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 KENTUCKY COAL ASSOCIATION'S
SECOND SUPPLEMENTAL REQUEST FOR INFORMATION
DATED MAY 31, 2023

FILED: JUNE 9, 2023

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Coal Association's
Second Supplemental Request for Information
Dated May 31, 2023

Case No. 2022-00402

Question No. 3.1

Responding Witness: Lonnie E. Bellar

Q. 3.1. Please confirm that the cost estimates for the NGCC plants in the Senate Bill 4 (SB 4)/Case No. 2023-00122 filing are estimates and do not reflect firm cost estimates, an EPC (engineering/procurement/construction) contract, Firm Transportation costs and terms, and all interconnection upgrades. If not confirmed, please provide the firm costs by category.

A. 3.1. Confirmed.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Coal Association's
Second Supplemental Request for Information
Dated May 31, 2023

Case No. 2022-00402

Question No. 3.2

Responding Witness: Philip A. Imber

Q. 3.2. Please confirm, all required permits for the NGCC's that are part of the SB 4/Case No. 2023-00122 filing have not been received. If confirmed, please provide the expected and outside dates when such permits are expected.

A. 3.2. Confirmed. The Kentucky Division for Air Quality indicates that a proposed Title V operation permit for E.W. Brown is targeted for September 2023. The Louisville Metro Air Pollution Control District indicates the construction permit for Mill Creek is targeted for September 2023.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Coal Association's
Second Supplemental Request for Information
Dated May 31, 2023

Case No. 2022-00402

Question No. 3.3

Responding Witness: Lonnie E. Bellar / Philip A. Imber / Stuart A. Wilson

Q. 3.3. Please confirm that the proposed New Source Performance Standards (NSPS) for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Unit and Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units that were published in the Federal Register on May 23, 2023 are not reflected in the SB 4/Case No. 2023-00122 filing.

A. 3.3. Confirmed, though the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units ("GHG NSPS") and Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units ("Rule for Existing EGUs") (collectively, "New CO_2 Rules") that were published in the Federal Register on May 23, 2023 support rather than undermine the Companies' proposals in this proceeding.

The following table is a summary of the GHG NSPS for new natural gas EGUs from U.S. Environmental Protection Agency ("EPA"):[1]

[1] Table taken from slide 8 of EPA's presentation, "Overview Presentation: Clean Air Act Section 111 Regulation of Greenhouse Gas Emissions from Fossil Fuel-Fired Electric Generating Units," available at https://www.epa.gov/system/files/documents/2023-05/111%20Power%20Plants%20Stakeholder%20Presentation2_4.pdf (accessed June 3, 2023).

Phase I (By date of promulgation or upon initial startup)	Phase II Beginning in 2032-2035	Phase III Beginning in 2038
Low Load Subcategory (Capacity Factor <20%)		
BSER: Use of low emitting fuels (e.g., natural gas and distillate oil) <u>Standard</u>: From 120 lb CO_2/MMBtu to 160 lb CO_2/MMBtu, depending on fuel type	No proposed Phase II or Phase III BSER component or standard of performance	
Intermediate Load Subcategory (Capacity Factor 20% to ~50%*) ***Upper bound limit based on EGU design efficiency and site-specific factors**		
BSER: Highly efficient simple cycle generation <u>Standard</u>: 1,150 lb CO_2/MWh-gross	**BSER:** Continued highly efficient simple cycle generation with 30% (by volume) low-GHG hydrogen co-firing beginning in 2032 <u>Standard</u>: 1,000 lb CO_2/MWh-gross	No proposed Phase III BSER component or standard of performance
Base Load Subcategory (Capacity Factor >~50%*) *Limit		
BSER: Highly efficient combined cycle generation <u>Standard</u>: 770 lb CO_2/MWh-gross (EGUs with a base load rating of 2,000 MMBtu/h or more) <u>Standard</u>: 770 lb – 900 lb CO_2/MWh-gross (EGUs with a base load rating of less than 2,000 MMBtu/h)	**Low-GHG Hydrogen Pathway BSER:** Continued highly efficient combined cycle generation with 30% (by volume) low-GHG hydrogen co-firing beginning in 2032 <u>Standard</u>: 680 lb CO_2/MWh-gross **CCS Pathway BSER:** Continued highly efficient combined cycle generation with 90% CCS beginning in 2035 <u>Standard</u>: 90 lbCO_2/MWh gross	**Low-GHG Hydrogen Pathway BSER:** Co-firing 96% (by volume) low-GHG hydrogen beginning in 2038 <u>Standard</u>: 90 lb CO_2/MWh-gross **CCS Pathway:** No Phase III BSER component or standard of performance
The proposed definition of low-GHG hydrogen is hydrogen produced with less than 0.45kgCO_2e/kgH_2 overall well to gate emissions, consistent with IRC section 45V(b)(2)(D).		

