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August 16, 2024

RE: SWEPCO – AR IRP – Response to Initial Stakeholder Comments

Dear Stakeholders:

Please find enclosed SWEPCO's written responses to the questions it received on June 27, 2024 and July 3, 2024. The requests were provided to SWEPCO without specific stakeholder attribution. As such, SWEPCO provides these responses to the broad group identified during its First Stakeholder Meeting. These written responses do not contain any Confidential or Highly Sensitive Protected Information.

Sincerely,

Chris Martel
Regulatory Consultant

cc: Sarah Tacker

SWEPCO 2024 IRP

Initial Stakeholder Committee Modeling Requests, Questions, and Data Requests

Modeling Requests:

Modeling Request 1: Environmental Compliance Modeling: On April 25, 2024, the U.S. Environmental Protection Agency (EPA) announced final carbon pollution standards for existing coal-fired and new gas-fired plants under Section 111(d) of the Clean Air Act.[1] **Please model the final EPA carbon pollution standards for existing coal-fired and new gas-fired power plants under section 111(d) of the Clean Air Act as one of the scenarios for the 2024 IRP.** Slide 24 of SWEPCO's 2024 IRP Stakeholder Meeting presentation indicates that SWEPCO will model the EPA's 111d rule changes based on the *proposed* rule published May 11, 2023 (rather than the final rule).[2] During the Stakeholder Meeting, SWEPCO stated that "In terms of environmental regulations for the base, the high and the low, we have all of the environmental regulations up to but not including the recent EPA greenhouse gas rules for 111(d)... So what we're proposing for this IRP is that we actually use the EPA proposed guidelines for the 111 D rule changes, which were published in May 11 2023." While it may be reasonable to also model the proposed EPA rule as one of the scenarios for the IRP, the final EPA rule should also be modeled as a scenario, including the final carbon pollution standards for existing coal-fired and new gas-fired power plants that were issued on April 25, 2024.

SWEPCO Response to Modeling Request 1: Use of the proposed rules in the Scenario analysis served to provide some insight to the potential for a strict control on existing gas units although the EPA removed this part of the rule in the final rule. Additionally, although the proposed rules used for the Scenario analysis included constraints on existing coal and new gas units that were altered, the requirements in the final rule were still in general alignment with coal units being forced to make significant decisions in a very short amount of time and new gas units having strict emissions limits imposed. Given also that the final rule intentionally delayed establishing standards on existing gas resources, the scenario analysis is reasonable for use in this IRP as specified in Slide 10. The Company will be modeling the EER Case which will impose the final EPA rules as inputs in the candidate portfolio analysis.

[1] FACT SHEET CARBON POLLUTION STANDARDS FOR FOSSIL FUEL-FIRED POWER PLANTS FINAL RULE STATE PLANS.

[2] swepco.com/lib/docs/community/projects/SWEPCO2024IRPStakeholderMeeting_June6.pdf.

<u>Modeling Request 2</u>: Coal Replacement Generation Modeling: Side 25 indicates that "Under all scenarios, coal is replaced primarily by NG/Hydrogen Blend units.

a. Please model replacing generation coal plants, including Welsh Units 1 and 3 and Flint Creek, with renewable alternatives, including solar plus storage and wind plus storage, and incorporating the 10% Energy Community Bonus tax credit.

b. **Please model replacing coal units with projects that would be eligible for Energy Infrastructure Reinvestment Financing** pursuant to the Title 17 Clean Energy Financing Program created by the Inflation Reduction At, under which the U.S. Department of Energy guarantees loans to "projects that retool, repower, repurpose, or replace energy infrastructure that has ceased operations or that enable operating energy infrastructure to avoid, reduce, utilize, or sequester air pollutants or anthropogenic emissions of greenhouse gases."[3]

SWEPCO Response to Modeling Request 2: To clarify, the question appears to assume SWEPCO manually selected a technology type to replace coal units in the regional analysis. The NG/Hydrogen Blend units were economically selected by the model rather than manually selected. Slide 25 references results from the broader regional analysis (SPP Market Scenario, see Slide 10) performed to assess potential resource mix changes and associated energy and capacity prices in the SPP market. This broader analysis included announced retirements within the region. The regional analysis is a broad, economic selection of resources under market commodity prices and loads.

SWEPCO Response to Modeling Request 2.a: SWEPCO declines to model the scenario requested in item 2.a. Specifically designating only renewable alternatives for replacement of retiring generation units undermines the purposes of the IRP as stated in the APSC's RPGs. Modeling on incremental needs is required to include "*all reasonably useful and economic supply and demand resources that may be available to a utility or its customers*" (see Guideline 4.3, emphasis added) rather than designating only specific technologies for selection.

With regard to the request to incorporate the 10% Energy Community Bonus (ECB) into modeling assumptions, SWEPCO also declines to model any scenarios with that input. Site-specific factors, such as applicability of the ECB, are not included in the Company's IRP analysis and are not appropriate for the IRP analysis. Site-specific factors are considered by the Company during resource selection processes such as Requests for Proposals and by its regulators and customers during regulatory approval processes for the acquisition or construction of new resources. Importantly, the IRP is designed to yield a "portfolio of

[3] ENERGY INFRASTRUCTURE REINVESTMENT | Department of Energy.

resources" to guide the selection of new resources rather than identify specific facilities or resource locations to meet incremental needs.

SWEPCO Response to Modeling Request 2.b: This question is outside the scope of this IRP and would be overly speculative on the potential success for assuming special financing approvals from the federal government. Project specific considerations such as eligibility for bonus tax credits are considered during the subsequent RFP bid selection process.

Modeling Request 3: **Tax Credit Bonus Modeling: For resource cost adjustments (Slide 34), please model all wind and solar technologies to include at least a 10% bonus credit for either the energy community bonus[4] or domestic content bonus credit.[5]** Based on guidance provided by the IRS, it is reasonable to assume that wind and solar technologies located in SWEPCO's Arkansas territory will qualify for at least the energy community bonus credit, if not both the energy community bonus and domestic content bonus. Likewise, it is not reasonable to assume that no wind and solar projects will qualify for either bonus tax credit.

