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	)))))))	**CASE NO. 2022-00402**

RESPONSE OF
KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY
TO
THE ATTORNEY GENERAL'S
SUPPLEMENTAL REQUEST FOR INFORMATION
DATED APRIL 14, 2023

FILED: MAY 4, 2023

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is Chief Operating Officer for Louisville Gas and Electric Company and Kentucky Utilities 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.

Lonnie E Bellar

Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 1st day of May 2023.

Caroline J. Dawson

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, **John Bevington**, being duly sworn, deposes and says that he is Director – Business and Economic Development 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.

John Bevington

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 1st day of May 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, **Robert M. Conroy**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates, 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.

Robert M. Conroy

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 1st day of May 2023.

TAMMY J. ELZY
COMM EXPIRES 11/09/2026
NOTARY PUBLIC
ID # KYNP61560
STATE AT LARGE, KENTUCKY

Tammy J. Elzy

Notary Public

Notary Public ID No. KYNP61560

My Commission Expires:

November 9, 2026

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Christopher M. Garrett**, being duly sworn, deposes and says that he is Vice President, Finance and Accounting, 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.

Christopher M. Garrett

Christopher M. Garrett

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 1st day of May 2023.

TAMMY J. ELZY
COMM EXPIRES 11/09/2026
NOTARY
PUBLIC
ID # KYNP61560
STATE AT LARGE, KENTUCKY

Tammy J. Elzy
Notary Public

Notary Public ID No. KYNP61560

My Commission Expires:

November 9, 2026

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Philip A. Imber**, being duly sworn, deposes and says that he is Director – Environmental and Federal Regulatory Compliance 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.

Philip A Imber

Philip A. Imber

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 2nd day of May 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, **Lana Isaacson**, being duly sworn, deposes and says that she is Manager – Emerging Business Planning and Development for Louisville Gas and Electric Company and Kentucky Utilities Company, 220 West Main Street, Louisville, KY 40202, and that she has personal knowledge of the matters set forth in the responses for which she is identified as the witness, and the answers contained therein are true and correct to the best of her information, knowledge, and belief.

Lana Isaacson
Lana Isaacson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 1st day of May 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, **Charles R. Schram**, being duly sworn, deposes and says that he is Director – Power Supply 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.

Charles R. Schram

Subscribed and sworn to before me, a Notary Public in and before said County and State this 1st day of May 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, **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

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 1st day of May 2023.

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. Wilson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 1st day of May 2023.

Caroline J. Davison
Notary Public

Notary Public ID No. KYNP 63286

My Commission Expires:

January 22, 2027

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

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 1

Responding Witness: Lonnie E. Bellar / Counsel

Q-1. Other than the petition that will be filed in docket no. 2023-00122, explain whether the Companies will initiate any additional steps in the instant docket in order to comply with Senate Bill 4 (2023 Regular Session of the Kentucky Legislature).

A-1. Because the subject matter of the application the Companies intend to file in Case No. 2023-00122 is essentially a subset of the subject matter of this proceeding, the Companies intend to file a motion with their application asking the Commission to consolidate Case No. 2023-00122 into this case and to incorporate by reference the record of Case No. 2020-00061. The Companies intend to file both their application in Case No. 2023-00122 and the consolidation and incorporation motion on May 10, 2023.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 2

Responding Witness: Lonnie E. Bellar

Q-2. Confirm that the Companies have entered into an agreement with PJM and TVA, termed the "PJM, TVA and LG&E/KU Joint Reliability Coordination Agreement."[1] If so confirmed:

a. Provide a copy of this agreement.

b. Provide a discussion regarding whether this agreement could improve the Companies' overall reliability, and if so, how.

c. If any cost-benefit analyses regarding joining this agreement were performed, provide copies. If such analyses were conducted in Excel, provide them with all cells and rows fully accessible.

d. Confirm that MISO will no longer participate in this agreement.

e. Explain whether the Companies anticipate any changes to their transmission system as a result of this agreement. Include in your discussion an explanation of whether the agreement could improve energy flows between the TVA, LG&E-KU and PJM transmission systems.

f. Explain whether the agreement will have any impact on the Companies' projected future reserve requirements, ability to sell capacity/energy, and/or ability to buy capacity/energy. If so, then describe each such impact.

g. Explain whether NERC and/or FERC approval is necessary for this agreement, and if so, provide the status of each such approval.

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[1] *See* the PJM slide deck presented to PJM's Interregional Market Operations MC Webinar, on March 20, 2023, accessible at: https://www.pjm.com/-/media/committees-groups/committees/mc/2023/20230320-webinar/item-02---pjm-tva-lge-ku-joint-reliability-coordination-agreement-update.ashx

A-2. The Companies have not yet entered into an agreement with PJM and TVA but are nearing execution of such agreement. The parties are hoping to execute the agreement in May.

a. The agreement has not yet been executed by the parties.

b. The agreement provides for more clarity in how the parties intend to coordinate in short term and long-term reliability planning and the processing of new service requests when it is identified that a new service request or planning issue could impact one of the other parties. The agreement also documents the parties' processes for communication and coordination in real time as adjacent operating entities and clarifies responsibilities with respect to pseudo-ties. Finally, the agreement incorporates the current Congestion Management Process ("CMP").

c. As a coordination agreement, the JRCA does not include any rates or service charges. Any assignment of costs between the parties would be memorialized in a separate agreement. As such, there was no cost-benefit analysis performed.

d. MISO has not been a party to the agreement since August 8, 2014, when MISO voluntarily withdrew as a signatory.

e. The Companies do not anticipate any changes to the transmission system as a result of the agreement but do anticipate improved communication and coordination in affected system studies and planning. The JRCA largely reflects the current operating practices of the parties and does not obligate any party to construct any new transmission or modify energy flows between the TVA, PJM, and LG&E-KU transmission systems. That said, the JRCA does incorporate the revised CMP, agreed to in 2022 by the Congestion Management Process Council, which are expected to enhance the management of flows between participating entities to the CMP.

f. No impact is expected.

g. Upon execution, PJM and LG&E-KU will file the JRCA with FERC for approval. TVA is non-jurisdictional and will not be joining in the request for FERC approval. NERC approval is not required.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 3

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

Q-3. Provide the annual value derived from the beneficial reuse of coal combustion residuals (CCRs).

a. Confirm that the full dollar value of the sale of CCRs inures to ratepayers' benefit.

b. Confirm that as the number of coal-fired power plants and CCR suppliers across the U.S. continues to decline, the value of CCRs continues to increase.[2]

c. Provide the projected total value derived from the beneficial reuse of CCRs that will cease based on the premature retirement of the Brown Unit 3, Ghent Unit 2, and Mill Creek Unit 2 coal-fired units.

d. Explain whether the lost value of the sale of CCRs was included in the Companies' cost-benefit analyses utilized in their proposals to retire these three units.

A-3. Note that all references to Exhibit SAW-1 herein and throughout the Companies' responses are to the updated May 2023 Exhibit SAW-1 provided in response to JI 2-60(a).

The revenue from CCR sales was $15 million in 2021, $19 million in 2022, and is projected to be over $20 million in 2023.

a. Confirmed. Beneficial reuse proceeds are included in the ECR mechanism.

b. Confirmed.