Note that the GHG NSPS does *not* require carbon dioxide ("CO_2") capture and sequestration ("CCS") or hydrogen co-firing per se for new gas-fired units; rather, the GHG standard is based on EPA's proposed determination that these technologies are the best system of emissions reduction ("BSER"). Thus, for baseload gas-fired units nothing is required prior to 2032 (at the earliest) other than achieving CO_2 emissions of no more than 770 lbs./MWh gross, which the Companies' proposed NGCC units will be capable of achieving. The rule then provides compliance flexibility for high-efficiency NGCCs beginning in 2032: (1) reducing capacity factor and operating as an intermediate-load unit indefinitely (which has a CO_2 emission restriction of no more than 1,000 lbs./MWh gross), (2) meeting the lowered 680 lbs./MWh gross CO_2 emission standard, which EPA has stated will be achievable by co-firing low-GHG hydrogen, or (3) meeting the 90 lbs./MWh gross CO_2 emission standard, which EPA has stated will be achievable through the CCS path, which does not require CCS to be operational until 2035.

The following table is a summary of the Rule for Existing EGUs from EPA:[2]

[2] Table taken from slide 13 of EPA's presentation, "Overview Presentation: Clean Air Act Section 111 Regulation of Greenhouse Gas Emissions from Fossil Fuel-Fired Electric Generating Units," available at https://www.epa.gov/system/files/documents/2023-05/111%20Power%20Plants%20Stakeholder%20Presentation2_4.pdf (accessed June 3, 2023).

<table>
<tr><th>Coal-Fired Boilers</th><th>Natural Gas and Oil-Fired Boilers</th><th>Natural Gas Combustion Turbines</th></tr>
<tr><td>For units operating past December 31, 2039,
BSER: CCS with 90% capture of CO_2 an (88.4% reduction)</td><td rowspan="3">**BSER:** routine methods of operation and maintenance with an associated degree of emission limitation of no increase in emission rate (lb CO_2/MWh-gross).</td><td rowspan="3">For turbines >300MW, >50% capacity factor

CCS Pathway BSER: By 2035: highly efficient generation coupled with CCS with 90% capture of CO_2 (90 lb CO_2/MWh)

Low-GHG Hydrogen Pathway BSER: By 2032: highly efficient generation coupled with co-firing 30% (by volume) low-GHG hydrogen (680 lb CO_2/MWh)
By 2038: highly efficient generation coupled with co-firing 96% low-GHG hydrogen (90 lb CO_2/MWh)</td></tr>
<tr><td>For units that cease operations before January 1, 2040 and are not in other subcategories,
BSER: co-firing 40% (by volume) natural gas with emission limitation of a 16% reduction in emission rate (lb CO_2/MWh-gross basis)</td></tr>
<tr><td>For units that cease operations before January 1, 2032, and units that cease operations after January 1, 2035, that adopt enforceable annual capacity factor limit of 20%,
BSER: routine methods of operation and maintenance with associated degrees of emission limitation of no increase in emission rate</td></tr>
<tr><td colspan="3">The proposed definition of low-GHG hydrogen is hydrogen produced with less than 0.45kgCO_2e/kgH_2 overall well to gate emissions, consistent with IRC section 45V(b)(2)(D).</td></tr>
</table>

Note that the proposed Rule for Existing EGUs would place significant constraints on existing coal-fired units by January 1, 2030. Assuming the proposed rule is finalized and effective in 2024, State Implementation Plans ("SIPs") need to be filed in two years (i.e., in 2026) that identify compliance planning and categorization of EGUs, including committing to planned retirement date ranges for existing coal units. The SIP decisions on implementing capacity factor constraints, CCS, or natural gas co-firing to be in place by 2030 lead to regulatory proceedings for compliance investments on the same timeline as the SIP approval process.

Although the Companies have not modeled the impacts of the proposed GHG NSPS and Rule for Existing EGUs, the EPA has published model results in the technical support documents of the proposed rule. As described below, EPA's modeling results show that in its base case (including the Good Neighbor Plan but not the New CO_2 Rules) and in the case in which the New CO_2 Rules go into effect, it is economically optimal for the Companies' balancing area to add *far more* NGCC capacity in 2028 than the Companies are proposing in this proceeding. The foregoing is not intended to reflect the positions the Companies may take on the substantive issues raised by the EPA's NSPS rulemaking or an unqualified endorsement of EPA's modeling or approaches. Rather, it is to note that the modeling conducted by the independent federal agency that promulgated the proposed New CO_2 Rules is consistent with the Companies' proposals in this proceeding.

<u>EPA model overview</u>

EPA's Regulatory Impact Analysis ("RIA") for the New CO_2 Rules describes how EPA modeled the impact of the rules using their Integrated Planning Model ("IPM"). According to EPA, "IPM is a state-of-the-art, peer-reviewed, dynamic linear programming model that can be used to project power sector behavior under future business-as-usual conditions and to examine prospective air pollution control policies throughout the contiguous United States for the entire electric power system."[3] EPA's RIA further states that IPM "provides estimates of least cost capacity expansion, electricity dispatch, and emissions control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraints."[4] EPA has used the IPM for over three decades to analyze a wide range of options for reducing power sector air emissions.[5]

<u>IPM Assumptions</u>

EPA first uses the IPM to establish a baseline (reference case) for comparison to evaluate the impact of proposed regulations. The IPM baseline reflects a business-as-usual forecast of the electricity sector in the absence of the proposed regulation. The baseline includes information from such sources as the U.S. Energy Information Administration ("EIA") and expected costs for new and existing generation technologies, fuels, and existing regulation and law. In this case, the recently passed Inflation Reduction Act ("IRA") is reflected in the baseline case, as well as the final Good Neighbor Plan and all other applicable federal environmental requirements.[6]

An important consideration in any electric system model are fuel prices. IPM has a detailed representation of the natural gas and coal markets that it uses to estimate prices for these commodities.[7] In other words, the demand for these fuels in the electric generation in the model is used to help determine their market clearing prices. Though the prices for natural gas and coal are determined endogenously in IPM, low-GHG hydrogen is an exogenous input represented as a fuel that is available at a delivered cost of \$1/kg under the baseline, and at a delivered cost of \$0.5/kg in years when the second phase of the proposed NSPS is assumed to be active, all of which includes \$3/kg subsidies under the IRA.

