COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

RESPONSE OF
LOUISVILLE GAS AND ELECTRIC COMPANY AND
KENTUCKY UTILITIES COMPANY TO
JOINT INTERVENORS
POST HEARING REQUESTS FOR INFORMATION
DATED JULY 18, 2022

FILED: AUGUST 8, 2022

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, 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 Bellar
Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 3rd day of August 2022.

BETTY LYNN BRINLY NOTARY ID KYNP52213 MY COMMISSION EXPIRES 6/21/2026 PUBLIC STATE AT LARGE, KY.

Betty L. Brinly
Notary Public

Notary Public ID No. KYNP52213

My Commission Expires:

June 21, 2026

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, 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 E. Bevington*___
John Bevington

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 5th day of August 2022.

Judy Schooler
Notary Public

Notary Public ID No. KYNP53381

My Commission Expires:

July 11, 2026

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, 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 2nd day of August 2022.

Caroline J. Davison

Notary Public

Notary Public ID No. 614103

My Commission Expires:

CAROLINE J. DAVISON
Notary Public, State at Large, KY
My commission expires Jan. 22, 2023
Notary ID# 614103

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, 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
Charles R. Schram

Subscribed and sworn to before me, a Notary Public in and before said County and State this 4th day of August 2022.

Notary Public

Notary Public ID No. KYNP32193

My Commission Expires:

June 25, 2025

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, 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 5th day of August 2022.

Notary Public

Notary Public ID No. KYNP32193

My Commission Expires:

June 25, 2025

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, 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 2nd day of August 2022.

Notary Public

Notary Public ID No. KYNP32193

My Commission Expires:

June 25, 2025

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Post Hearing Request for Information Dated July 18, 2022

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Question No. 1

Responding Witness: Robert M. Conroy / David S. Sinclair

Q-1. Following up on the issuance of the Request for Proposals on June 22, 2022 and the application for interconnections in Mercer and Jefferson Counties for gas-fired capacity,

a. Have the Companies (LG&E and/or KU) begun the internal process for development of an application to the Public Service Commission (PSC or Commission) for a Certificate of Public Convenience and Necessity (CPCN) for new gas-fired generation resources? If so, please state when that internal process began.

b. If the self-build proposal for one or two 660 MW gas-fired units is selected in response to the RFP, when do the Companies (or either of them) anticipate filing the CPCN application with the Commission?

c. Based on past experience, what is the lag time between filing a CPCN to add a gas-fired generating unit and the construction of such a unit after approval of the CPCN?

d. Have the Companies begun the process of identifying the equipment manufacturer for the combined cycle units? If so, how far along in that process are the Companies?

e. Which entity will provide engineer, procure, construct ("EPC") services for the proposed units? If no entity has yet been identified do the Companies intend to contract for this service or perform it using an inhouse team?

f. If any contract has been signed for equipment or EPC services for either or both of the two proposed 660 MW gas-fired units please identify and provide a copy of the contract(s).

A-1.

a. No, the Companies have not begun the internal process to develop an application to the Commission for a CPCN for new gas-fired generation resources. As the Companies stated in this proceeding, they anticipate evaluating self-build options with the responses to the pending Request for Proposals ("RFP") and demand side management options. But the responses to the current RFP are not due until August 17, 2022, and the Companies will not begin to evaluate any responses, including self-build submissions, until that time. The Companies expect to complete their RFP evaluation by October 31, 2022.

b. See the response to part (a). As the Companies stated during the hearing in this proceeding, if the Companies file an application for a CPCN or PPA (or some combination of the two) based on the results of the current RFP, they anticipate doing so toward the end of this year or early next year. As the Companies further stated during the hearing in this proceeding, any such application would include a full analysis of cost-effective DSM-EE programs to ensure that customers' projected needs are met with a cost-effective balance of supply and demand side resources.

c. The Companies' most recent gas unit construction experience concerns Cane Run Unit 7, which is a 662 MW summer rated natural gas combined-cycle unit. The Companies filed a CPCN application for that unit in September 2011. The Commission granted the requested CPCN in May 2012. Cane Run Unit 7 began commercial operation in June 2015.

d. See the response to part (a). Note that the evaluation and application process that ultimately led to the construction of Cane Run Unit 7 included an RFP process that identified the least-cost alternative (i.e., purchasing the Bluegrass CTs and building Cane Run Unit 7) in May 2011.[1] The Companies did not begin their pre-qualification processes for major equipment or an EPC contractor until the third quarter of 2011, ***after*** the RFP process was complete.[2]

e. No decision has been made regarding any EPC services for any self-build options.

f. See the response to part (e).

[1] Case No. 2011-00375, Attachment to Companies' Response to PSC 1-17 (LG&E-KU 2011 Resource Assessment) at 24 (Nov. 9. 2011).
[2] Case No. 2011-00375, Companies' Response to PSC 1-29 (Nov. 9. 2011).