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[2]See, e.g., https://www.bizjournals.com/louisville/news/2023/04/01/sustainable-efforts-save-19-million-for-customers.html?ana=e_me_native&j=31044835&senddate=2023-04-03

c. The Companies disagree with the question's premise that Brown Unit 3, Ghent Unit 2, and Mill Creek Unit 2 are being "premature(ly)" retired. They are being economically retired. Because of its location, very little CCR is beneficially reused from Brown Unit 3. The table below shows the PVRR difference in revenues from beneficial reuse of CCR between Portfolio 1 (retiring Mill Creek 2 and Ghent 2; adding Mill Creek and Brown NGCCs and 637 MW PPA solar) and Portfolio 5 (SCR on Mill Creek Unit 2 and Ghent Unit 2) from Stage Two, Step Two of the Resource Assessment across the six fuel price scenarios with zero CO_2 price. The reduction in CCR revenue in Portfolio 1 does not overcome the higher cost of Portfolio 5 as can be seen in Table 13 on page 32 of Exhibit SAW-1.

Fuel Price Scenario (Gas, CTG Ratio)	**CCR PVRR Delta ($M, 2022 Dollars)**
Low Gas, Mid CTG	(119)
Mid Gas, Mid CTG	(110)
High Gas, Mid CTG	(97)
Low Gas, High CTG	(121)
High Gas, Low CTG	(85)
High Gas, Current CTG	(111)

d. Yes. See Exhibit SAW-1, Section 7.4.1.

KENTUCKY UTILITIES COMPANY
AND
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Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 4

Responding Witness: Philip A. Imber / Stuart A. Wilson / Counsel

Q-4. Reference the responses to AG-DR-1 and 2.

a. Confirm that the Companies' responses were based on the proposed Good Neighbor Plan ("GNP") rule.

b. If so confirmed, explain whether the Companies' responses to these (and any other data requests) remain unchanged based on the EPA's March 15, 2023 publication of the GNP Pre-Publication Final Rule, as announced in the footnote below.[3] The link to the actual Final Rule is accessible in the following footnote.[4]

A-4.

a. Confirmed.

b. The following addresses changes and supplements to previously filed data responses based on pre-publication of the Good Neighbor Plan final rule. This response is an update to the following data responses issued in the initial requests for information:

- Public Service Commission Question Nos. 9, 11, 41, and 56
- Attorney General Question Nos. 1, 2, and 42
- Joint Intervenor Question Nos. 25, 26(b), 35, 51, and 99
- Kentucky Coal Association Question Nos. 7, 9, and 14
- LFUCG/Lou Metro Question Nos. 14, 22, and 47
- KIUC Question No. 2(c)

[3] https://www.epa.gov/newsreleases/epa-announces-final-good-neighbor-plan-cut-harmful-smog-protecting-health-millions
[4] https://www.epa.gov/system/files/documents/2023-03/FRL%208670-02 OAR_Good%20Neighbor_Final_20230314_Signature_ADMIN%20%281%29.pdf

The final Good Neighbor Plan was pre-published on March 15, 2023; as of May 3, 2023, it has not been published to the Federal Register. It can be found at:

https://www.epa.gov/system/files/documents/2023-03/FRL%208670-02-OAR_Good%20Neighbor_Final_20230314_Signature_ADMIN%20%281%29.pdf

The final Good Neighbor Plan contains several updates from the proposed version:

1. The rule preset firm state budgets for 2023 through 2025.
2. The rule preset state budgets for 2026 through 2029 as a floor level. However, ultimately, the 2026 through 2029 state budgets will be based on the higher of the preset state budget or what the dynamic budgeting process yields. The dynamic budgeting process will dictate state budgets in 2030 and beyond.
3. The preset state budget for Kentucky increased through 2026. This increase resulted in a 1,374 ton increase in the Companies' unit allocations. The final rule adjusted the 2026 control period allocations to be based on state-of-the-art combustion control limit for half of the ozone season and SCR control limit for half of the ozone season.
4. The backstop limit on non-SCR units is delayed from the 2027 ozone season to one year after SCR installation or no later than the 2030 ozone season.
5. With respect to the backstop limit, the final rule exempts 50 tons of NOx from a unit with existing SCR controls prior to implementing a 3-for-1 allowance surrender ratio for backstop limit emissions exceedances. As a result, the allocations available to non-SCR units allow self-compliant ozone season operation for approximately 25 days (150/6) from 2026-2029 and approximately 8 days in 2030.
6. As part of the allowance bank recalibration process, the target percentage of the sum of the state budgets for the 2024-2029 control periods was increased from 10.5% to 21%.
7. The secondary emissions limits, which are contingent on state assurance level exceedances, will only apply to units with post-combustion NOx controls and that operate for more than 10% of ozone season operating hours.
8. Generation shifting was eliminated in the final rule.
9. Tennessee and Wyoming were removed from the Federal Implementation Plan. EPA anticipates addressing their potential impacts on downwind receptors in a subsequent rulemaking.

In the preamble of the final Good Neighbor Plan, EPA contends the final rule adds flexibility and resolves reliability issues by extending the deadline for the backstop limit, using higher bank recalibration target percentage through the 2029 control period, and presets state emissions budgets not only for the control periods in 2023 and 2024 as proposed, but also for the control periods in 2025 through 2029.

Overall, the Companies recognize the final Good Neighbor Plan offers additional compliance flexibility. However, the final Good Neighbor Plan continues to base compliance on implementation of SCR controls on non-SCR units in 2026. Assuming SCR implementation is the compliance strategy, the Companies must implement SCR controls in 2026 (approximately a three-year engineering, procurement, and construction schedule) to provide reliable service while complying with the reduction of allocations in 2026. If SCR controls are not implemented, non-SCR unit availability will be severely impacted by the State Budget, Unit Allocations, and Bank Recalibration aspects of the final rule. Since pre-publication of the final Good Neighbor Plan, EPA staff has responded to stakeholder concerns about reliability and suggested supplemental rulemaking is under consideration to further address reliability concerns.

Assuming no investment in SCR controls and no implementation of NGCC in 2027 and 2028 as proposed in the CPCN, modeling for the proposed Good Neighbor Plan depicted a reliance on the allocation market as early as 2026. With the same operational assumptions, the final Good Neighbor Plan depicts a reliance on the allocation market as early as 2027. As a result, the final Good Neighbor plan does not change the timeline for the need to transition to lower emitting generating sources and therefore does not change the 2022 Resource Assessment.

The following tables are projected NOx emissions (with implementation of SCR control) and NOx allocations from the Good Neighbor Plan. The allocation numbers for 2023, 2024, and 2025 are fixed pre-set values provided by the EPA. The 2023 values will be prorated based on the effective date of the rule. The 2026 through 2029 preset allocations are calculated based on implementation of SCR controls on all non-SCR units. The preset budget allocation values in these years are a floor; actual unit allocations for 2026 through 2029 will be the greater of dynamic budgeting or the preset allocations. Per the question, this table assumes the units operate and receive allocations via dynamic budgeting. Allocations for 2030 are “to be determined” (“TBD”) because EPA did not produce a preset state budget value for 2030 and beyond.

