RESPONSES TO STAKEHOLDER QUESTIONS SUBMITTED BY THE ARKANSAS ATTORNEY GENERAL AND ARKANSAS ELECTRIC ENERGY CONSUMERS

An Integrated Resource Plan (IRP) is a compass and provides general direction for future resource selections but does not identify specific resources to meet identified needs. The IRP helps inform those future decisions but does not dictate or specify what decisions a utility should make. It is a planning process and framework in which the costs and benefits of supply-side and demand-side alternatives are evaluated to develop resource portfolio options that are intended to help meet EAL's planning objectives. Results of the IRP are not intended as static plans or pre-determined schedules for resource additions or deactivations. The IRP plays an important role in the iterative process of planning EAL's future resource portfolio by providing a comprehensive and transparent look at long-term themes and tendencies in designing and leveraging a diverse, balanced, and forward-thinking portfolio of resources. While these long-term and forward-looking indicators are important guides to resource planning, the IRP fulfills a distinctly different purpose and process from near-term, specific resource decisions that typically are presented to the Commission for approval. Again, the IRP does not serve as a definitive plan for identifying EAL's long-term generation needs or its options for meeting those needs. Rather, the IRP provides a snapshot of current conditions and future expectations, both of which must be periodically reevaluated to account for changing facts, circumstances, and any new market opportunities.

The IRP's future resource portfolios are developed consistent with the Commission's Resource Planning Guidelines but as explained above, do not represent planning decisions by EAL. Rather, the Company's specific resource planning actions (e.g., capacity additions) are generally subject to review and approval by the Commission. In the same respect, the IRP's assumptions regarding the cost and availability of various supply-side resources do not reflect the actual cost or ownership structure for implementing those options. They are planning assumptions, with the actual costs and structures to be determined at the time of execution. In addition, while the IRP seeks to identify EAL's capacity needs and appropriate resources to fill those needs, this approach should not be read to foreclose the identification of a future resource which may be in the public interest. Importantly, EAL is not seeking specific approvals for this IRP pursuant to the Commission's Resource Planning Guidelines.

To the extent any of the stakeholder questions are requesting information subject to the attorney client privilege, privileged information will not be provided.

Further, EAL is not providing responses to Question Nos. 1 - 6, 8-14, 16, 17,19-26, 29, 30, 33-39, 42, 44-51, 57, and 92, which were questions previously submitted by the Stakeholder Group and determined to be outside the scope of the resource planning/IRP development and analysis process set forth in the Commission's Resource Planning Guidelines. Specifically, the information requested would not change the outcome of the Aurora modeling.

Additionally, Question Nos. 18, 28, 31, 32, 43, 54, 58, 62, 65, 74, 76, 77, 81, 82, 86, 88, 93, 96, and 97 are outside the scope of the resource planning/IRP analysis process set forth in the Commission's Resource Planning Guidelines. The information requested would not change the outcome of the Aurora modeling.

Responses

7. *Will EAL have a supply shortfall in 2026? If yes, when did EAL recognize the shortfall*?

Response: EAL is projected to have sufficient capacity to cover its customers' peak load in 2026. Based on current assumptions including customer load, MISO-determined planning reserve margins, transmission loss factors and resource capacity accreditations, EAL may be short of the needed capacity credits in MISO's capacity auction construct for at least one planning season in 2026. The factors will be updated between now and then, such that EAL cannot definitively conclude that there will be a capacity credit shortage in 2026.

27. *Please identify EAL's projected transmission projects for the next five years. For each project identified, please include all cost assumptions.*

Response: Projected transmission projects are outside the scope of this proceeding. The Aurora model used for the IRP capacity expansion analysis relies on a zonal hub and spoke construct and does not include assumptions with respect to transmission constraints or future projects. EAL's approach is consistent with the RPGs, which predate EAL joining MISO (that now serves the long-term transmission planning role) and which provide that "[t]he transmission plan necessarily results from a separate planning process and is a separate plan; however, it should be integrated into the overall resource planning process, such that the analysis of generation options and demand response options can be synthesized and optimized. Transmission planning will be done by an independent entity and is regional in scope."

40. *How will EAL address the gap in load and supply in 2026 and 2027?*

Response: See EAL's response to Question No. 29 from the Second Set of Questions from the Stakeholder Group. If additional capacity credits are needed in that time frame, EAL may consider meeting that need either through a request for proposals for short-term capacity products or through the MISO capacity market.