SWEPCO Response to Modeling Request 3: As discussed in the Company's response to Modeling Request 2.a., the Company does not model any type of location-specific resource. Site-specific factors are considered by the Company during resource selection processes such as Requests for Proposals and by its regulators and customers during regulatory approval processes for the acquisition or construction of new resources. Importantly, the IRP is designed to yield a "portfolio of resources" to guide the selection of new resources rather than identify specific facilities or resource locations to meet incremental needs. Modeling assumptions that bid responses to an RFP would meet the additional ten percent tax credit available would be overly speculative. In the Company's experience, based on a large sample of renewable RFP responses in SPP since the IRA was enacted, the vast majority of projects that could actually be available to SWEPCO in central SPP are either not located in energy communities, or the developers are not willing to make binding commitments to the level of domestic content needed to allow the project to receive either or both of these credits.

To the extent project developers bid projects into future RFPs with binding commitments that the projects will qualify for these adders, the higher tax credits will be factored into the evaluation of a project's economics.

[4] Energy Community Tax Credit Bonus - Energy Communities.

[5] IRS provides initial guidance for the domestic content bonus credit | Internal Revenue Service.

<u>Modeling Request 4</u>: Modeling and Planning appropriate solutions to resolve the load pocket and reliability issues in Northwest Arkansas:

On June 10, 2011, the Commission found that "it is reasonable to predict that implementation of a major transmission alternative(s) to serve the Northwest Arkansas load pocket could take up to seven years" and directed that "SWEPCO and AECC will continue to work with SPP to conduct an appropriate solutions study to timely address reliability issues in the Northwest Arkansas load pocket."[6] It has now been more than 13 years and SWEPCO has not implemented appropriate transmission solutions to timely address reliability issues in the Northwest Arkansas load pocket. **Please model appropriate solutions, including transmission investments/upgrades, to resolve the load pocket and reliability issues in Northwest Arkansas**, including the following:

- Transmission Solutions:
    a. Planning transmission for a large profile of wind resources that will be serving the region from Oklahoma and Texas,
    b. Planning transmission for increased adoption of utility scale solar.

SWEPCO Response to Modeling Request 4, Transmission Solutions:

This request assumes a number of factors that are not accurate. First, no reliability issues are present in SWEPCO's northwest Arkansas (NWA) territory. The transmission system in NWA meets all reliability standards set by the SPP and the North American Electric Reliability Corporation (NERC).

Second, the Commission's RPGs specifically identify transmission planning as a process separate from the IRP process, conducted by an independent entity, which in this case is SPP, and regional in scope. (*See* Guideline 4.7). As such, SWEPCO declines to model the transmission investments stated in item 4 in the IRP.

SWEPCO is timely addressing all the needs of its NWA customers through its participation in SPP's Integrated Transmission Planning (ITP) process, which is an annual planning cycle that assesses near- and long-term economic and reliability transmission needs. Needs identified through the ITP process have already been addressed or are being addressed currently by SPP. SPP works with its members to determine the transmission infrastructure needed in the near-term and long-term planning horizon to maintain compliance with applicable transmission planning reliability criteria, meet public policy mandates and provide economic benefits.

SWEPCO relies on the SPP Transmission Expansion Plan (STEP) which is a compilation of SPP-directed projects based on studies performed by SPP to determine upgrades needed to

[6] APSC Docket No. 12-008-U, Order No. 14 at 37, 39 12-008-u_227_1.pdf (arkansas.gov).

maintain reliability, provide transmission service, provide for generation interconnections, and provide economic benefit to its members into the future.

Rather than looking at the needs of just one load serving entity (LSE), SPP assesses needs from a larger, regional perspective and determines necessary new transmission infrastructure that would provide the most net benefits to the region.

As a key component of SPP's STEP-based studies, the ITP process assesses near and long term economic and reliability transmission needs. The set of transmission system upgrade projects included in the ITP project portfolio, approved annually by the SPP Board of Directors, are aimed at mitigating these issues. A potential transmission solution might be needed after the Flint Creek plant retires. For purposes of this IRP, the plant will continue operation until its commissioned-approved depreciable life, which is 2038. The long-term planning at the SPP looks out 10 years. Therefore, the studies for any Flint Creek retirement impacts will not begin until 2028 in accordance with SPP's regional process.

To the extent that Stakeholders wish to participate in SPP's regional planning processes, SWEPCO directs them to https://www.spp.org/engineering/transmission-planning/integrated-transmission-planning/.

- Generation Solutions: Model the following generation addition scenarios as options to resolve the load pocket and reliability issues in NWA:
    a. Renewable generation:
        i. Located within the NWA load pocket
        ii. Located outside the load pocket but within SWEPCO's territory
    b. Gas generation:
        i. Located within the NWA load pocket
        ii. Located outside the NWA load pocket but within SWEPCO's territory

SWEPCO Response to Modeling Request 4, Generation Solutions: The IRP does not include analysis of location-specific resources. Instead, the IRP provides broad insight into economic resources for SWEPCO customers and the Company's obligations to SPP. Further, the Commission's RPGs require that resources meet existing reliability criteria (see Guideline 4.4) and as discussed in the Company's response above, no reliability issues are present in the NWA area. As such, SWEPCO declines to model the requested analysis.

- Solutions that include ceasing to burn coal Flint Creek prior 2038, including, converting Flint Creek to gas and/or renewables.

SWEPCO Response to Modeling Request 4, Conversion of Flint Creek: For this IRP, the Company will model the Enhanced Environmental Regulations (EER) Case where the new EPA 111d rules will be imposed on resources modeled. This will include alternatives for the Flint Creek plant to comply with the final rule.