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[3] U.S. Environmental Protection Agency, "Regulatory Impact Analysis for the Proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule" ("RIA") at 3-7 (May 2023), available at https://www.epa.gov/system/files/documents/2023-05/utilities_ria_proposal_2023-05.pdf.

[4] *Id.*

[5] *Id.* at 3-7 to 3-8.

[6] *Id.* at 3-10.

[7] *Id.* at 3-8.

Subsidies for other technologies such as renewables and CCS are also included in the baseline and other IPM-modeled cases.[8]

<u>EPA Model Results for SERC-KY</u>

The IPM model includes information on individual generating units and optimizes reliability and energy costs within NERC subregions while allowing for electricity trade between the subregions. One of the NERC subregions modeled in IPM is SERC-KY. Based on a review of the data, this subregion appears to be the LG&E-KU balancing area ("LKE-BA"). The LKE-BA includes all of the Companies' generation and load as well as the load of various Kentucky municipal entities. Because these municipal entities have very little generation in the LKE-BA, the IPM model essentially reflects the Companies' generation fleet and EPA's projections of how that will change over time based on their modeling.

The two tables on the following pages summarize installed capacity in the LKE-BA in EPA's reference case (i.e., without the New CO_2 Rules) and the proposed New CO_2 Rules case.[9] In both cases the IPM model constructs much more NGCC capacity (about 3,000 MW) in 2028 than the Companies have proposed in this proceeding (about 1,300 MW), all of which operates through the end of EPA's modeling period. Note also that in the New CO_2 Rules case, IPM:

- Retrofits only 1,097 MW of new NGCC capacity with hydrogen-firing capability by 2035, with the remaining almost 1,800 MW of NGCC capacity installed in 2028 operating through the end of EPA's modeling period without hydrogen or CCS retrofit;

- Retires nearly all coal capacity by 2035;

- Retrofits CCS to a limited amount of coal capacity (only 526 MW capacity after CCS retrofit); and

- Adds 419 MW of solar in 2028 and 382 MW of battery capacity by 2035.

[8] *Id.* at 3-13.
[9] The Companies have omitted existing and new landfill gas generation from both tables, which are less than 10 MW in total and are not the Companies' generating units.

EPA's Modeled Installed Capacity for the LKE-BA (Reference Case)[10]

Capacity Type	2028	2030	2035	2040	2045	2050	2055
New Combined Cycle (MW)	3,173	3,173	3,173	3,173	3,173	3,173	3,173
Capacity Factor (%)	87	87	87	85	64	52	49
New Combustion Turbine (MW)	0	0	583	1,774	2,330	2,808	3,240
Capacity Factor (%)	0	0	14	5	2	1	1
New Battery Storage (MW)	0	44	382	382	382	382	382
Capacity Factor (%)	0	14	15	17	17	17	17
New Onshore Wind (MW)	0	0	0	845	3,250	4,856	5,655
Capacity Factor (%)	0	0	0	39	39	39	39
New Solar PV (MW)	419	419	419	419	697	1,693	2,171
Capacity Factor (%)	23	23	23	23	24	24	24
Existing & New Distributed Solar PV (MW)	34	38	47	62	80	104	135
Capacity Factor (%)	16	16	16	16	16	16	16
Existing Combined Cycle (MW)	663	663	663	663	663	663	663
Capacity Factor (%)	74	85	79	55	42	36	36
Existing Combustion Turbine (MW)	2,176	2,176	2,176	2,176	2,176	2,176	2,176
Capacity Factor (%)	1	5	1	0	0	0	0
Existing Coal (MW)	3,535	2,111	234	0	0	0	0
Capacity Factor (%)	45	40	10	0	0	0	0
Existing Hydro (MW)	137	137	137	137	137	137	137
Capacity Factor (%)	28	28	28	28	28	28	28
Existing Solar PV (MW)	13	13	13	13	13	13	13
Capacity Factor (%)	19	19	19	19	19	19	19

[10] Taken from "S_C_KY" tab of the "Post-IRA_2022_Reference_Case_RegionalSummary" Excel file in the zip file available at https://www.epa.gov/system/files/other-files/2023-04/Post%20IRA%202022%20Reference%20Case.zip.