41. *Has EAL identified any demand-side management opportunities in its 2024 IRP? If so, what are they, and how does EAL plan to implement and encourage participation? If not, why were none identified?*

Response: See EAL's response to Question No. 6 from the Second Set of Questions from the Stakeholder Group.

52. *From its initial presentation on January 30, 2024, to the updates provided on April 15, 2024, did the base case load forecast change? If yes, please explain what adjustments were made and why. Please provide all supporting workpapers with formulas intact and with sources and assumptions clearly identified.*

Response: Yes, a more updated base case load forecast replaced the forecast included in the initial presentation. The April forecast includes updated assumptions on electric load growth informed by an updated pipeline of prospective growth.

53. *Reference slide 5, "Load Forecasts – Elements and Peaks," of "2024 Integrated Resource Plan Stakeholder Updates" dated April 15, 2024. How did EAL change its High and Low load forecasts? Please provide a rationale for each of the changes in the table of load growth levers. Please provide all supporting workpapers with formulas intact and sources and assumptions clearly identified.*

Response: Due to expectations of higher load growth during the development of the IRP, the original Reference forecast became the Low forecast and adjustments were made to Reference and High load forecasts, using the levers included in the table. The levers were used as escalators to develop higher load scenarios.

55. *What assumptions did EAL make in its assessment of summer and winter capacity need for 2026-2045?*

Response: Charts were developed showing the assessment of capacity need based on the reference case load forecast and seasonal reserve margins compared to the seasonal capacity accreditation of supply resources and LMRs that are either already online or are under development.

56. *Did the AURORA model select the "planned resources" in the Assessment of Winter and Summer Capacity Need? If not, how were those resources selected? Please provide any internal memos or documents prepared on this topic.*

Response: The planned resources are resources identified in prior IRPs. Most of the resources are solar resources selected out of the 2021 and 2022 renewable RFPs. See

EAL's 2021 IRP for more information on those RFPs. The thermal resource additions are also resources identified in the 2021 IRP as well but have been advanced to meet updated timing of the capacity need. See response to Question No. 63.

59. *What specific type(s) of thermal resources is EAL planning to add in year 2029? Please explain why EAL decided to add these thermal resources in year 2029 rather than another resource option.*

Response: Based on the result of the 2021 IRP, EAL is evaluating advancing the CCCT to the 2029 timeframe. See responses to Question Nos. 53 and 56.

60. *What capital cost assumptions were used to support the capital costs provided in the April 15, 2024 update? Please provide any supporting documents including any applicable reports (e.g., S&P and Wood Mac).*

Response: Numerous external resources are used to help compile the capital cost assumptions for generation storage resources. Many of those sources are received pursuant to a paid subscription and cannot be publicly disclosed. EAL is providing the link to the publicly available NREL Annual Technology baseline, which is one of the sources used to develop the cost for renewable resources, BESS, and nuclear. Utility-Scale PV | Electricity | 2022 | ATB | NREL

61. *Please provide the capital costs assumptions that were used to support the proposed transmission costs, including the high voltage direct current transmission option. The interconnection cost assumptions provided do not include costs for any new transmission lines. Please provide assumptions for transmission line costs. Please provide any internal memos or documents prepared on this topic.*

Response: See EAL's response to Question No. 105 from the Second Set of Questions from the Stakeholder Group with respect to the high voltage direct current transmission cost assumptions and EAL's response to Question No. 27 above.

Assumptions were not compiled for the cost of transmission lines beyond the point of interconnection.

The interconnection cost of transmission lines up to the POI substation (e.g., tie line) are included on the slide titled "Transmission Interconnection Adders – Excluding Transmission Network Upgrades."

These individual estimates are approximately $1.9 million per mile at 230kV. It is assumed that the transmission line length from the collector station to the

transmission POI substation is relatively short (<1 mile) and represents an insignificant cost to the project at this stage in the planning process.