- Solutions that include continuing to burn coal at Flint Creek until 2038, as indicated in APSC Docket No. 22-044-U.

SWEPCO Response to Modeling Request 4, Flint Creek through 2038: For this IRP, the Flint Creek base assumption is that it will remain in operation until its retirement in 2038. This will be consistent in all cases except when the EPA 111d rule is imposed in the EER Case where the Flint Creek plant will be modeled with additional alternatives to comply with the EPA rule.

Modeling Request 5: Transmission Modeling and Planning:

Please model updates to transmission plans that will be required in light of the recent FERC Order No. 1920 regarding regional transmission planning, including the following:

a. The requirement that transmission providers incorporate factors including "utility and corporate commitments… affecting resource mix and demand"?[7] For instance, please model the transmission upgrades necessary for "adding nearly 14,000 MW of regulated wind and solar through 2033" pursuant to AEP's clean energy strategy.[8] **Please model transmission upgrades that incorporate AEP's clean energy strategy and corporate clean energy commitments from the following specific SWEPCO customers**:

- City of Fayetteville;[9]
- Walmart;[10] and
- University of Arkansas.[11]

b. FERC Order No. 1920 requires transmission providers to consider commercially available alternative transmission technologies (i.e., grid enhancing technologies), such as dynamic line ratings, advanced power flow control devices, advanced conductors, and transmission switching. These technologies must be evaluated in both regional and long-term transmission planning process. **Please model incorporating grid enhancing technologies into SWEPCO's 2024.**

SWEPCO Response to Modeling Request 5: Please see SWEPCO's Response to Modeling Request 4, Transmission Solutions above. Please also see Guideline 4.7. Transmission Modeling is outside the scope of the IRP.

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[7] E1 | RM21-17-000 | Federal Energy Regulatory Commission (ferc.gov).

[8] AEP's Clean Energy Future.

[9] Energy Action Plan | Fayetteville, AR - Official Website (Energy Supply goals include: "Achieve 100% local government clean energy by 2030; Achieve 50% community clean energy by 2030; and Achieve 100% community-wide clean energy by 2050.")

[10] Powering an Emissions Free Future for Walmart and Our Communities ("By the end of 2030, our aim is to advance our transition as a society toward emissions free energy by enabling up to 10 gigawatts of new clean energy projects into service on- and off-site – the equivalent of the annual power consumption of more than 2 million households.").

[11] University of Arkansas Climate Action Plan – v2.0 ("achieve climate neutrality by 2040.")

Modeling Request 6: **Demand Response/Demand Side Management Modeling:** In Docket No. 09-090-U, the Commission is considering whether to remove the state "opt-out" and allow retail customers and aggregators of retail customers to directly sell demand response into wholesale markets (i.e., MISO and SPP) without having to use utility tariff programs, pursuant to the Regulation of Demand Response Act (Ark. Code Ann. § 23-18-1001 et. seq). Please model a scenario where the Commission determines that the marketing, selling, or marketing and selling of demand response into wholesale electricity markets by aggregators of retail customers or by retail customers is in the public interest pursuant to Ark. Code Ann. § 23-18-1004, and thus allows customers more opportunities to participate in demand response. Please included updates to "Baseline Assumptions – New Resources" on Slide 31, including to identify which new "Peaking" resources would not be necessary if customers were permitted and incentivized to reduce demand in periods of peak demand by having the ability to participate in wholesale markets.

SWEPCO Response to Modeling Request 6: SWEPCO cannot incorporate third party demand response aggregations in its resource planning or rely on enrollments in these programs. Essentially, while a carrot exists for these activities, an appropriate stick does not yet exist to ensure compliance in a way that allows a planning utility to rely on the commitments. Absent sufficient penalties for non-performance in the SPP, there is no way to ensure that the load will actually be curtailed. Moreover, customers can terminate participation in the market on very short notice—leaving insufficient time to procure additional capacity to serve the load. With SWEPCO's obligation to serve and ultimate responsibility to provide service to customers participating in demand response programs, SWEPCO must consider this load when modeling its system peak.

Questions:

- **Questions regarding specific slides from the June 6th presentation:**

Question 1. Slide 11: Slide 11 states that SWEPCO will "[c]ontinue to evaluate and/or conduct Request for Proposals (RFP) to explore opportunities to add cost effective renewable generation in the near future to take advantage of the Federal Tax Credit" as part of its "Five Year Action Plan form the 2021 IRP." Is SWEPCO planning to issue any new RFPs or other competitive procurement processes to procure generation for its 2024 RFP, in addition to the ongoing RFPs that are already underway. Please explain the expected timeframe of future RFPs.

SWEPCO Response to Question 1: The Company is currently conducting an RFP which was issued in 2024. The information is available at: https://www.swepco.com/business/b2b/energy-rfps/2024-Energy-RFP..

At this time, an additional RFP is not currently planned.

Question 2. Slide 19: What factors specifically are being incorporated into forecasted load growth or decline for residential, commercial and industrial classes other than projected EV adoption? Please include correlated assumptions for each. (IE: Data centers are projected to increase industrial usage by 5%.) If data centers specifically were not included in this forecast, then why not?

SWEPCO Response to Question 2: There are a number of factors incorporated into the load forecast, including but not limited to economic, demographic, energy prices, and changes in end-use efficiencies and appliance saturations. They all contribute to differing degrees across the customer classes. Generally speaking as it pertains to Arkansas, the expected economic growth in Northwest Arkansas will lead to growth across classes. Meanwhile, projected efficiency gains in commercial lighting will offset and limit some of the growth in the commercial class, for example.

In regard to data centers, they are included as they are captured in the historical data. SWEPCO only has a few data centers online to date, and they are very small operations at that. SWEPCO works closely with our customer service engineers to include potential new data centers in the forecast once they have a signed Letter of Agreement (LOA) or Electric Service Agreement (ESA). Currently, there are no prospective data center customers who meet these criteria.

