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
SOUTHERN RENEWABLE ENERGY ASSOCIATION'S
SUPPLEMENTAL REQUESTS FOR INFORMATION
DATED MARCH 4, 2022

FILED: MARCH 25, 2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)

COUNTY OF JEFFERSON)

The undersigned, **Christopher D. Balmer**, being duly sworn, deposes and says that he is Director – Transmission Strategy and Planning 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.

Chr D Bal

Christopher D. Balmer

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 24th day of March 2022.

Judy Schooler

Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

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

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 22nd day of March 2022.

Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

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 22nd day of March 2022.

Judy Schooler
Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

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 22nd day of March 2022.

Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

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 22nd day of March 2022.

Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Supplemental Request for Information
Dated March 4, 2022

Case No. 2021-00393

Question No. 1

Responding Witness: Christopher D. Balmer / Stuart A. Wilson

Q-1. Reference the Companies' response to SREA's Initial Requests for Information, Question 18, parts a and b ("SREA 1-18(a) and (b)").

a. Please specify how much the Companies' estimated trade volumes changed upon joining PJM and MISO in your modeled scenarios (e.g., did the volume of sales double, triple, etc.?) and the expected savings per unit traded.

b. In the Companies' analysis of energy market benefits, was the Companies' entire fleet subject to security constrained economic dispatch? If not, then identify the portion of the fleet not subject. Further, fully explain how unit commitment was decided.

c. What is the granularity of dispatch in the analysis? Is it in 5-minute intervals for real time markets and hourly increments for day ahead markets? Explain in detail.

d. In the Companies' analysis of energy market benefits, how much did the Companies "self schedule" versus dispatch according to market prices or purchase from the market based on prices?

e. Does the analysis permit the Companies to quantify how much these traded amounts were in relation to the Companies' total energy demand (e.g., the trade amount was x% of the total peak demand)? If yes, please provide the quantification. If no, explain why the Companies believe the quantification is unnecessary.

f. Are the Companies' energy market benefits estimates solely from sales into the MISO and PJM markets and the savings from economy purchases? If no, please identify and describe the other source(s) of the estimates.

g. Did the Companies conduct production cost modeling? If yes:

i. Identify the modeling software the Companies use (e.g., PROSYM).

ii. What were the Companies' inputs?

iii. What was the hurdle rate under each scenario?

If no, explain why not.

h. Did the Companies calculate production cost savings as a result of dispatching the most efficient resources selected from across the PJM / MISO footprints? If yes:

   i. What were the production cost savings in terms of a percentage of the total?

   ii. How did the results compare to other studies, and how do the Companies account for any differences?

   If no, explain why not.

i. Does the Companies' model consider or otherwise include how security constrained economic dispatch could optimize available transmission and reduce congestion? If yes, fully explain. If no, explain why not.

j. If the Companies did not conduct production cost modeling and did not subject their entire fleet to economic dispatch, explain whether the Companies have underestimated energy market savings benefits? If it is the Companies' position that they have not underestimated energy market saving benefits, explain the basis for the position.

k. How will the Companies' participation in the Southeast Energy Exchange Market (SEEM) impact any of its findings in its 2021 RTO Membership Analysis (hereinafter "RTO Study")? Did the Companies model production cost or other benefits from participating in SEEM? How do those results or any estimates the Companies made compare to the results of the RTO Study? Please provide related modeling or studies. Additionally:

   i. How much annual benefit did the Companies estimate that SEEM will provide?

   ii. How much will the Companies spend on SEEM implementation, participation, and management costs?

   iii. How much energy do the Companies anticipate they will sell into SEEM on an annual basis?

iv. How much energy do the Companies anticipate they will purchase from SEEM on an annual basis?

v. How do these results compare with joining MISO or PJM as a full member?

l. Did the Companies model or estimate savings from the ancillary services markets, e.g., from reduced regulation and spinning reserve needs? What are the results of those analyses in terms of reduced requirements and savings?

m. Are LG&E and/or KU a Transmission Owner with Reliability Coordinator ("TORC")? If yes, identify the date upon which TORC status was obtained. If no, explain why not.

n. For the response to SREA 1-18(e), confirm that the Companies do not have the data or information to provide the estimate or otherwise offer a narrative addressing which cost would be larger. If this cannot be confirmed, provide the estimate through a narrative explaining the Companies' understanding of each cost and how they compare.

o. For the response to SREA 1-18(h), is it the Companies position that there have been no changes in circumstances since the Companies' previous membership in MISO that render the $1.0 million amount identified in the response as an unrealistic or unreliable assumption?

p. For the response to SREA 1-18(j), explain what the Companies mean by the phrase "when more certainty is available." Include in the discussion:

i. Each material or major element, topic, or consideration that the Companies deem currently uncertain,

ii. The circumstances or development that would transform the element, topic, or consideration from uncertainty to certainty including but not limited to, for example, establishment of a market rule, technological change, market development, etc., and

iii. Explain why the Companies have not performed "what if" scenarios or other types of analysis through which the Companies consider capacity replacement costs under a variety of scenarios.

A-1.

a. It is impractical to compare the trade volumes expected in an RTO to those when not in an RTO. If in an RTO, the Companies would sell all available generation that clears the market and purchase all energy to meet load.

Whereas absent RTO membership, the Companies sell as-available energy and purchase only when warranted. The sales and purchases volumes reflected in Appendix C of the _2021 RTO Membership Analysis_ are hundreds of times more than the relatively small amount of RTO energy sales and purchases that the Companies make today. The average savings is between $5/MWh to $9/MWh, depending on commodity price scenarios.

b. The Companies' entire fleet was economically dispatched based on market prices, except for solar resources and the Ohio Falls run-of-river hydro station, which were assumed to generate as available. See Section 8.2 of the *2021 RTO Membership Analysis*.

c. The analysis was performed in hourly increments only for real-time prices. The Companies did not model day-ahead markets in their analysis. See Section 6 of the *2021 RTO Membership Analysis*, p. 22.

d. See the response to part (b).

e. The table below shows the percentages of RTO sales volumes to the Companies' base load energy forecast for the three commodity price scenarios.

MISO	**2023**	**2024**	**2025**	**2026**	**2027**
Low Prices	95.2%	93.5%	93.3%	91.3%	89.8%
Mid Prices	99.5%	99.5%	99.3%	98.3%	98.8%
High Prices	94.8%	96.6%	96.0%	95.0%	95.0%
PJM	**2023**	**2024**	**2025**	**2026**	**2027**
Low Prices	86.7%	87.0%	88.3%	88.7%	88.7%
Mid Prices	96.3%	97.3%	97.3%	96.7%	97.7%
High Prices	95.2%	96.5%	96.6%	96.0%	96.6%

f. Yes, energy market benefits come only from sales into the MISO and PJM markets and their related expenses. See Section 8.2 of the *2021 RTO Membership Analysis*.

g. Yes.

   i. PROSYM. See Section 8.2 of the *2021 RTO Membership Analysis*.

   ii. See Section 8.2 of the *2021 RTO Membership Analysis*. The PROSYM input files were provided in response to JI 1-3 in the folders at the following file path: \2021RTOAnalysis\PROSYM.

iii. See Section 8.2 of the *2021 RTO Membership Analysis*, p. 33, "Market price buffer" section.

h. No. See Section 8.2 of the *2021 RTO Membership Analysis*, p. 32 and the responses to PSC 2-8 and 2-10.

i. No. See Section 6 of the *2021 RTO Membership Analysis*, p. 21.

j. See the responses to parts (b) and (g).

k. It is currently unknown whether the Companies' participation in SEEM will impact its findings in the 2021 or any future RTO Study. The Companies did not model potential production costs or other benefits from SEEM participation in the RTO Study, and therefore no comparisons are available.

   i. See the response to part (k).
   ii. The Companies expect SEEM implementation costs to be approximately $600,000 and ongoing costs to be approximately $200,000 annually. These estimates could change because SEEM systems are still under development.
   iii. Although the Companies do not have volumes associated with the purchases and sales in SEEM, it is anticipated the benefits from SEEM participation will range from approximately $1 million to $4 million per year.[1]
   iv. See the response to part k (iii).
   v. The Companies have not performed an analysis of being in SEEM and an RTO simultaneously. Also see the response to part (a).

l. Yes. See Section 8.2, p. 32, of the *2021 RTO Membership Analysis*. By reducing spinning reserve requirement from 327 MW to 220 MW, the Companies estimated that around $2 million would be saved in production costs every year.

m. Yes. TVA is the Companies' reliability coordinator and has been since the Companies exited MISO in 2006.

n. Confirmed.

o. No. There have likely been changes in circumstances in regard to the RTO's calculation of transmission revenue allocation since the Companies' experience in MISO over 15 years ago. Note that the Companies' response to SREA 1-18(h) did not say the Companies assumed such revenues would be $1 million; rather, the Companies' RTO analysis did not attempt to

[1] *See* page 8 of attachment 1 in response to PSC-2 Question No. 30(b) in case 2020-00349.

calculate such revenues because they would be unlikely to appreciably affect the analysis. That assumption finds support in the Companies' prior MISO experience, but it does not depend solely on that experience.

p.

i. See Sections 3.2 and 3.3.1 of the *2021 RTO Membership Analysis*. See also the response to PSC 2-6.

ii. More certainty could be achieved in the RTOs' capacity markets through market development and revised market rules. See the response to part (p)(i).

iii. Such an analysis was unnecessary to decide whether the Companies should join an RTO at this time. See the response to PSC 2-10.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Supplemental Request for Information
Dated March 4, 2022

Case No. 2021-00393

Question No. 2

Responding Witness: Christopher D. Balmer

Q-2. Reference the Companies' response to SREA 1-18(f). What are the assumptions for current and projected transmission buildout costs or expenses under the status quo?

A-2. The Companies' assumed transmission buildout costs in the status quo are based on the Companies' transmission planning guidelines (posted on OASIS), which are based on meeting the NERC TPL reliability standards. The Companies' planning guidelines and associated project costs are assumed to be the same in an RTO, and the cost shown in the RTO Analysis report for transmission expenses in an RTO are assumed to be incremental to stand-alone, status quo operations.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

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Question No. 3

Responding Witness: David S. Sinclair

Q-3. Reference the Companies' response to SREA 1-18(k). Please confirm that the Companies did not include the benefits of reduced capacity and lower target reserve margin requirements arising from being a part of a larger footprint with greater load and resources diversity? If this cannot be confirmed, please identify and explain the inclusion of benefits.

A-3. The Companies did not quantify avoided capacity costs. See the response to SREA 1-18(j). The Companies included the benefits of a lower target reserve margin by quantifying the amount of the Companies' capacity that could be sold into the RTOs capacity markets net of the capacity required for load as a function of the RTOs' lower target reserve margin requirements. See Section 8.1, p. 28 of the *2021 RTO Membership Analysis*.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

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Question No. 4

Responding Witness: Stuart A. Wilson

Q-4. Reference IRP Vol. I pp. 47-48. Are the Companies' proposed target reserve margins in installed capacity (ICAP) or unforced capacity (UCAP)?

A-4. Installed capacity.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
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Case No. 2021-00393

Question No. 5

Responding Witness: Charles R. Schram

Q-5. Reference the Companies' response to SREA 1-26.

a. How much energy do the Companies currently buy from PJM markets annually?

b. How much energy do the Companies currently sell to PJM markets annually?

c. How much energy do the Companies currently buy from MISO markets annually?

d. How much energy do the Companies currently sell to MISO markets annually?

e. How will SEEM change these trading volumes with PJM and MISO?

A-5.

a. In 2021, the Companies purchased 1,250 MWh of non-firm economy energy from PJM.

b. In 2021, the Companies sold 168,135 MWh to PJM.

c. In 2021, the Companies purchased no energy from MISO.

d. In 2021, the Companies sold 194,696 MWh to MISO.

e. It is currently unknown whether the Companies' participation in SEEM will change historic trading volumes with PJM and MISO. SEEM transactions will be conducted using Non-Firm Energy Exchange Transmission Service (NFEETS), which, unlike current transactions with MISO and PJM, is a zero-cost transmission service.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
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Dated March 4, 2022

Case No. 2021-00393

Question No. 6

Responding Witness: David S. Sinclair

Q-6. Reference the Companies' response to SREA 1-28.

a. What would be the criteria for joining an RTO, and how would the Companies judge whether there is a clear demonstration of "permanent cost savings" for customers?

b. Please identify and explain both the baseline and the metrics for the assessment.