Ghent Unit 2 Ozone Season NO_x Emissions

Year	Forecasted Ozone Season NO_x Emissions by Fuel Price Scenario (tons)						Projected NO_x Allocations (tons)
	Low Gas, Mid CTG	Mid Gas, Mid CTG	High Gas, Mid CTG	Low Gas, High CTG	High Gas, Low CTG	High Gas, Curr CTG	
2023	1,827	1,822	1,838	1,805	1,838	1,784	756
2024	1,700	1,707	1,749	1,669	1,727	1,658	788
2025	862	901	905	854	925	657	780
2026	224	221	220	221	226	211	483
2027	223	221	224	220	225	213	345
2028	223	227	227	223	227	222	342
2029	223	224	226	221	227	219	318
2030	212	211	214	216	214	209	TBD

Mill Creek Unit 2 Ozone Season NO_x Emissions

Year	Forecasted Ozone Season NO_x Emissions by Fuel Price Scenario (tons)						Projected NO_x Allocations (tons)
	Low Gas, Mid CTG	Mid Gas, Mid CTG	High Gas, Mid CTG	Low Gas, High CTG	High Gas, Low CTG	High Gas, Curr CTG	
2023	1,243	1,175	1,143	1,233	1,154	1,093	410
2024	1,320	1,199	1,208	1,288	1,231	1,140	427
2025	619	656	672	626	661	678	422
2026	177	175	171	178	174	165	261
2027	193	183	183	191	182	173	187
2028	193	185	178	193	181	169	185
2029	187	179	173	186	175	165	172
2030	184	181	175	186	177	163	TBD

Brown Unit 3 Ozone Season NO_x Emissions

Year	Forecasted Ozone Season NO_x Emissions by Fuel Price Scenario (tons)						Projected NO_x Allocations (tons)
	Low Gas, Mid CTG	Mid Gas, Mid CTG	High Gas, Mid CTG	Low Gas, High CTG	High Gas, Low CTG	High Gas, Curr CTG	
2023	63	95	119	64	127	85	383
2024	119	128	130	125	130	108	282
2025	160	157	162	158	166	140	282
2026	121	120	125	119	128	112	244
2027	129	130	133	129	136	108	175
2028	126	132	133	125	133	106	173
2029	113	115	120	113	121	97	161
2030	116	110	114	114	118	103	TBD

The Companies have no sound basis to expect any potential litigation will successfully delay the implementation of the Good Neighbor Plan. The contention that litigation will likely cause a delay implementing Good Neighbor Plan is speculative and an imprudent assumption for purposes of complying with the law and providing reliable least-cost service to customers.

The changes from the proposed version of the Good Neighbor Plan continue to base a NOx trading program on strict environmental controls, dynamic budgeting, bank recalibration, assurance level penalties, and back stop limits. The final rule offers marginally more emissions allocations in Kentucky's State Budget and the resulting Unit Level allocations; nonetheless, the Companies estimate a shortage of allowances in the timeframe of 2026, 2027, or 2028 that supports the retirement or idling of non-SCR units and the resulting need for lower-emitting replacement generation as posed in the CPCN filing. For the reasons discussed in Mr. Bellar's testimony, the time to act is still now.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 5

Responding Witness: Lonnie E. Bellar

Q-5. Reference the response to AG-DR-1-13 (j).

a. Explain whether the Trimble CTs are capable of operating on fuel oil.

b. If the response to subpart a., above, is "yes," and given further that: (i) the Texas Gas Transmission is the sole supply of natural gas to the Trimble Station; and (ii) no other gas pipelines are located near Trimble Station,[1] explain whether the Companies have conducted any studies regarding whether the addition of dual fueling capability at Trimble Station could enhance reliability in a cost-effective manner. If any studies have been conducted, then please provide copies.

c. Confirm that Trimble-1 is capable of operating from gas firing. If so, then provide the amount of the derate, if applicable.

d. Explain whether Trimble-2 is capable of operating from gas firing. If so, then provide the amount of the derate, if applicable.

A-5.

a. In their current configuration, the Trimble CTs are not capable of operating on fuel oil. However, the Companies are evaluating options to modify the Trimble CTs to allow them to operate on fuel oil. In addition, the Companies are evaluating commercially available software improvements and gas compression options for these units that may provide incremental resiliency when operating on natural gas in conditions similar to those presented on December 23, 2022.

b. See the response to part (a).

c. The Companies cannot confirm that Trimble 1 is capable of operating from gas firing on a continuous basis. Trimble 1 has the capability to startup and provide flame stabilization via gas firing and generate approximately 100 MW in emergency

[1] See response to AG-DR-1-13 (f).

situations. The current TC1 air permit does not allow the unit to operate on gas other than for startup and stabilization.

d. The Companies cannot confirm that Trimble 2 is capable of operating from gas firing. Trimble 2 has the capability to startup and provide flame stabilization via gas firing but requires a coal mill to be in service to come online.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 6

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

Q-6. Reference the response to AG-DR-1-18. The note at the bottom of the table provided therein states, "Hydro and Solar based on nameplate ratings."

a. Provide the actual capacity factor for hydro and solar during those periods.

b. Given that winter peaks occur in mornings and/or in evenings, confirm that solar generation would be unable to contribute toward meeting the Companies' winter-time peak energy requirements.

c. Reference also the 2021-00393 docket,[6] the Companies' response to AG-DR-1-35, in which the Companies stated in pertinent part: "The increase in summer reserve margin is due to increased adoption of renewables, but not to account for any expected intermittency associated with renewables. The summer reserve margin increases because solar generation provides no contribution to winter reserve margin, and the Companies must add other forms of capacity to meet winter reserve margin requirements." Explain whether: (i) the Companies still agree that solar generation provides no contribution to winter reserve margin, and (ii) whether the Companies' response to AG-DR-1-33 in the instant docket is an affirmation of that statement.

A-6.

a. Capacity factor is calculated for the period under review by dividing the energy produced by the product of the unit's capacity and the hours in the period. For example, for a 30-day month, capacity factor = (energy produced)/(unit rating x 720 hours). The use of nameplate ratings in the denominator of the capacity factor calculation results in the "actual" capacity factor for hydro and solar units as displayed in the response to AG 1-18 for the eight requested months. Unit nameplate ratings are higher than the

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[6] In Re: Electronic 2021 Joint Integrated Resource Plan Of Louisville Gas & Electric Co. And Kentucky Utilities Co.

"expected" output at the time of winter peak for hydro and solar. Using a lower peak winter rating for hydro units would result in a less relevant and inflated capacity factor. Using the expected zero output of solar for a peak winter hour would result in a mathematical error (division by zero), regardless of the amount of solar energy produced during each month under review in the response to AG 1-18.

b. Confirmed. Winter peaks tend to occur in the mornings and evenings during non-daylight hours when solar resources would be unavailable.

c. The Companies agree with both points. As stated in the Companies' response to AG 1-33, "The Companies assume a winter capacity credit of zero for all solar because winter peaks tend to occur during non-daylight hours."