EPA's Modeled Installed Capacity for the LKE-BA (New CO_2 Rules Case)[11]

Capacity Type	2028	2030	2035	2040	2045	2050	2055
New Combined Cycle (MW)	2,886	2,886	1,789	1,789	1,789	1,789	1,789
Capacity Factor (%)	87	87	50	50	50	50	50
New Combined Cycle with Hydrogen Retrofit (MW)	0	0	1,097	1,097	1,097	1,097	1,097
Capacity Factor (%)	0	0	87	87	69	49	46
New Combustion Turbine (MW)	0	0	886	1,650	2,617	3,095	3,527
Capacity Factor (%)	0	0	14	3	2	1	1
New Battery Storage (MW)	0	0	382	382	382	382	382
Capacity Factor (%)	0	0	16	15	16	17	17
New Onshore Wind (MW)	0	0	60	1,388	4,047	4,856	5,655
Capacity Factor (%)	0	0	40	39	39	39	39
New Solar PV (MW)	419	419	419	419	962	2,050	2,528
Capacity Factor (%)	23	23	23	23	24	24	24
Existing & New Distributed Solar PV (MW)	34	38	47	62	80	104	135
Capacity Factor (%)	16	16	16	16	16	16	16
Existing Combined Cycle (MW)	663	663	663	663	663	663	663
Capacity Factor (%)	75	85	85	81	45	38	39
Existing Combustion Turbine (MW)	2,176	2,176	2,176	2,176	2,176	2,176	2,176
Capacity Factor (%)	1	8	1	0	0	0	0
Existing Coal (MW)	3,535	0	0	0	0	0	0
Capacity Factor (%)	48	0	0	0	0	0	0
Existing Hydro (MW)	137	137	137	137	137	137	137
Capacity Factor (%)	28	28	28	28	28	28	28
Existing Solar PV (MW)	13	13	13	13	13	13	13
Capacity Factor (%)	19	19	19	19	19	19	19
Existing Coal with CCS Retrofit (MW)	0	526	526	526	0	0	0
Capacity Factor (%)	0	79	79	79	0	0	0
Existing Coal with Designated Retirement Date (MW)	0	1,916	0	0	0	0	0
Capacity Factor (%)	0	20	0	0	0	0	0

In sum, regardless of whether the New CO_2 Rules take effect in their current form, EPA's IPM modeling results show:

- NGCC technology is a reliable, economic generation resource to meet long-term energy needs.

[11] Taken from "S_C_KY" tab of the "Proposal_RegionalSummary" Excel file in the zip file available at https://www.epa.gov/system/files/other-files/2023-04/Proposal.zip.

- Also, though it is prudent to explore options to use some quantity of hydrogen in the future, the Companies do not have to make that decision now. Future hydrogen use will depend on the future generating portfolio and capacity factor needs from NGCC units. The Companies' proposed NGCC units will be capable of combusting gas and hydrogen at levels exceeding any blending rates continuously used today, and they will be capable of combusting even higher levels of hydrogen with appropriate retrofits.

- Beginning to transition from coal-fired generation to gas-fired generation now as part of GNP compliance is also prudent given the effect of the New CO_2 Rules on existing coal units. If the Commission approves the Companies' CPCN and SB4 requests in this proceeding, the Companies will still have about 3,200 MW of other coal generation that could have to be replaced in a relatively short period of time.

- Adding some quantity of solar in the near-term is prudent, but it is certainly not the only generation resource the Companies should add.

- Battery energy storage will likely play an important role in the Companies' future resource mix, which is consistent with the Companies' reasoning for including a modest amount of battery storage in their proposed CPCN-DSM portfolio.

KENTUCKY UTILITIES COMPANY
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Question No. 3.4

Responding Witness: Philip A. Imber

Q. 3.4. Please confirm that it is the Companies understanding that affected facilities of the aforementioned NSPS include facilities that commence construction (or reconstruction) after the date of publication in the Federal Register of the proposed rulemaking.

A. 3.4. Confirmed. Specifically, the proposed regulatory language of 40 CFR Part 60, Subpart TTTTa is applicable to affected facilities that commence construction, modification, or reconstruction after the date of publication of the proposed rulemaking in the Federal Register (i.e., May 23, 2023).

KENTUCKY UTILITIES COMPANY
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Response to Kentucky Coal Association's
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Question No. 3.5

Responding Witness: Lonnie E. Bellar / Philip A. Imber

Q. 3.5. Please confirm that the two NGCC plants reflected in the CPCN are not under construction as defined by the proposed NSPS. If not confirmed, please provide documentation supporting the Companies' position.

A. 3.5. Confirmed.

KENTUCKY UTILITIES COMPANY
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Question No. 3.6

Responding Witness: Lonnie E. Bellar / Philip A. Imber

Q. 3.6. Please confirm that the two NGCC plants in the SB 4/Case No. 2023-00122 filing are not compliant with the NSPS for new natural gas plants (or the regulations for existing natural gas plants), as proposed in the May 23, 2023 Federal Register notice. If not the case, please describe in detail the basis upon which the Companies think they are compliant.

A. 3.6. Not confirmed. See the response to Question No. 3.3.

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Question No. 3.7

Responding Witness: Lonnie E. Bellar / Philip A. Imber

Q. 3.7. Please confirm that under all scenarios, the NGCC UCAP capacity represented in the SB 4/Case No. 2023-00122 filing would likely be impaired through compliance with the proposed changes to Section 111(b) and Section 111(d) of the Clean Air Act.

A. 3.7. Not confirmed. See the response to Question No. 3.3.

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Question No. 3.8

Responding Witness: Lonnie E. Bellar / Philip A. Imber

Q. 3.8. As it pertains to the preceding question, please provide any analysis performed as to how compliance could impair the capacity factor, plant efficiency, or other operating characteristics.

