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	) CASE NO. 2021-00393
UTILITIES COMPANY	)

INITIAL DATA REQUESTS OF JOINT INTERVENORS METROPOLITAN HOUSING COALITION, KENTUCKIANS FOR THE COMMONWEALTH, KENTUCKY SOLAR ENERGY SOCIETY AND MOUNTAIN ASSOCIATION

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DEFINITIONS

1. “Document” means the original and all copies (regardless of origin and whether or not including additional writing thereon or attached thereto) of any memoranda, reports, books, manuals, instructions, directives, records, forms, notes, letters, or notices, in whatever form, stored or contained in or on whatever medium, including digital media.

2. “Study” means any written, recorded, transcribed, taped, filmed, or graphic matter, however produced or reproduced, either formally or informally, a particular issue or situation, in whatever detail, whether or not the consideration of the issue or situation is in a preliminary stage, and whether or not the consideration was discontinued prior to completion.

3. “Person” means any natural person, corporation, professional corporation, partnership, association, joint venture, proprietorship, firm, or the other business enterprise or legal entity.

4. A request to identify a natural person means to state his or her full name and business address, and last known position and business affiliation at the time in question.

5. A request to identify a document means to state the date or dates, author or originator, subject matter, all addressees and recipients, type of document (e.g., letter, memorandum, telegram, chart, etc.), identifying number, and its present location and custodian. If any such document was but is no longer in the Company’s possession or subject to its control, state what disposition was made of it and why it was so disposed.

6. A request to identify a person other than a natural person means to state its full name, the address of its principal office, and the type of entity.

7. “And” and “or” should be considered to be both conjunctive and disjunctive, unless specifically stated otherwise.

8. “Each” and “any” should be considered to be both singular and plural, unless specifically stated otherwise.

9. Words in the past tense should be considered to include the present, and words in the present tense include the past, unless specifically stated otherwise.

10. Unless otherwise specified in each individual interrogatory or request, the terms “you,” “your,” “LG&E,” “KU,” “LG&E/KU,” or “Companies” refer collectively to Louisville Gas & Electric Company and Kentucky Utilities Company, including any affiliated companies, predecessors-in-interest, employees, authorized agents, outside consultants or contractors, or other representatives.

11. “LG&E” means Louisville Gas & Electric Company and/or any of their officers, directors, employees or agents who may have knowledge of the particular matter addressed, and affiliated companies including Pennsylvania Power and Light.

12. “KU” means Kentucky Utilities Company and/or any of their officers, directors, employees or agents who may have knowledge of the particular matter addressed, and affiliated companies including Pennsylvania Power and Light.

13. “The Companies” means LG&E and KU.

14. “Joint Intervenors” means the Mountain Association, Kentuckians For The Commonwealth, and Kentucky Solar Energy Society, who were granted the status of full joint intervention in this matter.

15. “Commission” or “PSC” means the Kentucky Public Service Commission, including its Commissioners, personnel, and offices.

16. “DSM-EE” means Demand Side Management-Energy Efficiency.

17. “RFP” means Request for Proposals.

18. “RTO” means Regional Transmission Organization.

19. “IRP” and “2021 IRP” mean the “Electronic 2021 Joint Integrated Resource Plan of Louisville Gas And Electric Company and Kentucky Utilities Company.”

INSTRUCTIONS

1. If any matter is evidenced by, referenced to, reflected by, represented by, or recorded in any document, please identify and produce for discovery and inspection each such document.

2. These requests for information are continuing in nature, and information which the responding party later becomes aware of, or has access to, and which is responsive to any request is to be made available to Joint

Intervenors. Any studies, documents, or other subject matter not yet completed that will be relied upon during the course of this case should be so identified and provided as soon as they are completed. The Respondent is obliged to change, supplement and correct all answers to interrogatories to conform to available information, including such information as it first becomes available to the Respondent after the answers hereto are served.

3. Unless otherwise expressly provided, each data request should be construed independently and not with reference to any other interrogatory herein for purpose of limitation.

4. Whenever the documents responsive to a discovery request consist of modeling files (including inputs or output) and/or workpapers, the files and workpapers should be provided in machine-readable electronic format (e.g., Microsoft Excel), with all formulas and cell references intact.

5. The answers provided should first restate the question asked and also identify the person(s) supplying the information.

6. Please answer each designated part of each information request separately. If you do not have complete information with respect to any interrogatory, so state and give as much information as you do have with respect to the matter inquired about, and identify each person whom you believe may have additional information with respect thereto.

7. Wherever the response to a request consists of a statement that the requested information is already available to Joint Intervenors, please provide a detailed citation to the document that contains the information. This citation shall include the title of the document, relevant page number(s), and, to the extent possible, paragraph number(s) and/or chart/table/figure number(s).

8. Where workpapers are requested, please provide them in electronic spreadsheet format with all formulas and links intact.

9. If you claim a privilege including, but not limited to, the attorney-client privilege or the work product doctrine, as grounds for not fully and completely responding to any discovery request, please describe the basis for your claim of privilege in sufficient detail so as to permit Joint Intervenors or the Commission to evaluate the validity of the claim. With respect to documents for which a privilege is claimed, please produce a "privilege log" that identifies the author, recipient, date, and subject matter of the documents or interrogatory answers

for which you are asserting a claim of privilege and any other information pertinent to the claim that would enable Joint Intervenors or the Commission to evaluate the validity of such claims.

10.In the case of multiple witnesses, each interrogatory should be considered to apply to each witness who will testify to the information requested. Where copies of testimony, transcripts or depositions are requested, each witness should respond individually to the information request.

11.The interrogatories are to be answered under oath by the witness(es) responsible for the answer.