KENTUCKY UTILITIES COMPANY
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Dated April 14, 2023

Case No. 2022-00402

Question No. 7

Responding Witness: Lonnie E. Bellar

Q-7. Reference the response to AG-DR-1-22 (c). Explain the difference between hydrogen's energy content on a volume basis and its energy content on a mass basis. Also explain any potential impact that the use of hydrogen could have on the Companies' Fuel Adjustment Clause filings.

a. Explain whether a hydrogen-natural gas mixture could ever be used in LG&E's gas LDC business. If so, explain whether any additional costs would be involved. Include in your explanation whether a separate distribution system would have to be constructed for hydrogen.

b. Explain whether the Companies agree with the report, accessible at the link in the footnote below, indicating that when burned, hydrogen ". . . contributes to climate change by increasing the amounts of other greenhouse gases such as methane, ozone and water vapor, resulting in indirect warming. . . . And when we look at the relative warming impact from continuous instead of pulse emissions — which are more representative of the real world — hydrogen is 100X more potent than CO2 emissions over a 10-year period."[7] Include in your explanation whether the Companies believe that the burning of hydrogen will increase costs of their efforts to comply with the GNP, or other environmental rules.

A-7. Energy content on a 'volume basis' is a term conveying the energy content inherent to a given volume of hydrogen or natural gas, whereas the term energy content on a 'mass basis' conveys the energy content of a given mass (weight) of hydrogen or natural gas. The comparison made in the Companies' initial response notes that for the same volume of gas, natural gas has an energy content ~2.9 to ~3.2 times greater than hydrogen gas, whereas given the same mass (weight) of gas, hydrogen gas has an energy content ~2.6 to ~2.7 times greater than natural gas. The practice of hydrogen blending would be expected to be included in the Companies Fuel Adjustment Clause filings.

[7] https://www.edf.org/blog/2022/03/07/hydrogen-climate-solution-leaks-must-be-tackled

a. Integrating a hydrogen-natural gas mixture into a LDC business is still being evaluated. According to the Electric Power Research Institute, blending hydrogen in existing natural gas pipeline infrastructure is feasible between 1% to 20% hydrogen depending on the pipeline material and operating conditions. Additional costs and separate distribution systems depend on many factors including the end user. For example, certain industrial customers might require that 100% hydrogen be supplied to their business for a chemical process or emissions purposes, in which case additional equipment would be required to separate the hydrogen from the natural gas.

b. The Companies did not comment on the global warming potential of hydrogen in the Joint Application because combusting pure hydrogen with pure oxygen releases pure water and does not produce greenhouse gases. The report referenced in 2-7b above states "hydrogen itself emits no carbon dioxide when burned or used in a fuel cell." The subsequent quotes cited above in 2.7b are not from burning hydrogen as a fuel but for hydrogen leaked into the ambient air. Indeed, hydrogen, or any fuel leak, must be prevented. While combusting pure hydrogen with pure oxygen releases only water, the combustion of hydrogen with ambient air—which is mostly nitrogen—releases water and a small amount of nitrous oxides because of the nitrogen from the air reacting during combustion. The source of the nitrous oxides is the ambient air and temperature of combustion, not the fuel. The amount of nitrous oxides produced from the nitrogen in the ambient air varies by hydrogen blend, combustion temperature, and turbine configuration. The Companies are supporting ongoing research with OEM's and EPRI to prevent nitrous oxide emissions from hydrogen and all fuel combustion. Using hydrogen produced from renewable resources is expected to be more expensive than burning fossil fuels, but compliance costs for the GNP or any other environmental rule are not a significant driver of these increased costs.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 8

Responding Witness: David S. Sinclair

Q-8. Reference the response to AG-DR-1-25. Explain whether the costs of the referenced transmission upgrades have been included within the project cost estimates contained in the Companies' application. Provide a break-out of the projected costs of these upgrades, regardless of whether they have already been included in the total project cost projections portrayed in the application.

a. Provide also a discussion of all additional costs that will, or could be incurred for the Mercer County facility, given that it will not be located entirely within KU's service territory. Include in your response whether any such additional costs are included in the total project cost projections for this proposed facility set forth in the application.

A-8. No, the costs of transmission system upgrades for solar facilities were not included in the project cost estimates contained in the Companies' application. For a break-out of projected costs, see the response to PSC 2-54(a).

a. As stated in response to AG 1-25, while the Mercer County facility will not be entirely located within KU's service territory, the substation and tie-in to KU's 69 kV transmission line are located in KU's service territory. Therefore, there are no additional costs due to the facility's location.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 9

Responding Witness: Lonnie E. Bellar / David S. Sinclair

Q-9. Reference the response to AG-DR-1-27 (a). In the event the Companies' patent-pending process for recycling decommissioned solar panels becomes cost-effective, explain whether any potential proceeds earned from such recycling would inure to ratepayers' benefit.

a. Provide a discussion regarding whether the Companies intend to move forward with this technology, and if so: (i) whether they would license it to third parties; and (ii) whether any portion of licensing fees earned would inure to ratepayers' benefit.

b. To the extent any information regarding the recycling process is publicly available, provide background information regarding how this process works and the types of materials and substances it can extract and recycle.

A-9. The research with the University of Kentucky on recycling solar panels is still at the lab scale and under development. If the process becomes cost-effective, customers could benefit from lower costs of recycling, particularly because the Companies will have royalty-free access to the process.

a. The Companies funded continued research and development of the recycling solar panel process with the University of Kentucky at the end of 2022. The University of Kentucky owns the intellectual property and if the technology was licensed to third parties, the University of Kentucky would collect the licensing fees. The Companies and their customers will not receive revenues from licensing fees, but the Companies' customers could benefit from the process as described above.

b. The solar panel recycling process uses an electrochemical cell to recover silver from end-of-life solar panel wafers. The research is currently focused on recovering silver but can recover cadmium and lead as well.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 10

Responding Witness: Robert M. Conroy

Q-10. Reference the response to AG-DR-1-28 (b). The question asked, inter alia, to "[e]xplain whether any off-system sales ("OSS") from the BESS would inure to the benefit of LG&E customers, KU customers, or both." The only response was to refer to the response to subpart (b), which did not answer the question posed in subpart (c). Provide an appropriate response.

a. If the Companies intend to allocate any of these proceeds to KU ratepayers, provide a complete, and comprehensive, justification.

A-10.

a. The response to AG 1-28 (b) explained that off-system sales are not directly made from specific units and explained the stacking process in the After-the-Fact Billing ("AFB") system through which the cost of off-system sales is determined. The utility owning the asset which was allocated to off-system sales in the AFB process will receive the benefits of the margins. At this time, the Companies anticipate that any off-system sales proceeds related to energy discharged from the BESS that may be allocated to off-system sales through AFB will be allocated solely to LG&E customers.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 11

Responding Witness: Stuart A. Wilson / Counsel

Q-11. Reference the original response to AG-DR-1-28 (e), and the supplemental response thereto filed on March 27, 2023, both of which referred to, *inter alia*, Exhibit SAW-1 § 6.2.3.

a. Exhibit SAW-1 § 6.2.3 states, in pertinent part: "Therefore, the Brown BESS's ownership was assigned using a method similar to the method used for the jointly-owned CTs[8] by better balancing 2028 summer reserve margins based on dispatchable and battery capacity, after assigning the NGCC[9] units' ownership allocation." [Emphasis added]. Explain precisely how the method utilized to determine the ownership of the Brown BESS differed from the method utilized determined ownership of the jointly owned CTs.

b. Assuming the two NGCC plants are approved, explain whether any potential summer reserve margin shortfall in the LG&E system could be addressed through allocation of power from the three NGCC plants as opposed to: (i) the proposed battery; or (ii) a new CT.

c. Provide all workpapers associated with the methodology to determine ownership of the proposed BESS in Excel format, with all formulae fully accessible and intact.

d. Explain how the Companies believe that they have satisfied their burden of proof regarding ownership of the proposed BESS.

