COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC 2026 INTEGRATED RESOURCE PLAN OF BIG RIVERS ELECTRIC CORPORATION	)))	CASE NO. 2026-00268

COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION TO BIG RIVERS ELECTRIC CORPORATION

Big Rivers Electric Corporation (BREC), pursuant to 807 KAR 5:001, shall file with the Commission an electronic version of the following information. The information requested is due on December 4, 2026. The Commission directs BREC to the Commission's July 22, 2021 Order in Case No. 2020-00085[1] regarding filings with the Commission. Electronic documents shall be in portable document format (PDF), shall be searchable, and shall be appropriately bookmarked.

Each response shall include the question to which the response is made and shall include the name of the witness responsible for responding to the questions related to the information provided. Each response shall be answered under oath or, for representatives of a public or private corporation or a partnership or association or a governmental agency, be accompanied by a signed certification of the preparer or the person supervising the preparation of the response on behalf of the entity that the

[1] Case No. 2020-00085, *Electronic Emergency Docket Related to the Novel Coronavirus COVID-19* (Ky. PSC July 22, 2021), Order (in which the Commission ordered that for case filings made on and after March 16, 2020, filers are NOT required to file the original physical copies of the filings required by 807 KAR 5:001, Section 8).

response is true and accurate to the best of that person's knowledge, information, and belief formed after a reasonable inquiry.

BREC shall make timely amendment to any prior response if BREC obtains information that indicates the response was incorrect or incomplete when made or, though correct or complete when made, is now incorrect or incomplete in any material respect.

For any request to which BREC fails or refuses to furnish all or part of the requested information, BREC shall provide a written explanation of the specific grounds for its failure to completely and precisely respond.

Careful attention shall be given to copied and scanned material to ensure that it is legible. When the requested information has been previously provided in this proceeding in the requested format, reference may be made to the specific location of that information in responding to this request. When applicable, the requested information shall be separately provided for total company operations and jurisdictional operations. When filing a paper containing personal information, BREC shall, in accordance with 807 KAR 5:001, Section 4(10), encrypt or redact the paper so that personal information cannot be read.

1. Refer to BREC's 2026 Integrated Resource Plan (IRP), pages 9-10 and Appendix F. Explain which of the Commission recommendations from the 2023 IRP were not adopted and why.

2. Refer to IRP, page 15, regarding bilateral power contracts. State whether BREC seeks to renew the expiring contracts and explain why or why not.

3. Refer to IRP, pages 16, 18, 27, 206 (Figure 6.7.1), and 221 (Figure 6.7.7). In the referenced information, Green is described as 454 MW in Chapter 1 but 205 MW plus 223 MW (428 MW) in Chapter 6, with an uprate to 231 MW in March 2029. Explain the uprate project and explain if it is included in the 144 MW winter accreditation gain.

4. Refer to IRP, pages 19, 206 (Figure 6.7.1), and 303. Explain the differing in-service dates for Wilson (1986 vs 1984) and Unbridled Solar (Feb. 2025 vs 2023; retirement 2043 vs PPA expiry 2045) and which dates were used in the model.

5. Refer to IRP, page 29.

a. Explain how the cost of the 30-mile 345 kV transmission line will be allocated across the MISO footprint and BREC's estimated share of that cost.

b. To the extent that upgrading BREC's transmission system will allow for greater energy import capability with MISO and any other interconnected entity, explain whether resulting import capability could be used in the EnCompass modeling to delay or obviate the need for additional capacity generation. If not, explain why not.

6. Refer to IRP, pages 30, 31, and 85. Explain why Demand Side Management (DSM) excludes Direct Serve customers although they are over 40 percent of sales.

7. Refer to IRP, page 33, Table 1.2.7(a) and page 34, Table 1.2.7(b).

a. Explain the meaning of Aux CP and Aux Load.

b. Explain the reasons for the decline in Aux CP and Aux Load over the 2020-2024 period.

c. Explain whether BREC's own energy and capacity usage is included in Aux CP and Aux Load. If not, explain where these are located.

d. Explain whether the TeraWulf data center load is included in either Native or Non-Native forecasts. If not, explain why not.