INITIAL DATA REQUESTS PROPOUNDED TO LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY BY JOINT INTERVENORS

1.1. The *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* ("NSPM-DER," available at https://www.nationalenergyscreeningproject.org/national-standard-practicemanual/) provides a comprehensive framework for cost-effectiveness assessment of distributed energy resources including distributed generation, distributed storage, demand response, and energy efficiency. The NSPM-DER also provides guidance on addressing multiple DERs and rate impacts and cost shifts. In their order in the Kentucky Power Company Case No. 2020-00174, concerning net metering, the Commission adopted a series of principles to be used when establishing new net metering rates. These principles are consistent with those presented in the NSPM-DER and are applicable to evaluating the benefits and costs of all DER's, in addition to net metering.
a. Is the Company aware of and familiar with the NSPM-DER?
b. Has the Company utilized the NSPM-DER within the IRP process for evaluating DSM, energy efficiency, and distributed generation resources?

1.2. These questions pertain to the impacts of the IRP on residential customers with low- and fixed-incomes.

a. Please provide any and all internal analysis and discussion materials used to forecast and consider the impact of the proposed IRP on low-income customers at 30%, 50%, and 80% Area Median Income (AMI).
b. Please provide any historical data on low-income households considered in the preparation of the IRP by census tract and zip code.
c. Please provide any internal analysis of Annual Use-per-Customer and

Total Energy Sales correlated to impact on average customer bills as 30%, 50%, and 80% Area Median Income (AMI). Please provide data by census tract and zip code if possible.

d. Please provide any analysis conducted on residential end-use trends and the impact on low-income customers at 30%, 50%, and 80% Area Median Income (AMI) by census tract and zip code.

e. Please explain how the Companies propose to create equitable models for collecting survey data and direct feedback for residential, small customers as is repeatedly mentioned in regard to large, nonresidential, commercial customers.

f. Please provide any analysis performed by the Companies specific to future low-income household customer demand for energy.

g. Please provide any analysis conducted on how "expected increases in the cost of generation"[1] will impact low-income households? How will this impact households at 30%, 50%, and 80% Area Media Income (AMI)? Provide the data by census tract and zip code.

h. Please provide any analysis on the impact of the Integrated Resource Plan (IRP) on the Low-Income Weatherization Program (WeCare).

i. Please provide any and all internal analysis and any discussion materials pertaining to the long-term planning and implementation of the WeCare program for the period covered by the proposed Integrated Resource Plan (IRP).

j. Please explain why the Company projects no further customer energy savings via the WeCare program after 2025 (as shown in Table 8-12, p.96 of pdf, 2021 IRP Volume I.)

k. Please provide any analysis performed by the Companies of the impact on low-income customers of the effective termination of the WeCare program after 2025.

l. Please provide any analysis and discussion materials from this IRP process pertaining to the planning and development of new DSM programs targeted at low-income households at 30%, 50%, and 80% Area Median Income (AMI). Please provide any data considered as a part of that analysis and discussions by census tract and zip code.

m. Please provide any analysis of the impact of the preferred portfolio of resources on low-income customers, and of how those concerns were considered as part of the Integrated Resource Plan (IRP) process.

n. Please provide any studies related to environmental and health impacts on low-income communities and communities of color

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[1] Case No. 2021-00393 (Ky. PSC January 11, 2022), *Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electic Company and Kentucky Utilities Company, Order* (in which the Commission granted Joint Intervenor statues to Metropolitan Housing Coalition (MHC), Kentuckians for the Commonwealth (KFTC), Kentucky Solar Energy Society (KYSES), and Mountain Association (MA) (collectively, Joint Intervenors), 4.

considered as a part of the Integrated Resource Plan (IRP) process. Please provide any and all internal analysis and discussion materials from the Companies of these studies.

o. Please provide any and all studies related to the impact of economic disparities on low-income communities and communities of color considered as a part of the Integrated Resource Plan (IRP) process. Please provide any and all internal analysis and discussion materials from the Companies of these studies.

1.3. Produce any workpapers (in machine readable and unprotected format, with formulas intact) used to produce the load forecast, the reserve margin analysis, the long-term resource planning analysis (including Table 20 of the same), and the RTO membership analysis.

1.4. Please refer to page 5-15 of the IRP where it says:

> *"For each energy requirements and fuel price case, the Plexos model from Energy Exemplar was used to identify the least-cost generation portfolio for serving customers at the end of the IRP planning period. The analysis considered all costs for new and existing resources, and it optimized the portfolio to minimize energy and new capacity costs. An annual resource plan was then developed for each case to meet minimum reserve margin requirements (i.e., 17 percent in the summer and 26 percent in the winter) throughout the planning period. To assess the potential for new DSM programs, the PROSYM production cost model from ABB was used to model annual production costs for the resource plan in the base energy requirements, base fuel case*."

a. Please confirm that the Companies used Plexos to perform capacity expansion modeling and PROSYM to perform production cost modeling.
b. Please explain why Plexos was not used to perform production cost modeling.
c. Please explain if the capacity expansion plans were optimized to meet a summer reserve margin, a winter reserve margin, or both a summer and winter reserve margin, and how the Company did so.
d. Please provide all PLEXOS modeling inputs and outputs, in spreadsheet format with all formulas and links intact, for all modeling runs performed for this IRP.
e. Please provide all PROSYM modeling inputs and outputs, in spreadsheet format, will all formulas and links intact, for all PROSYM production cost modeling modeling runs performed for this IRP.

1.5. Please refer to Table 9-1 on page 9-1 of the IRP.

a. Please provide the supporting workbooks, with all formulas and links intact, used to develop the annual revenue requirements for all modeling runs performed for this IRP.
b. Please explain how the revenue requirements were developed from some or all of the PLEXOS, PROSYM, and other modeling conducted for this IRP.
c. Please provide the name of the model used to develop the revenue requirements.

1.6. Please refer to pdf page 26 of Volume III. Why, in the Companies' opinion, are the results of one year (2025) of production cost modeling sufficient basis to conclude that "In other words, it is not cost-effective to alter annual or summer peak hour reliability by either retiring existing resources or adding new resources"?