A-11.

a. The Companies determined the ownership allocations of the joint-owned CTs at times when both LG&E and KU had a capacity need to reach the then-current minimum summer reserve margin targets. Each company's share of

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[8] Combustion turbines.
[9] Natural Gas Combined Cycle.

the capacity additions was calculated such that the Companies' resulting summer reserve margins were effectively equal.

In the case of the proposed Brown BESS, once the ownership allocations of the other resources in this application were assigned, KU did not have a capacity need to meet the minimum summer reserve margin target. However, LG&E, which has a typically summer-peaking load, had a summer capacity need of 394 MW. Therefore, to better balance each company's summer reserve margin, the 125 MW Brown BESS was fully allocated to LG&E. This method differs from that of the joint-owned CTs in that it does not equate the Companies' summer reserve margins, but it does reduce the disparity.

b. This could be implemented but would be an inappropriate method of allocating ownership in that the ownership of energy-intensive baseload resources would be assigned using capacity measures. It would also be inconsistent with the Companies' historical and prior-approved methodology for allocating joint ownership of energy-intensive baseload resources based on energy savings.

c. See Exhibit SAW-2 at \CONFIDENTIAL_05_ResourceOwnership\20221128_2022RFPRAOwnership_0308_D04.xlsx.

d. The Companies object to this request to the extent it calls for a legal conclusion regarding what satisfies a burden of proof. That notwithstanding, the Companies have explained their reasoning and evidence for allocating 100% of Brown BESS to LG&E in Section 6.2.3 of Exhibit SAW-1 and the Companies' responses to PSC 1-47(a) and AG 1-28(e) and (h).

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 12

Responding Witness: Stuart A. Wilson

Q-12. Explain whether the Companies prepared any cost-benefit analyses regarding the proposed BESS. If so, provide copies.

a. Explain whether any such cost-benefit analyses include O&M costs over the projected 15-year lifespan. If not, explain why not.

b. Given that the Companies' projected lifespan of the BESS is only 15 years, explain whether benefits ever could exceed costs.

c. If costs exceed benefits, confirm that the BESS would not be a least-cost resource.

A-12. Yes. See section 4.6.2 of the updated Exhibit SAW-1 Resource Assessment provided as an attachment in response to PSC 1-47(a).

a. Yes, the 2028 carrying cost includes capital and O&M costs for the proposed BESS.

b. As currently modeled, the costs exceed the benefits of the BESS. As stated in section 4.6.2, the primary value in adding the BESS is to provide operational experience for integrating future renewable generation. Benefits could exceed costs in a scenario where the BESS eliminates or defers the need to replace an SCCT or in a scenario with high penetration of renewable generation.

c. See the response to part (b).

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 13

Responding Witness: Stuart A. Wilson

Q-13. Reference the response to AG-DR-1-30. Explain why the BESS's projected operating costs for the December-March period are generally significantly lower than the April-November period in the referenced fuel price scenarios.

A-13. The operating expenses for the BESS were assumed to be divided evenly throughout the year. Projected operating costs for the December-March period are lower than the April-November period because December-March spans four months while April-November spans eight months.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 14

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

Q-14. Explain whether the Companies agree that in a hypothetical situation, a utility seeking to move to 100% renewable generation resources should, as a matter of prudent cost estimation, also include the cost of replacement power needed to maintain system reliability.

a. Regarding the Companies' proposed solar resources in the instant docket, discuss to what extent the Companies' modelling analyzed and assessed the additional costs that would be incurred in procuring replacement power needed to maintain a reliable system due to the intermittent nature of solar generation.

b. Discuss whether the Companies' modeling identified not just the cost of adding more renewables to its system, but also the value of those resources. Include in your discussion how the Companies chose to define value.

c. Explain whether the Companies agree that in comparing the relative costs of dispatchable resources and renewables, utilizing a measure of the levelized avoided cost of electricity can provide a meaningful value.[10]

A-14. Prudent resource planning always considers the physical performance capabilities, risks, and uncertainties of each technology in evaluating and developing an optimal portfolio to reliably serve a given load profile. Developing a 100 percent renewable generation portfolio would be no different.

a. As stated in Mr. Sinclair's Direct Testimony on page 18 lines 15-20 and page 19 line 1, "…the Companies must ensure that adequate supply will be available at all times. Thus, the Companies' generation portfolio proposed in this filing maintains minimum reserve summer and winter reserve margins with fuel-dispatchable generation technology (which includes batteries since

[10] See, e.g., P. Bonifas and T. Considine, "The Limits to Green Energy," Cato Regulation Institute, Winter 2022-2023, accessible at: https://www.cato.org/regulation/winter-2022-2023/limits-green-energy (last accessed March 20, 2023).

they would be charged with fuel-dispatchable generation at this time) while at the same time significantly increases the volume of solar generation on the system to hedge future natural gas price volatility and reduce exposure to future CO_2 regulations."

b. See the response to part (a).

c. The Companies do not utilize the levelized cost of energy, avoided or not, to compare technologies. It is an overly simplistic value that fails to recognize the key objective function of a utility: minimizing the cost of reliably serving actual customer load in real-time across a broad array of weather conditions. Effectively doing this requires a portfolio approach to technology evaluation, not a simplistic levelized average cost approach.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 15

Responding Witness: Robert M. Conroy / Christopher M. Garrett

Q-15. Reference the response to AG-DR-1-38. Confirm that the net book value as of the most recent projected retirement dates for the four units discussed therein totals $694.3 million.

a. Confirm that these sums will be recovered via the Companies' Retired Asset Recovery Rider (RARR), together with weighted average costs of capital (WACC).

b. Provide the amortization period that will be applied to the recovery of these funds through the RARR.

c. Confirm that costs of decommissioning, and demolition of the four plants will also be recovered through the RARR.

d. Confirm that the costs of the four plants recovered in base revenues will be credited to any recoveries through the RARR until base rates are reset in a future base rate case proceeding. If this is not the case, then explain how the Companies will ensure that: i) customers will not pay twice for the return of and on the rate base investment in the four plants, and ii) customers will timely receive the benefit of the reduction in non-fuel and non-depreciation operating expenses after the plants are retired.

e. Based on the WACC charges that will be applied over the amortization period, provide the total known costs that will be passed through to ratepayers as of the final year for the amortization period. Provide the support for your response in Excel live format with all formulas intact.

A-15. Confirmed.

a. The applicable retirement costs (including the associated carrying costs calculated using the companies' weighted average cost of capital) for Mill Creek Unit 1, Mill Creek Unit 2 and Brown Unit 3 will be recovered via the

RARR as specified in the Stipulation and established in the Orders in Case Nos. 2020-00349 and 2020-00350. With regards to Ghent Unit 2, the specific rate recovery methodology for the associated retirement costs has not been established at this time. The ultimate retirement costs to be recovered through the RARR or other rate recovery will not be known until the units are retired. Furthermore, the $694.3 million is an *estimate* of the remaining net book values at the dates of projected retirements and does not include any associated decommissioning costs.

b. The RARR provides for a 10-year amortization period from the retirement date of the unit.

c. The RARR provides for the recovery of decommissioning and demolition costs. See the response to part (a) for additional information.

d. As agreed to in the Stipulation Section 5.3 (C), the RARR includes a credit for the depreciation expense and rate of return component for each retired unit embedded in base rates, but no credit for any other expense embedded in base rates.

e. See attachment being provided in Excel format.