A-6.

a. The criteria would be lower revenue requirements for customers over a broad range of possible futures compared to remaining outside an RTO.

b. See the response to part (a).

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
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Question No. 7

Responding Witness: Charles R. Schram

Q-7. Reference the Companies' responses to SREA 1-29 and 1-30.

a. What were those primary circumstances and drivers that led other Kentucky electric utilities to join RTOs and how is the Companies' situation different?

A-7.

a. See attached, which is Appendix D of Exhibit LEB-2 from the Direct Testimony of Lonnie E. Bellar in Case Nos. 2018-00294 and 2018-00295. This is the document to which footnote 26 in the Companies' response to SREA 1-29 referred.

Appendix D – Kentucky Entities in RTOs

The Companies and the Tennessee Valley Authority are transmission-owning entities operating in Kentucky that are not currently members of an RTO. Big Rivers Electric Corporation, Duke Energy Kentucky, East Kentucky Power Cooperative, and Kentucky Power are currently transmission-owning entities in the Commonwealth that are RTO members.

As part of this analysis, the Companies reviewed prior PSC filings and orders to understand the primary circumstances and drivers that indicated RTO membership was beneficial for the Kentucky entities operating within an RTO. The Companies determined that the Companies' current situation is different from the circumstances and drivers that led to these entities deciding to join their respective RTOs. A brief summary of each entity is provided below to support that view.

Big Rivers Electric Corporation ("BREC")

BREC joined MISO in 2010 primarily to comply with NERC's contingency reserve requirement (i.e., to ensure supply resources and demand are balanced following a contingency event). In its Order granting MISO membership to BREC, the PSC noted that MISO membership could carry substantial financial risks for BREC, its members, and their retail customers. Therefore, the PSC required BREC to file annually with the PSC a report that: (1) evaluates available options to BREC for complying with NERC's contingency reserve requirement, and (2) reviews and analyzes future short-term and long-term costs and benefits of continued membership in MISO. The report to the PSC filed by BREC on September 28, 2017, noted the only viable option for BREC to continue to satisfy its NERC requirements is continued MISO membership.

In comparison, the Companies are currently satisfying NERC requirements without RTO membership. The Companies can continue to meet the NERC reliability standards contingency reserve requirements, and there is no evidence that meeting the contingency reserve requirement is having an appreciably negative impact on the Companies' ability to optimize the dispatch of their generation fleet. Further, although RTO membership is assumed to result in a decrease in the reserves necessary to meet the contingency reserve requirement, the benefit of this reduction in the reserves requirement alone is not a major driver of net costs or benefits.

Duke Energy Kentucky ("Duke KY")

Duke KY joined MISO in 1997 and moved to PJM in 2012. Duke KY is a transmission-dependent utility heavily interconnected with Duke Energy Ohio. In requesting PSC approval of the transfer into PJM, Duke KY stated that the move into PJM would allow it to participate fully in PJM markets and avoid potential inefficiencies, operational complexities, and additional costs that would result from creating a MISO/PJM seam that would affect Duke KY's generation and load. The PSC approved of Duke KY following Duke Energy Ohio in joining MISO and subsequently PJM because of Duke KY's reliance on Duke Energy Ohio and associated transmission interconnectivity. In granting Duke KY's request to transfer function control of its transmission assets from MISO to PJM, the PSC stated that had Duke KY not been so dependent on Duke Energy Ohio transmission for serving its Kentucky load, they would have expected a more in-depth analysis of the costs and benefits of the transfer before approving it.

The Companies do not depend on another entity for transmission to serve native load. While transmission line maintenance or outages may effect customers located in areas connecting with adjoining transmission systems, these limited transmission dependencies are adequately addressed under existing arrangements. Furthermore, unlike the circumstances facing Duke KY at the time of its requested transfer into PJM, the complex issues associated with the MISO/PJM seam are not at issue in the Companies' arrangements with adjoining transmission systems.

East Kentucky Power Cooperative ("EKPC")

EKPC fully integrated into PJM in 2013. In the PSC proceeding, EKPC provided a ten year cost-benefit study conducted by Charles River Associates (CRA). The CRA analysis indicated that joining PJM presented a net expected economic benefit of $142 million over the ten-year period of 2013-2022. The CRA study identified three key benefits that EKPC could achieve through PJM membership:

(1) A decrease in production costs;
(2) Peak load diversity resulting in a decrease in needed planning reserves and cost avoidance as a result of the lower planning reserve margin needed for its winter peaking load; and
(3) Elimination of the cost of long-term, firm point-to-point transmission service.

EKPC noted that fully integrating into PJM also would ameliorate three other challenges to its operations at that time:

(1) Increasing challenges of operating as a stand-alone Balancing Authority;
(2) Increased firm transmission costs to the regional markets necessary for the sale of excess capacity or purchase of economic energy; and
(3) Limited ability to optimize its fleet due to the capacity reserves requirement.

EKPC also argued that there were qualitative benefits to joining PJM, namely that it would be better positioned to respond to future environmental and regulatory requirements and that PJM had structural protections to safeguard the integrity and stability of the market. Major costs included PJM administration and transmission charges. CRA also noted key risks, including transmission cost allocation, capacity market diversity benefits, exit costs, and financial transmission rights. The PSC approved EKPC's integration into PJM and noted that PJM membership does present some degree of risk. EKPC was required to submit reports to the PSC addressing some of these risks on an annual basis to ensure that EKPC's continued membership in PJM is beneficial to its members and consumers.

In contrast to EKPC, the Companies' RTO membership analyses over more than a decade have consistently shown net costs of membership. The Companies are not experiencing difficulties operating as a stand-alone Balancing Authority, nor are there concerns around increasing transmission costs or planning reserve margins. The Companies further believe that they have adequate ability to optimize the Companies' generation fleet outside of an RTO and have plans and processes in place to address current and future environmental and regulatory requirements.

Kentucky Power Company (KY Power)

KY Power joined PJM in 2004. KY Power's holding company, American Electric Power Company (AEP), had been ordered to join an RTO by FERC as a condition of a merger approval and FERC had conditionally approved AEP's plan to join PJM in 2002, subsequently issuing a final order approving the PJM membership in 2003. In 2002, KY Power filed an application with the PSC for approval to join PJM in 2003 in an effort to have all approvals in place prior to a transfer of functional control of its facilities. KY Power pointed to the fact that FERC's approval of the AEP-CSW merger was conditioned on AEP joining an RTO and argued that AEP therefore had no discretion on whether to become part of an RTO. The PSC denied the application, primarily for not demonstrating benefits to Kentucky customers, among other things. FERC moved to override the PSC action. The PSC granted rehearing requests and the parties reached a stipulation that addressed the PSC's concerns. The PSC approval of the stipulation was based, in part, on a cost-benefit study that compared a scenario in which AEP and Kentucky Power were not part of PJM to one in which they were fully integrated into PJM. The study found net economic benefits in the period of 2004-2008 of greater off-system sales, net revenues from the sale of financial rights to transmit power on the AEP-East transmission system,[22] and avoided costs associated with contracts for services that would instead be performed by PJM.

[22] AEP-East is a collection of five AEP subsidiaries in Indiana, Michigan, Kentucky, Ohio, Tennessee, Virginia, and West Virginia.

In contrast to KY Power, the Companies' RTO membership analyses over more than a decade have consistently shown net costs of membership. Furthermore, the Companies have not been ordered by FERC to join an RTO as a merger condition or otherwise.

Summary

In all of the situations described above, transmission-owning entities in Kentucky that sought and received PSC approval to integrate into an RTO did so as a result of circumstances, drivers, and expected costs and benefits from membership unique to each entity. The diversity in these prior decisions, as well as the PSC's approach in determining whether to approve the transfer of functional control to an RTO, demonstrates that membership should be evaluated individually and determined on a case-by-case basis. As discussed above, the key drivers and net benefits that led to the request for and approval of the entities' integration into RTOs outlined above are not present when evaluating the position of the Companies.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Supplemental Request for Information
Dated March 4, 2022

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Question No. 8

Responding Witness: Christopher D. Balmer / Charles R. Schram

Q-8. Reference the Companies' response to SREA 1-33(b).

a. Why is the failure rate for transmission so high compared to distribution and generation?

b. Could more transparent regional transmission planning and cost allocation through an RTO improve how the Companies transmission system performs under these metrics? If it is the Companies' position that it could not, then please fully explain why not.

c. Has transmission been a factor in restricting energy trade?

   i. Are transmission constraints inhibiting otherwise efficient trades?

   ii. Would a more robust transmission system improve the efficiency of the markets?

A-8.

a. Because the SAIDI reported in the RTO Study is specific to transmission reliability, most of the interruptions included in *transmission* SAIDI are unsurprisingly associated with *transmission* causes. There was a small percentage of distribution, generation, and external interferences that resulted in transmission interruptions. The Companies track reliability metrics for the generation and distribution systems separately.

Moreover, it is important to note that the Companies' response to SREA 1-33(b) provided a *percentage* breakdown of causes of transmission SAIDI; it did not report *absolute* SAIDI values. It is not uniformly true that RTO members have better transmission SAIDI than non-RTO members or that RTO members' transmission SAIDI consistently improves over time.[2]

[2] *See* IRP Vol. III, 2021 RTO Membership Analysis at 19, Figure 9 (Oct. 19, 2021).

b. No. As noted in part a. above, being an RTO member does not necessarily result in better transmission SAIDI in absolute terms.

   Also, SAIDI is influenced by factors other than transparency of planning and cost allocation. SAIDI is primarily influenced by factors such as geography of the service territory, weather, and restoration time. It is also important to note that LG&E and KU have a planning process that is transparent and complies with the FERC's local and regional planning and cost allocation requirements. In addition, the Companies have an Independent Transmission Organization that oversees and has ultimate authority and approval rights over transmission planning.

c.
   i. In 2021, non-firm hourly transmission was unavailable less than six percent and two percent of the time for sales into PJM and MISO, respectively, some of which was due to unavailability of RTO transmission. This affected an estimated 110,000 MWh and 21,000 MWh of energy the Companies could have potentially sold into PJM and MISO, respectively. Non-firm hourly transmission was unavailable less than one tenth of one percent of the time when the Companies could have potentially purchased economy energy from PJM or MISO.

      The Companies do not have information as to the potential impact of transmission reliability events on traded energy volumes. As indicated in the response to item 9(g), significant volumes of energy have been sold by the Companies despite the occurrence of Major Event Days.

   ii. In the abstract, yes, having more transmission capacity in the right locations presumably would tend to increase the efficiency of any bulk power market that experiences transmission constraints because it would allow a greater number of transactions to occur. But whether it is economical to relieve a particular transmission constraint requires a much better specified query, as well as a rigorous engineering and economic analysis.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

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Question No. 9

Responding Witness: Christopher D. Balmer / Charles R. Schram

Q-9. Reference the Companies' response to SREA 1-33(c) and (d).

a. How do the Companies define Major Event Days?

b. Do the Companies consider the extreme cold weather from February 2021, cold snaps from polar vortices and bomb cyclones, and the western heat storms in 2020 and 2021 to be examples of Major Event Days? If not, explain why not.

c. Do the Companies believe events like these are becoming more common or more frequent such that utilities should take them into account when planning for emergencies? Fully explain why or why not.

d. What reliability metrics do the Companies track that include Major Event Days?

e. How many of these Major Event Days occurred in the last five years, by year?

   i. What were their durations?

   ii. What were the causes of the outages?

   iii. What were the costs of the outages?

f. How are the Companies quantifying the impact from such events and the ability to weather them cost-effectively?

g. Did the Companies import more power from MISO and PJM during Major Event Days? Fully explain.

h. During the five-year period in part e (above), could more have been done to prepare, coordinate with neighbors, and exchange power efficiently if the Companies were part of an RTO? Fully explain.