63. *Please provide a list of all the Planned Resources, including nameplate capacity, summer and winter accredited capacity, resource type, and status of each addition.*

Response:

Resource	Nameplate Capacity	Resource Type	COD
Walnut Bend	**100**	**Solar**	**2024**
West Memphis	**180**	**Solar**	**2024**
Driver	**250**	**Solar**	**2024**
Flat Fork	**200**	**Solar**	**2025**
Forgeview	**200**	**Solar**	**2025**
2022 RFP	**Target up to 1000 MW**	**Solar**	**Target 2027**
2028 CT	**428 Generic**	**Gas**	**Target 2028**
2029 CCCT	**733 Generic**	**Gas**	**Target 2029**
2030 Solar	**600 Generic**	**Solar**	**Target 2030**
2030 Battery	**350 Generic**	**Battery**	**Target 2030**

64. *Reference "2024 Integrated Resource Plan Stakeholder Updates" dated April 15, 2024. Please explain why the load forecast on slide 4 shows lower peak loads than either of the forecasts on slides 7 and 8.*

Response: Slide 4's forecast period is 2024 – 2044 and represents the non-coincident peak forecast with distribution losses added. Slides 7 & 8 represent a MISO seasonal load forecast that includes a Planning Reserve Margin (PRM) adder.

66. *What are EAL's contingency plans to meet the "Total Load Requirement" with proven technologies for the 2026-2045 period?*

Response: The preferred portfolio to be identified in the 2024 IRP will inform EAL's plan to meet its total load requirement over the planning period, although it should be noted that deviations from the preferred portfolio should be expected due to market conditions, legal requirements, or a number of other variables that could change over time (such as changes to accreditation methodologies).

67. *How is EAL currently modeling compliance with the Final Rules under Section 111 of the Clean Air Act for each of the following resource types?*
    a. *Existing coal unit*

b. *New baseload gas units (annual average capacity factors of 40 percent or greater)*

c. *New gas units with annual average capacity factors of less than 40 percent.*

Response: A future based on the reference future but including compliance with CAA 111 will be included in the analysis.

a. Coal resources will cease to use coal by end of 2030.
b. CAA future limits new build options to CCGTs with CCS.
c. All new CTs are projected to run less than an annual 40% capacity factor. Therefore, no limitations were placed on new CTs.

68. *When incorporating EAL's energy efficiency portfolio into its load forecast, is EAL's energy forecast already net of energy efficiency savings?*

Response: Yes.

69. *Is the accredited capacity for solar and wind resources an output of the Aurora model? If not, please explain which model was used.*

Response: See EAL's response to Question No. 22 from the Second Set of Questions from the Stakeholder Group.

70. *Please provide an illustrative example of how the accredited capacity for solar and wind resources will be calculated.*

Response: See EAL's response to Question No. 100 from the Second Set of Questions from the Stakeholder Group for a description of how Aurora calculates the accredited capacity for solar and wind. Also, see EAL's response to Question No. 22 from the Second Set of Questions from the Stakeholder Group. For example, if there are 20 GW of solar capacity and 40 GW of wind capacity in a given year in the simulation, Aurora will calculate the maximum 22 net load (gross load minus solar and wind output) hours for January (winter) and August (summer). Aurora will then calculate the accredited capacity for each of those hours by dividing the energy output of the solar and wind resource classes in each hour by the nameplate solar or wind capacity, and then average each of those 22 values together for the final seasonal peak credit for that resource class for that year.

71. *Please provide an estimate of the range of accredited capacity for solar and wind resources.*

Response: **The accredited capacity for solar and wind varied from 17%-46% and 22%-39%, respectively, in Summer and 2%-16% and 44%-63%, respectively, in Winter.**

72. *Has EAL completed its internal Effective Load Carrying Capacity ("ELCC") study identifying the accredited capacity of battery storage resources? If so, please identify the range of accredited capacities for battery storage tranches and provide the ELCC study. If not, when does EAL expect to complete this study?*

Response: Yes, tranches are defined for battery used in the IRP as shown below.

	Summer ELCC	Winter ELCC
Battery Tranche 0	**95%**	**43%**
Battery Tranche 1	**62%**	**25%**
Battery Tranche 2	**41%**	**18%**
Battery Tranche 3	**19%**	**11%**

73. *Please explain why EAL does not believe it is necessary to model integration costs for intermittent resources.*

Response: There are no inputs for integration costs in the modeling.