The attachment is being provided in a separate file.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 16

Responding Witness: John Bevington

Q-16. Reference the response to AG-DR-1-62. Provide the Total Resource Cost (TRC) test score for rooftop solar as a DSM program.

a. Confirm that the attachment provided in response to this question entitled, "2021 Rooftop Solar Potential Study Report" at p. 42 indicates that residential rooftop solar has a TRC of 0.88.

b. Explain the difference(s) between the Modified TRC test, and the traditional TRC test.

A-16. The Companies have not performed a TRC test on rooftop solar.

a. Not confirmed. The "2021 Rooftop Solar Potential Study Report" indicates that residential rooftop solar has a *Modified* TRC score of 0.88. A traditional TRC score would be lower because it would not include the non-energy benefits in the cost-benefit analysis.

b. As stated in the "2021 Rooftop Solar Potential Study Report, the Modified TRC score as calculated in the report also includes reduced or avoided emissions as a benefit. As described on page 20, these benefits were valued at $0.013/kWh.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 17

Responding Witness: John Bevington

Q-17. Reference the response to PSC-DR-1-23. Given that residential rooftop solar requires significant up-front capital, explain whether the Companies' proposed increase in their Market Research budget to research possible solar DSM offerings will include community solar, and any potential programs targeted specifically to Income Qualified customers.

A-17. The Companies have not yet determined the specific market research activities, but they could include potential programs that serve the needs of income qualifying customers, including community solar, in addition to the stated research on rooftop solar as a possible DSM offering.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 18

Responding Witness: Lana Isaacson

Q-18. Reference the response to AG-DR-1-66. With regard to both: (i) the existing Residential and Small Nonresidential Demand Conservation subcomponent; and (ii) the new Smart Thermostats, Room Air Conditioners, Water Heaters measure, explain how the Companies:

a. communicate to customers that their thermostat will be controlled; and

b. obtain affirmative authority from the customers to do so.

A-18.

a. For the existing Residential and Small Nonresidential Demand Conservation subcomponent, the Companies communicate all aspects of the possibility of a control event (to air conditioners or heat pumps) during the enrollment process. For the proposed Bring-Your-Own-Device subcomponent, the Companies plan to inform customers that their devices will be controlled at several times, including during the enrollment process, in advance of planned events, and when events begin. The Companies anticipate communicating with the customer during enrollment through the customer DSM platform portal. The Companies expect to communicate event-based details through the customer's preferred communications channels, which may include text messaging, interactive voice response phone call, and email. The Companies will also use the communication capabilities of the enrolled devices where possible.

b. For the existing Residential and Small Nonresidential Demand Conservation subcomponent, the Companies obtain affirmative authority from customers to control their air conditioners and heat pumps at the time of enrollment. During enrollment for the proposed Bring-Your-Own-Device subcomponent, the Companies will obtain affirmative authority from the customer to control their enrolled devices. Also, during enrollment the Companies will ask customers for their preferred communications channel or channels and approval to use those channels to send the customer information of events.

The Companies will seek software for the Bring-Your-Own-Device subcomponent that allows participants to opt out of events using their device or by responding to event communications through text, interactive voice response phone call, or email.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 19

Responding Witness: John Bevington

Q-19. Reference the response to AG-DR-1-69. Provide the most recent actual amounts of the dues for both organizations identified in the response.

A-19. E Source Companies LLC: $47,150 for 1-year period of 4/1/2022 to 3/31/2023.
MEEA: $30,600 for 2-year period of 7/1/2022 to 6/30/2024.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 20

Responding Witness: Lana Isaacson

Q-20. Reference the response to PSC-DR-1-20. Confirm that when the Companies perform cost-benefit analyses of prospective DSM programs, the costs thereof are passed on to ratepayers, either through the DSM surcharge, or in base rates.

a. Provide an estimate of the costs of completing the requested cost-benefit analyses.

b. Explain whether the referenced cost-benefit analyses will include costs for preparing the cost-benefit analyses.

c. Provide an itemization of all costs considered in the referenced cost-benefit analyses.

A-20. Program development costs are typically recovered through the DSM mechanism.

a. The estimated cost to complete the requested cost-benefit analysis for the three new programs the Companies agreed to perform in response to PSC 1-20 is $50,000. The Companies do not have an estimate of the cost to run the cost-effectiveness analyses for all seven programs requested in PSC 1-20.

b. The referenced cost-benefit analyses will not include as a "cost" any costs specific to preparing the cost-benefit analyses.

c. The itemization of all related costs should be available at the conclusion of the work. The Companies will supplement the request should the details not be provided in time for inclusion. The itemized costs will include the consultant's job level, hours worked for the invoiced period, the respective hourly rate, and the equivalent total cost.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 21

Responding Witness: Lonnie E. Bellar / Robert M. Conroy / Charles R. Schram / David S. Sinclair

Q-21. Reference the response to PSC-DR-1-27. Assuming the solar merchant facilities are in fact completed and become commercially operable, confirm the following:

a. Retail ratepayers will be responsible for the $9.8 million in transmission interconnection costs for the Song Sparrow (Clearway Energy) facility. If the amount is not correct, please provide: (i) the amount of the transmission interconnection cost for which retail ratepayers will be responsible; and (ii) the overall total system upgrade costs required to accommodate the output from this facility.

b. Retail ratepayers previously paid a certain amount of costs for the Gage (BrightNight LLC) facility. Please provide: (i) the amount of those costs; and (ii) the overall total system upgrade costs required to accommodate the output from this facility.

c. Neither the Grays Branch (ibV Energy Partners) nor the Nacke Pike (ibV Energy Partners) have submitted generator interconnection requests to the Companies' Independent Transmission Organization. Explain whether any of the other components of the overall total system upgrade costs required to accommodate the output from these facilities have been identified, and if so, provide them and explain the proportion for which retail ratepayers will be responsible.

A-21.

a. (i) The approximate $9.8 million related to the Transmission Owner's Costs for Interconnection Facilities will be primarily recovered through future retail base rates; however, a portion of the costs will be recovered through the Transmission Owner's Open Access Transmission Tariff ("OATT") transmission formula rate. Unaffiliated transmission customers contribute approximately 15-20% of the Companies' joint transmission revenue requirement as calculated by the OATT formula rate. OATT revenue is a credit to retail ratepayers in a retail rate case since the transmission costs are included in the Companies' retail revenue requirements. (ii) Total system upgrade costs beyond the interconnection facilities are not yet certain. The Companies are still evaluating the most effective mitigation for constraints in the area.

b. (i) Phase I of the Gage facility does not yet have an executed LGIA, nor has construction started; therefore, LG&E and KU retail customers have not paid anything related to that effort.