Question 3. Slide 22 indicates that SWEPCO projects Solar distributed generation (DG) saturation to double between 2023-2030, projecting that 1.4% of customers will have installed DG by 2023, compared with 1.4% in 2030.

a. How did SWEPCO model the 2023 changes to Arkansas net-metering law, including the Arkansas Public Service Commission ("APSC" or "Commission") rule changes in Docket No. 20-021-R,[12] when making this projection? For instance, given that the net-metering rate structure for DG solar will be considerably less favorable for customers who do not obtain "Legacy Status" by 2024, including by submitting a Standard Intersection Agreement before September 30, 2024, why does SWEPCO project that DG solar will double in years where customers installing new DG solar will only be able to obtain an avoided cost compensation rate for exported energy?

SWEPCO Response to Question 3.a: SWEPCO did not explicitly include the net-metering rule change impact in this IRP due to limited data around its impact at the time this forecast was completed. SWEPCO is actively monitoring its solar interconnection data to assess its impact and to account for it in future updates. The Company's forecast is driven through the Company's econometric analysis and is based on total company data. Additionally, SWEPCO has continued to receive distributed generation applications in its other jurisdictions, even after rule changes similar to those imposed in Arkansas.

b. Does SWEPCO plan to offer any new programs or incentives to encourage customers to install DG solar following the sunsetting of net-metering in Arkansas, such as tariff programs that compensate exports during hours of peak demand? For example, is SWEPCO considering demand-side management opportunities such as the 2024 Duke Energy PowerPair Incentive program, which is available to residential customers who install new solar panels and a battery storage system and was designed to test how distributed solar and battery storage helps stabilize North Carolina's power grid while reducing the need for peak power plant capacity? The program allows Duke to have control over the battery storage device of customers who are not served under time of use rates, thereby allowing the electric utility to reduce its capacity needs during peak hours. Please explain the costs and benefits of implementing a similar program in Arkansas compared with supply side alternatives.

SWEPCO Response to Question 3.b: SWEPCO intends to re-propose a Time-of-Use tariff and Electric Vehicle Tariff in its next base rate case which is anticipated to be filed in the first quarter of 2025. In order to minimize cost shifting, participation in some tariffs may be limited for customers who net meter. SWEPCO does not intend to offer a program similar to the Duke program in the near future. SWEPCO has robust participation in its interruptible tariffs and

[12] APSC Docket No. 23-021-R, Order No. 7 (adopting changes to the Commission's Net-Metering Rules pursuant to Act 278 of 2023).

net metering programs in Arkansas at this time and does not see the need for additional incentives for DG customers beyond its current offerings. In response to the Commission's questions regarding Aggregation of Retail Customers in Docket No. 09-090-U, SWEPCO discussed a program utilized by its sister company, Indiana and Michigan Power, which could expand access to demand response markets but through a mechanism which enables the incumbent utility to have visibility into customer plans as well as appropriate compliance monitoring and accountability. The I&M program has three demand response offerings where the utility serves as a market participant and interfaces between its customer or a customers' aggregator, and the regional transmission organization (RTO) under a third-party tariff approved by the Company's retail regulator. The third-party aggregator (TPA) acts on behalf of end-use retail customers it has aggregated and contracted with. I&M then registers these DR resources with the applicable RTO and passes through proceeds from the RTO to the TPA who in turn would pass on those proceeds to the retail customer(s) whose loads comprise the DR resource(s) and who reduce their load(s) in response to a signal from the RTO. This approach ensures that a utility like SWEPCO and a regulatory commission like the APSC have the necessary insight into the TPA's operations and can navigate or mitigate impacts to reliability and resource planning related to the demand response. Penalties for non-performance could be incorporated into the utility tariff separate from the RTO's operations, further holding participants accountable for demand response commitments and protecting non-participating customers.

Question 4. Slide 24: During the Stakeholder Meeting on June 6, SWEPCO stated the following: "In terms of environmental regulations for the base, the high and the low, we have all of the environmental regulations up to but not including the recent EPA greenhouse gas rules for 111(d). The fourth scenario does cover that and that's the enhanced environmental regulation scenario." Slide 24 indicates that SWEPCO will model the EPA's 111d rule changes based on the *proposed* rule published May 11, 2023, rather than the final rule (i.e., not including final carbon pollution standards for existing coal-fired and new gas-fired power plants that were issued on April 25, 2024).[13]

a. Please clarify which version of Section 111(d) of the Clean Air Act will be modeled for the enhanced environmental regulation scenario. If SWEPCO is not planning to model the final rule, please explain why an effective law should not be modeled as one of the scenarios?

SWEPCO Response to Question 4a: The Company will include the final Section 111(d) rules published on May 9, 2024 to model the EER Case.

b. Please clarify which environmental regulations, including which version of Section 111(d), will be modeled for the other three scenarios (i.e., Base, High, and Low).

SWEPCO Response to Question 4.b: The Base, High and Low Candidate Portfolios shown on Slide 38 of the Stakeholder Presentation will exclude restrictions on plants included in the final EPA 111d rules.

[13] https://www.epa.gov/system/files/documents/2024-04/cps-111-fact-sheet-state-plans-2024.pdf.

Question 5. Slide 25 ("SPP Supply Mix Changes") indicates that "Under all scenarios, coal is replaced primarily by NG/Hydrogen Blend units."

a. Is SWEPCO considering and modeling other reasonable alternatives to replace coal, including (but not limited to) solar or wind plus storage? Please explain why or why not. Consider Section 2 of the Resource Planning Guidelines[14] and Order No. 6 in Docket No. 20-019-U, wherein the APSC provided the following regulatory guidance:

"[T]he Commission clarifies that it nonetheless encourages the use of an RFP or other reasonable method for evaluating resource options that compares SWEPCO's resource planning decisions to all reasonable alternatives."[15]

SWEPCO's Response to Question 5.a: Slide 25 of the Stakeholder presentation is referring to the SPP Market Scenario (broader regional analysis) and not to the company-specific candidate portfolios and sensitivities. The change in the mix of resources in the Company's regional analysis is based on announced retirements in the SPP region and an additional broad analysis for economic selection of resources under different market conditions.