1.7. Please provide any workbooks used to post-process, adjust, or compile modeling results from any modeling performed in PROSYM, PLEXOS, or SERVM that was used in this IRP.

1.8. Please explain if short term market purchases were available in the capacity expansion modeling. If purchases were allowed, please provide the annual amount and cost that was available for selection.

1.9. Please confirm if the Companies performed any modeling runs in Plexos or PROSYM that looked at market interactions with MISO or PJM. If modeling runs were performed with market interactions, please provide the input and output files associated with those modeling runs.

1.10. Please refer to the discussion of why a CO_2 price was not modeled on page 5-20 of the IRP. Please confirm whether any carbon reduction emissions were modeled as a constraint for the capacity expansion or production cost modeling.

1.11. Please confirm that PPL has made public statements committing to the goals of achieving net-zero carbon emissions by 2050, a 70% reduction from 2010 levels by 2035, and an 80% reduction from 2010 levels by 2040. If confirmed, please explain in detail how, if at all, the 2021 IRP helps the Companies to achieve those goals.

1.12. Refer to the 2021 IRP, Volume I, page 5-31, stating that overnight charging of EVs likely could be accomplished using the Companies' existing dispatchable generation assets, whereas charging of EVs in the early evening "could exacerbate summer and winter peak energy requirements and potentially create the need for additional peaking capacity or load control programs . . . ."Please provide any analyses, workpapers, and documentation (in machine readable and unprotected format, with formulas intact) supporting the above quoted statement.

a. Have the Companies prepared or caused to be prepared any analysis of (i) the potential for measures to shift EV charging to off-peak hours and (ii) the potential for incentivizing customers to shift EV charging to off-peak hours via changes in the Companies' rate design? If so, please produce any such analyses. If not, please explain in detail why not.
b. Did the companies model how expanded distributed generation (for example that might occur with the elimination of the 1% cap on net metered solar), and expanded utility scale solar combined with battery storage, could be used to moderate the effects of expanded EV adoption on load profiles? If so, please produce any such analyses. If not, please explain in detail why not.

1.13. Have the Companies prepared or caused to be prepared any estimate of current or projected switching from gas to electric appliances by LG&E/KU's customers, and/or of the effects on load of such switching? If so, please produce any such estimates and supporting analyses, workpapers, and documentation (in machine-readable format with formulas intact). If not, please explain in detail why not.

1.14. Refer to the 2021 IRP, Volume I, Tables 8-12 and 8-13.

a. Please explain in detail why the incremental and cumulative energy and demand impacts of the AMS Customer Service Offering is 0.0 for all years.
b. Please explain in detail why incremental DSM energy and demand impacts are zero for all DSM programs from 2026 through 2036. Please provide supporting analyses, workpapers, and documentation (in machine readable and unprotected format with formulas intact).
c. With respect to the DSM Summer Peak Demand Reductions shown in Table 8-12, please clarify if the negative values for "Residential and Small Nonresidential Demand Conservation" are intended to reflect an increase in demand. If so, please explain in full how this demand conservation program increases the summer peak demand.

d. With respect to the DSM Summer Peak Demand Reductions shown in Table 8-12, please clarify whether the negative values for "Total Annual Demand Reduction" are intended to reflect a net increase in demand. If so, please explain in full how DSM increases the summer peak demand.

1.15. Refer to Volume I at page 5-19, which states: "Furthermore, because annual peak demands can occur during the winter months and because winter peaks typically occur during nighttime hours, solar generation has virtually no value in the Companies service territories as a source of winter capacity." Please explain why the Company's winter peak occurs at night and detail the steps, if any, the Company has taken to shift and to flatten this peak.

a. Refer to Volume I, Tables 5-15 and 5-16. Have the Companies considered solar paired with storage, which would allow the storage to benefit from the federal investment tax credit? Please provide any supporting workpapers (in machine readable and unprotected format, with formulas intact). If not, why not?

1.16. Refer Section 4.8 ("Weather-Year Forecasts") of the Electric Sales & Demand Forecast Process (July 2021).

a. Please explain in full why the Companies rely on 48 years of actual weather (1973 through 2020) as compared with a shorter period (e.g., 30 years or 20 years).
b. Are the Companies aware of any empirical analyses or studies validating a hypothesis that energy forecasts using the most recent 40+ years of weather data would have greater predictive value than an energy forecast using the most recent 30 or 20 years of weather data? If so, please produce such analyses or studies.

1.17. For the Companies' coal-fired units, please provide the following historical annual data by unit, or, if the Companies do not maintain unit-level data, by plant, from 2012 to present:

a. Fixed O&M cost
b. Variable O&M cost (without fuel)
c. Fuel costs
d. Capital costs
e. Heat rate
f. Generation
g. Capacity rating
h. Capacity factor
i. Forced outage rate
j. Planned outage rate

k. Energy revenues
l. Capacity revenues
m. Ancillary services revenues

1.18. For each existing coal-fired unit, please provide the following projected annual data by unit, or, if the Companies do not maintain unit-level data, by plant, for the economic analysis period in this filing (i.e., 2021-2036):

a. Fixed O&M cost
b. Variable O&M cost (without fuel)
c. Fuel costs
d. Capital costs
e. Capacity factor
f. Generation
g. Depreciation
h. Heat rate
i. Forced outage rate
j. Planned outage rate
k. Energy revenues
l. Capacity revenues
m. Ancillary services revenues

1.19. Refer to the 2021 IRP Long-Term Resource Planning Analysis.

a. Did the Companies conduct or cause to be conducted any economic analysis, under any of the scenarios, of when existing units would have costs (fixed costs and variable costs) that exceed their revenues? If so, please provide any such analyses. If not, please explain in detail why not.
b. Did the Companies conduct or cause to be conducted any economic analysis, under any of the scenarios, of when it would be economic to retire any existing generating units? If so, please provide any such analyses. If not, please explain in detail why not.
c. Within the last five years, have the Companies prepared or caused to be prepared any analysis of whether to continue to operate or retire any of their existing generating units? If so, please produce any such analyses. If not, please explain in detail why not.
d. Have the Companies prepared or caused to be prepared any analysis of the reliability impacts of retiring existing units? If so, please produce any such analyses, including all supporting workpapers and modeling input and output files. If not, please explain in detail why not.