   (ii) The Transmission Owner's costs related to Phase I of the Gage facility could be approximately $13 million, of which a portion would be recovered through future retail base rates. However, there is a very substantial possibility that these projects will ultimately not be needed as the planned retirement of an unaffiliated generating facility nearby will negate the need for these projects. That retirement is not yet certain and could be withdrawn.

c. To accommodate the output from Grays Branch, transmission system upgrades at the cost of $240,000 are expected based upon preliminary internal studies. To accommodate the output from Nacke Pike, transmission system upgrades at a cost of $4,812,500 are expected. Please see "\04_FinancialModel\Support\TransmissionCapital\ CONFIDENTIAL_Generation Replacement Scenarios - Impacts on the Transmission System_2022.docx" in Exhibit SAW-2. The proportion for which retail ratepayers will be responsible is the same as stated above.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 22

Responding Witness: Lonnie E. Bellar / David S. Sinclair

Q-22. Reference the following: (i) the application generally; (ii) the Companies' most recent assessment of the cost-effectiveness of joining an RTO; and (iii) the PJM report, "Energy Transition in PJM: Resource Retirements, Replacements and Risks" ("PJM Report") accessible at the link in the footnote below.[11]

a. Confirm that according to the PJM Report at page 1: (i) The growth rate of electricity demand is likely to continue to increase from electrification; (ii) thermal generators are retiring at a rapid pace and those retirements are at risk of outpacing the construction of new resources; and (iii) PJM's interconnection queue is composed primarily of intermittent and limited-duration resources.

b. Confirm that according to the PJM Report at p. 2, 21% of PJM's installed capacity is at risk of retiring by 2030.

c. Confirm that the PJM Report at p. 3 states: "The composition and performance characteristics of the resource mix will ultimately determine PJM's ability to maintain reliability. It is critical that all PJM markets effectively correct imbalances brought on by retirements or load growth by incentivizing investment in new or expanded resources."

d. Given the PJM Report's findings and conclusions, explain whether the cost-benefit analyses within the Companies' most recent RTO membership analysis evaluated any potential benefits of securing reliability must-run status for Ghent Unit 2, and/or Mill Creek Unit 2. If so, explain how the value of that status was calculated.

e. Confirm that if the Companies were to both join an RTO and secure reliability must-run status for Ghent Unit 2 and/or Mill Creek Unit 2, that status would

[11] https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx

not toll or delay the need for complying with some or all aspects of the GNP while the must-run status is in effect.

A-22.

a. Confirmed.

b. Confirmed.

c. Confirmed.

d. According to PJM, a Reliability Must Run ("RMR") refers to a generating unit that is slated to be retired by its owners but is needed to be available for reasons of reliability.[12] Typically, it is requested to remain operational beyond its proposed retirement date until transmission upgrades are completed. Note that this status would not exempt the unit from complying with federal law and regulations such as the Good Neighbor Plan. Also, the definition is clear that RMR status would apply only until the reliability issue can be addressed. Implementation of the Companies' proposed portfolio on the timeline proposed precludes considering RMR status for Ghent Unit 2 and Mill Creek Unit 2. Therefore, there would be no impact on the Companies' RTO analysis.

e. See the response to part (d).

[12] https://www.pjm.com/Glossary#index_R

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

**Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023**

Case No. 2022-00402

Question No. 23

Responding Witness: Lonnie E. Bellar / David S. Sinclair

Q-23. Explain whether the SCR for Brown Unit 3 could, after the unit is decommissioned, be removed and utilized on Ghent Unit 2. If so, provide: (i) a cost estimate, including how the potential moving of the SCR would affect the Companies' other relevant cost-benefit analyses; and (ii) a projection of possible months of operation for Ghent Unit 2 that would comply with the GNP.

a. If the Brown Unit 3 SCR cannot be utilized on Ghent Unit 2, then explain why not; explain also whether it would or could be cost effective to modify the SCR from Brown Unit 3 and utilize it on Ghent Unit 2 or explain why it would not be possible or cost effective; provide all studies performed to evaluate this option, including all analyses in Excel live format with all formulas intact.

b. To the extent that the Brown Unit 3 SCR can be utilized on Ghent Unit 2, provide the results of a portfolio that reflects the continued operation of Ghent Unit 2, including, but not limited to, the net present value savings or costs compared to the Companies' base reference portfolio in the same format as Tables 9 and 13 in Exhibit SAW-1.

A-23. The Brown Unit 3 SCR cannot be utilized on Ghent Unit 2 in its current configuration.

a. Brown Unit 3 must operate with its SCR; transferring the SCR forces cessation of Brown Unit 3 operation earlier than planned and eliminates a low-NOx generating resource during key years of GNP compliance. Ghent Unit 2 is approximately 20% larger than Brown Unit 3, 556 MW and 464 MW respectively. SCR sizing is directly related to unit rating, making the Brown 3 SCR approximately 20% too small for Ghent. Installing an undersized SCR at Ghent Unit 2 will not meet the stringent reduction requirements of the GNP. Retrofitting air quality control equipment is site specific based on available space, orientation, and boiler design. Attempting to take apart a large-scale custom piece of equipment, transport it, and reconfigure it under new site constraints has significant logistical, engineering, and construction uncertainty particularly given the tight compliance timeline of the GNP. The Companies did not evaluate this option.

b. See the response to part (a).

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 24

Responding Witness: Lonnie E. Bellar / David S. Sinclair

Q-24. Explain whether the SCR for Brown Unit 3 could, after the unit is decommissioned, be utilized on Mill Creek Unit 2. If so, provide: (i) a cost estimate, including how the potential moving of the SCR would affect the Companies' other relevant cost-benefit analyses; and (ii) a projection of possible months of operation for Mill Creek Unit 2 that would comply with the GNP.

a. If the Brown Unit 3 SCR cannot be utilized on Mill Creek Unit 2, then explain why not; explain also whether it would or could be cost effective to modify the SCR from Brown Unit 3 and utilize it on Mill Creek Unit 2 or explain why it would not be possible or cost effective; provide all studies performed to evaluate this option.

b. To the extent that the Brown Unit 3 SCR can be utilized on Mill Creek Unit 2, provide the results of a portfolio that reflects the continued operation of Mill Creek Unit 2, including, but not limited to, the net present value savings or cost compared to the Companies' base reference portfolio in the same format as Tables 9 and 13 in Exhibit SAW-1.

A-24. The Brown Unit 3 SCR cannot be utilized on Mill Creek Unit 2 in its current configuration.

a. Brown Unit 3 must operate with its SCR; transferring the SCR forces cessation of Brown Unit 3 operation earlier than planned and eliminates a low-NOx generating resource during key years of GNP compliance. Mill Creek Unit 2 is approximately 30% smaller than Brown Unit 3, 355MW and 464 MW respectively. SCR sizing is directly related to Unit rating, making the Brown 3 SCR too large for Mill Creek Unit 2. More specifically, the Brown Unit 3 SCR was designed for a 464 MW unit, whereas the Mill Creek Unit 2 is a 355 MW unit. The resulting difference in megawatt ratings would require a redesign of the Brown Unit 3 SCR based on a new Computational Fluid Dynamics model utilizing Mill Creek Unit 2 design parameters. In addition to redesigning the SCR itself, new foundations, support steel, and ancillary equipment would be required due to site-specific constraints between the two locations. Therefore, the Companies did not evaluate this option.

b. See the response to part (a).