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

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Question No. 2

Responding Witness: John Bevington / Stuart A. Wilson

Q-2. On page 47 of the Companies' response to comments, the Companies note that they "are well aware of these incentives and have traditionally had the most expansive and robust DSM-EE program portfolio in Kentucky."

a. As a percentage of annual total sales, how much savings overall and by rate class do the Companies achieve through their offered DSM programs?

b. As a percentage of annual total sales, how much savings overall and by rate class do the Companies achieve through their offered EE programs?

c. As a percentage of annual total sales, how much savings do the Companies estimate that ratepayers, by class, achieve through their own efforts (i.e., independent from the Companies DSM-EE programs)?

d. Please provide the evidence to support the claim that the Companies "have traditionally had the most expansive and robust DSM-EE program portfolio in Kentucky."

A-2.

a. Based on 2021 actual annual sales and savings calculated based on actually deployed DSM-EE program measures:

Sector	LG&E/KU 2021 Annual Sales (GWh)	2021 DSM-EE Annual Savings (MWh)	%
Residential	10,517	5,077	0.05
Non-Residential Retail	18,912	86,085	0.5
Total Retail	29,429	91,162	0.3

b. See the response to part (a).

c. The Companies do not possess the information needed to estimate the impact of energy efficiency savings, specifically, by class. In addition to energy efficiency savings, changes to total sales over time are explained by changes in operations, production levels, and customer behavior. Compared to 2010, annual weather-normalized residential use-per-customer in 2021 was 9% lower in the LG&E service territory and 5.5% lower in the KU service territory. These decreases reflect the impacts of customer-initiated energy efficiency improvements as well as past and current DSM-EE programs.

d. The statement is based on the total history of the Companies' programs—not just the current program portfolios—evaluated both in terms of numbers of programs and savings (demand and energy) those programs achieve, compared to other electric utilities in Kentucky. In making such comparisons, it is important to note that utilities group and label their programs differently. For example, compare the Companies' current and immediately prior DSM-EE Program Portfolios to those of Duke Energy Kentucky, Kentucky Power, and East Kentucky Power Cooperative, Inc. The Companies' DSM-EE Program Portfolio through 2018 was more expansive than those of other Kentucky utilities, and it is more expansive than, or is largely comparable to, those of other Kentucky utilities currently.

In terms of savings, the Companies' DSM-EE portfolio remains the most successful in Kentucky overall according to data from the U.S. Department of Energy's Energy Information Agency ("EIA"). The following data for calendar year 2020 is the most recent available from EIA on DSM and energy efficiency programs:

DSM Programs: Customers Enrolled and Cumulative Demand Savings[3]

	Number of Customers Enrolled		Potential Peak Demand Savings (MW)	
Utility Name	Residential	Commercial	Residential	Commercial
East Kentucky Power Coop, Inc	2,073	0	3.3	0.0
Kentucky Utilities Co	68,455	797	73.4	11.3
Louisville Gas & Electric Co	82,319	791	88.3	13.0
Duke Energy Kentucky	12,076	17	12.8	15.4
Kentucky Power Co	0	0	0.0	0.0

[3] Industrial customer data excluded due to EKPC's and Duke Energy Kentucky's inclusion of the Companies' equivalent of their Curtailable Service Riders in their EIA-reported DSM data, which the Companies do not include.

EE Programs: Incremental Annual Energy and Demand Savings

	Energy Savings (MWh)		Peak Demand Savings (MW)	
Utility Name	Residential	Commercial	Residential	Commercial
East Kentucky Power Coop, Inc	5,595	0	1.9	0.0
Kentucky Utilities Co	1,515	36,592	.	7.4
Louisville Gas & Electric Co	3,203	41,347	0.0	7.8
Duke Energy Kentucky	7,149	10,464	1.1	1.6
Kentucky Power Co	144	0	0.0	0.0

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

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Question No. 3

Responding Witness: Lonnie E. Bellar

Q-3. Please confirm that if the Companies were members in an RTO, that there would be cost savings for solar or wind purchases from inside the RTO that would not exist for non-RTO members.

A-3. The Companies cannot confirm solar or wind purchases from inside an RTO would result in cost savings if the Companies were members of that RTO. As described below, the evaluation of such costs is more complex than asserted in the request.

The Companies are not currently members of an RTO. Therefore, firm point-to-point transmission must be purchased to ensure deliverability of energy from any generation source, including wind and solar generation that might be part of a power purchase agreement ("PPA"), located within an RTO.

If the Companies were RTO members, the need for purchasing firm point to point would be eliminated, but the ultimate cost of the RTO-based generation would be a function of the PPA price, the locational marginal pricing ("LMP") at the generator interface, and the LMP at the interface where the Companies transact with the RTO. Transmission congestion at points within RTOs can cause LMPs to vary significantly, even to the point of negative LMPs. It is possible that Financial Transmission Rights ("FTR") could be used to hedge potential losses related to the price risks due to congestion.