A-9.

a. The Companies use the IEEE 1366 2.5 β Method definition of Major Event Days. The standard defines Major Event Day as a day in which the total daily system SAIDI (i.e., transmission and distribution combined SAIDI) exceeds a threshold value. Please refer to the IEEE standard for how the threshold is calculated.

b. The threshold is utility-specific, so not all major weather events would result in a Major Event Day for the Companies. Based on the threshold value, February 5, 10, 11, and 15, 2021 were Major Event Days due to distribution SAIDI; they did not result in SAIDI on the transmission system. Please refer to (e) for Major Event Days that impacted transmission.

c. System restoration and storm recovery are important to the Companies' service, and the Companies implement preventive measures to help minimize the impacts of severe weather events. These preventive measures include strong vegetation maintenance programs and design standards to help ensure grid resiliency and customer reliability, regardless of event frequency.

d. The Companies track System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI), which include Major Event Days.

e. The Companies had 24 Major Event Days with transmission outages in the last 5 years.

    i. A Major Event Day is a day in which the total daily system SAIDI exceeds a threshold value. Therefore, the duration of a Major Event Day is 24 hours by definition.

    ii. The initial causes of the outages were either severe weather events or equipment failure. Below is a list of Major Event Days and the causes of the outages:

Year	Weather Events	Equipment Failure	Total Cost ($)
3/1/2017	X		442,117
5/10/2017		X	49,877
5/27/2017	X		56,716
4/4/2018	X		370,339
5/31/2018	X		104,963
6/1/2018		X	24,027
6/13/2018		X	0
6/26/2018	X		27,427
7/20/2018	X		496,089
7/22/2018	X		0
10/20/2018	X		0
11/14/2018	X		0
3/14/2019	X		351,393
6/21/2019	X		127,631
7/2/2019	X		0
8/18/2019		X	25,790
12/12/2019		X	13,970
1/11/2020	X		74,037
4/12/2020	X		364,456
6/10/2020	X		79,541
7/25/2020		X	0
6/5/2021		X	1,477
12/10/2021	X		4,227,402
12/11/2021	X		*
Total	17	7	6,837,252

*Cost included with 12/10/2021

iii. See the response to ii for known and tracked costs associated with these outages.

f. Each transmission outage is reviewed by subject matter experts to identify the root cause. This information is then considered when reviewing potential operational and system improvements to enhance reliability.

g. The Companies did not import any energy from either MISO or PJM during the Major Event Days listed in the days listed in item (e) (ii); rather, the Companies sold over 18,000 MWh of energy to the two RTOs during those days.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Supplemental Request for Information
Dated March 4, 2022

Case No. 2021-00393

Question No. 10

Responding Witness: Charles R. Schram

Q-10. Reference the Companies' response to SREA 1-34(c), (d), and (e).

a. Do the Companies agree that reliability within an RTO is served by all resources available to that RTO and not confined to a subset of resources deemed to be baseload or similar to the Companies' resources? If no, explain why not.

b. Can the Companies obtain the data needed to do a more thorough analysis or ask the RTOs or the ReliabilityFirst Corporation (RFC) to help them obtain the data or assist with the analysis? If yes, please explain why they have not done so.

c. SREA 1-34(e), requests, among other things and in pertinent part, a description of how the results would differ if the Companies included all units. Please provide the description in narrative form. If the Companies are unable to provide the description, explain why not.

d. For SREA 1-34(e), explain why the Companies have not developed or obtained this data.

A-10.

a. It is unclear what is meant by "reliability within an RTO is served." Any utility or RTO presumably serves load using all available resources subject to load levels and the economics of the resources. The Companies economically dispatch all available resources to reliably meet moment-to-moment load requirements.

b. It is unclear what analysis SREA is seeking. SREA's original question in SREA 1-34 (c) referred to the Companies' Figures 6 and 7 in the RTO study, which included (and explained in the text immediately preceding Figure 6) a view of RFC's top quartile and average performance for units of similar size to those of the Companies.

c. As stated in the Companies' response to SREA 1-34(e), the Companies do not have this data. As clearly marked in the headers of Figures 6 and 7 of the RTO Analysis, the figures present data for EFOR and EUOR for steam and CC units only, which are the Companies' baseload units. EFOR and EUOR are industry standard metrics for these types of units. Peaking unit reliability metrics include starting, availability, and Equivalent Forced Outage Rate during demand periods (EFORd). See the response to JI 1.22(c) for EFORd for the Companies' primary peaking units.

d. See the response to (c).

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Supplemental Request for Information
Dated March 4, 2022

Case No. 2021-00393

Question No. 11

Responding Witness: Christopher D. Balmer / David S. Sinclair

Q-11. Based upon the various requests for information to date (from both Commission Staff and the various intervenors), have the Companies developed or conducted any modifications to existing studies, additional studies, and/or alternative scenarios regarding the costs and benefits of their membership in an RTO? If yes, please provide the results. If no, please explain why the Companies have not prepared additional information regarding costs and benefits of RTO membership in view of the requests by the Commission and/or parties to the proceeding.

A-11. Since the conclusion of the Companies' 2018 base rate cases, the Commission has required the Companies to file annual RTO membership analyses.[3] These analyses are significant undertakings that the Companies develop over a period of months based on the input of multiple parts of the business. Therefore, the Companies have not developed any changes to their most recent RTO study or developed new studies during the course of this proceeding. The Companies will consider the requests in this proceeding while developing their next RTO Membership Study, which the Companies will file with the Commission by October 31, 2022.[4]

[3] *See* Case Nos. 2018-00294 and 2018-00295, Order (Ky. PSC Mar. 22, 2021).
[4] *See id.* at 2.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILTIES COMPANY

Response to Southern Renewable Energy Association's
Supplemental Request for Information
Dated March 4, 2022

Case No. 2021-00393

Question No. 12

Responding Witness: David S. Sinclair

Q-12. Reference the Companies' December 22, 2021, response to Ordering Paragraphs 9 and 10 in the Commission's September 24, 2021, joint Order in Case Numbers 2020-00349 and 2020-00350, filed into the Post Case Referenced Correspondence for both dockets. Have the Companies made any updates, revisions, or otherwise generated any additional information to the "Generation Planning & Analysis" dated and submitted on December 22, 2021? If yes, provide (or reference in this proceeding) each update, revision, and/or all additional information. In addition to the forgoing request through this item, have the Companies prepared "a more granular summary of model inputs and outputs" as proposed in their response filed on December 22, 2021? If yes, provide the summary. If no, explain why not.

A-12. It is unclear what this request is asking. The Companies have not updated or revised the December 22, 2021 post-case filing the Companies made in their 2020 rate cases in accordance with the Commission's Sept. 24, 2021 Orders in those proceedings. A primary purpose of that filing was to address increasing modeling transparency in *future* proceedings. In this proceeding, which began *prior* to December 22, 2021, the Companies have provided all 2021 IRP workpapers, which include all levels of granularity used in the IRP, in response to JI 1-3.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Supplemental Request for Information
Dated March 4, 2022

Case No. 2021-00393

Question No. 13

Responding Witness: Stuart A. Wilson

Q-13. Reference the Companies' IRP.

a. Define "baseload" resources, as that term is used in the Companies' IRP.

b. Define "dispatchable" resources, as that term is used in the Companies' IRP. Please explain in your response the differences between a "baseload" and a "dispatchable" resource.

c. Confirm or deny with explanation that renewable energy resources, including utility-scale solar and wind facilities, that are paired with battery energy storage facilities are dispatchable resources under the Companies' definition.

d. Confirm or deny with explanation that it is technically possible to reliably meet demand without any "baseload" resources if there are sufficient non-baseload resources available to meet demand at all times. Provide any studies, reports, or analysis the Companies relied on for determining whether "baseload" resources are necessary.

e. Identify the minimum amount of "baseload" resource capacity the Companies believe are technically necessary to provide reliable electricity service to their customers over the term covered by their IRP. Explain how the Companies arrived at this determination.

A-13.

a. See page 5-5 of Volume I of the 2021 IRP.

b. See page 5-5 of Volume I of the 2021 IRP.

c. The battery portion of a system of renewable resources paired with batteries would be dispatchable only to the extent the batteries are charged. Pairing batteries solely with renewable resources reduces the likelihood the battery will be available when needed.

d. The answer to this question is very fact-specific, based on load, the penetration of dispatchable resources, etc. Even if this is technically feasible, the economics may not be attractive to customers. See attached.

e. The Companies have not performed this calculation. See also the response to part (d). The requested calculation would also be irrelevant to this proceeding, which the Commission's IRP regulation states is for the purpose of "review[ing] … load forecasts and resource plans … to meet future demand with an adequate and reliable supply of electricity at the *lowest possible cost*," not with the lowest level of baseload resources.[5]

[5] 807 KAR 5:058, Necessity, Function, and Conformity (emphasis added).

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

LG&E
a PPL company

Summary

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 circuit has approximately 1,600 residential customers and 240 commercial customers that use approximately 20,500 MWh annually with a summer peak hourly demand of 8.9 MW. While the electricity consumption on the Highland 1103 circuit accounts for less than 0.4% of Jefferson County's total electricity consumption, its size and load characteristics are typical of many of LG&E's circuits and includes a customer mix that uses natural gas in their homes and businesses.

After evaluating a wide range of alternatives, this study shows that:

- 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) that would result in land being used for solar panels and battery storage on a scale that would likely not be acceptable to the local community.

- 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.

- 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.

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. In addition to the findings in this study, a number of questions, issues, and challenges were identified that were not addressed but were captured and documented for future consideration and included as part of this report.

Background

There is growing national interest in using renewable generation technologies to displace fossil-fuel generation in order to reduce CO_2 emissions.[1,2] Many advocates claim this can technically and economically be accomplished using existing renewable technologies in combination with current developments in storage technology.[3] Furthermore, some are interested in accomplishing this transition to 100% renewable generation via the use of microgrids based solely on distributed solar generation and battery storage.[4] This focus on local generation and storage development is often premised on the idea of creating local jobs and eliminating the need for central station power generation and its associated transmission grid.[5,6]

To understand and identify some of the challenges and issues that would need to be addressed in pursuing a local 100% solar/storage solution, this study used actual 2017 load and solar irradiance data for a representative LG&E distribution circuit to develop a range of possible technology and cost cases and compared the results to a range of costs of continuing with traditional utility grid service. The circuit that was selected is Highland 1103, which is located in the heart of Louisville. Figure 1 shows the geographic location (red rectangle) and electrical lines associated with this circuit.