8. Refer to IRP, pages 33-34, Tables 1.2.7(a), and 1.2.7(b). Explain the methodology and underlying assumptions used to forecast Aux CP and Aux Load from 2025 through 2044, including the reasons for the relatively stable projected values over this period.

9. Refer to IRP, Section 1.2.8 and pages 35-36, Table 1.2.8(a). Given the decline in requests for information (RFIs) and fluctuations in proposed capital investment, explain the criteria BREC uses to assess the credibility and potential economic impact of prospective development projects. Include in the response how BREC evaluates the likelihood of these projects proceeding to implementation.

10. Refer to IRP, page 36. Explain the approach BREC references in the first sentence under Table 1.2.8(a).

11. Refer to IRP, pages 36-39 and 58-59. Explain, when a large customer bears its own supply risk, who holds the MISO planning reserve and accredited capacity obligation for that load, and who pays if market supply is short.

12. Refer to IRP, pages 37-39, 76 (Table 3.2), and pages 200-203. State if the 482 MW TeraWulf load approved in Case No. 2026-00115[2] is included in the Reference Case load. If not, explain how the capacity position, reserve requirement and portfolio would change if it is served.

13. Refer to IRP, page 38, regarding isolating data center load from other load.

[2] Case No. 2026-00115, *Electronic Tariff Filing of Big Rivers Electric Corporation of a Retail Electric Service Agreement with Justified Datapower, LLC, a Subsidiary of TeraWulf, Inc.* (Ky. PSC Aug. 8, 2026).

a. Describe any benefits ratepayers should expect to receive from having data centers with isolated load located in BREC's service territory.

b. Describe any disadvantages ratepayers should expect to receive from having data centers with isolated load located in BREC's service territory.

c. Identify all planning considerations applicable to providing capacity for data center load.

14. Refer to IRP, page 51. Explain why class average load factors were previously used instead of individual consumer load factors in load forecasting.

15. Refer to IRP, pages 58-59, and 192, Figure 6.5.4.2.

a. State if the large-load sensitivities are reflected in the IRP.

b. Explain why the scenarios only vary load as base, low, or high if it runs data center sensitivity.

16. Refer to IRP, page 59.

a. State whether BREC's high-demand/data center customer integration strategy includes MISO.

b. If yes, describe how MISO factors into BREC's generation planning strategy.

17. Refer to IRP, page 69. State whether solar capacity figures represent nameplate or accredited capacity.

18. Refer to IRP, page 72, Table 2.6 and page 209, Figure 6.7.2. DSM is modeled as a fixed resource rather than competing in optimization. Explain what the model would select if demand response competed against new capacity.

19. Refer to IRP, page 76, Table 3.2 and pages 30-31 which show Direct Serve peak rose from 106 MW to 262 MW between 2020 and 2024, and 16 customers are 42.7 percent of sales. Explain how concentrated this load is, what contract protections exist, and what happens to resource needs if one of the largest customers leaves BREC's territory.

20. Refer to IRP, page 77, Tables 3.3 and 3.4, and footnote 64. Refer also to page 71, Figure 2.6 and page 202, Figure 6.6. [redacted]

21. Refer to IRP, pages 77-79, Tables 3.3 and 3.4, and page 15, footnote 13, which shows non-member sales fall from about 252 MW to 50 MW by 2030 and zero by 2040. Explain if renewals are being pursued, and how the freed Wilson energy is valued.

22. Refer to IRP Sections 3.7 and 3.8, pages 81-82, and Appendix A, Sections 4.1, 6.1, and 8.4. Explain how cooling degree days, heating degree days, and peak-day weather conditions were incorporated into the rural coincident peak load factor econometric models for each of BREC's three member systems. Identify the specific weather variables used in each model and explain how the 20-year historical averages were applied in developing the forecasts.

23. Refer to IRP, page 87. Explain how it was determined and the significance behind allocating 50 percent of the hypothetical budget to energy efficiency programs and the remaining to demand response programs.