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Question No. 4

Responding Witness: Charles R. Schram / David S. Sinclair

Q-4. Regarding the Companies' 2021 RFP for power:

a. Did the Companies receive proposals for renewable power from resources located in an RTO territory?

b. Did any of the responding bids include all costs of getting the power to KU-LGE? Please explain in full.

c. Would those costs have been any different if KU-LGE had been members of the RTO where the resources were located, and if so, how would they have been different? Please explain in full.

d. Have the Companies performed analysis of the total costs of securing renewable power from resources located within RTO territories, and evaluated scenarios in which the Companies ARE and ARE NOT members of the RTO? Please explain.

A-4.

a. Yes.

b. No. The RFP specified that the Companies would apply to use the applicable tariff(s) for firm point-to-point transmission to account for costs related to delivering the energy to the Companies.

c. See the response to Question No. 3.

d. See the response to Question No. 3. The Companies did not analyze 2021 RFP responses as if the Companies were members of an RTO.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Post Hearing Request for Information Dated July 18, 2022

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Question No. 5

Responding Witness: David S. Sinclair

Q-5. Using documented costs associated with the most recent CTs and CCGTs constructed by the Companies (or either of them) corrected for inflation, and assuming a decision to construct either of both types of units at 660 MW of nameplate capacity so that the unit would be available in 2028, please calculate the NPV of the cost of design and construction of such capacity in 2022, 2023, 2024, 2025, 2026 and 2027.

A-5. The most recent CTs constructed by the Companies were Trimble County 7-10, commissioned in 2004 with total design and construction costs of $201.9 M. The most recent and only CCGT constructed by the Companies was Cane Run 7, commissioned in 2015 with total design and construction costs of $527.1 M. Detailed cost profile data for Trimble County 7-10 was not readily available, so the Companies assumed a compressed timeline of the CC cost profile to develop a CT cost profile. The 660 MW figure referenced in the Companies' transmission studies is associated with net winter capacity (not nameplate capacity), so this historical cost data was scaled to a net winter capacity to 660 MW. Using the changes in the consumer price index ("CPI") to escalate historical costs to 2022, and using a 2.0% escalator beyond 2022 (mirroring the assumption used in the 2021 IRP) results in the following cost profiles for 660 MW of CT or CC capacity that would be available in 2028:[4]

[4] CPI data used in this response is available at: https://www.minneapolisfed.org/about-us/monetary-policy/inflation-calculator/consumer-price-index-1913-.

Design and Construction Cost ($M)	CT	CC
2023	0.0	0.3
2024	0.2	2.5
2025	1.2	86.6
2026	41.2	445.4
2027	276.7	141.4
2028	7.6	16.5
2029	0.1	0.2
Total	326.9	692.9

The NPV of costs from 2022-2027 is $236.1 M for CT capacity and $525.4 M for CC capacity. As shown in the table above, costs of design and construction may continue into and past the commissioning year, so the full NPV of these costs is $241.3 M for CT capacity and $536.9 M for CC capacity.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

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Question No. 6

Responding Witness: John Bevington / Stuart A. Wilson

Q-6. The IRP assumes 6% savings based on DSM and customer energy efficiency measures.

a. Please explain the derivation of the 6% figure and provide all spreadsheets with all formulas and links intact used to derive it.

b. Is the 6% a constant or by a certain year?

c. Is it anticipated to grow or shrink as a percentage over time?

d. Does the 6% figure assume any utility-sponsored DSM or EE measures in place, or to be developed and implemented? Please explain in full.

e. Does the 6% figure assume only naturally occurring DSM or EE measures in place, or to be developed and implemented? Please explain in full.

f. Refer to tables 8-12 and 8-13 in Volume I of the IRP. Please confirm that these tables reflect how "[l]oad changes for the DSM programs are embedded in the load forecast for energy and demand presented throughout" the IRP, as stated on Vol. I page 8-20. If anything but confirmed, please explain your response in full.

g. Please provide the spreadsheet(s) with all formulas and links intact showing how the 6% savings were factored into the load forecast.

A-6.

a. See Volume I of the IRP beginning on page 5-26 and specifically the paragraph pertaining to Figure 5-12. Historically, the declining trends in residential and commercial use-per-customer reflect the impacts of both utility-sponsored DSM-EE programs and customer-initiated energy efficiency improvements (see the response to Question No. 2). These trends are consistent with electric end-use efficiencies, which have improved historically and are assumed to continue to improve throughout the IRP planning period. The Companies' residential and commercial forecast models are specified, among other things, as a function of end-use efficiencies and capture the historical relationship between improving end-use efficiencies and the combined impact of DSM-EE programs and customer-initiated energy efficiency improvements. Because this relationship is assumed to remain unchanged over the forecast period, the forecast implicitly assumes the combined impact of DSM-EE programs and customer-initiated energy efficiency improvements grows over the forecast period as end-use efficiencies improve.