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1 Bloomberg New Energy Outlook 2018 — https://www.bnef.com/core/new-energy-outlook

2 Benefits of Renewable Energy Use, Union of Concerned Scientists — https://www.ucsusa.org/clean-energy/renewable-energy/public-benefits-of-renewable-power

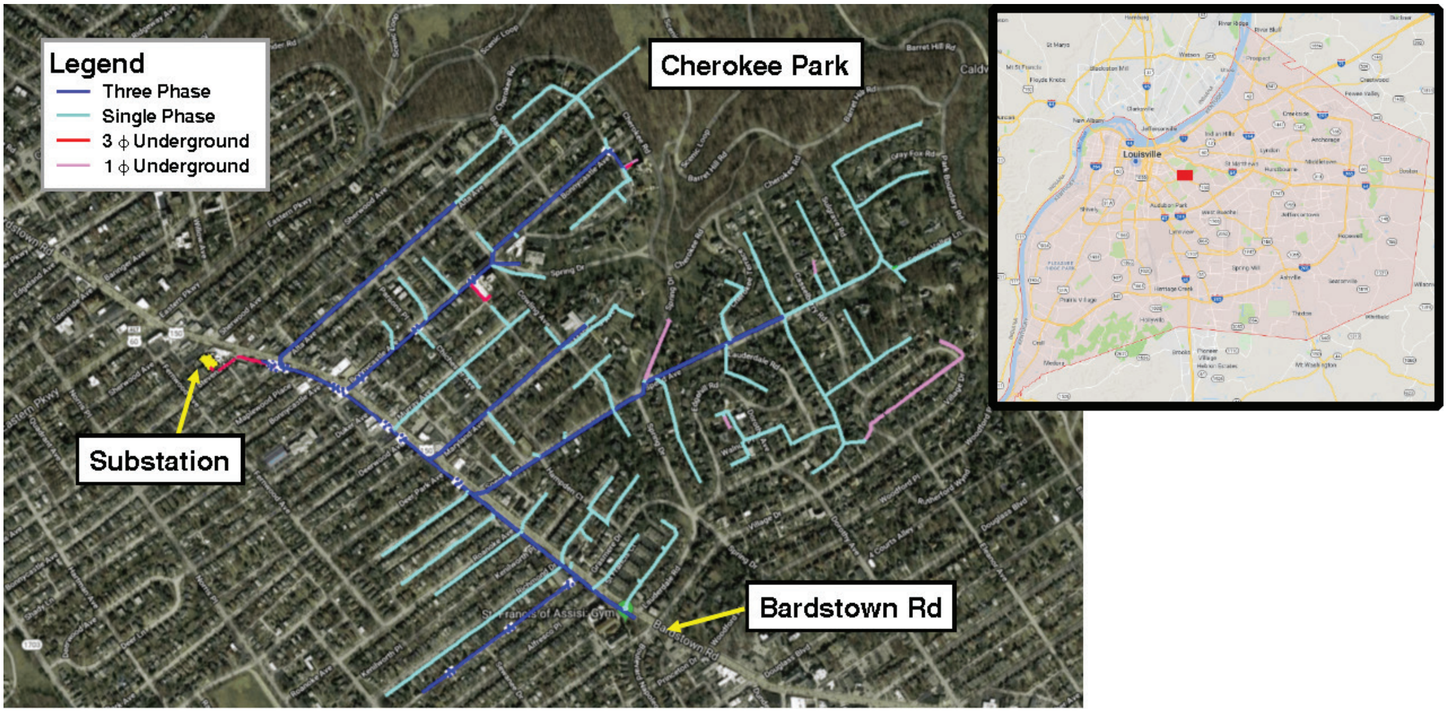
3 How Energy Storage Can Pave the Way for Renewable Energy Adoption — http://climate.org/how-energy-storage-can-pave-the-way-for-renewable-energy-adoption/

4 https://www.renewableenergyworld.com/articles/2017/08/100-percent-renewable-powered-microgrid-in-illinois-islands-from-the-grid-for-24-hours.html

5 A Resolution for 100% Clean Energy for Metro Louisville Operations by 2030 and Community-wide by 2035.

6 Distributed Generation of Electricity and its Environmental Impacts — https://www.epa.gov/energy/distributed-generation-electricity-and-its-environmental-impacts

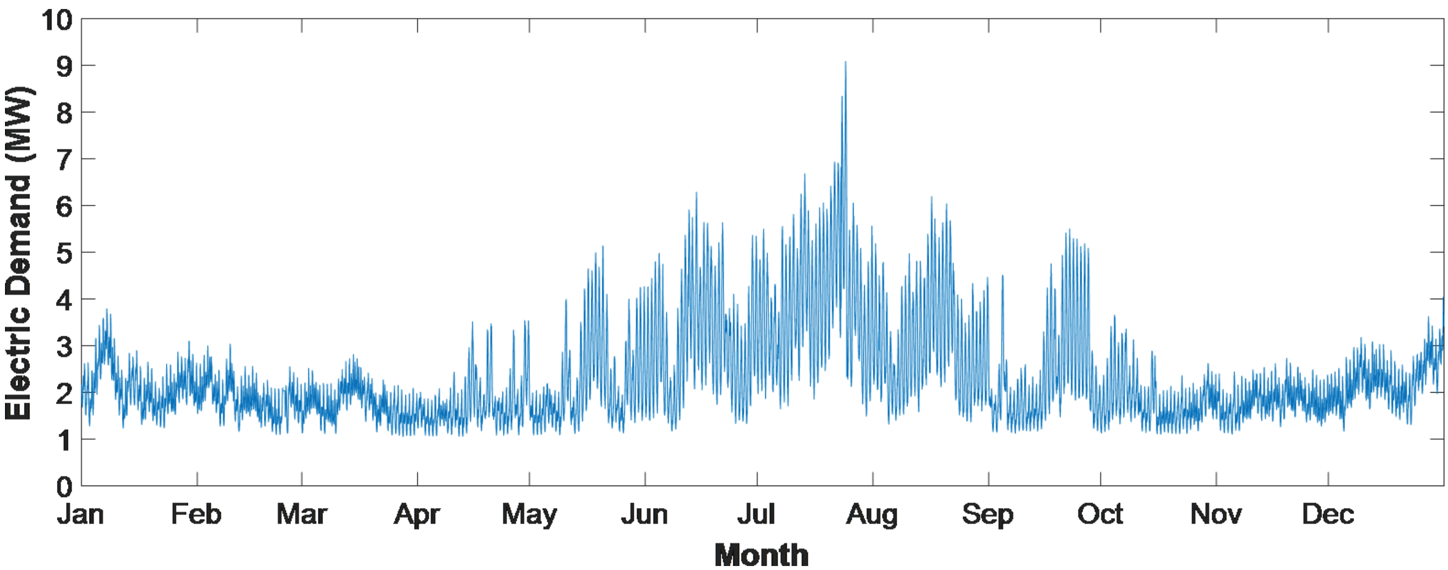
Figure 1: Google Earth Overview of Highland 1103 Circuit Distribution Infrastructure



LG&E operates 6,445 total miles of electric distribution lines making up 572 distribution circuits in and around Jefferson County serving approximately 411,000 electric customers.[7] Highland 1103 is a typical residential/small commercial circuit in that it has approximately 1600 residential customers and 240 small commercial customers, most of which also use natural gas, particularly for space and water heating. It is a 12.47kV circuit consisting of 9.26 total circuit miles (90% overhead, 10% underground and 30% 3 phase, 70% 1 and 2 phase).

Figure 2 displays the 5-minute load data on Highland 1103 for 2017 used in this study. It shows the summer peaking nature of the circuit as well as the lower winter electric demand due to natural gas space heating.

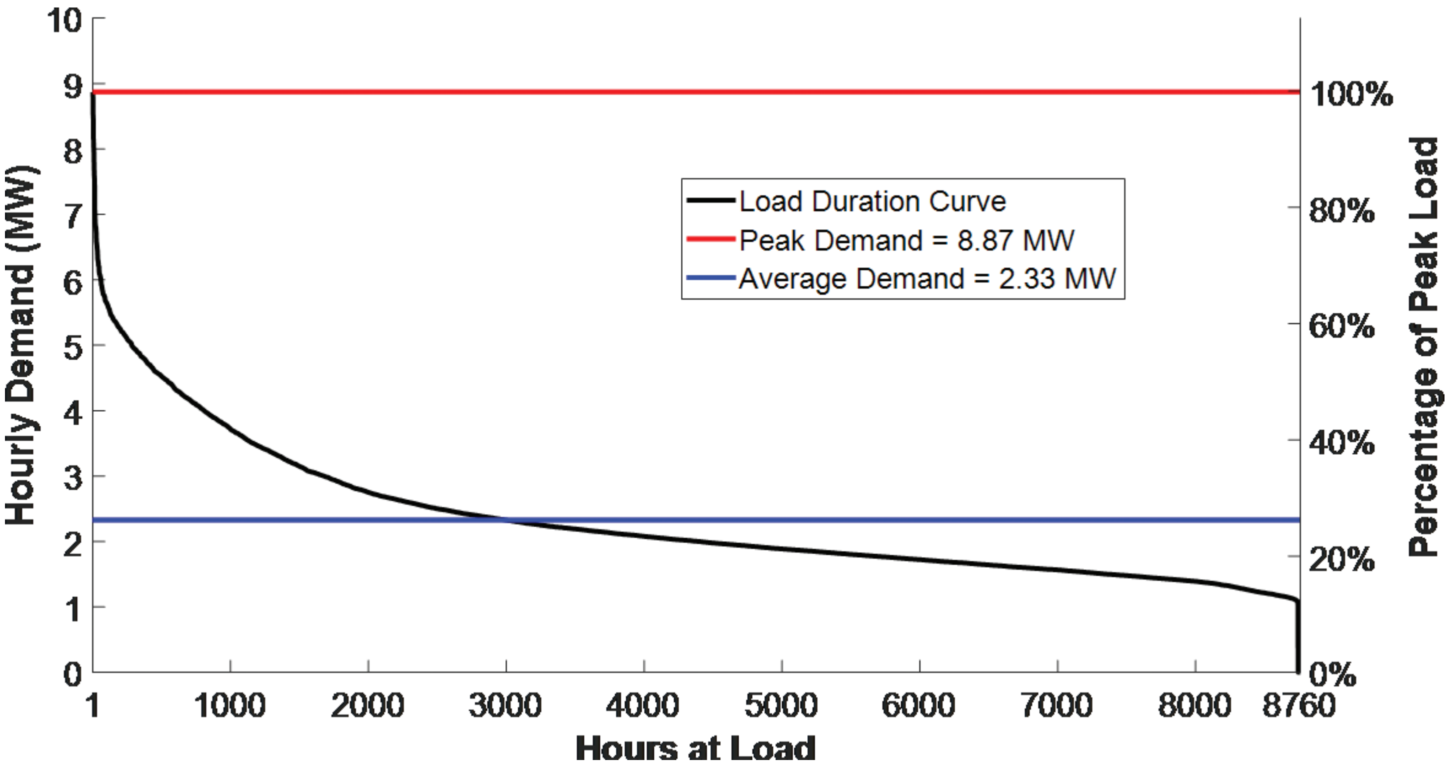
Figure 2: Five-Minute Electric Demand ("Load") for Highland 1103



[7] Data as of December 31, 2017. Includes pro-rata share of indirect or jointly owned assets.

Figure 3 displays average hourly electric demand in 2017 on Highland 1103 from highest to lowest in what is known as a load duration curve. The load duration curve shows that in 2017 the highest hourly load was 8.9 MW, the lowest hourly load was 1.04 MW, and the average hourly load was 2.3 MW. This circuit's load duration curve is typical for a summer peaking system with very high loads occurring in less than 500 hours of the year.