24. Refer to IRP, page 89, Table 4.1.3; page 91, Table 4.1.4; and page 303, footnote 139. Economic energy efficiency potential is about 23 percent of sales, yet

funded program potential is only about 1 to 5 percent. Explain what budget level is assumed in the roughly 17 MW winter reduction in the portfolio and what its cost per kW is.

25. Refer to IRP, page 92. Explain whether other modeling platforms besides Excel were considered for cost-effectiveness screening. If so, identify the modeling platforms and explain why each platform was not selected.

26. Refer to IRP, page 143. The graph is not displaying properly in the publicly filed IRP. Provide the graph from page 143.

27. Refer to IRP, page 146, Table 4.7 and pages 149-151. Explain how many of the programs with Total Resource Cost (TRC) lower than 1.0 will be piloted.

28. Refer to IRP, pages 153-172.

a. Identify how each environmental regulation discussed in this section was modeled, excluding the Greenhouse Gas rule modeling discussed on pages 182-183.

b. Describe BREC's policies, plans or strategies regarding continued use or discontinuance of environmental mitigation measures deemed non-mandatory by the EPA.

29. Refer to IRP, page 180, Section 6.3, EnCompass Planning Model.

a. Provide a detailed description of the EnCompass modeling methodology used to develop BREC's 2026 IRP. Identify the model versions, modules, and principal optimization algorithms utilized in the capacity expansion and production cost simulations.

b. Explain how the capacity expansion model determines the optimal combination, quantity, and timing of new generation resources, retirements, and market purchases. Identify the principal assumptions and constraints that influence the model's resource selection decisions.

c. Provide all input data, modeling assumptions, and output files used in the EnCompass capacity expansion and production cost simulations, including, but not limited to load forecasts, fuel price forecasts, market price forecasts, generation profiles, transmission constraints, and generating unit operating characteristics.

d. Explain how EnCompass evaluated the reliability implications of alternative resource portfolios. Specifically, describe how MISO resource adequacy requirements, planning reserve margins, and other applicable reliability criteria were incorporated into the model.

e. Identify all candidate generation resources considered in the capacity expansion analysis, including renewable generation, battery storage, natural gas generation, market purchases, and investments in existing resources. For each resource, provide the assumed capital costs, fixed and variable operating costs, expected useful life, capacity factor, and commercial operation date.

f. Explain how the model evaluates the trade-offs between constructing new generation resources, extending the operating lives of existing generating units, retiring existing resources, and purchasing energy from the wholesale market. Provide the economic justification for the resources selected in each planning scenario.

g. Explain how the hourly production cost simulation incorporates the 8,760 hourly load requirements, renewable generation profiles, fuel prices, market prices,

transmission limitations, and generating unit operating characteristics. Identify the sources of the underlying data and explain how each input was developed.

h. Explain whether the production cost simulation accounts for forced outages, planned maintenance outages, minimum generation requirements, ramping limitations, minimum up/down times, and start-up costs. If so, describe how these operational constraints were incorporated into the model.

i. Provide the annual generation, capacity factor, fuel consumption, operating costs, market purchases, and energy sales for each generating resource under each modeled scenario. Include the annual system production costs and total portfolio costs.

j. Describe the procedures performed by Alliance for Cooperative Energy Services Power Marketing, LLC (ACES) and BREC to validate the EnCompass model and verify the reasonableness of its results. Explain whether the model was calibrated against BREC's actual historical generation, load, fuel consumption, and market purchases. If not, explain why.

30. Refer to IRP, page 184.

a. Describe how reinstatement of solar and wind tax credits would affect portfolio selection.

b. Provide an estimate of the annual cost to ratepayers of the elimination of solar and wind tax credits under the One Big Beautiful Bill Act.

31. Refer to IRP, page 189.

a. For each of the scenario analyses and portfolio developments, explain whether normal weather was assumed throughout or was varied depending on the specific scenario.

b. For each of the four scenario analyses, explain what demand/energy forecasts were used.

c. Except for the Reference Case, if the same demand/energy forecast was used in each of the four scenarios, explain how the demand forecast was or was not affected by the differing assumptions driving each scenario.