To estimate the impact on sales of improving end-use efficiency assumptions over the forecast period, the Companies forecasted residential and small commercial sales with no assumed end-use efficiency improvements (i.e., end-use efficiencies in these forecast models were held constant over the planning period). With this assumption, residential and small commercial sales are 6 percent higher by the end of the IRP planning period.[5]

b. No. See Figure 5-12 in Volume I at page 5-26. The impact of DSM-EE programs and customer-initiated energy efficiency improvements increases over the forecast period.

c. See the response to part (b).

d. Yes. See the responses to part (a) and PSC 1-13.

e. See the responses to part (a) and PSC 1-13.

f. These tables summarize the impacts of the Companies' existing DSM-EE programs through 2025. The IRP does not speculate on the specific DSM-EE programs assumed to achieve the energy savings beyond 2025. The Companies' DSM-EE program development process includes advisory group meetings, potentials studies, cost effectiveness evaluation and more, and is more formally performed when a new portfolio of programs is to be presented before the commission.

g. See the response to part (a).

[5] *See* Companies' Response to JI 1-3, especially the attachments within the Load Forecast folder: 6_IRP \ Vol_I_Data \ Efficiency_Scenarios.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors'
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Question No. 7

Responding Witness: Robert M. Conroy

Q-7. Is it the Companies' interpretation of the net metering statute that the 1% cap on aggregate net metering capacity prohibits the Companies from choosing to continue to offer net metering to customers after that 1% cap is reached?

A-7. No. Under KRS 278.466(1), a utility has no obligation to offer net metering to any new customer-generator if the cumulative net metering generating capacity on the utility's system reaches one percent (1%) of the utility's single hour peak load. But the cost data in the record of this proceeding for utility-scale versus customer-installed renewable generation, particularly solar generation, indicate it is unlikely that allowing net metering to exceed the statutory 1% cap would be consistent with lowest reasonable cost service for all customers, at least for the foreseeable future. The Companies will evaluate this issue more fully when their customers' aggregate net metering capacity approaches the statutory 1% cap.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

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Question No. 8

Responding Witness: Stuart A. Wilson

Q-8. Did the Companies model the impact of increased utility investment in customer energy efficiency, and/or DSM, on moderating or deferring the need for new generation resources? If so, please provide those modeling inputs and the outputs in electronic format with all formulas and links intact.

A-8. The Companies did not directly model increased utility investment in DSM-EE programs. See Volume 1 of the IRP at page 5-11 and the response to PSC 1-4.

But the Companies arguably did indirectly model the demand and energy effects of increased DSM-EE programming in their base and low load scenarios, which included increased energy efficiency and higher levels of distributed generation. The reduced demand and energy requirements modeled in those scenarios due to increased energy efficiency and higher levels of distributed generation could be comparable to similar effects created by increased levels of DSM-EE programming by the Companies.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors'
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Question No. 9

Responding Witness: David S. Sinclair

Q-9. To confirm, the interconnection requests dated June 21, 2022 that are posted in the Trans Serv Transmission Management Services Interconnection Queue Report and identified as 2022-003 and 2022-004 represent potential self-build combined-cycle gas plants of 660 MW that might be located and constructed at Mill Creek or Brown or both? If selected as a result of the now-open RFP, when would the Companies anticipate filing CPCN(s) for such unit(s)? When would the Companies anticipate the unit(s) would be on-line?

A-9. Confirmed. See the response to Question No. 1.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

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Question No. 10

Responding Witness: Stuart A. Wilson

Q-10. To confirm, no modeling, analysis, or assessment of the impact of the various portfolios and scenarios was conducted that specifically focused on the impact of the portfolios or scenarios on low- and fixed-income residential ratepayers, correct? If incorrect, provide such analysis.

A-10. See the response to JI 2-8.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors'
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Case No. 2021-00393

Question No. 11

Responding Witness: Stuart A. Wilson

Q-11. Refer to the 2021 IRP Reserve Margin Analysis, particularly Section 4.7, titled "Cost of Unserved Energy (Value of Lost Load)", and Section 4.10, titled, "Scarcity Pricing."

a. Section 4.10, page 22 states, "At reserve capacities less than 4.0% of the hourly load, the scarcity price is equal to the Companies' value of unserved energy ($19,800/MWh; see Section 4.7). Please confirm that the "cost of unserved energy" determines the scarcity price. If anything but confirmed, please explain in full.

b. Section 4.7 at 21 states, "For this study, unserved energy costs were derived based on information from four publicly available studies," with citations to those four studies.