Figure 3: Load Duration Curve for Highland 1103

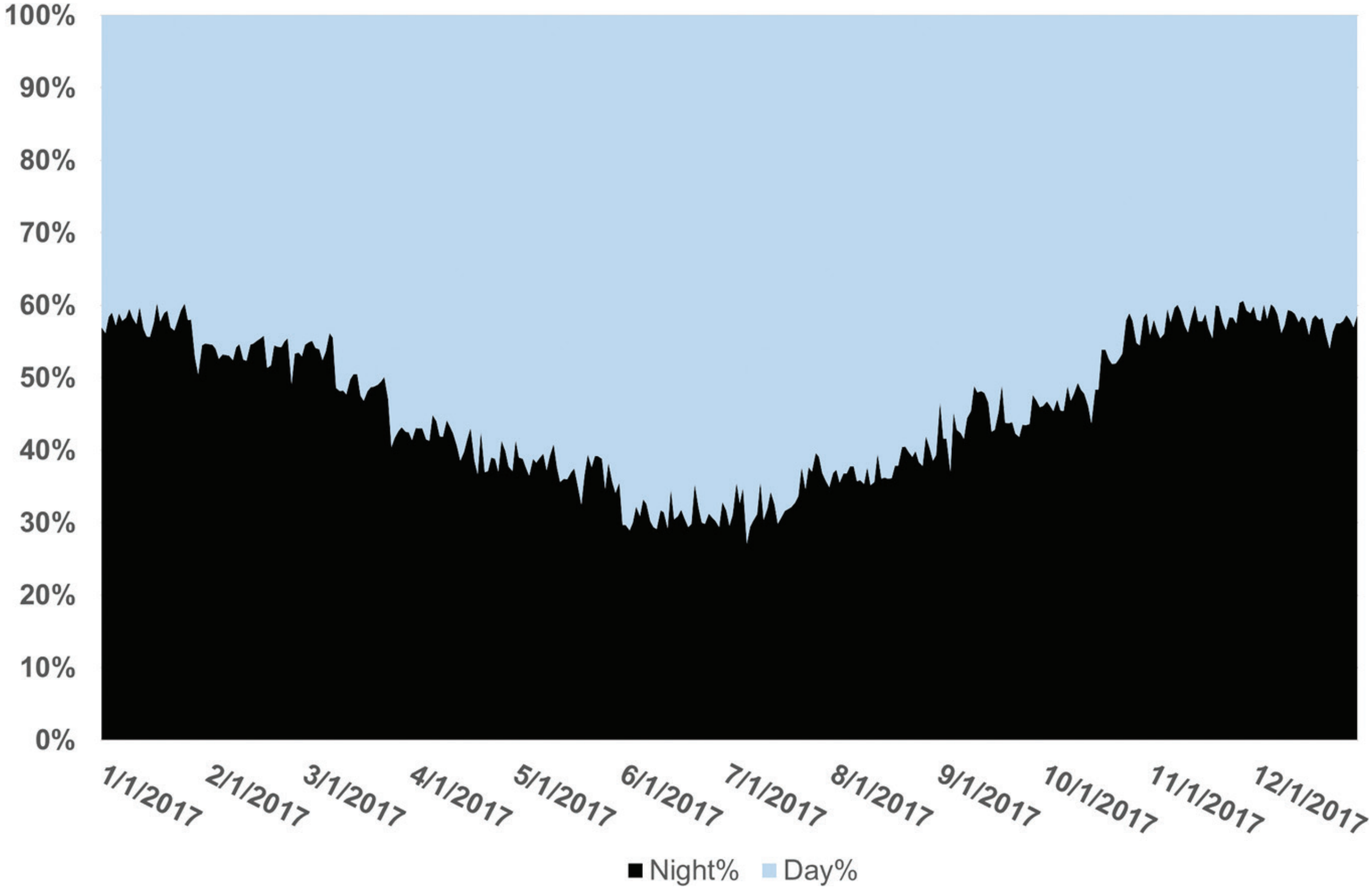


In 2017, base load generation (typically coal and combined cycle natural gas) satisfied the majority of the load shown in the load duration curve, and peaking generation capacity (simple cycle natural gas) served the peaks that only occur for a handful of hours in the year. If this circuit were to be served by 100% local solar generation then solar capacity would be needed to serve the peak hour and an additional amount of solar generation would be required to charge the energy storage required to meet customers' energy needs when the sun is down and on cloudy days. Therefore, much of the solar generation capability will be underutilized for a substantial portion of the year.

To further understand some of the challenges of just using local solar generation and energy storage, it is important to understand how much of Highland 1103 circuit's load occurs during daylight hours and nighttime hours. As shown in Figure 4, despite customers on this circuit predominately using natural gas for space heating, over 50 percent of their electricity is used during the night in winter months. Their usage at night decreases to around 35 percent to 40 percent in summer months as longer days and daytime air conditioning load increases the share of electricity used when the sun is up. Regardless of the season, the customers on this circuit use a substantial amount of energy when the sun is down, energy that must be stored in batteries.[8]

[8] The day/night energy profile of this circuit is comparable to the profile of the entire LG&E and KU system. See Figure 8 in PPL Corporation Climate Assessment at https://www.pplweb.com/wp-content/uploads/2017/12/Climate-Assessment-Report.pdf

Figure 4: Proportion of Energy Consumed during Daylight and Nighttime Hours for Highland 1103



Evaluation Methodology

This case study uses actual five-minute load for 2017 from Highland 1103 and actual five-minute solar irradiance data measured from a NOAA weather station located in Versailles, KY. While the solar irradiance data is from a site that is about 50 miles from Highland 1103, it is representative of regional solar conditions that are adequate for this high-level case study. In general, it should be noted that this is a high-level conceptual study and is not meant to represent a final or optimal engineering or economic design. To design and size the equipment for an actual "off-the-grid" project would require additional analysis and engineering associated with issues such as, but not limited to, load diversity over time, motor starting/stall currents, fault current sources, protection, and over/under voltage risks. Table 1 shows the major assumptions used in preparing this case study.

Table 1: Major Assumptions for Case Study

	Assumption	Low Range	High Range
Utility-scale solar	$/kW installed[9]	810 (installed in 2030)	951 (installed in 2020)
	Annual capacity factor	~17% on average	
	Land requirement — acres / MW	3.2 Acres/MW (DC), 3.84 Acres/MW (AC)	
	Useful life of panels	25 years	30 years
	Useful life of inverters	10 years	20 years
Roof-mounted solar	$/kW installed[9]	1,493 (2030 Dollars)	2,306 (2020 Dollars)
	Average system size (per roof)	5 kW	15 kW
	Annual capacity factor	~17% on average	
	Space requirement — sq. ft./kW	~60 ft^2/kW (DC), 72 ft^2/kW (AC)	
	Useful life of panels	25 years	30 years
	Useful life of inverters	10 years	20 years
Utility scale Li-ion storage	$/kWh installed[9]	327 (installed in 2030)	435 (installed in 2020)
	Peak energy delivery — kW	1,000 kW	
	Energy storage — kWh	4,000 kWh	
	Battery size	0.015 Acres/MWh[10]	
	Useful life	10 years	15 years
In home Li-ion storage	$/kWh installed[9]	476 (installed in 2030)	634 (installed in 2020)
	Peak energy delivery — kW	5 kW (RS)	15 kW (GS)
	Energy storage — kWh	13.5 kWh (RS)	40.5 kWh (GS)
	Battery size	~9.5 ft2 per 13.5 kWh[11]	
	Useful life	10 years	15 years
Average retail rate in 2017 — cents/kWh	Residential	10.90 cents/kWh	
	Commercial	9.28 cents/kWh	
Distribution-only rate in 2018 — cent/kWh	Residential	25% of average retail rate	
	Commercial	26% of average retail rate	
Future retail rate escalation		2%	5%
Cost of Capital		4.40% (100% Debt Financing)	7.58% (Utility Cost of Capital)

When considering utility scale energy storage applications, it is important to be aware of its size and proximity to other structures. Employing the large number of batteries that would be necessary for these cases will require a keen attention to location, spacing, and fire mitigation strategies.[12] Figure 5 shows a typical utility-scale lithium-ion battery site with a 30 MW, 120 MWh (4 hours at peak discharge rate) energy storage system consisting of twenty-four 40-foot containers and a dedicated switchgear/control room, which is much smaller than the system needed for this circuit.

[9] Source: NREL's 2018 ATB (https://atb.nrel.gov/).

[10] Includes spacing required per fire codes, inverter footprint, and associated electrical infrastructure. Assumed 2400 ft2 for 1 MW, 4 MWh block.

[11] Residential and small commercial energy storage is typically wall-mount. 9.5 ft2 indicates wall space required. Actual footprint is dependent on local fire and building codes.

[12] "Big Battery Boom Hits Another Roadblock: Fire-Fearing Cities" https://www.bloomberg.com/news/articles/2018-05-18/the-big-battery-boom-hits-another-roadblock-fire-fearing-cities

Figure 5: Typical 30 MW, 120 MWh Lithium-Ion Energy Storage Site[13]

For all cases analyzed in this study, it is assumed that LG&E's distribution system costs will be included since the system is being relied upon to deliver solar energy to end-users and charge batteries. Other than escalation uncertainty, these costs are the same across all cases and do not drive differences. Also, this case study does not address potential stranded generation and transmission system costs that would be associated with a larger system-wide study.

The study assessed the cost of investments based on i) LG&E's cost of capital and ii) the cost of 100% debt financing. As identified in the "Potential Issues" section below, there are a number of possible ways that behind-the-meter rooftop and storage investments might be financed if owned by the property owner as well as some legislative and regulatory changes that could impact how utility system solar and storage might be owned and financed. This case study is focused on the scope and scale of the technology investments required to be 100% renewables and off-the-grid, not on the financial engineering of specific cases.

This study looks only at the 5-minute load profile from 2017. It does not address how future changes in load or load shape might impact system sizing and cost. For example, weather patterns could alter hourly and daily load shape and energy and widespread charging of electric vehicles would impact both the amount of electricity consumed as well as the daily load shape. Similarly, no assumption is made regarding future rate design or direct load control that might attempt to alter the load shape and the quantity of energy consumed. Lastly, no material change is assumed in natural gas utilization in the homes and businesses on this circuit that would impact electrical load.

Alternative Technology Solutions

Through initial modeling using the Highland 1103 circuit's 5-minute load and corresponding weather measured in 2017, it was determined that 75 MW (AC) of photovoltaic solar accompanied by 300 MWh of energy storage would be required to satisfy 100% of all electric demand in 2017 on this distribution circuit. This study assumes no equipment failures and zero generation capacity margin (for potential load changes), both of which would need to be considered for an actual sizing study. Figure 6 and Figure 7 show estimated solar production overlaid with electrical demand for representative winter and summer weeks. These figures show the variability in solar production day to day as well as by season and illustrate the need for such large solar and energy storage systems for this distribution circuit. A large solar and battery system is required in order to remain off grid during the winter, when there are fewer daylight hours, skies are more frequently overcast, the sun doesn't shine as brightly in the sky, and the majority of electricity demand occurs during the night. During the summertime, however, generation from this same system will exceed the neighborhood's electricity needs. When solar generation exceeds electric demand, the excess energy will be stored in batteries to be used to meet electricity requirements when solar generation is inadequate.

[13] Source: San Diego Gas & Electric.

Figure 6: Representative Week in January 2017 Showing Solar Generation and Electric Demand