32. Refer to IRP, page 192, Figure 6.5.4.2(a). Explain the assumptions inherent in the Thermal CapEx and Renewable CapEx change, if at all, in each of the four scenarios.

33. Refer to IRP, page 193.

a. State the expected useful life of Green and Wilson units and whether the fixed retirement dates correspond to when the units are fully depreciated.

b. If not, explain how the fixed retirement dates were determined.

c. Describe the level of risk of catastrophic forced outage associated with continued use of Green and Wilson Stations under the Model Optimization scenarios.

34. Refer to IRP, Figure 6.5.5.2(a), page 194. For each of the analyses in the Model Optimization row:

a. Explain whether the model added any generation capacity either through building or purchasing in each of the scenarios over the time horizon.

b. Explain the assumptions regarding how the ongoing operations and maintenance and any associated capital expenditures for equipment repair or

replacement for the existing Green and Wilson units compare to the costs of potential alternative new generating units.

c. If not answered above, explain whether BREC's contracted share of SEPA capacity and energy terminates prior to 2050 and, if so, explain how that capacity and energy are replaced in the model.

d. Explain the difference between the High Regulatory (Carbon Tax) and High Regulatory (Carbon Tax) Kentucky Law Compliant scenarios.

e. Comparing the Reference Case assumptions to each of the four remaining scenarios, for each remaining scenario, provide a list showing the Reference Case assumptions and what changed to drive each remaining scenario.

35. Refer to IRP, Figure 6.5.5.2(a) page 194. For each of the analyses in the Fixed Retirement row;

a. Explain the generation resources the model selects for BREC's generation portfolio when the Green and Wilson units are retired.

b. There are long current wait times and escalating prices for turbines, transformers and other components of generators and generation stations for which there are few manufacturers, and labor to install these components/stations. Explain the escalation factors used in the modeling for these types of components and labor to install.

c. Across all the scenarios in both the Model Optimization and Fixed Retirements model runs, explain the assumptions regarding BREC's and MISO's transmission capacity and any costs associated with transmission expansion.

36. [redacted]

a. [redacted]

b. [redacted]

c. [redacted]

37. Refer to IRP, Figure 6.5.6(a) page 195. It is not clear how the differing assumptions represented by the scenarios in each row and column are combined to obtain the resulting Present Value Revenue Requirement (PVRR) generation cost. For example, the $91.34 PVRR is obtained by some combination of the assumptions from two different scenarios: Low Load & Gas Prices and Natural Gas Infrastructure Challenges. Explain how the assumptions inherent in each of the differing scenarios are blended to achieve the resulting PVRR generation cost.

38. Refer to IRP page 196, Stochastic Analysis.

a. Explain in detail the machine learning techniques utilized by ACES in developing its Weather-Driven Stochastics methodology. In the response, identify each machine learning model or algorithm employed, describe how the models were developed and trained, and explain how they were used to generate the 100 correlated hourly simulations referenced in the IRP.

b. Identify the historical data used to develop and train the machine learning models, including the applicable time period, data sources, historical weather observations, wholesale electricity prices, power price basis differentials, natural gas prices, system load, and intermittent generation data. Explain how BREC and ACES

account for changes in market conditions, generation resources, transmission constraints, and other factors that may cause historical relationships to differ from future conditions.

c. Explain how the Weather-Driven Stochastics methodology captures and preserves the correlations among weather conditions, electricity demand, wholesale power prices, natural gas prices, power price basis differentials, and intermittent generation. Provide an example illustrating how the methodology models the simultaneous effects of extreme weather conditions on these variables.

d. Describe the process used to validate the machine learning models and assess the accuracy and reliability of their forecasts and simulated outcomes. Include any back-testing, out-of-sample testing, historical comparisons, error measurements, or other validation procedures performed by ACES. Provide the results of these evaluations, if available.