1.20. Please refer to Table 5-4 on page 5-18 of the IRP.

a. Did the Companies evaluate early retirement dates for Ghent 1 or Ghent 2?
b. If an analysis was performed, please provide the results of any analysis performed to evaluate the early retirement of Ghent 1 and Ghent 2.

1.21. Please refer to page 3 of the 2021 IRP Reserve Margin Analysis where it says "To evaluate operating at lower reserve margins with less reliability, the Companies compared the reliability and production cost benefits for their marginal baseload and peaking resources to the savings that would be realized from retiring these resources. Specifically, the Companies evaluated the retirements of one or more Brown 11N2 simple-cycle combustion turbines ("SCCTs"), Mill Creek 2, and Brown 3."
a. Please explain if any other analysis was done outside of reserve margin analysis modeling to evaluate retirement dates. If other analysis was performed to evaluate the retirement of units, please provide the results of that analysis.

1.22. Please confirm if the Companies are modeling the thermal resources on a UCAP or ICAP basis, and provide the following information for each of the Companies' thermal units:
a. Forecasted annual capital expenditures
b. Summer and Winter capacity contributions
c. Forced outage rates for the last five years
d. Forecasted forced outage rates

1.23. Please refer to Table 8-4 on page 8-13 of the IRP. Please explain what is driving the increase in capacity factor for Mill Creek 2 between 2025 and 2028.

1.24. Please provide the most recent condition assessment report for each of the Companies' generating units.

1.25. Refer to the 2021 IRP, Volume I, Table 8-3, column entitled "Upgrades, Derates, Retirements."
a. For each unit, please specify the month of the upgrade, derate, or retirement and whether the date indicated corresponds to an upgrade, derate, or retirement.

b. Please specify for which units the retirement date is the end of the unit's book depreciation life. Please provide supporting analyses, workpapers, and documentation (in machine readable and unprotected format, with formulas intact).

1.26. For each of the Companies' existing coal-fired units, please produce the most recent estimate that the Companies have prepared or caused to be prepared of the capital and O&M costs to comply with the following regulations:

a. Acid deposition control program
b. Cross State Air Pollution Rule
c. Mercury and Air Toxics Standards
d. Combustion turbine NESHAP rule
e. NAAQS
f. Regional Haze rule
g. Greenhouse gas regulations
h. 316(b) cooling water intake rule
i. Effluent Limitations Guidelines
j. Any new definition of waters of the United States
k. Coal Combustion Residuals rule
l. Pending enforcement actions by citizen groups or regulatory agencies of any state and/or federal environmental requirements.

1.27. For each of the Companies' existing coal-fired units, please provide the capital and O&M costs projected to be incurred each year from 2021 through 2036 to comply with the following regulations:

a. Acid deposition control program
b. Cross State Air Pollution Rule
c. Mercury and Air Toxics Standards
d. Combustion turbine NESHAP rule
e. NAAQS
f. Regional Haze rule
g. Greenhouse gas regulations
h. 316(b) cooling water intake rule
i. Effluent Limitations Guidelines
j. Any new definition of waters of the United States
k. Coal Combustion Residuals rule
l. Pending enforcement actions by citizen groups or regulatory agencies of any state and/or federal environmental requirements.

1.28. Please produce the energy market price forecasts and capacity market price forecasts used in the 2021 IRP Long-Term Resource Planning Analysis, along with supporting analyses, workpapers, and documentation (in machine readable and unprotected format with formulas intact).

1.29. Please refer to the modeling conducted for the 2021 IRP Long-Term Resource Planning Analysis.

a. Please identify all constraints placed on the model's ability to select or not select existing generating units, such as must-run designations or operational constraints.
b. For each of the Companies' coal-fired generating units and each modeling run, state whether the model was allowed to select retirement dates of existing coal-fired generating units, or whether the retirement dates for each coal unit were inputs into the modeling. For each unit for which the retirement date as an input into the modeling, explain how that retirement was determined.
c. Did the model evaluate dispatch of the Companies' generating units on an hourly, monthly, or annual basis?
d. Was the model limited in the amount of additional solar, wind, and battery resources it was allowed to select each year and/or cumulatively over 2021-2036? Please describe and provide the basis for any such constraints.
e. In developing the scenarios, did the Companies assume a relationship or correlation between any of the variables (load, natural gas prices, coal prices, and/or CO_2 prices)? If so, please identify the assumed correlations between each variable and provide supporting analyses, workpapers, and documentation (in machine readable and unprotected format with formulas intact).

1.30. Refer to the 2021 IRP Long-Term Resource Planning Analysis, Table 14. Please explain the basis for the Companies' assumption that no incremental reduction in peak load will be achieved through DSM programs between 2025 and 2036. Please provide supporting analyses, workpapers, and documentation (in machine readable and unprotected format with formulas intact).

a. Compare the referenced Table 14 with Table 15 in the same document. Please explain in full the basis for the Companies' assumption that DSM programs (including demand response and energy efficiency) have no impact on the winter peak demand throughout the study period.

1.31. Please provide the results of, and any supporting analyses, workpapers, and documentation (in machine readable and unprotected format with formulas intact) for, the Companies' January 7, 2021 RFP for 300 MW to 900 MW beginning in 2025 and no later than 2028.

a. Refer to the 2021 IRP Long-term Resource Planning Analysis. What steps, if any, did the Companies take to ensure that costs assumed in the 2021 IRP are consistent with the results of the RFP? Please explain your response in detail and provide supporting analyses, workpapers, and documentation (in machine readable and unprotected format with formulas intact).