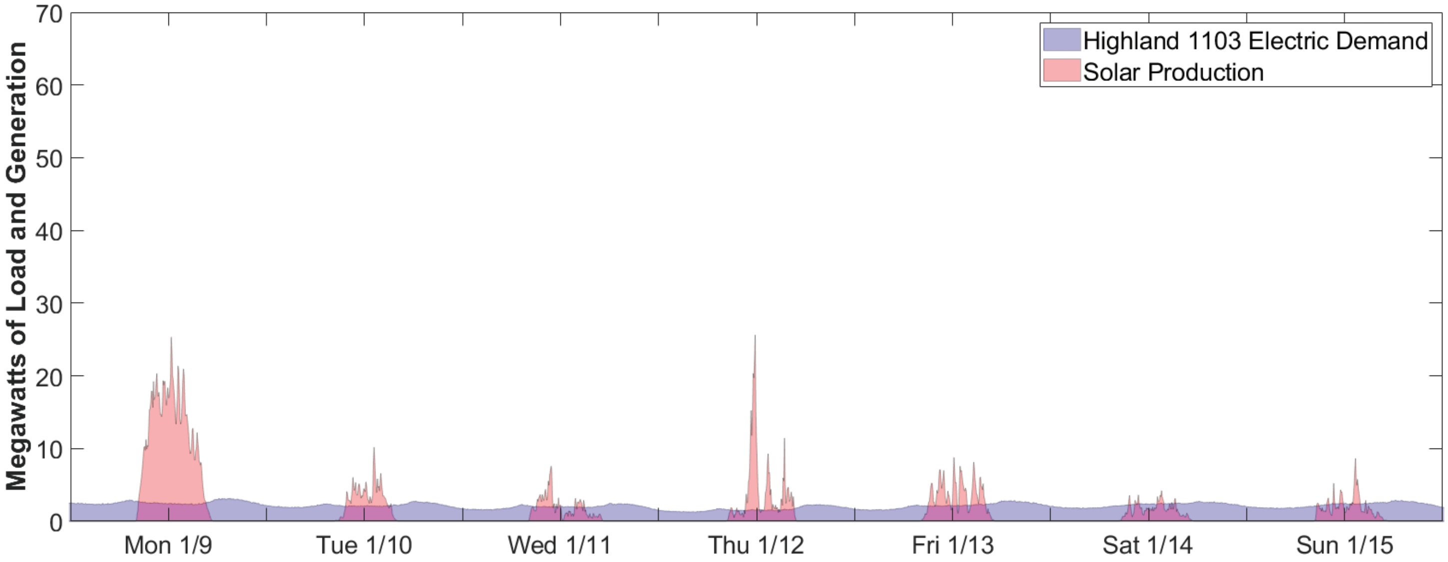
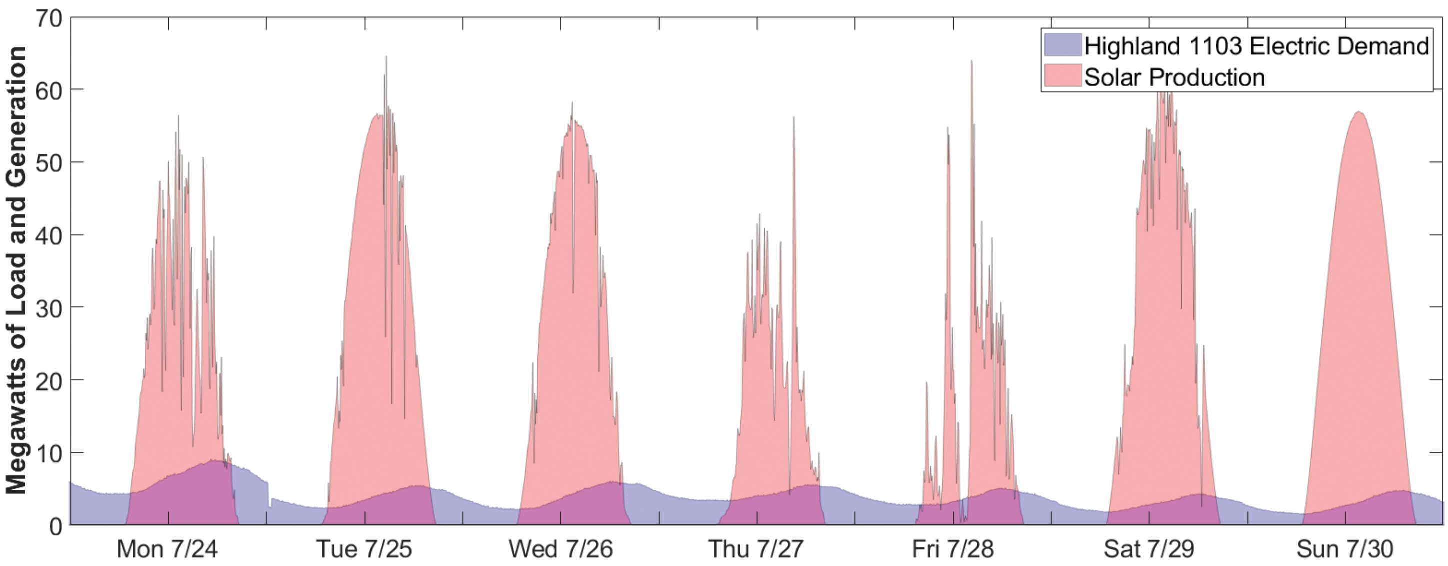


Figure 7: Representative Week in July 2017 Showing Solar Generation and Electric Demand



The study assumed each residential customer on the Highland 1103 circuit could install up to 5 kW of solar and up to 13.5 kWh of battery storage at their homes; non-residential customers were assumed to install up to 15 kW of solar and up to 40.5 kWh of battery storage. The range of results for the quantity of solar and storage technology is shown in Table 2. Note that the quantity of the required utility-scale battery storage is approximately two times the size of the typical storage facility shown in Figure 5.

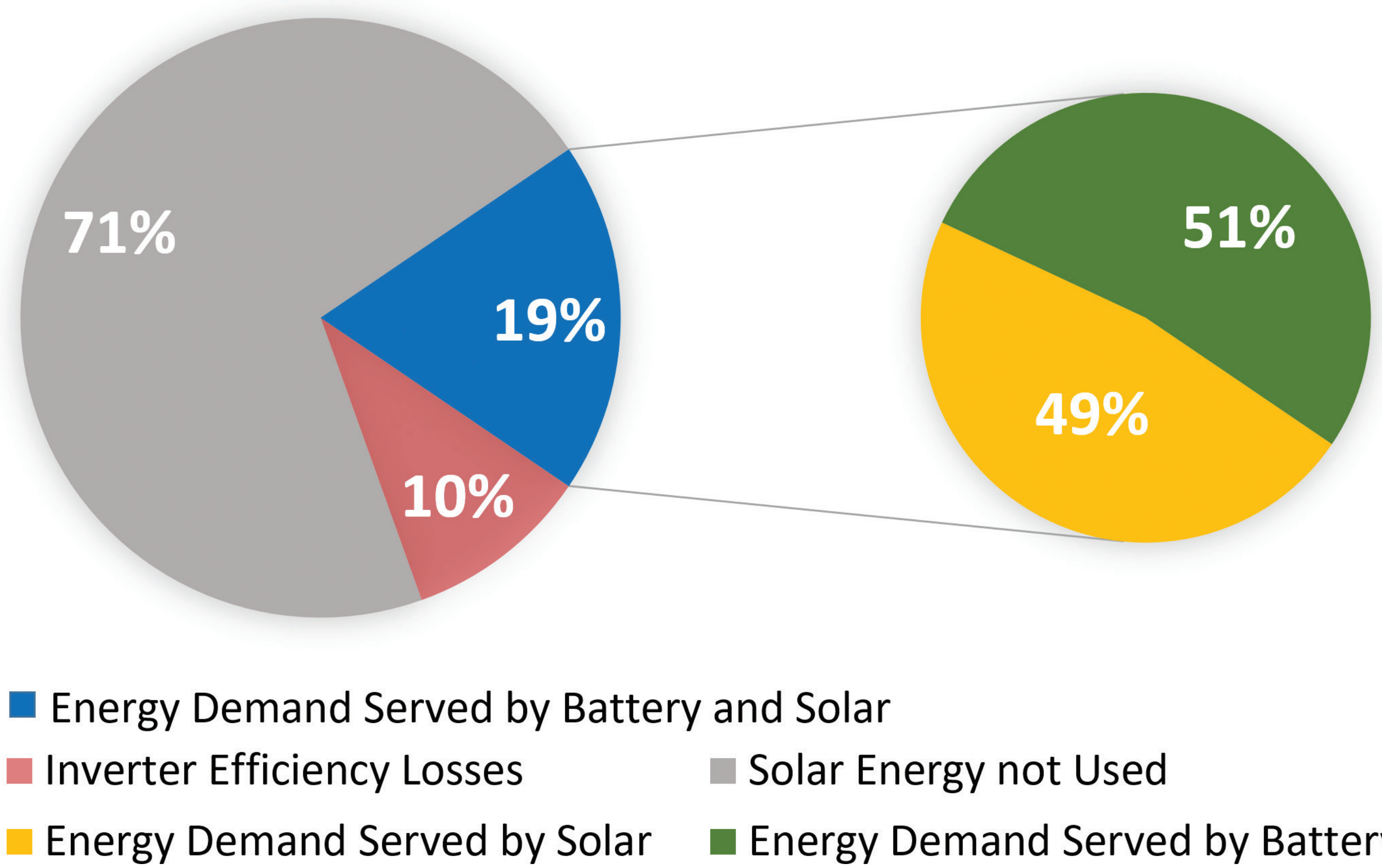
Table 2: Rooftop Solar/In-Home Storage Scenarios

% of Potential Rooftop Solar and In-Home Storage Capacity	Quantity of Solar and Battery Storage				Land Area Required for Utility-Scale Infrastructure (Acres)	Total Capital Cost $(millions)	
	Rooftop Solar (MW)	In-Home Storage (MWh)	Utility-Scale Solar (MW)	Utility-Scale Storage (MWh)		Nominal Cost in 2020	Nominal Cost in 2030
0%	0	0	75	300	293	202	159
50%	6	16	69	284	270	213	165
100%	12	32	63	268	246	224	172

Even assuming every home and business installs solar panels and storage, there is still a large need for utility scale solar generation and storage. In fact, the degree of home and business rooftop solar has a very limited impact on the quantity of utility scale solar required to reliably meet the circuit's energy needs. However, it does reduce the utility-scale infrastructure footprint by almost 50 acres which could be important in land constrained areas like Highland 1103.

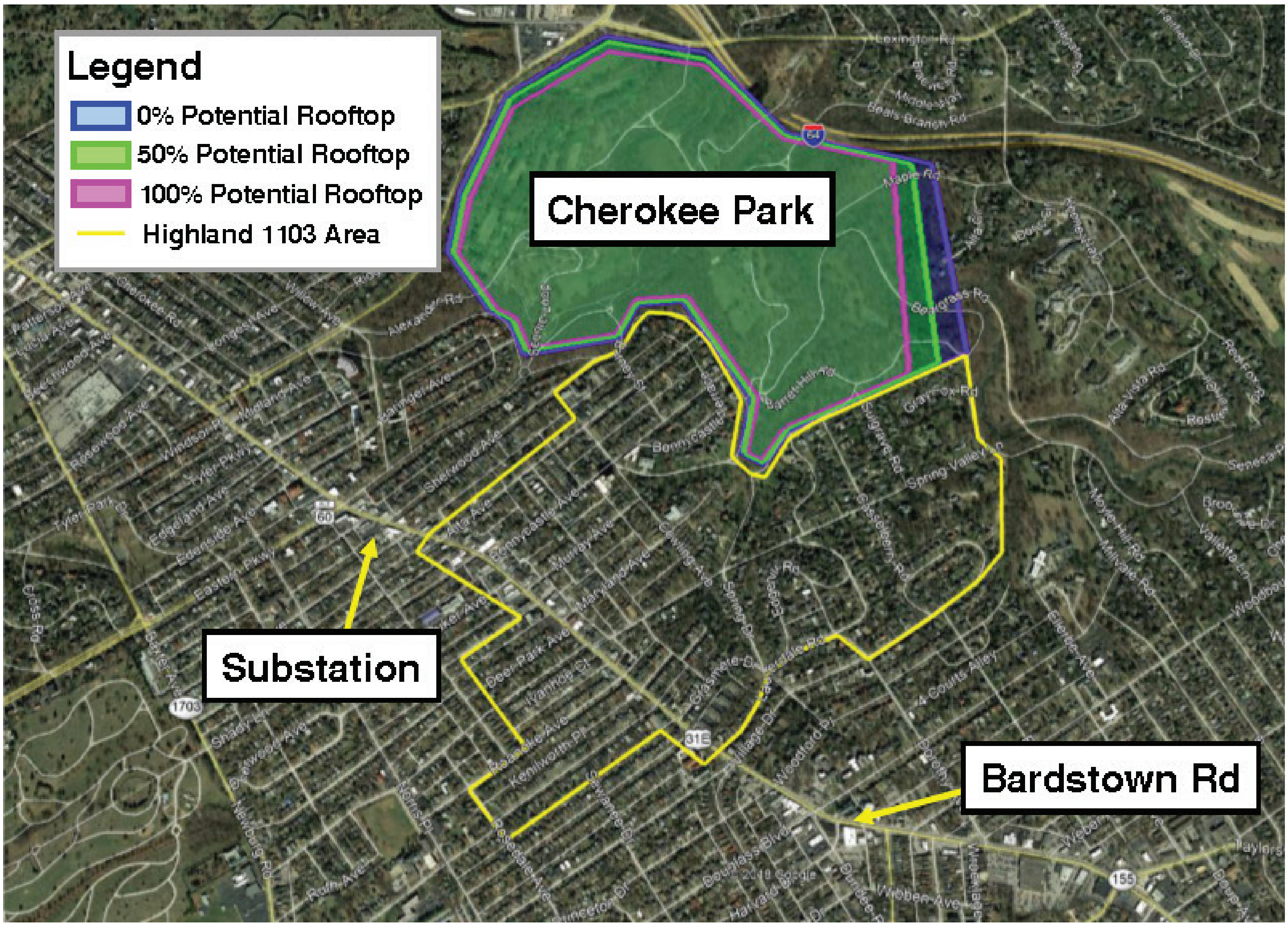
As shown in Table 2, approximately 75 MW of solar generating capacity is required to store sufficient energy to serve load during the winter when nights are longer and clouds are more prevalent. This capacity is approximately eight times larger than Highland 1103's summer peak of around 9 MW. This excess capacity can produce far more energy annually than is required to serve the customers' energy needs. In fact, as shown in Figure 8, approximately 71 percent of the potential solar energy would be unused. Figure 8 also shows that approximately 49 percent of the circuit's electricity would be generated directly by the solar panels with the remainder coming from storage. With so much energy flowing through storage, approximately 10 percent of solar generation would be consumed by inverter losses.