e. Explain whether ACES considered or evaluated traditional Monte Carlo stochastic simulation methods in developing its Weather-Driven Stochastics methodology. If so, describe the differences between the two approaches, including their underlying assumptions, treatment of correlations among variables, generation of simulated outcomes, and ability to capture extreme weather events and market conditions.

f. Explain why ACES considers its Weather-Driven Stochastics methodology preferable or more appropriate than traditional Monte Carlo stochastic analysis for evaluating BREC's resource portfolios. Identify the specific analytical advantages of incorporating machine learning techniques and explain whether these

advantages result in more accurate forecasts, more representative market conditions, or a more reliable assessment of portfolio cost and risk.

g. Explain the basis for selecting 100 correlated hourly simulations for each optimized resource portfolio. Describe whether ACES evaluated a greater number of simulations and whether 100 simulations are sufficient to capture the range of potential outcomes, including extreme market conditions and tail-risk events. Provide any supporting analysis.

h. Describe how the stochastic simulation results are used to calculate the expected PVRR and the 5th and 95th percentile PVRR metrics incorporated into the IRP Scorecard.

i. Explain how ACES determined that these percentile measures provide a reasonable representation of upside opportunity and downside risk.

39. Refer to IRP, Figure 6.5.8.1(a), page 199.

a. Explain whether every portfolio represented in Figure 6.5.6(a) was evaluated using the scorecard metrics.

b. Under affordability, explain whether the 15-year Levelized Generation cost is obtained by running the model over the full study through 2050 and then calculating the levelized cost for the 15-year period. If not, explain the differences in assumptions used between the 15-year and full study time period.

c. For any new capitalized equipment added in any scenario in any given installation year, explain whether the depreciation rates used were truncated to fit the study time horizon. For example, a combustion turbine installed in 2039 will have a

useful life well beyond 2050 and would be depreciated accordingly for rate making purposes.

40. Refer to IRP, Figure 6.5.8.1(a), page 199. For Reliability, explain why the analyses only evaluated the winter peak in 2046.

41. Refer to IRP, Figure 6.5.8.1(a), pages 199-200. For Risk and Opportunity,

a. Explain whether the P5 and P95 results are obtained by subtracting results from 2025 from 2027 results. If not, explain how the results were obtained.

b. Many investment and capital expenditure decisions have long term ramifications. Explain why BREC is evaluating risk and opportunity on what appears to be a short-term basis versus a longer term outlook.

42. Refer to IRP, Figure 6.5.8.1(a), page 200. For Environmental Performance, explain BREC's environmental goals and milestones in its strategic plan and whether these goals were carried over into the IRP. If not, explain how they have evolved as a result of recent or pending changes in current environmental regulations.

43. Refer to IRP, page 204. Explain whether BREC being constrained in the winter season refers to energy import and export capability for MISO.

44. Refer to IRP, Figure 6.7.1(a) page 206. Explain the source of the 26 MW uprate for Green Unit 1 in March 2029. Include in the response if the capacity ratings represent nameplate or unforced capacity.

45. Refer to IRP, page 206. Explain what resources make up the stated 1,005 MW of owned thermal when Figure 6.7.1(a) indicates a different amount and state which resources the model counts as thermal.

46. Refer to IRP, page 207.

a. Explain why MISO is transitioning to Direct Loss of Load (DLOL) and away from Expected Load Carrying Capability (ELCC) methods for capacity accreditation.

b. Explain how MISO calculated ELCC and applied it to BRECs capacity resources.

47. Refer to IRP, page 207.

a. Explain why the Green Units have winter fuel availability issues.

b. Explain whether the interstate gas pipeline supplying BREC offers seasonal firm transportation and, if so, why BREC does not take advantage of this option seasonally.

c. Provide the number of times in the last ten years of which BREC is aware that its interstate gas pipelines have been unable to supply gas during the winter heating season. Include in the response an explanation for each instance of whether the issue was with gas supplies being put on the pipeline or with pipeline transport issues.