(i) Please confirm that LG&E and KU were not included among the 22 utilities studied in the cited June 2009 publication titled "Estimated Value of Service Reliability for Electric Utility Customers in the United States." If anything but confirmed, please explain in full.

(ii) Please confirm that LG&E and KU were not included among the utilities studied in the August 2005 publication titled "Assessment of Other Factors: Benefit-Cost Analysis of Transmission Expansion Plans." If anything but confirmed, please explain in full.

(iii) Please confirm that LG&E and KU were not included among the 8 utilities examined in support of the 2003 study titled "A Framework and Review of Customer Outage Costs." If anything but confirmed, please explain in full.

(iv) Please confirm that company-specific data from LG&E and KU was not included in the 2000 study titled "Value of Lost Load". If anything but confirmed, please explain in full.

(v) Please confirm that the spreadsheet entitled "20210929_CHW_CostofUnservedEnergy_2025Escalation" shows how these studies were aggregated to develop the Companies' scarcity pricing. If anything but confirmed, please explain in full.

c. Please confirm that "scarcity pricing" was used in the SERVM modeling as an adder to power purchased during any hour in which reserve capacity was 16% or less in excess of load. If anything but confirmed, please explain in full.

d. Please confirm that, in the SERVM modeling and as reflected by the scarcity price curve shown in Figure 9, when generation exceeds load by 11.5% or more, a $264 / MWh fee was assessed on any power transfers. If anything but confirmed, please explain in full.

e. Please confirm that, in the SERVM modeling and as reflected by the scarcity price curve shown in Figure 9, when reserve capacity is 4.0% in excess of hourly load, an approximately $19,800 per MWh fee was assessed on any power transfers. If anything but confirmed, please explain your response in full.

A-11.

a. The level of reserves the Companies carry to comply with NERC reliability standards is approximately 4% of peak demand. Therefore, the cost of unserved energy determines the scarcity price at reserve capacities less than 4%.

b.

(i) Confirmed.

(ii) Confirmed.

(iii) Confirmed.

(iv) Confirmed.

(v) Confirmed.

c. Confirmed. The cost of power purchases, which includes the scarcity price, comprises approximately 1.5 percent of total reliability and generation production costs.

d. Confirmed.

e. Confirmed. See the response to part (a).

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

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Question No. 12

Responding Witness: Charles R. Schram / Stuart A. Wilson

Q-12. The June 22, 2022, RFP indicates that the Companies will consider proposals that are "reliable, feasible, and represent the least-cost means of supplying our customers with capacity and energy."

a. Please confirm whether proposals that include, in whole or in part, energy-efficiency and DSM measures could provide reliable, feasible, and least-cost means of meeting customers energy needs while deferring or eliminating the need for new capacity?

b. If DSM and EE proposals were not considered within the scope of the RFP, explain why such strategies for addressing energy needs of customers were excluded?

c. Have the Companies conducted any evaluation of whether the one or two 660 MW natural gas combined cycle plants could be avoided in whole or in part through more robust deployment of DSM and EE measures? If so, please provide that evaluation. If not, will such an evaluation be undertaken prior to a decision on one or more of the currently contemplated 660 MW units?

A-12.

a. The Companies' June 22, 2022 RFP clearly states that the Companies are seeking capacity and energy proposals. The Companies do not anticipate respondents would submit energy efficiency and DSM-EE measures in response to such an RFP.

b. See the response to PSC 1-4.

c. No decision has been made to build natural gas combined cycle ("NGCC") units. See the response to Question No. 1(b). No evaluation can begin until the RFP responses are received on August 17, 2022.

LOUISVILLE GAS AND ELECTRIC COMPANY
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Question No. 13

Responding Witness: John Bevington / Stuart A. Wilson

Q-13. Refer to the Companies' response to Joint Intervenors' information request 1-37(b), particularly footnote 9 at page 10 of the attached document, which reads: "LG&E and KU provided Cadmus with a draft document with estimated avoided capacity costs based on the year of capacity need and the year a newly dispatchable program is available." Please provide the referenced document.

A-13. See attached.

December 3, 2020

Avoided Capacity Cost

Introduction

The avoided capacity cost for future energy efficiency ("EE") programs is a function of the year the program begins, the timing of the Companies' need for new generating capacity, and the nature and duration of the program's energy reductions. This assessment estimates the avoided capacity cost for two types of EE programs.[1] The first type of EE program is a dispatchable program, such as the Companies' direct load control program. This program includes annual incentive payments and displaces the need for new capacity indefinitely. The second type of EE program is a one-time expense program. This program includes a one-time investment in an energy efficiency asset (e.g., high-efficiency lighting or insulation), and the capacity benefit extends through the life of the asset.