Figure 8: Distribution of Solar Energy Production



Because the interest in distributed solar and storage is often described in terms of local economic impact and reduced need for investment in transmission assets, it is important to understand the space requirements associated with isolating Highlands 1103 from the grid. Figure 9 shows the range of geographic space requirements for the three rooftop solar/in-home storage scenarios. The space required for the utility-scale facilities is large, even in the best-case use of rooftop solar/in-home storage. For this particular circuit, the only large vacant land area contiguous to the Highland 1103 circuit is Cherokee Park. LG&E is not recommending using the park in this manner but placing utility scale solar in other areas still impacts land use and would require additional electric lines to connect the facilities to this particular circuit. These costs are not included in this study.

Figure 9: Representative Land Use Required for Utility-Scale Solar and Battery Storage



Cost Comparison of Solar/Storage Cases to Remaining Connected to the Grid

Each of the rooftop solar with in-home storage scenarios in Table 2 were evaluated based on both LG&E's cost of capital (7.58%) as well as the cost of 100% debt financing (4.40%). The study was performed using NREL's cost forecasts for 2020 and 2030, which show continued future declines in both solar and energy storage costs.[14] In this study, the solar and battery storage systems were evaluated in a very favorable light. For example, all assets were assumed to have a useful life of 30 years, fixed operating costs for the solar and battery systems were ignored, and an inflation rate of zero percent was used to estimate nominal solar and battery storage costs in 2020 and 2030 from NREL's forecast. These and other assumptions are optimistic for the solar with storage concept (see "Favorability of Major Assumptions" for further discussion).

[14] NREL expects the costs of solar and battery storage to decline from 2020 to 2030 by 1.6% per year and 2.8% per year, respectively, in real terms.

In order to compare the cost of using 100% solar and storage to serve the electric load on the Highland 1103 circuit, the investments in solar and storage were levelized over 30 years and added to an estimate of the costs of maintaining and operating the existing distribution system that would still be required to serve load. These costs were then compared to a range of possible future costs of continuing to receive energy from the LG&E system. Note that the range of possible future LG&E costs are not predictions of future electricity prices but are meant to capture a range of possible future price paths over the next 30 years for comparing to the solar/storage off-grid cases.

Table 3 shows the levelized cost of electricity of serving the Highland 1103 load for all of the cases evaluated. These costs exclude the costs of operating and maintain the distribution system that would still be required. Not surprisingly, cases with a higher cost of capital have a higher levelized cost of electricity. The cases with rooftop solar and in-home battery storage require less land for utility infrastructure but are more expensive. Finally, the cost of installing the solar and battery systems in 2030 is less expensive than in 2020 due to the forecast of decreasing solar and battery storage costs.

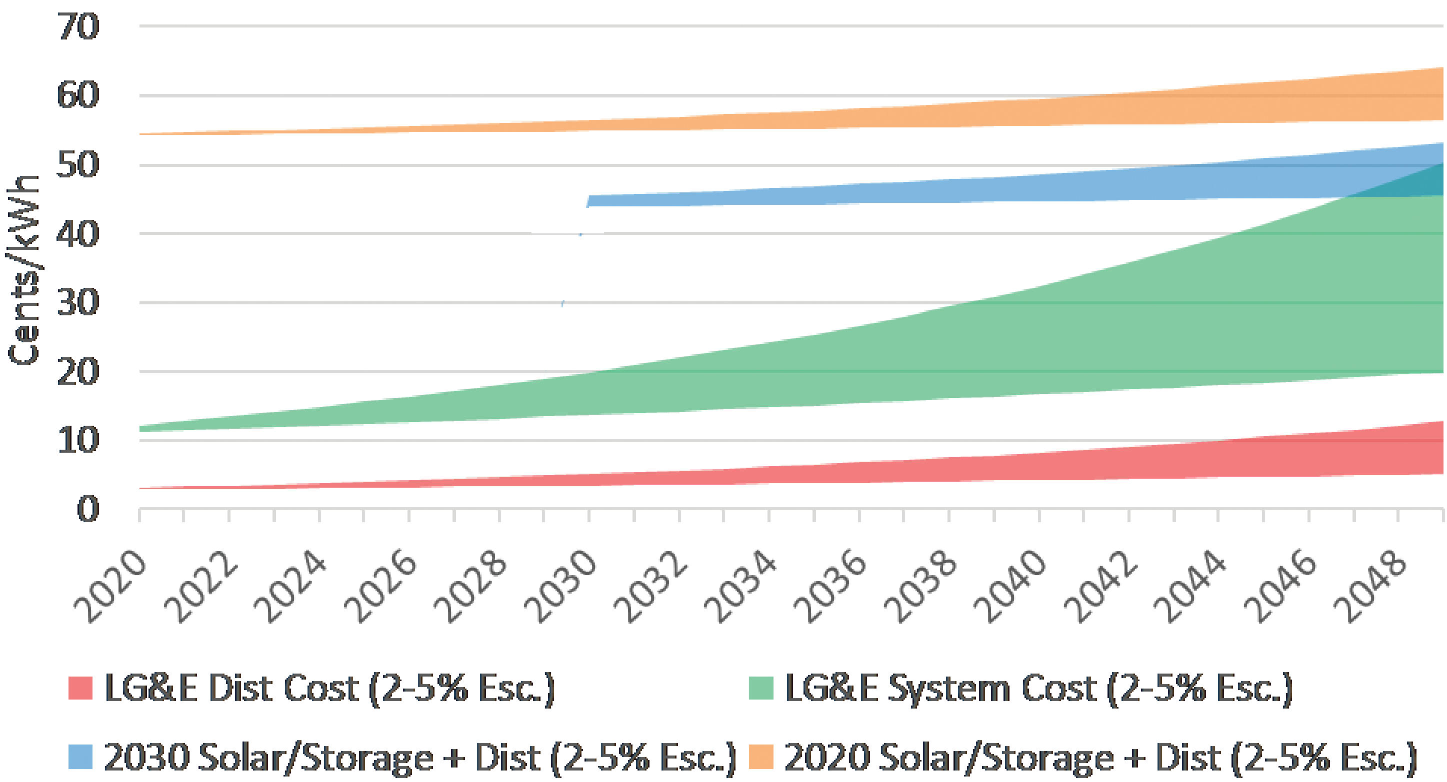
Table 3: Levelized Cost of Electricity excluding Distribution System Costs

Commission Year	Cost of Capital	% of Potential Rooftop Solar and In-Home Storage Capacity	Solar & Battery Storage System Cost Levelized Cost of Energy (cents/kWh)
2020	7.58%	0%	79.2
		50%	83.2
		100%	87.1
	4.40%	0%	51.4
		50%	54.0
		100%	56.6
2030	7.58%	0%	62.2
		50%	64.5
		100%	66.8
	4.40%	0%	40.4
		50%	41.9
		100%	43.3

Adding the cost of maintaining the distribution grid to the best 2020 and 2030 cases from Table 3 allows the comparison to a range of rate paths for staying on the existing LG&E grid. Figure 10 contains a range of rate paths for the LG&E distribution system in red and the entire LG&E system in green.[15] The ranges were created by escalating actual 2017 costs by 2 percent and 5 percent. The total costs for the best 2020 and 2030 cases were created by adding the range of distribution costs to the levelized costs in Table 3. This cost reflects the average cost of electricity for all customers on the Highland 1103 circuit.

[15] LG&E distribution system costs are assumed to grow proportionally with LG&E system costs.

Figure 10: Total Solar/Battery Storage Cost versus LG&E System Cost



As shown in Figure 10, the cost of isolating the Highland 1103 circuit from the grid and serving its electricity requirements with solar and battery storage is 2.5 to 3.5 times greater in 2030 than the LG&E system. Assuming LG&E's rates were to escalate at 5 percent annually, then it is possible that a solar and battery storage system installed in 2030 might be less expensive by the late 2040s. It should be noted that since 1990, LG&E average electricity rates have increased at an average rate of about 2.1 percent meaning that future rates would have to escalate at more than twice the historical rate in order for the solar and storage system to be even plausibly economical. The study also shows that with both solar generation and battery storage costs forecasted to decline, waiting as long as possible to make such investments would increase the probability of being economical compared to the LG&E system rates.

Favorability of Major Assumptions

In preparing the financial analysis for this study, a number of the operational and technology performance parameters were assumed to be favorable toward reducing the cost of using 100% solar generation and energy storage to serve Highland 1103. For example:

- The financial results presented assumed all panels, inverters, and batteries perform perfectly for 30 years. Based on what we know today, inverters and batteries are likely to have much shorter lives.
- The solar panels and battery storage were sized to exactly match 2017 actual load. Some contingency would need to be built in order to address load uncertainty and random equipment failure.
- No land cost was assumed for the utility scale solar generation and battery storage.

While recognizing that there would be incremental costs associated with addressing these issues in an actual project design, these items are also more uncertain and subject to change over time. Because the purpose of this case study was to evaluate the local solar generation and storage concept at a high-level, the Company did not want to distract from the study's fundamental purpose by explicitly trying to incorporate costs to address these issues.

Potential Issues Identified in Preparing this Case Study

As stated at the outset, this case study is a high-level analysis of the technology and financial implications associated with serving the load on a single LG&E distribution circuit. One of the benefits of preparing such a study is that it identified a number of issues and questions that a more detailed study would certainly need to address should such a project ever be considered in the future. Like this study, the questions and issues identified below are not meant to be exhaustive.

1. This study assumed that all roof-top solar and in-home storage was built overnight. In the real world, that would not occur so provisions (technical and financial) would need to be made to address changes (both increases and decreases) in the quantity of roof-top solar and in-home storage over time.

2. It was assumed that load (energy and shape) would be rather stable over 20 years. Provisions (technology and financial) would need to be put in place among the customers on the circuit to deal with material changes in load and load shape that would impact asset utilization and possibly cost recovery and future asset investment. Because the costs of this off-grid system are for all practical purposes fixed, changes in energy usage would not materially impact costs but could result in over- or under-collection of fixed costs. For example, unless load is forecasted to grow (say due to increased market penetration of electric vehicles or converting from natural gas to electric space heating), the economics of energy efficiency may not reduce overall costs but instead only shift fixed costs to other customers on the circuit depending on rate design.

3. Once such a system is created, the ability to undo it in the future may be limited or very expensive, so exit costs should be considered.

4. 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. Some legal and regulatory issues would have to be addressed in this new type of system.

5. Because all assets were assumed to be owned and financed by LG&E there was no need to address compensation to individuals who invest their own funds in rooftop solar and in-house storage. However, in reality, it is highly likely that individual homeowners and business would invest their own funds and would seek compensation for contributions to supporting the circuit's load.

Conclusion

The declining cost of solar generation and projections of future cost declines for battery storage along with increasing focus on CO_2 emissions have raised the interest of both customers and utilities identifying opportunities to deploy these technologies. To date, the vast majority of applications of these technologies have focused on applications that still require connection to the national power grid, a grid that today relies heavily on fossil fuel resources to reliably meet customers' real time electricity needs. This study was a valuable exercise in identifying and evaluating the numerous technological, economic, land use, and transitional challenges that must be met in the future in order to scale solar and storage to the levels required to meet a sizable proportion of the nation's electricity needs.

The report was prepared by staff from the following departments at LG&E and KU Energy: Electrical Engineering & Planning, Technology Research & Analysis, Generation Planning, and Sales Analysis & Forecasting.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
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Dated March 4, 2022

Case No. 2021-00393

Question No. 14

Responding Witness: Robert M. Conroy

Q-14. Confirm or deny with explanation that if actual natural gas prices are higher than the forecasted price of natural gas utilized in the Companies' IRP, the higher-than-forecasted costs would be borne by the Companies' retail customers and not the Companies' shareholders.