75. *Please provide a list of all EAL's planned resource retirements, including unit name, amount of capacity to be retired, and year of retirement.*

Response:

Resource	Full Unit Capacity MW	Planned Retirement or Cease to Use Coal Date
Lake Catherine 4	**522**	**Dec 2027**
White Bluff 1	**815**	**Dec 2028**
White Bluff 2	**823**	**Dec 2028**
Independence 1	**826**	**Dec 2030**

78. *Will EAL model a variant of the Business-as-Usual future? If not, please explain why not.*

Response: **Future 2A is Business-as-usual.**

79. *What was the Weighted Average Cost of Capital ("WACC") assumed by EAL in its modeling?*

Response: The WACC used in the IRP is 6.14%, which is based off of EAL's December 31, 2023 cost of capital.

80. *What are the specific options that EAL is considering to meet its winter capacity needs in 2026 and 2027?*

Response: See EAL's response to Question No. 40.

83. *How will EAL's increased industrial load impact EAL's coincident peak?*

Response: An increased industrial load would be expected to increase EAL's coincident peak based on the magnitude of the effect of the industrial load on EAL's own peak (non-coincident to MISO's peak) combined with the coincidence factor used for EAL's MISO CP.

84. *If behind the meter solar does not drive and cannot by its very nature drive load growth as stated by EAL, please explain the relevance of non-coincident peaks in system planning.*

Response: EAL and other utilities have explained in various proceedings before the APSC that behind the meter solar installations typically are intended to reduce a customer's load and cannot be relied upon for purposes of utilities' resource planning. *See* Klucher Rebuttal Testimony, Docket No. 22-061-U at 11. With respect to the relevance of non-coincident peaks, EAL's non-coincident peak ("NCP") is developed first and then a coincident factor that accounts for the relationship to MISO's coincident peak ("CP") is applied to the NCP to estimate MISO CP load used in resource planning.

85. *How are MISO's changes to the eligibility rules for Load Modifying Resources (LMR) incongruent with EAL's Optional Interruptible Service Rider ("OISR")?*

Response: See the following links eLibrary | File List (ferc.gov) and 20231107-08 RASC Item 11aii LMR Accreditation (RASC-2019-9)630751.pdf (misoenergy.org). As a result of MISO's changes to the eligibility rules for LMRs and the resulting incongruence with OISR (e.g. required number of interruptions per season) , EAL was not able to register OISR as a capacity resource and receive auction revenues for the entire 2024 year.

87. *Why did EAL not develop sensitivity cases for capital cost projections of non-renewable resources?*

Response: EAL has received stakeholder comments in prior IRPs suggesting that there were concerns that renewable cost assumptions were high; therefore, EAL included renewable and BESS cost scenarios to proactively address the previous stakeholder feedback.

As has been well publicized, there has been price volatility around the cost of renewable resources with recent supply chain disruptions including AD/CVD,

UFLPA, and other market impacts that do not similarly affect thermal resources. Accordingly, EAL developed sensitivity cases for renewable resources to incorporate the risk around renewable resource pricing into its capacity expansion modeling.

89. *Please provide workpapers demonstrating how the $141/MWh for Southwest Power Pool wind and the $58/MWh for MISO South On-shore Wind were derived, with formulas intact and sources and assumptions clearly identified.*

Response: Cost assumptions for the IRP were updated to reflect the latest information available. The LCOE for Onshore, Offsystem wind is now approximately $107/MWh, while the LCOE for MISO South Onshore Wind is approximately $72/MWh. See the workpapers titled "Offsystem Wind" and "Onshore Wind" for the calculations.

90. In addition to the information on interconnection adders previously provided, please provide details on any costs incurred for transmission lines.

Response: See EAL's response to Question No. 89 from the Second Set of Questions from the Stakeholder Group.

91. *Please provide all assumptions used to forecast EAL's total load requirement in developing its Assessment of Capacity Need.*

Response: The Total Load Requirement is calculated as: Total Load Requirement = EAL Peak Load Coincident to MISO + Planning Reserve Margin. See EAL's response to Question No. 20 from the Second Set of Questions from the Stakeholder Group for reserve margin. See slides 4 and 5 of Supplementary Data Posting date April 15, 2024 for peak loads.

94. Does EAL's modeling include the option for endogenous retirement of any resources in AURORA? If yes, please explain which resources have this option. If no, please explain why not.

Response: See EAL's response to Question No. 24 from the Second Set of Questions from the Stakeholder Group.

95. Please describe any license renewal activities with the U.S. Nuclear Regulatory Commission pertaining to the Grand Gulf nuclear plant.

Response: See EAL's response to Question No. 68 from the Second Set of Questions from the Stakeholder Group.