1.32. Please refer to the 2021 IRP Resource Screening Analysis. Did the Companies consider out-of-state wind, solar, and battery resources? If so, please indicate what out-of-state resources were considered and provide supporting analyses, workpapers, and documentation (in machine readable and unprotected format with formulas intact). If not, please state why not.

1.33. Please refer to the 2021 RTO Membership analysis.

a. What analytical approach, e.g., modeling, spreadsheet analysis, etc. was used to conduct this study?
b. Provide all workbooks with formulas and links intact used to conduct this analysis.
c. Provide the documents that support the assumptions made regarding the costs and benefits of RTO membership including but not limited to uplift charges, lost transmission revenue, administrative fees, energy market benefits, capacity market benefits, etc.
d. How did the Companies' treat the impacts of changes in reserve margin requirements from joining an RTO?

1.34. Refer to the 2021 RTO Membership Analysis, page 13, stating, "The RTOs have seen very low capacity prices, much lower than the actual cost of new entry. This combined with the limited forward visibility of PJM's 3-year-ahead and MISO 1-year-ahead market leads to little incentive for the construction of new capacity, which could lead to capacity deficiencies if not addressed."

a. Please identify any examples of capacity deficiencies in PJM or MISO, as referred to in the above sentence, of which you are aware.
b. Have the Companies prepared or caused to be prepared any analysis of the capacity deficiency concerns described in subpart a? If so, please produce any such analyses and identify the portions of such analyses that support the above quoted sentence. If not, please explain in detail why not.

1.35. Refer to the 2021 RTO Membership Analysis, page 17, stating, "The Companies have identified eight EEA events experience within MISO since 2017." Please identify the eight EEA events and provide supporting documentation.

1.36. Please provide the Companies' average total annual electricity usage per residential customer.

1.37. Refer to Vol. I, section 8.(2).(b), addressing "New Demand-Side Management Programs."

a. Please identify each DSM-EE program evaluated for implementation during the planning period and provide the data and analysis used to evaluate each such DSM-EE program.
b. Have the Companies studied or caused to be studied the demand response and energy efficiency potential among their (i) residential customers or (ii) commercial customers since the March 2017 Residential and Commercial Potential Study prepared by Cadmus and submitted as Exhibit GSL-3 in Case No. 2017-00441? If so, please provide each such study.
c. Please provide the Companies' most recent study of demand response and energy efficiency potential among their industrial customers.
d. Please provide the most recent three full years of reported DSM-EE data (including program planned budgets and savings, actual spending and savings, and planned and actual participation) by program, in executable Excel format with formulae intact. Please also provide any energy efficiency or demand response Annual Reports prepared during this period.
e. Refer to Vol. I, Figure 5-9. Have the Companies considered winter demand response as a resource to address the variability in winter peak load? Please explain your response in detail.

1.38. At page 5-15 of Volume I, the Companies states "To assess the potential for new DSM programs, the PROSYM production cost model from ABB was used to model annual production costs for the resource plan in the base energy requirements, base fuel case." With respect to this statement, please answer the following:

a. Precisely how was the PROSYM modeling used to assess potential for DSM?
b. What specific pieces of its PROSYM modeling did the Companies use to assess the potential for new DSM?
c. What were the results of that assessment? Please provide them.
d. Provide any documentation in electronic spreadsheet format with all formulas and links intact which support your responses to subparts a, b, and c.

1.39. Page 5 – 3 of the IRP states, "Due to the potential for cold winter temperatures and the increasing penetration of electric heating, the Companies are somewhat unique because annual peak demands can occur in both the summer and winter months." With respect to this statement please answer the following:

  a. What is driving the increasing penetration of electric heating in the Companies' service territories?
  b. Do the Companies offer any efficiency programs which target electric heating? If so, what are the annual projected kWh and kW savings from this program?
  c. If the Companies offer an efficiency program targeting electric heating what measures does it incentivize, if any?
  d. Have the Companies sought to implement an electric heating demand response program? If not, why not? If so, please provide any documentation describing the Companies' efforts.

1.40. Please provide program descriptions of the demand response programs in Table 5-1. Are these programs open to new enrollment?

1.41. Do the Companies provide any formal demand response program offerings to industrial customers? If so, please provide the details of those offerings including incentive level paid, administrative fees, enrollment fees, notification times etc. If the Companies do not offer any formal demand response programs offerings to industrial customers, please detail the steps the Companies have taken to explore the option of doing so.

1.42. Refer to Volume III, page 4, stating: "Similar to the process in 2017, the Companies have again engaged with Cadmus, Inc. to assist in the development of the upcoming filing." What programs does the Company intend to request approval of? Please provide any documentation supporting your answer.

1.43. Please provide a breakdown of peak MW and MWH of industrial load by sector and season. This could be provided using NAICS or SIC or a comparable segmentation.

1.44. Please refer to Table 21 on page 23 of the 2021 IRP Long-Term Resource Planning Analysis. Please provide the energy and peak DSM savings that were modeled for the base load and base fuel case.

1.45. Please provide the winter and summer capacity contributions assumed for the existing DSM programs across the IRP planning horizon.

1.46. Please provide the total program costs for each of the existing DSM programs.

1.47. Please provide the measure life and measure savings for each of the existing DSM programs.

1.48. Please refer to page 5-11 of the IRP where it says "The Companies did not directly evaluate new demand-side management ("DSM") programs in this IRP." Please explain why the Companies did not evaluate new DSM programs in this IRP.

1.49. Please refer to page 5-44 of the IRP where it says "As AMI is implemented, the Companies plan to evaluate new DSM mechanisms that leverage AMI data and communications through the development of pilot programs."

   a. Please explain what pilot programs the Companies are considering.
   b. Please explain what new DSM programs might be offered through the use of the AMI data.