Dispatchable Program

The avoided capacity cost for new dispatchable EE programs is primarily dependent on the year the program begins and the timing of the Companies' need for new generating capacity. Because the duration of the program is assumed to extend through the life of the capacity that would be needed in the absence of the program, a dispatchable EE program is assumed to eliminate this need for capacity. In addition, because a dispatchable EE program includes annual incentive payments, the avoided capacity cost is higher for a dispatchable EE program that is added closer to the Companies' need for capacity. If the Companies do not have a need for new capacity, the avoided capacity cost is zero; however, if the Companies have an immediate need for new capacity, the avoided capacity cost is approximately equal to the carrying cost of new capacity. If a dispatchable EE program is added after the year new capacity is needed, the avoided capacity cost will be significantly diminished, as it will then be a function of the Companies' next need for capacity.

Table 1 and Table 2 demonstrate how the avoided capacity cost for new dispatchable EE programs changes with the year the program begins and the timing of the need for new capacity. A dispatchable program's energy reductions can be peaking or intermediate in nature. Table 1 shows the avoided capacity cost for a dispatchable program based on the capital and fixed costs of a simple-cycle combustion turbine ("SCCT"), which is typically a peaking resource.[2] Based on the 2021 Plan load and current retirement assumptions, the Companies have a need for new capacity in 2028.[3] Therefore, if a new dispatchable EE program with peaking energy reductions begins in 2023, its avoided capacity cost in 2023 and subsequent years would be $88/kW-yr. If another new dispatchable EE program with peaking energy reductions begins in 2024, its avoided capacity cost in 2024 and subsequent years would be $95/kW-yr, and so on. If a dispatchable EE program with peaking energy reductions is added in 2028

[1] This analysis focuses only on avoided capacity cost. Avoided energy costs are not considered.
[2] The avoided capacity costs in this assessment assume program characteristics similar to and are computed based on the cost of generating resources evaluated in the Companies' Analysis of 2020 Environmental Compliance Plan Projects in March 2020 and their Analysis of Generating Unit Retirement Years in October 2020. Table 4 shows capital and fixed costs assumptions for new capacity in this assessment. Before the Companies commit to building new capacity, the cost of new capacity is assessed against other market available alternatives to identify the lowest reasonable cost alternative.
[3] See Table 6 for the Companies' current retirement assumptions.

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(i.e., the year of capacity need), its avoided capacity cost in 2028 and subsequent years is approximately equal to the carrying cost of the new peaking capacity that would have been added in 2028 ($128/kW-yr).

Table 1 – Avoided Capacity Cost for Dispatchable Programs with Peaking Energy Reductions ($/kW-yr)

		First Year of New Dispatchable Program													
		2023	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Year of Capacity Need	**2023**	117													
	2024	110	119												
	2025	104	112	121											
	2026	98	106	114	123										
	2027	93	100	108	116	125									
	2028	88	95	102	110	118	128								
	2029	83	90	96	104	112	120	130							
	2030	79	85	91	98	106	114	123	132						
	2031	75	80	86	93	100	107	116	125	135					
	2032	71	76	82	88	95	102	109	118	127	137				
	2033	67	72	78	83	90	96	104	111	120	129	139			
	2034	64	69	74	79	85	91	98	105	113	122	132	142		
	2035	61	65	70	75	80	86	93	100	107	115	124	134	145	
	2036	58	62	66	71	76	82	88	94	102	109	118	127	136	147

Table 2 shows the avoided capacity cost for a dispatchable program based on the capital and fixed costs of a natural gas combined cycle unit ("NGCC"), which is typically a baseload or intermediate resource. If a dispatchable EE program with intermediate energy reductions is added in 2028 (i.e., the year of capacity need), its avoided capacity cost in 2028 and subsequent years is approximately equal to the carrying cost of the new intermediate capacity that would have been added in 2028 ($165/kW-yr).

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Table 2 – Avoided Capacity Cost for Dispatchable Programs with Intermediate Energy Reductions ($/kW-yr)

		First Year of New Dispatchable Program													
		2023	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Year of Capacity Need	**2023**	151													
	2024	143	154												
	2025	136	146	156											
	2026	129	138	148	159										
	2027	123	131	141	151	162									
	2028	116	125	134	143	154	165								
	2029	111	118	127	136	146	156	168							
	2030	105	113	121	129	138	148	159	171						
	2031	100	107	115	123	131	141	151	162	174					
	2032	95	102	109	117	125	134	143	154	165	177				
	2033	90	97	103	111	119	127	136	146	156	168	180			
	2034	86	92	98	105	113	121	129	139	149	159	171	183		
	2035	82	87	93	100	107	115	123	132	141	151	162	174	186	
	2036	78	83	89	95	102	109	117	125	134	143	154	165	177	190

One-Time Expense Program

The avoided capacity cost for new one-time expense programs is primarily dependent on the timing of the Companies' need for new generating capacity, the nature and duration of the program's energy reductions, and the year the program begins. Because the duration of the program's energy reductions is limited to the life of the energy efficiency asset, a one-time expense program typically only defers the need for new capacity and does not eliminate it altogether.