A. 3.8. See the response to Question No. 3.3.

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Question No. 3.9

Responding Witness: Lonnie E. Bellar / Stuart A. Wilson

Q. 3.9. Please confirm that the Companies selection of the NGCCs in the SB 4/Case No. 2023-00122 filing was not based upon an analysis which considered CCS on coal plants with or without the incentives provided in the Inflation Reduction Act (IRA). If not confirmed, please provide all assumptions and analyses related to CCR retrofits on coal plants.

A. 3.9. Confirmed.

KENTUCKY UTILITIES COMPANY
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Question No. 3.10

Responding Witness: Lonnie E. Bellar / Stuart A. Wilson

Q. 3.10. Please confirm that the Companies analysis in the SB 4/Case No. 2023-00122 filing did not reflect the Commission Order on June 30, 2021 "to conduct an analysis and submit a report on the potential application of tax incentives, particularly the federal 45Q incentives, and other matters relating to carbon dioxide emissions that could have an impact on the companies' fossil fuel generation units." If not confirmed, please provide all analyses related to CCS on coal plants including all analyses performed subsequent to the IRA.

A. 3.10. The Companies assume the request refers to the Commission's June 30, 2021 Orders in the Companies' 2020 base rate cases (Case Nos. 2020-00349 and 2020-00350).[12] In the KU Order, the Commission stated regarding Section 45Q of the Internal Revenue Code (the LG&E Order was substantively identical on this issue):

> Based on the Commission's concern, we find that KU shall conduct an analysis of the future of LG&E and KU's fossil-fuel generation with particular attention to avenues to reduce undepreciated assets and to protect ratepayers. This shall include an analysis of the 45Q tax incentives and any other approved incentives regarding carbon capture, storage and utilization. This analysis shall be provided in a report to the Commission by November 30, 2021, and should be subsequently updated and provided as part of KU's subsequent Integrated Resource Plans, until further notice.

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[12] *Electronic 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); *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 Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*, Case No. 2020-00350, Order (Ky. PSC June 30, 2021).

> …
>
> KU shall file by November 30, 2021, a report of KU's analysis of the future of LG&E and KU's fossil-fuel generation, including but not limited to an analysis of avenues to reduce undepreciated assets to protect ratepayers; 45Q tax incentives; and any other government-approved incentives regarding carbon capture, storage and utilization.[13]

On their own terms, the cited Orders do not apply to this proceeding per se. The Companies complied with the Commission's Orders by filing an *Analysis of Avenues for Reducing Undepreciated Fossil-Fuel Generation Assets at Retirement* in the records of the Companies' 2020 rate cases on November 30, 2021. Links to that analysis are provided in the response to KCA 1-40. The Companies have not filed an IRP since that time, but they will provide an updated analysis in their next IRP as the Commission's Orders require. Notably, the Companies' November 30, 2021 analysis states that \$60/metric ton of CO_2 is a reasonable cost of CCS for a gas-fired unit, with CCS costs for coal-fired units estimated to be 50% higher (i.e., about \$90/metric ton of CO_2).

It is correct that the Companies did not include CCS costs for coal-fired generating units in their analyses in this proceeding. Even net of Section 45Q tax credits (\$85/metric ton of CO_2 captured and stored), those costs would have *increased* the cost of continuing to operate coal units and increased the PVRR benefits of the proposed CPCN-DSM portfolio vis-à-vis continuing to operate the existing portfolio without any unit retirements.

[13] Case No. 2020-00349, Order at 61-62, 66 (Ky. PSC June 30, 2021).

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Question No. 3.11

Responding Witness: Lonnie E. Bellar

Q. 3.11. Please estimate the length of time it would take the Companies to revise their resource plans to reflect the EPA proposals under Sections 111(b) and 111(d) of the Clean Air Act and generate actionable cost estimates for CCS, co-firing with Low GHG Hydrogen, and any other compliance options contemplated by the Companies in a revised SB 4/Case No. 2023-00122 filing.

A. 3.11. The Companies disagree with the premise of this request in that it assumes any such effort would impact the proposals in this case. The EPA's proposals under Sections 111(b) and 111(d) have no impact on the proposed resource changes in these proceedings. See the response to Question No. 3.3.

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Question No. 3.12

Responding Witness: Lonnie E. Bellar

Q. 3.12. As it pertains to the preceding question, in any updated analysis, would the Companies reduce the depreciation period for the NGCCs to 2034 or add additional costs post 2035 to reflect the new requirements?

A. 3.12. No. See the response to Question No. 3.3.

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Question No. 3.13

Responding Witness: Lonnie E. Bellar

Q. 3.13. Please estimate the length of time it would take to completely update the 2022 Resource Assessment to include CCS on existing coal plants given the changes to the Section 45Q tax credits in the IRA and EPA's recent proposals limiting greenhouse gas emissions from new and existing power plants.

A. 3.13. See the responses to Question Nos. 3.3, 3.9, and 3.11.

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Question No. 3.14

Responding Witness: Lonnie E. Bellar

Q. 3.14. Please confirm that the SB 4/Case No. 2023-00122 filing did not reflect the changes in the promulgated Good Neighbor Plan. If not confirmed, please explain the errors in Table 1 of the Bellar Direct Testimony in the SB 4/Case No. 2023-00122 filing.