A-14. Confirmed. The Companies recover their actual cost of fuel for their fossil-fuel-fired generation through base rates and their Fuel Adjustment Clause mechanisms, which recovery is subject to periodic retrospective reviews by the Commission.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

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Supplemental Request for Information
Dated March 4, 2022

Case No. 2021-00393

Question No. 15

Responding Witness: Stuart A. Wilson

Q-15. Reference the Companies' Response to Commission Staff's First Request for Information Dated January 21, 2022, Item 43 ("Staff 1-43"). Provide the Companies' evaluation of batteries referenced in their response in an executable format with formulas intact. Identify the assumptions and inputs used, and the sources relied upon for those assumptions and inputs.

A-15. See the response to JI 1.3. The battery evaluation is located at the following file path:
\0283_2021IRP\ResourceAssessment\BatteryTest\20210826_WPK_BatteryOperationExploration_Test.xlsx

This spreadsheet contains a simple battery dispatch model on the data tab, with the primary model inputs in cells B1:B13. Load reflects 2035 energy requirements from the base IRP load forecast scenario. Solar and wind capacity factors are based on an aggregation of profiles used in the 2021 IRP and are in columns H and I.

The model computes the percentage of unserved energy (or energy that would need to be served by other resources) in cell V13 for a given amount of solar and wind resources. For a range of solar and wind portfolios, the Companies used the model to determine the amount of battery storage required to reduce unserved energy to 20 percent. Batteries were evaluated in 250 MW increments,[6] and the cost of these portfolios are calculated in cells P3:S8. A summary of results is available on the Sheet1 tab. As an example, a portfolio consisting of 8,000 MW of solar and 4,000 MW of wind would require either 6,000 MW of 4-hour batteries, 4,000 MW of 6-hour batteries, 3,000 MW of 8-hour batteries, or 2,750 MW of 10-hour batteries to meet 80% of system load. The lowest cost of these is the scenario using 8-hour batteries. Overall, the 8-hour battery alternatives were the preferred solution in more scenarios than 6-hour or 10-hour batteries.

[6] In this analysis, for simplicity the Companies modeled batteries in 250 MW increments. In the 2021 IRP's Long-Term Resource Planning Analysis, the Companies modeled batteries at a more granular 100 MW level.

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Case No. 2021-00393

Question No. 16

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

Q-16. Reference the IRP Vol. III, p. 10 [PDF 20 of 140], stating "To align the analysis with the Rhudes Creek price, the 2031 cost of solar was utilized throughout the IRP planning period."

a. Confirm or deny with explanation that the Companies' assumed cost of utility-scale solar for all future years in its IRP period was $28.05/MWh.

b. If a cost other than $28.05/MWh was used when modeling the future costs of utility-scale solar in any year, provide the assumed cost for each year in which it differed and explain the methodology or source used to arrive at those values.

c. Explain why the Companies did not model additional cost declines for utility-scale solar in future years, given the cost of utility-scale solar has decreased significantly over the past decade and most, if not all, long-range forecasts of utility-scale solar pricing, including the National Renewable Energy Laboratory's 2021 Annual Technology Baseline, anticipate additional price declines over the coming decades.

d. Identify any sources the Companies relied upon for the position that forecast that the cost of utility-scale solar will not decline over the next 20 years.

e. Confirm or deny with explanation that if the actual costs of constructing or operating and maintaining the Rhudes Creek facility are higher than expected, those costs will not be passed on to ratepayers.

A-16.

a. Confirmed.

b. Not applicable.

c. As shown in Table 5 on page 10 of the Resource Screening Analysis, NREL's 2021 ATB assumptions result in LCOE for utility-scale solar in 2022 of $38.62/MWh. Rather than model a decline from the 2022 value to the 2031 value of $28.05/MWh, the Companies aligned their analysis with the Rhudes Creek price by using the 2031 LCOE throughout the IRP analysis period. See the response to PSC Question No. 1-26 part (a). The Companies would evaluate available market options before committing to any additional resources.

d. See the response to part (c).

e. Confirmed. The Companies' Rhudes Creek power-purchase agreement requires the Companies to pay only a fixed price per MWh actually produced; the developer bears the construction and ongoing operational cost risk.

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KENTUCKY UTILITIES COMPANY

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Question No. 17

Responding Witness: Stuart A. Wilson

Q-17. Reference the Companies' Response to SREA 1-9.

a. Confirm or deny with explanation that the Companies do not have more granular data on their Available Transmission Capacity than daily data, as shown in the attachment to the response to 1-9(a). If confirmed, explain why the Companies do not have more granular data (e.g., hourly). If not confirmed, provide the more granular data in the Companies' possession for the calendar years 2019, 2020, and 2021.

A-17. Confirmed. Daily transmission capacity is the most granular firm transmission product that the Companies can purchase. Hourly transmission capacity is non-firm.

LOUISVILLE GAS AND ELECTRIC COMPANY
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Response to Southern Renewable Energy Association's
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Question No. 18

Responding Witness: David S. Sinclair

Q-18. Reference the PPL Corporation's 2021 Climate Assessment Report.

a. Confirm or deny with explanation that the Companies' Base Load, Base Fuel scenario is consistent with PPL's carbon dioxide emissions reductions goals for 2035, 2040, and 2050.

b. Confirm or deny with explanation that the Companies plan to achieve net-zero carbon emissions across their generation portfolio by 2050.

c. Explain how the Companies' IRP is aligned with PPL's goal of achieving net-zero carbon emissions by 2050 given the Companies' Base Load, Base Fuel scenario assumes the continued operation of fossil fuel generating resources beyond 2050 based on assumed unit retirement dates.

A-18.

a. CO_2 emissions from the Base Load, Base Fuel scenario are consistent with PPL's goal for emission reduction by 2035.[7] The IRP does not extend beyond 2036.

b. The Companies have not developed an IRP beyond 2036.

c. See the response to part (b).

[7] *See* PPL's Sustainability page at https://www.pplweb.com/sustainability/climate-action/#:~:text=PPL%20Corporation%20Climate%20Assessment&text=Our%202021%20climate%20assessment%20report,to%20a%20cleaner%20energy%20future.

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Response to Southern Renewable Energy Association's
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Question No. 19

Responding Witness: David S. Sinclair

Q-19. Reference the Companies' IRP Vol. I, p. 5-20 [PDF 26 of 118], stating in pertinent part that, "Currently, there is no price associated with CO2 emissions and no law or regulation is being seriously discussed that would explicitly put a price on such emissions. Instead, much focus recently has been on addressing CO2 emissions indirectly via a Clean Energy Standard rather than through a CO2 price or cap and trade scheme. During the Obama administration, the Clean Power Plan sought to reduce CO2 emissions via state-administered programs that focused on either emission rates or mass reductions rather than through a CO2 price. The Companies have no basis for assuming that a price on CO2 emissions will or will not be part of part of any such regulations. For these reasons, the 2021 IRP does not evaluate resource expansion plans with an assumed price for CO2 emissions."

a. Refer to the Companies' IRP Vol. I, p. 5-39 and 5-40 [PDF 45, 46 of 118], stating "Based on the Biden administration's energy policy and the national focus on moving to clean energy, the current environment does not support the installation of NGCC without CCS due to its CO2 emissions." What policies or regulations do the Companies assume will prevent or diminish the attractiveness of the installation of a NGCC without CCS given the Companies also contend there is no basis to assume a price will be imposed on carbon dioxide emissions?

b. Please explain how the Companies' contention regarding the viability of NGCC without CCS is consistent with its contention that they should not include a scenario as part of their IRP that includes a price on carbon dioxide emissions.

c. Explain how the Companies incorporated a scenario modeling a Clean Energy Standard as part of their IRP. If the Companies did not model a portfolio consistent with a Clean Energy Standard scenario, explain why not.

d. Explain why the Companies assumed a NGCC without CCS is not supported in the current environment but a natural gas combustion turbine without CCS is supported in the current environment.

e. Identify the annual carbon dioxide emissions the Companies forecast will be emitted from each new natural gas plant included in its Base Load, Base Fuel scenario for each year of its IRP period.

f. Confirm or deny with explanation that future changes to federal and state policy with respect to carbon dioxide emissions could significantly impact the least cost resource mix for the Companies. If confirmed, explain why constructing new natural gas combustion turbines does not impose a substantial risk to customers.

g. Explain why the Companies included a range of load and fuel scenarios in their IRP, but did not include a range of policy scenarios with respect to carbon dioxide emissions or a scenario identifying how the Companies intend to align their emissions from generating resources with PPL's carbon dioxide emissions reduction goals.

A-19.

a. See the response to PSC 2-2(a).

b. See the response to PSC 2-2(a).

c. The Companies did not explicitly model a Clean Energy Standard in the 2021 IRP because there is no such standard in effect or planned. That aside, the assumptions made for new resources in the 2021 IRP result in portfolios that are up to 40% renewable energy by 2035.

d. See the response to PSC 2-2(b).

e. See the table below.

Year	Number of New SCCTs	CO_2 Emissions (000s tons)	CO_2 Emissions Per SCCT (000s tons)
2022	0	0	0
2023	0	0	0
2024	0	0	0
2025	0	0	0
2026	0	0	0
2027	0	0	0
2028	2	509	255
2029	2	547	273
2030	2	533	266
2031	2	502	251
2032	2	450	225
2033	2	483	242
2034	6	1,646	274
2035	6	1,754	292
2036	6	1,597	266

f. Environmental regulations have historically impacted the least-cost resource mix and would likely do so in the future. NERC published its *2021 Long-Term Reliability Assessment* ("LTRA") in December 2021 with an assessment period of 2022-2031.[8] According to this report, "until storage technology is fully developed and deployed at scale (which cannot be presumed to occur within the time horizon of this LTRA), natural-gas-fired generation will remain a necessary balancing resource to provide increasing flexibility needs." Furthermore, total CO_2 emissions for SCCTs operating as peaking units are low (see response to part e.).

g. The future technologies available for the Companies' modeling tools to select from were all consistent with a future of lower CO_2 emissions. Figure 8 on page 21 of PPL's 2021 Climate Assessment Report lays out a range of possible future CO_2 emissions reductions depending on load, technology development, relative prices of fuels and technologies, and future regulations. Also, as noted in the response to Question 18(a), the Companies' IRP is consistent with PPL's 2021 Climate Assessment Report.[9]

[8] See https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf.
[9] *See* PPL's Sustainability page at https://www.pplweb.com/sustainability/climate-action/#:~:text=PPL%20Corporation%20Climate%20Assessment&text=Our%202021%20climate%20assessment%20report,to%20a%20cleaner%20energy%20future.

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Question No. 20

Responding Witness: Charles R. Schram

Q-20. Provide the following data in Excel format on the Companies' load and generation for each month of the 2021 calendar year.

a. The average load in megawatts for each Hour Ending 1 through 24.

b. The hourly peak load in megawatts for each Hour Ending 1 through 24.

c. The average load in megawatts net of all resources listed in (d) below.

d. The average generation (or estimated avoided generation in the case of demand-side management programs) in megawatts for Hour Ending 1 through 24 for each of the following resources:

i. Solar

ii. Wind

iii. Natural Gas Combined Cycle

iv. Natural Gas Combustion Turbine

v. Natural Gas Steam

vi. Reciprocating Internal Combustion Engine

vii. Battery Storage

viii. Pumped Storage

ix. Demand-Side Management

x. Hydropower

xi. Bioenergy

xii. Other Market Purchases

xiii. Oil

xiv. Coal

e. To the extent the Companies do not have the analysis requested in (c) and (d), provide the requested data for each of the Companies' generating units, or to the extent that is not available, for each of the Companies' generating plants.

A-20.

a. – e. See attachment being provided in Excel format. Regarding the data in part (d), solar reflects generation at E.W. Brown only; negative values in some nighttime hours for natural gas combustion turbines reflect allocation of auxiliary load. The Companies do not have an hourly allocation for the approximately 14 MW of demand-side reduction throughout 2021, and did not have any demand response events in 2021. "Other market purchases" include the Companies' purchases from OVEC.

The attachment is being provided in a separate file in Excel format.