A one-time expense program's energy reductions can be peaking or intermediate in nature (e.g., the energy reductions associated with a one-time investment in high-efficiency lighting or insulation may more closely resemble intermediate generating capacity, while the energy reductions associated with an investment in high-efficiency air conditioning units may more closely resemble peaking capacity). Table 3 shows how the avoided capacity cost for one-time expense programs changes with the timing and duration of the program, assuming the program's energy reductions are typically peaking in nature. The year of capacity need is assumed to be 2028, as with the Companies' 2021 Plan load and current retirement assumptions. If a new one-time expense program begins in 2023 and provides energy reductions for one to five years, its avoided capacity cost would be zero because the program would end before the Companies' next capacity need in 2028. If a new one-time expense program begins in 2023 and affects load in mostly peak hours for 12 years, its avoided capacity cost in years 2023 through 2034 would be $44/kW-yr. Likewise, if a new one-time expense program begins in 2028 and affects load in mostly peak hours for 15 years, its avoided capacity cost in years 2028 through 2042 would be $96/kW-yr.

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Table 3 – Avoided Capacity Cost for One-Time Expense Programs with Peaking Energy Reductions, Assuming 2028 Capacity Need ($/kW-yr)

	First Year of New One-Time Expense Program													
Duration of New Program (years)	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
1	0	0	0	0	0	86	0	0	0	0	0	96	0	0
2	0	0	0	0	42	87	0	0	0	0	47	97	0	49
3	0	0	0	27	56	88	0	0	0	30	63	98	32	66
4	0	0	20	41	64	89	0	0	22	45	71	99	48	75
5	0	15	31	49	69	89	0	17	35	55	76	100	58	81
6	12	25	40	55	72	90	14	28	44	61	80	100	65	85
7	21	33	46	60	75	91	23	37	51	66	83	101	70	88
8	28	39	50	63	77	92	31	43	56	70	85	102	74	90
9	33	43	54	66	79	92	37	48	60	73	87	103	77	92
10	37	47	57	68	80	93	42	52	64	76	89	103	80	94
11	41	50	60	70	81	94	46	56	67	78	91	104	82	96
12	44	53	62	72	83	94	49	59	69	80	92	105	85	97
13	47	55	64	74	84	95	52	61	71	82	93	106	86	98
14	49	57	66	75	85	96	55	64	73	83	95	106	88	100
15	51	59	67	76	86	96	57	66	75	85	96	107	90	101

Table 4 shows how the avoided capacity cost for one-time expense programs changes with the timing and duration of the program, assuming the program's energy reductions are typically intermediate in nature. Capital and fixed expenses of a natural gas combined cycle unit ("NGCC"), which is typically a baseload or intermediate resource, are used to calculate avoided capacity costs. The year of capacity need is assumed to be 2028, as with the Companies' 2021 Plan load and current retirement assumptions.

Table 4 – Avoided Capacity Cost for One-Time Expense Programs with Intermediate Energy Reductions, Assuming 2028 Capacity Need ($/kW-yr)

	First Year of New One-Time Expense Program													
Duration of New Program	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
1	0	0	0	0	0	122	0	0	0	0	0	135	0	0
2	0	0	0	0	59	123	0	0	0	0	65	136	0	69
3	0	0	0	38	79	124	0	0	0	42	88	137	44	93
4	0	0	28	57	90	125	0	0	31	64	100	139	67	105
5	0	21	44	69	96	126	0	24	49	77	107	140	81	113
6	17	36	56	78	101	127	19	40	62	86	112	141	91	118
7	30	46	64	84	105	128	33	51	71	93	116	142	98	123
8	39	54	71	89	108	129	43	60	79	98	120	143	104	126
9	47	61	76	93	110	130	52	67	84	103	123	144	108	129
10	53	66	80	96	113	131	59	73	89	106	125	145	112	132
11	58	70	84	99	114	131	64	78	93	110	127	146	115	134
12	62	74	87	101	116	132	69	82	97	112	129	147	118	136
13	66	78	90	103	118	133	73	86	100	115	131	148	121	139
14	69	80	92	105	119	134	77	89	103	117	132	149	124	141
15	72	83	95	107	121	135	80	92	105	119	134	151	127	143

To demonstrate how the avoided capacity cost changes with the year of capacity need, Table 5 shows the avoided capacity cost for one-time expense programs with peaking energy reductions, assuming the year of capacity need is 2026.