1.50. For each of the Companies' DSM-EE Programs, please provide the Companies' most recent cost effectiveness test screening and answer the following requests:

   a. Please explain in detail how avoided costs were determined for each cost benefit test used (e.g., Total Resource Cost Test, Utility Cost Test, Participant Cost Test, Rate Impact Measure Test, Societal Cost Benefit Test).
   b. If the Companies have not used the Societal Cost Benefit Test to evaluate the DSM-EE Programs, please explain why not in full.
   c. Please provide the values for each element of the avoided cost categories listed below. Please provide the source of the values used and state whether the values are in nominal dollars or in real, inflation-adjusted dollars.
      i. Energy cost
      ii. Capacity cost
      iii. Capacity reserves (if not included in capacity costs)
      iv. Natural gas price
      v. Environmental externalities, including avoided methane loss from gas transmission, distribution, and storage infrastructure
      vi. Line losses, for energy and peak (please specify if the estimate is based on average or marginal line loss rates).
   d. Please state whether any of the following avoided cost categories listed below are included in the Companies' avoided cost calculation and if so, please provide the value, source of the

value, and state whether the value is in nominal dollars or in real, inflation-adjusted dollars.

i. Ancillary services
ii. Transmission and distribution
iii. Non-energy benefits ("NEBs") (please specify which NEBs are included)
iv. Increased reliability
v. Reduced risk (e.g., reduced exposure to future fuel price volatility, future environmental regulation compliance costs, uncertainties of demand forecasts and related capital investments, etc.)
vi. Reduced credit and collection costs
vii. Reduced pollution and environmental damage
viii. Reduced negative health impacts
ix. Any other avoided cost values incorporated into cost-effectiveness analyses.

1.51. Refer to Vol. I, Tables 5-15 and 5-16. Within each column, do the dollar amounts correspond to the stated capacity values? (e.g., for a SCCT unit with 220 MW summer capacity, the estimated capital cost would be $885/kW). If not, please explain in detail.

a. What was the assumed (i) capital cost and (ii) fixed O&M cost for each 100 MW increment of 4-hour battery storage?
b. What was the assumed (i) capital cost and (ii) fixed O&M cost for each 100 MW increment of 8-hour battery storage?
c. On what basis do the Companies conclude that 100 MW is a "typical" installation size for each of (i) battery storage (footnote 37), (ii) solar (footnote 40), and (iii) wind (footnote 40)?
d. Do the Companies have analysis or documentation supporting their characterization of 100 MW as a "typical" installation size for each of (i) battery storage, (ii) solar, and (iii) wind? If so, please produce that analysis or supporting documentation.

1.52. Please provide the spreadsheets with all formulas and links intact used to develop the inputs for the PLEXOS and PROSYM including but not limited to spreadsheets used to develop Build Cost assumptions.

1.53. Did the Companies evaluate the potential for adding pumped storage capacity to their systems including retrofitting existing dam within or near their service territories? If not, why not? If so, provide any documents summarizing that assessment.

1.54. Please refer to table 5-16 on page 5-40 of the IRP. Do the summer and winter capacity contributions for solar and wind resources remain constant throughout the planning horizon at the values provided in Table 5-16? If not, please provide the summer and winter capacity contributions for solar and wind across the entire planning horizon.

a. Please provide the analysis supporting the development of the summer and winter capacity contribution assumptions for solar and wind resources.
b. Please provide the summer and winter capacity contribution assumptions for 4- and 8-hour battery storage resources.
c. Please confirm if battery storage resources could be selected in partial units within the capacity expansion model or if they could only be added in 100 MW increments.
d. Please confirm if the Investment Tax Credit ("ITC") was assumed to be credited in the first year of the project or normalized for new solar resources. If normalized, please explain the Companies' justification for this assumption.
e. Please provide any resource constraints that were placed on the new supply side resources within the capacity expansion modeling.

1.55. Please refer to page 12 of the 2021 IRP Long-Term Resource Planning Analysis where it says, "For purposes of this analysis, the Companies are assuming the Investment Tax Credit ("ITC") will be expanded to apply to battery storage installation regardless of whether or not they are co-located and associated with solar generation." Please confirm if the costs reported for 4 and 8 hour battery storage resources in Table 5-16 on page 5-40 of the IRP incorporate the ITC.

a. Please explain if the ITC assumption for battery storage resources was credited in the first year of the project or normalized. If normalized, please explain the Companies' justification for this assumption.

1.56. Please refer to Table 5-15.

a. Did the Companies assume that all new combined cycle units would be installed with carbon capture? If so, please explain why that assumption was made.
b. What percentage of CO_2 is assumed to be captured?
c. What sink for the captured CO_2 is assumed?
d. What capture technology is assumed and why?

1.57. Refer to Vol. III, 2021 IRP Resource Screening Analysis report at page 8.

a. What was the assumed "round-trip efficiency" used to model utility-scale lithium ion batteries?

b. Do the Companies have any analysis or documentation supporting the assumed round-trip efficiency used to model utility-scale lithium ion batteries? If so, please provide that analysis or supporting documentation.
c. What was the assumed reduction in available battery capacity (on a percentage basis, as presented on page 8 of the Vol. III, 2021 IRP Resource Screening Analysis report)?
d. Do the Companies have any analysis or documentation supporting the assumed reduction in available battery capacity? If so, please provide that analysis or supporting documentation.