Notwithstanding, for this IRP, the Company is planning to model the candidate portfolios and additional alternative portfolio sensitivities shown on slides 38 and 39 of the Stakeholder presentation. The IRP assumes the announced retirement dates for its existing resources and planned new resources as part of the going in position. The Company is modeling all portfolios to allow economic selection of a broad and diverse set of resources shown on slide 31 of the presentation to meet the Company's forecasted demand and capacity obligations.

b. If SWEPCO is not considering and modeling other reasonable alternatives to replace coal, including (but not limited to) solar or wind plus storage, please explain how this is consistent with Section 2 of the Resource Planning Guidelines, which requires consideration of "all reasonable resources to for meeting the demand for a utility's product, including those which focus on traditional supply sources and those which focus on conservation and the management of demand."[16]

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[14] resource_plan_guid_for_elec_06-028-R_1-7-07.pdf (arkansas.gov) ("Resource planning is a utility planning process which requires consideration of all reasonable resources for meeting the demand for a utility's product, including those which focus on traditional supply sources and those which focus on conservation and the management of demand.")

[15] APSC Docket No. 22-019-U, Order No. 6 at 6 (Doc. # 124). 22-019-U_124_1.pdf (arkansas.gov).

[16] resource_plan_guid_for_elec_06-028-R_1-7-07.pdf (arkansas.gov).

SWEPCO's Response to Question 5.b: Please see the Company's response to Question 5.a.

Question 6. Slide 31: What assumptions were made when determining the costs for new resources on slide 31? Please provide more details regarding how the assumptions (e.g., Installed Cost in $/kW) were determined.

SWEPCO Response to Question 6: Costs for new resources were informed by the responses SWEPCO received to its recent RFPs in the SPP region.

Question 7. Slide 34: Slide 34 indicates that SWEPCO will model IRA Production Tax credits at 100% until 2034.

a. Is SWEPCO also modeling the bonus tax credits that are available under the IRA, including the 10% energy community bonus[17] and/or domestic content bonus?[18] Please explain.

SWEPCO Response to Question 7.a: Please see the Company's response to the Modeling Request 3above.

b. What is SWEPCO approach to the "energy community" adder to the PTC (or ITC)? Currently, much of Arkansas is considered an "energy community" by the federal government under the employment-related prong.[19] As those areas may change over time, would SWEPCO consider using an approach that accounts for this uncertainty by assuming, for example, 60% of the "energy community" adder? This is the approach Duke Energy Indiana is taking.[20] For storage, shouldn't SWEPCO assume the "energy community" adder applies because it could site storage at any retiring coal facilities, such as Welsh Units 1 and 3?

SWEPCO Response to Question 7.b: Please see the Company's response to Modeling Request 3 and Question 7.a above.

[17] Energy Community Tax Credit Bonus - Energy Communities.

[18] IRS provides initial guidance for the domestic content bonus credit | Internal Revenue Service.

[19] IRA Energy Community Tax Credit Bonus (doe.gov).

[20] *See* Meeting #1, Duke slide 44. Indiana Integrated Resource Plan - Duke Energy (duke-energy.com).

Question 8. Slide 35: Please explain how SWEPCO determined the "Technology Propose Modeling Limits" on Slide 35? For instance, why are batteries and utility-scale solar photovoltaic tier 1 and 2 technologies limited to a block size of 50 MW rather than a higher block size?

SWEPCO Response to Question 8: The reference to a 50MW block size might be a misunderstanding of the information presented on Slide 35. The 50MW block size referenced in the question above is only a modeling parameter to allow a smaller addition of the resource up to the annual limits imposed in the modeling. By allowing a smaller block size, the model has the opportunity to select resources that better align to the capacity needs. The proposed annual limits included in the modeling are shown on slide 35 under the Annual Limit column.

· **Additional Questions:**

Question 9. Is SWEPCO using Aurora for modeling? If not, please clarify which modeling tool is being used for the IRP models.

SWEPCO Response to Question 9: For this IRP, the Company is using Plexos to model candidate portfolios and sensitivities.

Question 10. What steps is SWEPCO taking to incorporate the interconnection reforms adopted in Federal Energy Regulatory Commission (FERC) Order No. 2023 into its resource planning process and modeling?

SWEPCO Response to Question 10: The requirements for FERC Order 2023 fall upon RTOs and not retail utilities such as SWEPCO. In the case of FERC Order 2023, many of the requirements, such as a cluster study process, are already part of the SPP's generator interconnection procedures. While there will be some indirect impact to SWEPCO, the exact nature of the compliance changes is still to be determined and, as with any change to the SPP practices, SWEPCO will respond accordingly as they are implemented by the SPP.

Question 11. Is SWEPCO considering expanding its green tariff options? If so, what types of programs has it considered?

SWEPCO Response to Question 11: In APSC Docket No. 24-032-TF, SWEPCO has proposed an expanded version of its existing REC tariff program with additional subscription offerings which would include a long-term option offering a 10-year subscription term as well as an option for Federal Government Agencies' participation.

Question 12. How is SWEPCO factoring the increased adoption of electric vehicles and heat pumps (i.e., "beneficial electrification") into its load growth projections, particularly considering the incentives offered by federal policies such as the energy efficient home improvement credit?

SWEPCO Response to Question 11: SWEPCO uses Itron's Statistically Adjusted End-Use (SAE) framework for load forecasts, which explicitly takes into account current heat pump saturations and any potential growth from federal incentives.