48. Refer to IRP, Figure 6.7.1(b), page 209. Due to the differences in time periods, the comparison between Summer Average Seasonal Accredited Capacity (Summer Average SAC) and DLOL do not appear to be an apples-to-apples comparison.

a. Provide an update to Figure 6.7.1(b) showing the two capacity measures with the same time periods. Also, include in the updated Figure an additional column showing the SAC for Green Units 1 and 2 with fuel oil backup.

b. Explain whether the fuel oil back up option is a more cost-effective solution for the Green Units than having firm gas pipeline transportation.

c. In the updated Figure, show how SAC and DLOL each satisfies BREC's seasonal MISO capacity requirements.

49. Refer to IRP, pages 209-210, and Appendix B (DSM Market Potential Study), page 27.

a. Since the TRC ratio is the same for the three budgets evaluated, state why the $2.5 million budget was not selected instead of a $1 million budget.

b. Identify which DSM programs were "selected" as referenced on IRP page 210.

50. Refer to IRP, page 210. Explain whether all of BREC's member systems offer the full suite of BREC's current DSM programs. If not, explain why.

51. Refer to the IRP, page 209-210. Explain how BREC weighed the selection between cost-effective Demand Response programs and Energy Efficiency programs.

52. Refer to IRP, Figure 6.7.3(a), page 212.

a. Explain whether the SAC PRM and DLOL PRM columns represent the MISO system wide planning reserve margin (PRM) or BREC's zonal PRM.

b. Explain whether the Final BREC Reserve Margin Adjustment for CPF of 2.31 percent means that, for IRP planning purposes, BREC Coincident Peak Factor (CPF) of 94.82 percent is adjusted upward to 97.13 percent, or that the 94.82 percent is BREC's final zonal CPF after being adjusted by 2.31 percent.

53. Refer to IRP, Figure 6.7.4(a), page 215.

a. Provide the data represented by the figure in tabular form.

b. Explain the meaning of the D.B. Wilson MISO extension.

54. Refer to IRP, confidential Figure 6.7.4(b), page 217.

a. Provide the data represented by the figure in tabular form.

b. [redacted]

55. Refer to IRP, page 218. Explain whether BREC's target total annual energy percentage implies that it intends and is planning to cover any remaining capacity needs through bilateral or market capacity purchases.

56. Refer to IRP, Figure 6.7.7(a) page 221.

a. Explain why gas would not be available during the other three seasons such that having the dual fuel capability would increase accredited capacity.

b. Explain if the capacity ratings are based on the MISO DLOL methodology.

57. Refer to IRP, page 222.

a. Explain why the projects listed for the Wilson Unit would not be conducted in the ordinary course of business to maintain the operational integrity of the plant and how these projects represent investment over and beyond ordinary operation and maintenance and capital investment expenditures.

b. Provide a listing of the scheduled and projected maintenance and capital investment projects associated with the Wilson Unit as part of the life extension project included in the modeling scenarios.

58. Refer to IRP, page 224. Confirm that BREC is planning through its IRP to satisfy its MISO PRM requirement and not necessarily its own forecasted coincident peak demand.

59. Refer to IRP, page 225. Explain the derivation of the 4.75 percent weighted average cost of capital (WACC).

60. Refer to IRP, page 249.

a. Explain how BREC selected 800 MW as the maximum solar/wind capacity.

b. State whether this is 800 MW of nameplate or accredited capacity.

61. Refer to IRP, page 260, and 261, Figure 6.9.3.1. Explain the capacity expansion capabilities of each scenario evaluated for BREC. Specifically, clarify whether BREC has the technical and operational capability to develop and integrate an 800 MW wind generation resource into its system by 2032.

62. Refer to IRP, Chapter 7 starting on page 287.

a. Identify any ways in which transmission planning impacted modeling.

b. Explain how transmission planning might be used to increase capacity, including creating access to additional capacity purchases.

63. Refer to IRP, page 302, Table 9(a).

a. Explain whether the prices are in nominal or real terms.

b. Explain what drives the reduction in projected member wholesale rates in 2029 and the sustained reduction beginning in 2032.

