioned net costs of between $0, $15, and $25 per short ton of CO_2 emissions.
- The DSM programs the Companies' proposed in this case are implemented as proposed.

Results

The Companies developed 18 portfolios covering all combinations of the three CO_2 price scenarios ($0, $15, and $25 per ST) and the six fuel price scenarios the Companies have used throughout this proceeding. All of the portfolios include the retirement of Mill Creek 2, Ghent 2, and Brown 3 by 2028 and the addition of at least two and up to seven NGCC units by 2030. NGCC with CO_2 reduction is selected in just one of the eighteen scenarios by 2030. These results support the Companies' no-regrets proposal to retire Brown 3, Mill Creek 2, and Ghent 2 and to construct the proposed Mill Creek and Brown NGCC units. Attachment 1 summarizes the resulting eighteen portfolios. Attachment 2 contains the workpapers associated with this modeling. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

The results are also broadly consistent with the EPA's modeling discussed in the responses to PSC 5-2 and KCA 3-3 in that the Companies' coal units retire over the study period, multiple NGCC units are added and operate at intermediate capacity factors, NGCC units with CO_2 reduction are added in limited circumstances, and a large amount of renewables and a modest amount of batteries are selected, especially in later years.

Given these conclusions, the Companies' proposed portfolio in this case is unchanged. Therefore, the 2028 LOLE, Reserve Margin, Net Summer/Winter Capacity, and Dispatchable Summer/Winter Range are unchanged from the metrics presented in Exhibit SB4-1. The Companies' SB4 analysis compared the PVRR for the proposed portfolio to a portfolio with no retirements and assumed in both cases no portfolio changes beyond 2028. With a non-zero compliance cost per ton of CO_2, the proposed EPA carbon regulations (or any variants of the rule) would only exacerbate the incremental PVRR presented in Exhibit SB4-1 (versus a case with no coal

[1] The OVEC retirement assumption is only a simplifying model assumption. It is not based on any analysis performed by or for the Companies or any guidance from OVEC.

retirements). As discussed in the response to PSC 5-2, the Companies do not have cost estimates for the proposed CO_2 reduction activities (e.g., CCS or gas co-firing for coal units) and cannot estimate the incremental PVRR more specifically.