Regarding electric vehicles, SWEPCO independently forecasts their adoption through econometric models. If the underlying load forecast models do not adequately capture their impact, SWEPCO then will make adjustments to the forecast to ensure their impact is captured.

Question 13. Are the costs for additional transmission associated with additional generating resources included in the model when determining the most cost-effective resource plan?

SWEPCO Response to Question 13: The Company is including additional transmission cost considerations as shown on Slide 34 of the Stakeholder presentation in the selection of economic resources in this IRP. Specifically, these include estimated Transmission Network Upgrades and Interconnection costs and a proxy for congestion and hedging costs for renewable resources.

Question 14. To what extent is SWEPCO updating (or considering updating) its transmission plans in light of the recent FERC Order No. 1920 regarding regional transmission planning, including the requirement that transmission providers incorporate factors including "utility and corporate commitments… affecting resource mix and demand"? For instance, how is SWEPCO planning transmission to accommodate the renewable generation necessary to meet its corporate clean and renewable energy goals, including AEP's goals of "Growing our renewable generation portfolio to approximately 50% of our total capacity by 2033", "Adding nearly 14,000 megawatts of regulated wind and solar through 2033", and "achieving net zero carbon dioxide emissions by 2045, with an interim goal to cut emissions 80% from 2005 levels by 2030"?[21]

SWEPCO Response to Question 14: Please see the Company's Response to Modeling Request 4, Transmission Planning. Please also see Guideline 4.7. Transmission planning is outside the scope of the IRP.

[21] AEP's Clean Energy Future.

Question 15. If the Louisiana Public Service Commission adopts its Staff's Final Phase 1 Report with Final Recommendations and Proposed Rules in Docket No. R-35462, the rulemaking to research and evaluate customer-centered options for all electric customer classes as well as other regulatory environments, does SWEPCO expect to provide similar customer-centered options in Arkansas? For instance, is SWEPCO considering offering a "Wholesale Pass-Through Sleeved PPA" option to its Arkansas customers? Please explain.

SWEPCO Response to Question 15: No, SWEPCO is not considering offering a Wholesale Pass-Through Sleeved PPA in Arkansas.

Question 16. Has SWEPCO estimated the cost of building a transmission solution that would resolve the 'load pocket' if Flint Creek were to retire? If so, produce such cost estimate(s).

SWEPCO Response to Question 16: Please see the Company's Response to Modeling Request 4, Transmission Planning.

Notwithstanding, the Rebuttal Testimony of Jeffrey L. Ellis filed January 13, 2022 on behalf of SWEPCO in APSC Docket No. 21-070-U addresses concerns raised by Staff witness John Athas about transmission that may be needed upon Flint Creek's retirement. The testimony is available at https://apps.apsc.arkansas.gov/pdf/21/21-070-U_183_1.pdf, beginning p. 25. The estimated cost for this proxy transmission solution was estimated to be approximately $205 million.

Question 17. Why is SWEPCO not modeling the final Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants that were published in April 2024, and instead is modeling the proposed rule in this IRP?

SWEPCO Response to Question 17: For the Company's EER Scenario, the proposed rules were modeled to reflect some impact for existing natural gas resources. The final EPA rules specifically retracted the proposed rules on existing natural gas units and also specifically did not replace them with any updated rules. The Company will include the final EPA rules in its EER Candidate Portfolio analysis.

Question 18. Does the Flint Creek site currently have gas pipeline service? If not, does SWEPCO have an estimate of the cost of bringing gas pipeline service to the Flint Creek site? If yes, produce such estimate.

SWEPCO Response to Question 18: The Flint Creek site does not currently have gas pipeline service. To supply natural gas service to the plant, SWEPCO would conduct an RFP to secure an interconnection to a pipeline and firm natural gas transportation capacity. The expectation is a gas company would provide a contract rate that would include the embedded cost for construction to build a gas pipeline to the plant and the associated gas reservation fee. The Company has a proxy estimate for this that will be used in the EER case.

Question 19. Does the Turk site currently have gas pipeline service? If not, does SWEPCO have an estimate of the cost of bringing gas pipeline service to the Turk site? If yes, produce such estimate.

SWEPCO Response to Question 19: Yes, there is currently gas pipeline service to the Turk plant.

Question 20. Has SWEPCO estimated the capital cost of converting Flint Creek to exclusively burn gas, including the cost of pipeline service? If so, provide such cost estimate.

SWEPCO Response to Question 20: The Company has developed estimates for this and will include these costs in the analysis as part of the EER Case.

Question 21. Has SWEPCO estimated the capital cost of converting Flint Creek to 40% natural gas co-firing, including the cost of pipeline service? If so, provide such cost estimate.

SWEPCO Response to Question 21: The Company has developed estimates for this and will include these costs in the analysis as part of the EER Case.

Question 22. Has SWEPCO estimated the capital cost of installing Carbon Capture and Sequestration with 90% capture for Flint Creek, including pipeline/injection equipment? If so, provide such cost estimate.

SWEPCO Response to Question 22: The Company has developed estimates for this and will include these costs in the analysis as part of the EER Case.

Question 23. Has SWEPCO estimated the capital cost of converting Turk to exclusively burn gas, including the cost of pipeline service? If so, provide such cost estimate.

SWEPCO Response to Question 23: The Company has developed estimates for this and will include these costs in the analysis as part of the EER Case.

Question 24. Has SWEPCO estimated the capital cost of converting Turk to 40% natural gas co-firing, including the cost of pipeline service? If so, provide such cost estimate.

SWEPCO Response to Question 24: The Company has developed estimates for this and will include these costs in the analysis as part of the EER Case.

Question 25. Has SWEPCO estimated the capital cost of installing Carbon Capture and Sequestration with 90% capture for Turk, including pipeline/injection equipment? If so, provide such cost estimate.

SWEPCO Response to Question 25: The Company has developed estimates for this and will include these costs in the analysis as part of the EER Case.