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 25

Responding Witness: Stuart A. Wilson

Q-25. Reference the response to PSC-DR-1-54 regarding how the Companies modeled the uncertainty of solar PPA execution risk.

a. Confirm the following statement from Ex. SAW-1, § 4.6.1. p. 34 of 104: "Project execution is a particularly acute risk in the current solar market, as the Companies have experienced with the two solar PPAs they executed in 2019 and 2021 (Rhudes Creek and Ragland, respectively); neither project has received all necessary approvals, neither is on schedule or has begun construction, and neither is likely to proceed any time soon because it will be difficult or impossible to finance the projects at the contracted price in today's solar market and interest rate environment."

b. Confirm that in the event the following proposed solar facilities (with which the Companies seek to enter into PPAs) for whatever reason(s) are not constructed: (i) all four of the proposed non-owned facilities identified in the application for the instant case; and (ii) both the proposed Rhudes Creek and Ragland facilities, that adding the proposed Mercer County and Marion County solar facilities is favorable in the majority of cases evaluated.

A-25.

a. Confirmed.

b. Confirmed. See Table 17 of the updated Exhibit SAW-1 Resource Assessment provided as an attachment in response to PSC 1-47(a).

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 26

Responding Witness: David S. Sinclair

Q-26. Reference the response to AG-DR-1-57, and the article accessible in the footnote below.[13] Explain whether the Companies agree with the report cited in the article that reuse of retired coal plants could cut the costs of small modular nuclear reactors by 35%.

A-26. The Companies have no basis to opine on the accuracy of the prediction, especially since no small module nuclear reactor has been commercially deployed in the U.S. and that the ability to permit an existing coal plant site for a nuclear plant will be very site specific.

As an aside, it should be noted that constructing new generation at an existing site should result in lower costs than constructing the same technology at a greenfield site assuming that some of the existing infrastructure can be reused. As stated in the Sinclair testimony at page 7, lines 10-13, "I also directed our Project Engineering group to evaluate alternative generation and storage technologies that could be installed at the Mill Creek and Brown sites to take advantage of existing infrastructure to reduce future costs …." Also, re-using existing sites can reduce costs and time (which often translates into money) related to permitting. Constructing Mill Creek Unit 5 and Brown Unit 12 at the site of retiring coal units reduces the cost of those projects.

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[13] https://www.utilitydive.com/news/coal-plants-retire-advanced-nuclear-reactors-smr/645974/?utm_source=Sailthru&utm_medium=email&utm_campaign=Newsletter%20Weekly%20Roundup:%20Utility%20Dive:%20Daily%20Dive%2004-01-2023&utm_term=Utility%20Dive%20Weekender

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 27

Responding Witness: Lana Isaacson

Q-27. Reference the response to PSC-DR-1-79.

a. Identify the information technology (IT) the Companies intend to implement in 2024.

b. Explain whether this IT would be part of the communications back haul system for the AMI system.

c. Explain whether the costs for this IT equipment would be recovered through base rates, or through the DSM surcharge.

d. Provide the projected Peak Time Rebate program participation rate in year two of its existence, in terms of percentage of total customers of both companies, separately and combined.

e. Explain whether the Companies believe that by year 5, a participation rate stretch goal of 20% is reasonable.

A-27.

a. The Companies intend to implement IT software to support the Bring-Your-Own-Device and Optimized Charging subcomponents and a central platform software that will support the overarching DSM portfolio with an anticipated launch in January 2024. The Companies also intend to implement software to support the Residential Online Audit and Peak Time Rebates programs that launch in 2025.

b. This IT is not part of the communications backhaul system for the AMI system.

c. Costs for this IT software and any associated equipment will be recovered through the DSM surcharge.

d. Participation in the Peak Time Rebates program is forecast to be 5.2% of the total electric customer base in year two. Forecasted participation of LG&E electric customers is 6.1% and KU customers is 4.6%.

e. The Companies believe the program participation goal is reasonable based on a benchmarking of Peak Time Rebates programs from other utilities.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 28

Responding Witness: David S. Sinclair

Q-28. Reference the response to Kentucky Coal Association DR-1-5, Attachment 2, "Using Solar and Storage to Meet 100% of the Electricity Requirements of a Distribution Circuit: A Case Study for LG&E Highland 1103 Circuit," December, 2018, p. 2. This study was prepared in response to the City of Louisville's 100 Percent Clean Energy Resolution, and was presented by Mr. David Sinclair to the Louisville Metro Council. According to this document:

> "This study evaluates the solar generation and energy storage requirements and associated economics of serving the electricity requirements of the LG&E Highland 1103 distribution circuit with local resources on a standalone basis, without connection to the power grid. . . . This study is an attempt to quantify, at a high-level, some of the technological and economic challenges associated with serving a typical distribution circuit with 100% locally generated renewable energy."

a. Explain whether the Companies still confirm the following:

(i) "While the technical challenges of using just local solar generation and energy storage to reliably serve the real-time electricity needs of customers on this circuit can likely be met, doing so would require a large geographic space (almost as large as the circuit footprint);"

(ii) "Despite assuming customers would continue to use natural gas for space and water heating, the quantity of solar generation capacity required to be built would need to be about eight times greater than the summer hourly peak to generate enough energy to charge the batteries to reliably serve nighttime load and address extended periods of dense clouds and short days that are common during winters in Louisville."

(iii) "The cost of electricity would likely be two to five times higher over the 30-year study period as compared to continuing to take electricity from the LG&E system."

b. Discuss and explain whether the results would be similar for other circuits in both the LG&E and KU systems which have populations and loads similar to the Highland 1103 circuit.

c. Referring to the quote in subpart (iii) immediately above, explain whether the cost of electricity would escalate by a similar amount if: (i) the Companies owned the renewable generation; and (ii) if the Companies entered into purchase power agreements with owners / developers of independent solar projects.

A-28.

a.
(i) Confirmed.
(ii) Confirmed.
(iii) Confirmed.

b. Yes, and the challenges of serving nighttime load and winter load (shorter days and more clouds) with just solar energy and batteries would be similar.

c. As stated on page 13 of the study, "It was assumed for purposes of this study that all assets are owned and financed by LG&E but that may not have to be the case, particularly for roof-top solar and in-home storage." It is possible that independent solar developers could finance a project with greater amounts of debt and perhaps lower costs.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 29

Responding Witness: David S. Sinclair

Q-29. Reference the response to Kentucky Coal Association DR-1-5, Attachment 1, p. 18. Confirm the statement, "For the LG&E/KU system to be 100% renewable annually would require ~14,500 MW of solar generation requiring over 110 square miles of solar panels."

a. Provide an estimate of how much energy storage would be required if the combined LG&E-KU systems were to convert to 100% renewable energy.

A-29. Confirmed.

a. In the referenced attachment, the statement quoted emphasized the word "annually" because that was the clean energy standard being discussed by the Louisville Metro Council committee. Such a standard does not involve serving actual load – only creating a requirement that annual energy used equal annual renewable generation; thus, no storage would be required.

The Companies have not performed the requested analysis in recent years but did estimate that approximately 23,000 MW of storage would be required to use 100% renewable energy to serve load in 2035 as part of an analysis performed in March 2021 and provided in the 2021 IRP. A copy of that analysis is attached. More recently, the Companies prepared a report titled "Energy Forward, Generation Study 2022, Addendum to 2021 Climate Assessment Report" (available athttps://www.pplweb.com/wp-content/uploads/2022/12/PPL_Corp-2022-Generation-Study-FINAL.pdf).
In that report, it was estimated that 3,735 MW of storage would be required to serve 80 percent clean energy by 2030 (see Figure A4 on page 10 of the report).

The attachment is being provided in a separate file.