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Table 5 – Avoided Capacity Cost for One-Time Expense Programs with Peaking Energy Reductions, Assuming 2026 Capacity Need ($/kW-yr)

	First Year of New One-Time Expense Program													
Duration of New Program	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
1	0	0	0	83	0	0	0	0	0	0	0	96	0	0
2	0	0	40	84	0	0	0	0	0	0	47	97	0	49
3	0	26	54	85	0	0	0	0	0	30	63	98	32	66
4	19	39	62	86	0	0	0	0	22	45	71	99	48	75
5	30	48	66	86	0	0	0	17	35	55	76	100	58	81
6	38	53	69	87	0	0	14	28	44	61	80	100	65	85
7	44	57	72	88	0	11	23	37	51	66	83	101	70	88
8	49	61	74	88	9	20	31	43	56	70	85	102	74	90
9	52	63	76	89	17	26	37	48	60	73	87	103	77	92
10	55	66	77	90	23	32	42	52	64	76	89	103	80	94
11	58	68	79	90	28	37	46	56	67	78	91	104	82	96
12	60	69	80	91	32	40	49	59	69	80	92	105	85	97
13	62	71	81	92	36	44	52	61	71	82	93	106	86	98
14	63	72	82	92	39	47	55	64	73	83	95	106	88	100
15	65	74	83	93	42	49	57	66	75	85	96	107	90	101

Table 6 shows the avoided capacity cost for one-time expense programs with intermediate energy reductions, assuming the year of capacity need is 2026.

Table 6 – Avoided Capacity Cost for One-Time Expense Programs with Intermediate Energy Reductions, Assuming 2026 Capacity Need ($/kW-yr)

	First Year of New One-Time Expense Program													
Duration of New Program	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
1	0	0	0	117	0	0	0	0	0	0	0	135	0	0
2	0	0	57	118	0	0	0	0	0	0	65	136	0	69
3	0	37	76	119	0	0	0	0	0	42	88	137	44	93
4	27	55	87	120	0	0	0	0	31	64	100	139	67	105
5	43	67	93	121	0	0	0	24	49	77	107	140	81	113
6	54	75	98	122	0	0	19	40	62	86	112	141	91	118
7	62	81	101	123	0	16	33	51	71	93	116	142	98	123
8	68	86	104	124	13	28	43	60	79	98	120	143	104	126
9	73	89	107	125	24	37	52	67	84	103	123	144	108	129
10	78	93	109	126	32	45	59	73	89	106	125	145	112	132
11	81	95	111	127	39	51	64	78	93	110	127	146	115	134
12	84	98	112	128	45	57	69	82	97	112	129	147	118	136
13	87	100	114	129	50	61	73	86	100	115	131	148	121	139
14	89	102	115	130	55	66	77	89	103	117	132	149	124	141
15	91	103	116	130	59	69	80	92	105	119	134	151	127	143

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Assumptions

New Capacity Costs

Table 7 shows the costs of new capacity used to determine avoided capacity costs. In evaluating avoided capacity cost, the Companies assumed the life of the new EE program is equal to that of the capacity being displaced.

Table 7 – New Capacity Costs (2019 Dollars)

	SCCT	1x1 NGCC
Capital ($/kW)	586	1,062
Capital Escalation Rate	1.65%	1.66%
Fixed Costs ($/kW-yr)[4]	35.4	29.9
Fixed Costs Escalation Rate	2.0%	2.0%
Life (Years)	30	40

Key Financial Inputs

Table 8 shows the key financial inputs used to determine avoided capacity costs.

Table 8 – Key Financial Inputs

Input	Value
Return on Equity	10.0%
Cost of Debt	4.02%
Capital Structure	
Debt	46.6%
Equity	53.4%
Tax Rate	24.95%
Revenue Requirement Discount Rate	6.75%

Retirement Assumptions

Table 9 shows the Companies' current retirement assumptions used in this assessment.

Table 9 – Current Retirement Assumptions

Units Assumed Retired	Assumed Retirement Year
Zorn 1	2022
Mill Creek 1	2025
Haefling 1-2, Paddy's Run 11-12	2026
Brown 3, Mill Creek 2	2028
Ghent 1-2	2034
Ghent 3-4	2037
Mill Creek 3-4	2039
Trimble County 1	2045
Trimble County 2	2066

[4] Fixed costs include fixed operating and maintenance costs as well as costs associated with reserving firm gas-line capacity.

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Reserve Margin Considerations

The Companies carry generating resources in excess of their forecasted peak demand to account for the uncertainty in peak demand due to weather and the uncertainty in generating unit availability. The Companies' minimum target reserve margin, calculated as (Capacity – Forecasted Peak Demand)/(Forecasted Peak Demand), is 17%. The avoided capacity costs for one-time expense programs were computed with the assumption that a 1 MW reduction from the program would enable the Companies to avoid building 1.17 MW of new generating capacity. Because dispatchable programs contain the risk of communications equipment failure, the avoided capacity costs for dispatchable programs were computed with the assumption that a 1 MW reduction from the program would enable the Companies to avoid building 1.085 MW of new generating capacity.