Question 26. How does SWEPCO plan to handle increased interconnection volume and comply with FERC Order 2023 reforms to generator interconnection agreements and procedures?

SWEPCO Response to Question 26: The requirements for FERC Order 2023 fall upon the RTO, not SWEPCO. In the case of FERC Order 2023, many of the requirements, such as a cluster study process, are already part of the SPP's generator interconnection procedures. While there will be some indirect impact to SWEPCO, the exact nature of the compliance changes is still to be determined and, as with any change to the SPP practices, SWEPCO will respond accordingly as they are implemented.

Question 27. FERC Order No. 1920 introduces significant changes to transmission planning for utilities in the United States.[22] How does SWEPCO plan to meet these new requirements including but not limited to:

- Long-term regional transmission planning - Transmission providers must engage in long-term regional transmission planning with a minimum 20-year horizon with updates at least every five years and must provide at least three plausible and diverse scenarios to anticipate future transmission needs, including consideration of the following seven factors:
    - Federal, state, Tribal, and local laws and regulations affecting the resource mix and demand. For example, a state Clean Energy Standard mandating 100% clean energy by 2050.
    - Federal, state, Tribal, and local laws and regulations affecting decarbonization and electrification.
    - State-approved Integrated Resource Plans (IRPs) and expected supply obligations for Load-Serving Entities (LSEs)
    - Trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources, and building and transportation electrification technologies. (For example, the Inflation Reduction Act's impact on clean energy costs, higher natural gas prices, etc.)
    - Resource retirements such as legislatively mandated closures or economic retirements driven by regulations. FERC allows each region to decide how to treat retirements.
    - Generator interconnection requests and withdrawals.
    - Utility and corporate commitments and federal, state, Tribal, and local policy goals.
- Coordination with generator interconnection - Transmission providers must coordinate the regional transmission planning process with the generator interconnection process
- Consideration of alternative transmission technologies (i.e., grid enhancing technologies) - Transmission planners are required to consider commercially available alternative transmission technologies, such as dynamic line ratings,

[22] E1 | RM21-17-000 | Federal Energy Regulatory Commission (ferc.gov); *See also* ferc_order_1920_factsheet_updated.pdf (rmi.org)

advanced power flow control devices, advanced conductors, and transmission switching. These technologies must be evaluated in both regional and long-term transmission planning process.

- Cost allocation - Transmission providers must propose specific cost allocation methods and allow a state engagement period.
- Enhanced transparency and stakeholder engagement - The order mandates greater transparency in local transmission planning processes, including public notice and stakeholder engagement. This includes regional "right-sizing" of local projects to meet long-term needs.
- Right-sizing - Transmission providers must identify opportunities to modify in-kind replacement of existing transmission facilities to increase their transfer capability, known as "right-sizing".

SWEPCO Response to Question 27: Please see the Company's Response above to Modeling Request 4, Transmission Planning. Please also see Guideline 4.7.

Data Requests:

Data Request 1. Please provide capital expenditure (CapEx) and performance assumptions for all the generations for each year in the models.

SWEPCO Response to DR 1: Overnight CapEx for each of the resources are illustrated on Slide 33 of the Stakeholder presentation. Tables of the annual overnight capital expenditures and key operating performance assumptions for resources modeled will be provided with the IRP.

Data Request 2. Please provide the retirement (or cease to burn) dates and quantities assumed in this IRP for SWEPCO generation resources on a unit-by-unit basis. Additionally, when should replacement plans begin? Please identify any "Baseline Assumptions - New Resources" on Slide 31 that are part of SWEPCO plans to replace capacity and energy from coal units, as well as any additional plans that are not included on Slide 31, including both plans which focus on traditional supply sources and those which focus on conservation and the management of demand pursuant to Section 2 of the Commission's Resource Planning Guidelines. For replacement resources and programs, please identify the dates that SWEPCO plans to file applications with the APSC (e.g., CECPN and CCN) and the anticipated in-service dates following APSC approval.

SWEPCO Response to DR 2: The Company will include announced retirement dates for existing resources as part of the IRP. The Company is unable to respond to the remainder of this particular question as it presumes replacement resources are already identified. The IRP serves to inform the Company of these specific questions based on the planned retirement dates of its current resources.

Data Request 3. Please provide the assumed capacity values for all generation technologies for all seasons modeled in this IRP.

SWEPCO Response to DR 3: The Company will include the nameplate MW ratings for all resources modeled and the associated annual accredited capacity assumptions for each resource type in this IRP.

Data Request 4. Identify SWEPCO's transmission projects due to load growth in the past five years and the projected transmission projects for the next five years. Include all cost assumptions.

SWEPCO Response to DR 4: Please see the Company's Response to Modeling Request 4, Transmission Planning.

For the purposes of this response, AEP interprets "transmission projects due to load growth" as projects categorized internally as "Customer (Load)" or "RTO-Mandated" projects in the SWEPCO region. Please see Table 4-1, below for actual expenditures on projects fitting these categories between 2019 – 2023. Please see Table 4-2, below for annual forecasted spending on these types of projects between 2024 – 2028.

MAJOR CATEGORY	2019	2020	2021	2022	2023
Customer (Load)	$12,454,393	$9,105,386	$9,121,135	$5,955,752	$7,994,624
RTO-Mandated	$2,902,136	$0	$151,637	$505,014	$5,603,740
GRAND TOTAL	**$15,356,529**	**$9,105,386**	**$9,272,773**	**$6,460,766**	**$13,598,364**

Table 4-1: Actual Expenditures by Year

MAJOR CATEGORY	2024	2025	2026	2027	2028
Customer (Load)	$32,471,335	$17,371,358	$12,548,950	$2,285,791	$0
RTO-Mandated	$13,145,004	$12,776,580	$1,799,528	$10,130,553	$9,846,893
GRAND TOTAL	$45,616,340	$30,147,938	$14,348,477	$12,416,344	$9,846,893

Table 4-2: Forecasted Spend by Year

Data Request 5. What federal funding from programs within IRA and IIJA is SWEPCO considering and/or pursuing? What is SWEPCO's view of the opportunities these provide? How are these funds being built into consumer affordability modeling?