64. Refer to IRP, page 303 and to Table 4.1.4(a), page 91. The table shows demand response cumulative savings of 15.4 MW in Summer and 16.0 MW in winter in 2041.

a. Reconcile the information in Table 4.1.4(a) with the statement that the "DSM portfolio contributes approximately 17 MW of winter peak demand reduction in 2033."

b. Explain whether the referenced DSM portfolio includes both energy efficiency and demand response programs.

65. Refer to IRP, Appendix A, Table Native System Summary, page 8. Confirm that distribution losses are included in the Total Rural Energy Requirements and the Rural System Coincident Peak Demand columns and transmission losses are included in the Direct Serve Energy Requirements and Direct Serve Coincident Peak Demand columns.

66. Refer to IRP Appendix A, page 11. Refile page 11 to show the complete graph and explanation.

67. Refer to IRP, Appendix A, Section 1.4, page 12. Identify the backup weather stations used to fill gaps in the historical weather data for each of BREC's three member systems. Specify the weather variables and periods for which data were missing and explain how data from the backup stations were used to replace the missing observations, including whether any adjustments were made to account for differences between the primary and backup weather stations.

68. Refer to IRP, Appendix A, pages 12-13. Explain when the load forecast was developed such that 2025 was excluded from the historical data.

69. Refer to IRP, Appendix A, page 15.

a. Explain whether BREC's three distribution owner members have any historical data pertaining to electric vehicle (EV) use and charging. Include in the response the reason for not relying on this data as opposed to using historical and projected data from the Energy Information Administration (EIA) Annual Energy Outlook.

b. Explain the extent to which any historical data from BREC's three distribution owner members compared to the historical data Clearspring Energy Advisors obtained from the EIA annual Energy Outlook.

70. Refer to IRP, Appendix A, page 17. Explain how forecasted annual distributed generation (DG) amounts were derived from the EIA Annual Energy Outlook.

71. Refer to IRP, Appendix A, page 22. Refile page 22 to show the complete graph and explanation.

72. Refer to IRP, Appendix A, Section 3.1.2, pages 23 - 24, and the Residential Class forecast table on page 21. Explain the factors underlying the projected average annual increase of 0.58 percent in residential electricity use per consumer over the first five forecast years, compared with the historical average annual declines of 0.99 percent and 1.51 percent over the preceding five and ten-year periods, respectively. Identify the principal explanatory variables and forecasting assumptions contributing to this reversal in trend, including the extent to which weather normalization accounts for the projected increase.

73. Refer to IRP, Appendix A, page 24. Refile page 24 to show the complete graph and explanation.

74. Refer to IRP, Appendix A, pages 27-28. Refile pages 27-28 to show the complete graphs and explanations.

75. Refer to IRP, Appendix A, footnotes 9 and 11, page 46, and page 50 respectively.

a. If the Kentucky Municipal Electric Agency (KYMEA) contract is assumed to extend to 2039 for IRP purposes, explain the rationale for excluding the associated 50 MW contract amount from the forecasts and tables.

b. Even though the 50 MW KYMEA contract amount is excluded from the tables, explain whether this amount was included in the load forecast made available to the modeling analyses that resulted in BREC's final preferred resource portfolio.

76. Refer to IRP, Figure 6.6(b) and Appendix A, page 50.

a. Explain why the coincident peak values do not match.

77. Refer to IRP page 203 and Appendix A, page 50. [redacted]

a. [redacted]

b. [redacted]

78. Refer to IRP, page 303, regarding the proposed Green fuel oil backup project.

a. State how the project would affect Green's ELCC.

b. State whether that effect was reflected in modeling.

79. Refer to IRP, Appendix A, Table DSM Scenario Impacts, page 52.

a. Explain the meaning of the dark highlighted rows.

b. Explain the budget level BREC used in modeling the DSM impact for the load forecast.

c. Explain whether each of BREC's three owner members offer every cost-effective DSM program from the DSM Potential Study and each owner member's DSM budget. Include in the response whether it was assumed that each owner member would offer every cost-effective DSM program.

d. For each of BREC's owner members, explain whether there are DSM programs being offered with more applicants than slots and which would have greater participation and could be expanded with a larger budget.