1.58. Refer to the 2021 IRP Resource Screening Analysis document (October 2021), Section 2.1.3 at page 8, which states: "Due to construction economies of scale and existing infrastructure, the capital cost of installing two or more SCCTs at an existing site are assumed to be approximately 25 percent lower"; and the 2021 IRP Long-Term Resource Planning Analysis, Section 3.3 at page 11, which repeats the same sentence.
a. Please confirm that the referenced 25 percent reduction was made to NREL's 2021 ATB value for SCCT capital costs. If you are unable to confirm, please identify the SCCT capital cost source reduced by approximately 25 percent.
b. Please provide the analysis and supporting documentation the Companies relied on to derive an appropriate reduction to SCCT capital costs in order to account for construction at an existing site (as opposed to a greenfield site). If no such analysis or supporting documentation exists, please explain in full the Companies basis for using an approximately 25 percent discount.
c. Please confirm that the Companies included the assumption that SCCT capital costs would be approximately 25 percent lower in the capacity expansion modeling. If anything but confirmed, please explain your response.
d. Did the Companies' Resource Screening Analysis consider the capital costs of new SCCT unit(s) at a greenfield site? Please explain in full.

1.59. Please provide the Companies' actual energy sales for calendar year 2021 on an annual and monthly basis, disaggregated by customer class.

1.60. Refer to Vol. I, Section 5.(3), page 5-21, stating that "Table 5-7 contains monthly energy requirements for 2025 as well as the percentage of total energy requirements consumed during nighttime hours."
a. Please explain (in sufficient detail to allow replication) how the

total energy requirement consumed during nighttime hours was forecasted.

b. Please provide the calculations used to derive the forecasted energy requirements and percentage nighttime hours represented in Table 5-7 in native file format with formulae intact.

1.61. Please produce all Appendices to the Electric Sales & Demand Forecast Process document (July 2021), including but not limited to Appendix A (referenced in Section 4.1.2) and Appendix B (referenced in Section 4.2.1).

1.62. Did the Companies' load forecast assume the development of any cryptocurrency mining operations in their service territory? If so, please identify the operations and explain your assumptions in full along with supporting analyses, workpapers, and documentation (in machine-readable format with formulas intact).

1.63. Refer to section 4.5 ("Distributed Solar Generation Forecast") of the Electric Sales & Demand Forecast Process (July 2021), specifically the following statement: "Because the ITC will no longer end in 2022, the model was trained though 2019 for KU and LG&E (2018 for ODP) to flatten out a recent steep increase in adoptions, which is thought to be related to the (supposed) end of the ITC and not indicative of a continued trend."

a. Why would "the (supposed) end of the ITC" impact the ODP service territory differently than each of the KU and LG&E service territories?
b. Please explain in full the Companies' reason(s) for training the model through 2018 for ODP to flatten out a recent steep increase as opposed to through 2019, as done for KU and LG&E.
c. Please produce the Companies' Distributed Solar Generation Forecast.
d. For each of KU, LG&E, and ODP, please provide the number and size (in kilowatts) of distributed solar generation additions in each of the last five years.

1.64. Please provide the assumed line loss rate used for purposes of the Electric Sales and & Demand Forecast. Please include an explanation of the source for that assumed line loss rate. If available, please also provide a line loss rate for each hour of the year, along with supporting workpapers (in machine readable and unprotected format, with formulas intact).

1.65. Provide the Companies' hourly energy forecast referenced on page 5-7 in electronic, spreadsheet format.

1.66. Are the FERC-wholesale sales referenced on page 5-8, requirements or non-requirements sales? If both, please provide the breakdown of each.

1.67. Please provide, in spreadsheet format, the input and output files produced in the development of the Companies energy requirements and peak forecasts.

1.68. Please provide a spreadsheet showing the specific post estimation adjustments, if any, made to the Companies energy requirements and peak forecasts.

1.69. Please refer to the discussion of the high and low energy requirements forecast on page 5-34 of the IRP. Please explain how the Companies developed the 180 MW industrial customer load growth or load loss.

1.70. Please explain how existing DSM programs were incorporated into the load forecast. I.e. were savings from historical programs added back to the load forecast to get a "no DSM" forecast or was a DSM variable included as an independent variable in the regression model?

1.71. Please explain how the Companies incorporated future DSM savings into the energy requirements forecasts.

1.72. Please provide the summer and winter capacity contribution assumptions modeled for distributed generation.

1.73. Refer to Vol. I at 8-34, regarding the Companies' "Carbon Capture Research."
   a. Is there an operational carbon capture system at any existing natural gas plant in the country? If so, please identify each such plant, including the following details to the extent known:
      i. Location, owner, and operator;
      ii. Estimated or actual capital cost for the plant;
      iii. Estimated or actual capital cost for the CCS component;
      iv. Estimated or actual O&M costs for each of the plant and the CCS component; and
      v. Estimated or actual operating costs for each of the plant and the CCS component.

b. Please describe in detail the "challenges of carbon capture at natural gas plants," including identification of supporting documentation.
c. What volume of gas can be processed on (i) an hourly, (ii) daily, (iii) monthly, and (iv) yearly basis by the installed carbon capture slip-stream pilot demonstration system at the E.W. Brown plant?
d. The Carbon Capture Research paragraph on page 8-34 includes the statement that "[t]he post-combustion process takes a small portion of the flue gas and uses an amine-based solvent to capture carbon dioxide." Please quantify the "small portion of the flue gas" discussed in that statement.
e. How much carbon dioxide has been captured to-date by the carbon capture slip-stream pilot demonstration system at the E.W. Brown plant?

1.74. If Astrape provided the Companies with a study summarizing its SERVM modeling on their behalf, please provide a copy of that study.

1.75. In reference to Figure 5-6, please answer the following:
a. What is meant by the inclusion of "Reliability" in the name "Reliability & Production Cost" that is not normally captured by the term "Production Cost"?
b. Why does Reliability & Production Cost go down while Capacity Cost goes up?
c. Why is the shape of Reliability & Production Cost asymptotic while Capacity Cost is linear?
d. How do the Companies distinguish, if at all, between an Economic Reserve Margin and a traditional Planning Reserve Margin?
e. Why, in the Companies' judgement, would it be reasonable to include that Total Cost decline and then increase?
f. Doesn't the portion of the graph in which Total Cost decreases while Capital Cost increases and Reliability & Production Cost decrease imply that Reliability & Production Cost is decreasing at a faster rate than Capital Cost is increasing? If not, why not? If so, why do the Companies believe this is a reasonable assumption?
g. Doesn't the portion of the graph in which Total Cost increases while Capital Cost increases and Reliability & Production Cost decrease imply that Reliability & Production Cost is decreasing at a slower rate than Capital Cost is increasing? If not, why not? If so, why do the Companies believe this is a reasonable assumption?
h. Why does the minimum of the Total Cost line correspond with the point at which Reliability & Production Cost intersects with Capacity Cost?