A. 3.14. Not confirmed. The cited table does not contain any errors. See the response to AG-KIUC 3-3.

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Question No. 3.15

Responding Witness: Lonnie E. Bellar

Q. 3.15. As it pertains to the previous question and Table 1, please confirm there are no undisclosed obstacles for the SCR retrofits if determined to be preferable. If not confirmed, please explain.

A. 3.15. Confirmed, there are no undisclosed obstacles to retrofit new SCRs. As discussed in response to PSC 4-1, implementing SCR on a timeline that results in timely compliance with the National Ambient Air Quality Standards and Good Neighbor Plan is challenging.

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Question No. 3.16

Responding Witness: Lonnie E. Bellar / Christopher M. Garrett

Q. 3.16. Please provide the actual costs of seasonal NOx allowances for Mill Creek 2 and Ghent 2 for the years 2020 through 2022 and the budgeted seasonal NOx allowance costs for these plants for 2023 and 2024.

A. 3.16. Mill Creek 2 and Ghent 2 incurred no costs related to NO_x allowances for the years 2020 through 2022. LG&E and KU have budgeted no NO_x allowance costs for these plants for 2023 and 2024. Per the FERC Uniform System of Accounts, allowances are recorded at cost and therefore no value is assigned to NO_x allowances allocated to LG&E and KU from the Environmental Protection Agency.

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Question No. 3.17

Responding Witness: Lonnie E. Bellar

Q. 3.17. Please provide all studies and/or work papers performed by or at the request of the Companies to improve the efficiency of the EB Brown 3 power plant described in the aforementioned Table 1 of the Bellar Direct Testimony.

A. 3.17. As a single unit plant with limited fuel delivery options, costs to operate E.W. Brown 3 include dedicated auxiliary costs (previously shared with now retired units, but now dedicated to the single unit), and high relative fuel costs, making it the least economic coal unit noted on Table 1. As part of the Companies' plan to comply with the Affordable Clean Energy ("ACE") Rule (subsequently rescinded by EPA), the Companies had a study performed by a third party in 2019 to evaluate potential efficiency improvements on E.W. Brown Unit 3 associated only with those projects specified by the ACE Rule. See attachment being provided in a separate file.

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Question No. 3.18

Responding Witness: Lonnie E. Bellar / Christopher M. Garrett

Q. 3.18. For each generating coal unit including Mill Creek 1, please provide the annual budgeted and actual O&M expenditures for the period between 2017 and 2022 and the forecast costs for 2023 through 2030 that support the Companies' findings in the SB 4/Case No. 2023-00122 filing.

A. 3.18. See the tables below for the actual and budgeted forecast spend. Common station budgeted and actual O&M reflects allocation in proportion with unit capacities, whereas common station forecasted O&M reflects allocation in proportion with the expected reductions if a given unit were to cease operations. Forecasted O&M reflects the portfolio where all four coal units continue to operate.

Budgeted O&M ($ Nominal)

Year	Brown 3	Mill Creek 1	Mill Creek 2	Ghent 2
2017	17,172,400	17,952,293	12,686,799	17,152,883
2018	17,327,709	13,095,668	18,992,687	17,151,347
2019	29,762,143	21,382,958	13,916,436	26,767,983
2020	24,592,336	14,107,736	18,261,757	19,476,081
2021	26,425,944	19,508,413	17,788,558	20,301,087
2022	24,252,538	13,260,676	14,827,453	20,298,334

Actual O&M ($ Nominal)

Year	Brown 3	Mill Creek 1	Mill Creek 2	Ghent 2
2017	18,226,144	16,855,089	11,492,539	18,368,433
2018	18,337,046	13,960,108	16,183,734	19,575,881
2019	30,774,710	20,865,225	13,269,013	28,854,570
2020	25,237,521	13,374,197	13,399,416	18,100,286
2021	25,256,931	19,107,231	17,234,928	22,642,826
2022	25,458,829	14,409,140	14,766,668	23,441,741

Forecasted O&M ($ Nominal)

Year	Brown 3	Mill Creek 1	Mill Creek 2	Ghent 2
2023	17,704,502	4,984,578	6,966,064	8,331,485
2024	18,473,350	2,773,347	9,787,202	10,624,731
2025	18,638,035	8,927,238	9,102,812	9,702,220
2026	19,569,527	3,626,056	15,764,606	9,036,484
2027	27,963,525	10,945,115	10,115,279	19,036,638
2028	20,990,364	3,789,731	12,502,782	10,594,547
2029	20,287,151	8,896,613	9,654,433	10,430,580
2030	21,483,195	3,960,761	14,653,887	12,174,861

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Question No. 3.19

Responding Witness: Lonnie E. Bellar

Q. 3.19. Please provide all notices related to the deactivation of power plants assumed in the SB4/Case No. 2023-00122 filing.

A. 3.19. See the response to KCA 2-1.

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Question No. 3.20

Responding Witness: Counsel

Q. 3.20. Please confirm that the Companies have announced in its financial filings that they expect significant earnings growth (EG) if the plan proposed in the SB 4/Case No. 2023-00122 filing is approved? If confirmed, please provide the expected EG by year through 2030.