80. Refer to IRP, Appendix A, page 62 and Appendix B Demand Side Management Potential Study. Explain whether either the residential end-use survey collects data on household income levels or the DSM Potential Study accounts for different household income levels.

81. Refer to IRP, Appendix A, page 63. Given BREC's economic development pipeline and its expectations for the possible siting of large loads (industrial or data center), explain the point at which that anticipated load would be included in the load forecast.

82. Refer to IRP, Appendix A, page 67. Explain how the econometric load factor model is used to forecast peak demand. Include in the response how system own-use, system losses and non-member sales are included in the final estimate.

83. Refer to IRP, Appendix A, page 74. Explain the temperature used to determine a cooling degree day and a heating degree day.

84. Refer to IRP, Appendix A, pages 76-86. Refile these pages with the page numbers and ensure that all graphs have titles and all axes are correctly labeled.

85. Refer to IRP, Appendix A, pages 93-104. For each owner member, provide a table showing the residential consumer model.

86. Refer to IRP, Appendix A, pages 93-104. For the Use Per Consumer models:

a. Explain why the (Residential Price/Alternate fuel price) variable is in log form, but the other variables are not in log form.

b. Explain how the alternate fuel price variable is constructed and what alternate fuels are included in variable.

c. Explain the AC Efficiency and Heating Efficiency variables.

87. Refer to IRP, Appendix A, pages 94 and 98. For each C&I Consumer Model explain each variable in the equation

88. Refer to IRP, Appendix A, pages 95, 99, and 103. For the C&I Use Per Consumer Models;

a. Explain why the C&I Electricity Price and Total Employment/C&I Consumer variables are in log form, but other variables are not.

b. For each distribution cooperative there are variables delineating time periods. For example, the JPEC model on page 95 contains the variables January 1999–July 2015, 2019 Forward, and March 2023 Forward. Explain these time period variables

and what events they are meant to represent for each of the distribution cooperative models.

89. Refer to IRP, Appendix A, pages 96, 100, and 104. Explain the rationale for including both cold peaking and hot peaking for the months of April and October.

90. Refer to IRP, Appendix A, pages 96, 100, and 104. The load factor models for the three member cooperatives include a variable labeled "September 2023 Forward," with reported p-values of 0.0661, 0.1195, and 0.3741, respectively.

a. Explain the purpose of this variable and the rationale for retaining it in the models, given that its coefficients are not statistically significant at the 5 percent level.

b. Describe how the inclusion of this variable affects the projected load factors.

91. Refer to IRP, Appendix A, page 102, MCRECC General C&I Consumer Model. The regression results report an adjusted R-squared of 0.248, with total employment as the sole explanatory variable. Explain the basis for selecting this model to forecast the number of general commercial and industrial consumers served by Meade County RECC, given its relatively low explanatory power. State whether alternative model specifications were evaluated.

92. Refer to IRP, confidential Appendix D.3. For each of the Tabs showing the scenario capacity modeling results:

a. [redacted]

b. [redacted]

c. [redacted]

d. [redacted]

93. Refer to IRP, confidential Appendix D.3. [redacted]

a. [redacted]

b. [redacted]

94. Refer to confidential Appendix D.1, Preferred Plan.

a. [redacted]

b. [redacted]

c. [redacted]

d. [redacted]

95. [redacted]

96. Refer to Appendix A, Section 3.2.2, pages 29-30. The Large Commercial and Industrial (LCI) class forecast projects a constant number of 42 consumers from 2026 through 2044, while use per consumer and total energy sales increase over the same period.

a. Explain the basis for assuming no change in the number of LCI consumers throughout the forecast period.

b. Identify the factors driving the projected increase in Use Per Consumer from 2026 through 2044.

97. Refer to Appendix A, Section 3.4, pages 35-36. The Irrigation Class forecast projects constant electricity use per consumer from 2025 through 2044, despite substantial fluctuations in historical consumption. State whether weather conditions and changes in irrigation activity were considered in developing the forecast and provide the rationale for this projection.

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