1.76. Regarding the SERVM modeling discussed at pdf page 47 of Volume III please answer the following:

  a. How many iterations (draws) were performed in this study?
  b. What was the relationship between weather years sampled for load and those sampled for renewables?
  c. What forced outage rates were assumed?
  d. What "unit availability" assumptions were used?
  e. How, if at all, was convergence determined? Please provide any documentation in electronic workbook(s) with all formulas and links intact that show your work.

1.77. With regards to the Equivalent Load Duration Curve Model, please answer the following:

  a. Who licenses and maintains the model?
  b. Please provide a user guide for the model.
  c. Does the model represent time using load duration curves? If so, why do the Companies believe this is a reasonable approach for purposes of evaluating reliability?
  d. How, if at all, was convergence determined? Please provide any documentation in electronic workbook(s) with all formulas and links intact that show your work.

1.78. Please refer to page 5-15 of the IRP where it states that "The Companies used the Equivalent Load Duration Curve Model ("ELDCM") and Strategic Energy Risk Valuation Model ("SERVM")" in the discussion of the reserve margin analysis.

  a. Please provide the input and output modeling files, in spreadsheet format, with all formulas and links intact for the ELDCM and SERVM models.
  b. Please confirm if the Companies put the capacity expansion plans from the modeling for this IRP back into SERVM to confirm that the plans met the Companies' reliability criteria. If this step was completed, please provide the results for each of the capacity expansion plans developed for this IRP.
  c. Are the reserve margin requirements developed out of these studies installed capacity (ICAP) or unforced capacity (UCAP) requirements? If ICAP, why do Companies' use this metric rather than UCAP?

1.79. Please refer to page 4 of the 2021 IRP Reserve Margin analysis that says "Therefore, the Companies' target reserve margin range is 17 to 24 percent in the summer and 26 to 35 percent in the winter." Please give the summer and winter reserve margin constraints used within Plexos for the capacity expansion modeling.

1.80. In the 2021 IRP Reserve Margin Analysis, "Table 7 summarizes the sum of daily ATC between the Companies' system and neighboring regions on weekdays during the summer months of 2019 and 2020 and the winter months of 2020 and 2021."

a. Please provide the workpaper underlying Table 7 ("Daily ATC") of the 2021 IRP Reserve Margin Analysis with formulae intact.
b. Please provide the specific dates represented in Table 7.
c. Please provide the available transmission capacity values shown in Table 7 disaggregated to reflect each neighboring region on an independent basis.
d. Among the dates represented in Table 7 and for each Daily ATC Range provided in the first column of Table 7, please specify the percentage of days when export capability of a neighboring system was greater than the Companies' import capability.
e. Among the dates represented in Table 7 and for each Daily ATC Range provided in the first column of Table 7, please specify the percentage of days when export capability of a neighboring system was less than the Companies' import capability.
f. Please explain why only weekdays were considered in Table 7's representation of Daily ATC.
g. Please provide the daily ATC between the Companies' system and neighboring regions from January 1, 2019, through December 31, 2021.

1.81. Refer to the following statements from page 17 of the 2021 IRP Reserve Margin Analysis: "During peak hours when ATC is most likely needed to ensure reliable supply, ATC in ELDCM and SERVM is assumed to be approximately 500 MW two-thirds of the time and zero MW one-third of the time. Alternative ATC scenarios are also considered to understand the impact of this input assumption on the analysis."

a. Please define each of the alternative ATC scenarios also considered.
b. For each alternative ATC scenario defined in response to subpart (b), please explain the empirical basis for each alternative, including analysis, calculations, or supporting documentation, if any.

1.82. Please clarify the source of the new SCCT capacity reported in Table 11 of the 2021 IRP Reserve Margin Analysis: Page 20 of the 2021 IRP Reserve Margin Analysis states that "[t]he cost of new SCCT capacity is taken from the 2021 IRP Resource Screening Analysis and is summarized in Table 11 in 2025 dollars," but Footnote 23 of the same document states that Table 11 reflects costs from NREL's 2018 ATB.

1.83. Refer to Vol. III, 2021 Reserve Margin Analysis at page 22, which states that, "The peak demand forecast is the forecast of peak demand under normal weather conditions. The impact of the Companies' DSM programs is reflected in the Companies' peak demand forecast."

a. Please identify the specific DSM programs and program years assumed to be reflected in the referenced peak demand forecast
b. Please explain in full the manner in which the impact of future DSM programs was accounted for in the Companies' peak demand forecast.

1.84. Refer to Vol. III, 2021 Reserve Margin Analysis at Tables 13–16.

a. Please list and specify the timing of each resource addition and retirement assumed in each of the Generation Portfolios.
b. Was SERVM used to evaluate the impact of adding 260 MW of nameplate solar to the generation portfolio, as modeled with ELDCM? If so, please provide that the reserve margin analysis results with new solar from SERVM. If not, please explain in full why the Companies did not use SERVM to evaluate the impact of new solar.

Respectfully submitted,

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CERTIFICATE OF SERVICE

In accordance with the Commission's July 22, 2021 Order in Case No. 2020-00085, *Electronic Emergency Docket Related to the Novel Coronavirus COVID*-19, this is to certify that the electronic filing was submitted to the Commission on January 21, 2022; that the documents in this electronic filing are a true representations of the materials prepared for the filing; and that the Commission has not excused any party from electronic filing procedures for this case at this time.

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Tom FitzGerald