A. 3.20. To the extent the phrase "financial filings" refers to filings with the Securities and Exchange Commission, this request does not correctly characterize those filings and seeks information that is irrelevant to whether the Companies' proposals are the least cost reasonable plan for serving their customers with reliable electric service. Therefore, the requested information is not provided with this response. The Companies are not seeking rate recovery of their proposed capital investments in this proceeding.

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Question No. 3.21

Responding Witness: Counsel

Q. 3.21. As it pertains to the previous question, please confirm that the EG is due to the increase in invested capital resulting from the new investments.

A. 3.21. The request seeks information that is irrelevant to whether the Companies' proposals are the least cost reasonable plan for serving their customers with reliable electric service. The Companies are not seeking rate recovery of their proposed capital investments in this proceeding. Therefore, the requested information is not provided with this response.

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Question No. 3.22

Responding Witness: Counsel

Q. 3.22. Please confirm that EG mentioned in the preceding questions is a significant determinant of executive compensation for the executives of the Companies and its parent, PPL.

A. 3.22. The request seeks information that is irrelevant to whether the Companies' proposals are the least cost reasonable plan for serving their customers with reliable electric service and is not provided with this response. The Companies are not seeking rate recovery of their proposed capital investments or any compensation costs of any kind in this proceeding. Executive incentive compensation costs historically have been excluded from the cost of providing service by the Companies when filing rate cases. For these reasons, the Companies decline to provide the requested information.

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Question No. 3.23

Responding Witness: Robert M. Conroy

Q. 3.23. Please confirm that residential rates are likely to increase in the period between 2026 and 2035 if the CPCN is approved due to the incremental capital investment and recovery of the remaining undepreciated capital of the retired coal plants. If not confirmed, please explain in detail.

A. 3.23. It is likely that all retail rates will change over the period requested. However, the change will be driven by many factors including, but not limited to, capital investments and operating costs. Those changes could increase or decrease retail rates and will be driven by the investments in this proceeding as well as potential other investments and advances in technology needed to comply with regulations while continuing to provide safe, reliable and affordable energy to customers. Although the capital investments proposed in this matter, taken alone, are likely to increase rates, because the Companies have proposed the least cost reasonable solution compared to other alternatives, any increase in rates will be less than it would otherwise be.

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Question No. 3.24

Responding Witness: Robert M. Conroy / Stuart A. Wilson

Q. 3.24. Please confirm that a forecast NPV savings is not equivalent to a rate analysis. If not confirmed, please explain in detail with data how an NPV analysis would translate to a determination of affordability represented in the SB 4/Case No. 2023-00122 filing for the years 2026 through 2035.

A. 3.24. It is not clear what is meant by "a forecast NPV savings" being equivalent to "a rate analysis." The analysis presented is the least reasonable cost plan to continue to provide safe, reliable and affordable energy to customers. See also the response to KCA 2-46.

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Question No. 3.25

Responding Witness: Stuart A. Wilson

Q. 3.25. As it pertains to the previous question, please indicate whether the NPV analyses referenced in the SB 4/Case No. 2023-00122 filing include "sunk costs" such as the undepreciated costs associated with the units which the Companies are requesting approval to retire. If any sunk costs are included, please document which ones are included and which are omitted.

A. 3.25. Yes, the PVRR analysis referenced in Exhibit SB4-1 includes estimated revenue requirements for past generation investments, specifically all undepreciated capital as of December 31, 2021. The PVRR for past investments is assumed to be the same in all cases. The PVRR analysis does not include undepreciated capital from 2022 capital expenditures. The undepreciated costs associated with the units which the Companies are requesting approval to retire can be found in rows 1815, 1816, 1820, and 1825 on the Detail tab of "\FinancialModel\CONFIDENTIAL_20230505_FinancialModel_0314_D01.xlsx" in Exhibit SB4-2.

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Question No. 3.26

Responding Witness: Christopher M. Garrett / Stuart A. Wilson

Q. 3.26. As it pertains to the previous question, please provide a schedule of the accredited generating capacity for the fossil fuel units the Companies are requesting approval to retire, the undepreciated capital at the time of the retirement, and the proposed replacement generation with the accredited capacity of each replacement generation source with the expect capital investment for each that the Companies would expect to include in rate base.

A. 3.26. See the tables below. Capacity values are net summer capacity values.

Schedule of Retiring Generating Capacity

Unit	Retirement Year	Net Summer Capacity (MW)	Undepreciated Capital at Time of Retirement ($M)
Mill Creek 1	2025	300	82.9
Paddy's Run 12	2025	23	(0.4)
Haefling 1-2	2025	24	(0.9)
Mill Creek 2	2027	297	160.4
Brown 3	2028	412	340.1
Ghent 2	2028	485	110.9

Schedule of New Generating Capacity and Brown BESS

Unit	Commissioning Year	Net Summer Capacity (MW)	Expected Capital in Rate Base ($M)
Brown BESS	2026	125	134.9
Mercer Solar	2026	120	242.8
Marion Solar	2027	120	220.0
Mill Creek NGCC	2027	621	661.3
Brown NGCC	2028	621	699.4

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Question No. 3.27

Responding Witness: David S. Sinclair

Q. 3.27. Under Section 2(2) of Senate Bill 4 the "Utility will replace the retired electric generating unit with new generating capacity that … [i]s dispatchable by … the utility …." Please explain in detail why the Companies include solar in their calculation even though they do not have "dispatch control." Also, please explain how owned solar is dispatchable.