SWEPCO Response to DR 5: The future potential impact of both pieces of legislation on a retail public utility cannot be ascertained with enough specificity to gauge any projected revenue requirement or resulting rates. Specifically, while the legislation supplies options for tax incentives, funding, and programs, the process by which to obtain or procure such with certainty for a utility such as SWEPCO requires complex analysis, application processes, award criteria, and passage of time. SWEPCO continues to diligently evaluate opportunities for customers afforded by both the IRA and the IIJA.

SWEPCO, through American Electric Power Company Service Corporation (AEPSC), employs a federal grants team which reviewed the recent grant legislation for opportunities that may be available to utilities. The grants team then coordinates with SWEPCO to identify programs which are available that may also align with customers' current needs. As a result of this process, SWEPCO has been diligently engaged in seeking opportunities. In January, it submitted a concept paper to the State Infrastructure Office for consideration in the State's application for Grid Innovation Program funds. That concept paper did not proceed to DOE's Application phase. More recently, the Company filed two applications to the State's Grid Enhancement Grant Subaward Program being administered by the Arkansas Department of Finance and Administration (DFA). Those application are currently under review.

For the IRP, no assumptions were made on the potential success for obtaining approvals of federal loans or specific locational tax credit opportunities.

Data Request 6. Please provide any memoranda and/or analysis supporting SWEPCO's decision regarding whether or not to model the current EPA GHG Rules for Section 111(d) of the Clean Air Act.

SWEPCO Response to DR 6: Please see the Company's Response to Question 17 above.

Data Request 7. Please provide any memoranda and/or analysis supporting SWEPCO's decision regarding whether or not to model bonus tax credits that are available under the IRA, including energy community and domestic content bonus credits.

SWEPCO Response to DR 7: Please see the Company's Response to Modeling Requests 2.a and 3 above.

Submitted to SWEPCO via email on July 3.

Additional Request 1: As an additional request, I would like to request (on behalf of SREA) that SWEPCO model at least 6 different scenarios, based on the reasoning provided in Duke's IRP. For example, on page 16 (Table 3.1) of the Duke Kentucky IRP, Duke indicates that they are modeling 6 different scenarios, with two policy scenarios (with or without EPA Section 111 update) being applied to 3 different fuel forecasts (base, low, and high). By contrast SWEPCO's 2024 IRP Stakeholder Meeting slides indicate that SWEPCO only proposes to model 4 scenarios (per slide 23), with the "enhanced environmental regulation" scenario only being applied to the "base" gas price scenario, rather than each of the base, low, and high gas price scenarios.

First, I note that Duke's modeling supports the Stakeholder Committee's previous request that EPA's Clean Air Act Section 111 April 2024 update be modeled as a scenario, and likewise indicates on page 8 that Duke's "Preferred Portfolio is developed under a scenario that includes the EPA CAA Section 111 Update."

Second, SREA particularly believes that it is appropriate to model the EPA Section 111 April 2024 update (i.e., "enhanced environmental regulation scenario") in combination with a high fuel forecast scenario, as Duke does in its IRP as one of the 6 scenarios on pages 18-19 (See Duke Scenario #2 and Figures 3.5-3.6). In support of this, Duke states the following (on page 62): "Should the EPA CAA Section 111 Update remain in place and the EPA successfully implements rules on existing natural gas generation, impacts to PJM market prices could be significant." We believe Duke's conclusion regarding PJM market prices would also be applicable to SPP market prices, and thus it is appropriate for SWEPCO to model the EPA Section 111 update with a high fuel price scenario (rather than just with the base gas price scenario).

SWEPCO Response: The Company declines to model the requested scenarios. Although the Scenario analysis was performed under the proposed 111(d) rule, the final 111(d) rule did not address all the feedback EPA received to the proposed rules. The impact in the near term to the SPP Market prices from the Company's analysis indicates, as shown on slide 27 of the Stakeholder Presentation, a delay in the SPP market prices until the mid-2040s at which time, market prices are forecasted to escalate to the Company's high forecast.

For this IRP, the Company intends to model potential impacts of the 111(d) rule and evaluate these results relative to a future where the rule was not in effect. The results of the Company's analysis is expected to be informative for a directional insight into the impacts the rule may have on SWEPCO's resources to meet its obligations and the associated affordability to its ratepayers. These results will inform the Company when it identifies a Preferred Plan.

Additionally, Duke's IRP indicates that "The combination of the EPA CAA Section 111 Update and high fuel prices drives several significant changes...Renewable generation benefits from the high fuel prices, particularly solar...Solar provides the most energy of all available resources starting in the 2030's." Thus, we have concerns that it would be unfair to our members, who develop renewable generation, including solar, wind, and batteries, if SWEPCO were to not model the combination of the EPA CAA Section 111 Update and high fuel prices as one of the scenarios for SWEPCO's 2024 IRP.

SWEPCO Response: Although Duke's analysis in PJM suggests that the high fuel prices would support the addition of more solar, there are several distinctly different factors that make an inference between the markets and the benefits of renewable resources (as noted, Solar primarily) inconsistent. Some of these include the recent move by SPP to plan for a seasonal capacity obligation construct where solar resources have a very low (less than 10%) accredited capacity to support the Company's SPP planning reserve margin (PRM) capacity obligations. Additionally, SPP is implementing, beginning in 2026, a winter PRM of 36% with an expectation that this will grow to above 40%. Another distinct difference between Duke and SWEPCO is that PJM has a capacity market while SPP does not. The Company's analysis will include an optimization of economic resource selection based on the seasonal accredited capacities of resources and the associated Accredited Capacity PRM (ACAP PRM).