COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matters of:

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

SOUTHERN RENEWABLE ENERGY ASSOCIATION'S SUPPLEMENTAL REQUESTS FOR INFORMATION TO LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY

Comes now the Southern Renewable Energy Association (also "SREA"), by and through counsel, and, in accordance with the Public Service Commission's Order dated November 12, 2021 its Supplemental Requests for Information to Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU" and collectively "Companies").

1) In each case in which a request seeks information provided in response to a request of Commission Staff, reference to the Companies' response to the appropriate Staff request will be deemed a satisfactory response.
2) Please identify the Companies' witness who will be prepared to answer questions concerning the request during an evidentiary hearing.
3) These requests shall be deemed continuing so as to require further and supplemental responses if the Companies receive or generate additional information within the scope of these request between the time of the response and the time of any evidentiary hearing held by the Commission.

4) If any request appears confusing, please request clarification directly from Counsel for SREA.
5) To the extent that the specific document, workpaper, or information as requested does not exist, but a similar document, workpaper, or information does exist, provide the similar document, workpaper, or information.
6) To the extent that any request may be answered by way of a computer printout, please identify each variable contained in the printout which would not be self-evident to a person not familiar with the printout.
7) If the Companies have any objections to any request on the grounds that the requested information is proprietary in nature, or for any other reason, please notify Counsel for SREA as soon as possible.
8) For any document withheld on the basis of privilege, state the following: Date; author; addressee; indicated or blind copies; all person to whom distributed, shown, or explained; and the nature and legal basis for the privilege asserted.
9) In the event that any document called for has been destroyed or transferred beyond the control of the Companies, state: The identity of the person by whom it was destroyed or transferred and the person authorizing the destruction or transfer; the time, place, and method of destruction or transfer; and the reason(s) for its destruction or transfer. If destroyed or disposed of by operation of a retention policy, state the policy.
10) As the Companies discover errors in its filing and/or responses, please provide an update as soon as reasonable that identifies such errors and provide the document to support any changes.

WHEREFORE, SREA respectfully submits its Supplemental Requests for Information to the Companies.

Respectfully submitted,

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NOTICE AND CERTIFICATION FOR FILING

Undersigned counsel provides notice that the electronic version of the paper has been submitted to the Commission by uploading it using the Commission's E-Filing System on this 4th day of March 2022. Pursuant to the Commission's Order in Case No. 2020-00085, *Electronic Emergency Docket Related to Novel Coronavirus Covid-19*, the paper, in paper medium, is not required to be filed.

/s/ David E. Spenard

NOTICE CONCERNING SERVICE

The Commission has not yet excused any party from electronic filing procedures for this case.

/s/ David E. Spenard

**SOUTHERN RENEWABLE ENERGY ASSOCIATION
SUPPLEMENTAL REQUESTS FOR INFORMATION
TO LOUISVILLE GAS AND ELECTRIC COMPANY
AND KENTUCKY UTILITIES COMPANY**

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.

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?

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.

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

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?

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.

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?

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?

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.

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.

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.

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.

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.

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.

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.

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.

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.

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.

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.

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.