A. 3.27. The premise of this request is flawed. The Companies have not represented that solar PPAs are dispatchable capacity.[14] Regarding dispatchability of owned solar, *see, e.g.*, the SB4 Bellar Testimony at 10-11. See the responses to AG-KIUC 3-4, AG-KIUC 3-12, and AG-KIUC 3-13.

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[14] *See, e.g.*, Table 2 on page 9 of the SB4 Bellar Testimony.

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Question No. 3.28

Responding Witness: David S. Sinclair

Q. 3.28. Please confirm that the lack of on-site natural gas storage for a natural gas plant potentially limits its dispatchability as Firm Transportation (FT) only guarantees delivery, not supply.

A. 3.28. See the response to KCA 2-37. Based on EIA's forecast of U.S. gas supply and the Companies' historical experience with regard to purchasing sufficient gas supply, the Companies do not have reason to believe that gas supply will not be available.

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Question No. 3.29

Responding Witness: Lonnie E. Bellar / Stuart A. Wilson

Q. 3.29. Under Sec. 2(2)(b) of Senate Bill 4 "(t)he retirement will not harm the utility's 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[.]" Please document that in years one through 10, how there will not be 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 this law.

A. 3.29. The premise of this request is flawed. Senate Bill 4 does not prescribe a time period over which to calculate net incremental costs. Moreover, a ten-year timeframe is an inappropriate period over which to assess the economics of replacement generation with a useful life well in excess of ten years, which is why the Companies calculated PVRR over a longer period.

That aside, the table below compares annual revenue requirements for Portfolio 8 in Exhibit SB4-1 (Final CPCN Portfolio) to Portfolio 0 (No Retirements; Add DSM) in the Mid Gas, Mid Coal-to-Gas Ratio Fuel Price Scenario. The PVRR (in 2022 dollars) in years one through 10 for Portfolio 8 is $150 million higher, but the PVRR over the entire analysis period for Portfolio 8 is $609 million lower. The Companies note that Portfolio 0 presumes continued operation of existing units through 2050 and does not contemplate incremental environmental regulations that may further increase the cost of the No Retirements portfolio.

RR Delta, Final CPCN Portfolio less No Retirements Portfolio ($M)

Year	**RR, Portfolio 8 less Portfolio 0**	**RR, Portfolio 5 less Portfolio 0**
2023	(0)	(1)
2024	4	(1)
2025	26	16
2026	54	23
2027	40	9
2028	45	22
2029	38	17
2030	7	(11)
2031	3	(9)
2032	(15)	(23)
Years 1-10 PVRR	150	39
Years 11+ PVRR	(759)	(646)
Full Analysis Period PVRR	(609)	(607)

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Question No. 3.30

Responding Witness: Robert M. Conroy

Q. 3.30. Please confirm that the Companies will be seeking recovery of the stranded costs out of all of the retirements proposed.

A. 3.30. The Companies have and will continue to seek recovery of all prudent costs including any remaining unrecovered net book balance on retired units.

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Question No. 3.31

Responding Witness: Christopher M. Garrett / Stuart A. Wilson

Q. 3.31. Please also confirm that the annual undepreciated costs for the existing coal capacity even with SCR retrofits through 2035 are significantly below the annual depreciated costs for the new NGCC's. If not confirmed, please explain why that is not the case.

A. 3.31. Not confirmed. The Companies are unclear on the definitions of the "annual undepreciated costs for the existing coal capacity even with SCR retrofits" and "annual depreciated costs for the new NGCCs." As shown in the response to Question No. 3.29, the PVRR of the Companies' proposed CPCN-DSM portfolio compared to maintaining the Companies' current portfolio becomes favorable to the proposed portfolio on an annual basis beginning in 2032 using mid gas price, mid-CTG assumptions, and it results in cumulative PVRR benefits of $609 million through the full analysis period. Similarly, retiring the seven fossil-fuel-fired generating units as the Companies have proposed and replacing them only with the two proposed NGCC units results in annual PVRR benefits beginning in 2030, and results in cumulative PVRR benefits of $607 million through the full analysis period.

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Question No. 3.32

Responding Witness: Lonnie E. Bellar

Q. 3.32. Please confirm that the decision to retrofit SCRs on Mill Creek 2 and Ghent 2 are separate decisions from extending the lives for these units beyond 2032. If not confirmed, please explain.

A. 3.32. Not confirmed. Given the large capital investment required for the SCRs, it would be imprudent to not consider the future operating lives of Mill Creek 2 and Ghent 2 and the future cost of operating those units beyond 2032 when comparing the SCR investment decision to other generating alternatives.

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Question No. 3.33

Responding Witness: Lonnie E. Bellar

Q. 3.33. Please confirm that the Companies analysis and supporting documentation that supports their decision to request approval to retire the seven fossil fuel-fired generating units, individually and/or collectively, does not include the benefit of any financial incentives or benefits offered by any federal agency. If not confirmed, please provide a schedule of each financial incentive or benefit the Companies expect to receive.

A. 3.33. See the response to AG-KIUC 3-15(a).