Appendix G - Stakeholder Committee Report

Stakeholder Committee Report on
Entergy Arkansas 2024 Integrated Resource Plan

Arkansas Advanced Energy Association, Inc.

Arkansas Electric Energy Consumers, Inc.

Sierra Club

Southern Renewable Energy Association

University of Arkansas System

October 23, 2024

TABLE OF CONTENTS

Stakeholder Committee Report on

Entergy Arkansas 2024 Integrated Resource Plan

The undersigned stakeholders participating in the 2024 Entergy Arkansas, LLC ("EAL" or "Entergy" or the "Company") Integrated Resource Plan ("IRP") appreciate the opportunity to provide this Stakeholder Committee Report for filing with the IRP submittal pursuant to Section 4.8 of the Arkansas Public Service Commission ("Commission") *Resource Planning Guidelines for Electric Utilities* ("Resource Planning Guidelines"). We have attended two stakeholder meetings and reviewed EAL's presentations on its IRP via WebEx in January and August, 2024, and have reviewed EAL's responses to many (but not all) of the questions that were asked by stakeholders. The following Stakeholder Committee Report provides recommendations for how EAL may improve this IRP, consistent with the objectives set forth in Section 4.1 of the Commission's Resource Planning Guidelines.[1]

I. Resource Modeling Recommendations

A. Entergy should not use unreasonably high costs and low capacity accreditations for modeling new renewable resources.

i. Entergy's clean energy input costs are substantially higher than costs used by other utilities and leading industry sources.

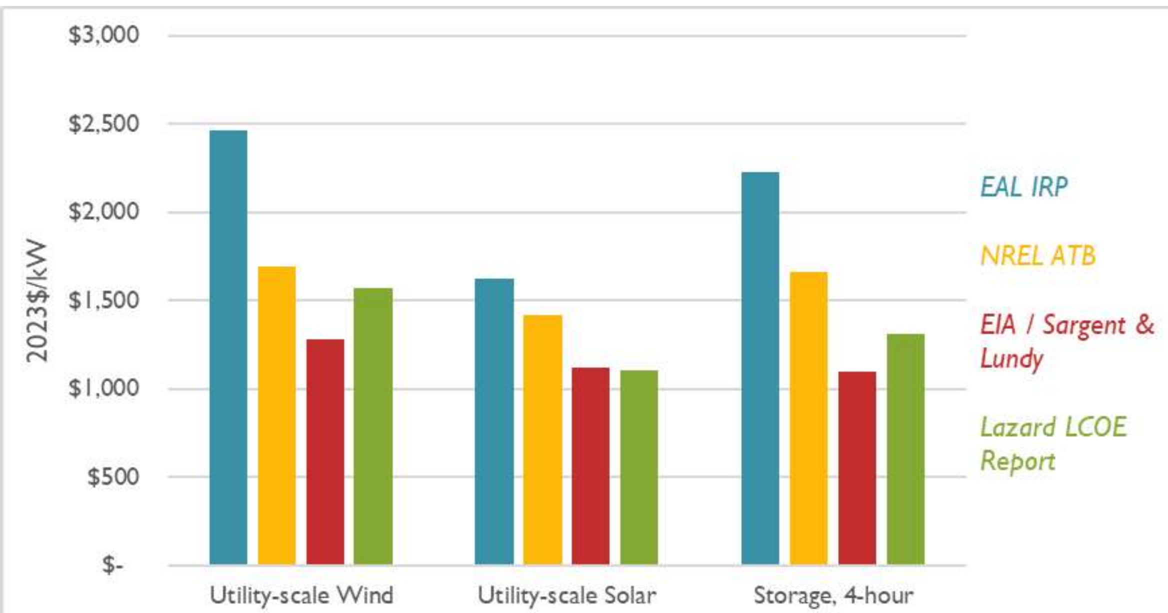
The input data provided by Entergy for the IRP shows capital cost estimates for new solar, wind, and storage resources that are substantially higher than expected both now and going forward. The Company's estimated costs are higher than other utility cost data and higher than leading industry cost data and projections, including from the National Renewable Energy Lab ("NREL"), the United States Energy Information Administration ("EIA"), and Lazard's Levelized Cost of Energy Report (Lazard). Entergy's capital cost values artificially inflate the costs of clean

[1] Resource Planning Guidelines, Section 4.1 ("The objectives of the Resource Plan include, but are not limited to, low cost, adequate and reliable mew services; economic efficiency; financial integrity of the utility; comparable consideration of demand and supply resources; mitigation of risks, consideration of demand impacts; and consistency with governmental regulations and policies.")

energy resources and are likely driving the minimal renewable deployment seen in Entergy's IRP portfolios, as further discussed herein, particularly compared to the much larger expansion of new gas generators that EAL is planning in its "preferred portfolio."[2]

In Figure 1 below, we compare the initial (2027) capital costs of solar photovoltaic (solar PV), wind, and battery energy storage system ("BESS") resources that Entergy uses to projections from NREL, EIA, and Lazard. On average, Entergy's cost estimates are 65 percent higher than NREL, EIA, and Lazard for wind, 36 percent higher for solar PV, and 69 percent higher for BESS.

Figure 1: 2027 capital costs of solar, wind, and BESS for Entergy compared to other industry sources[3]

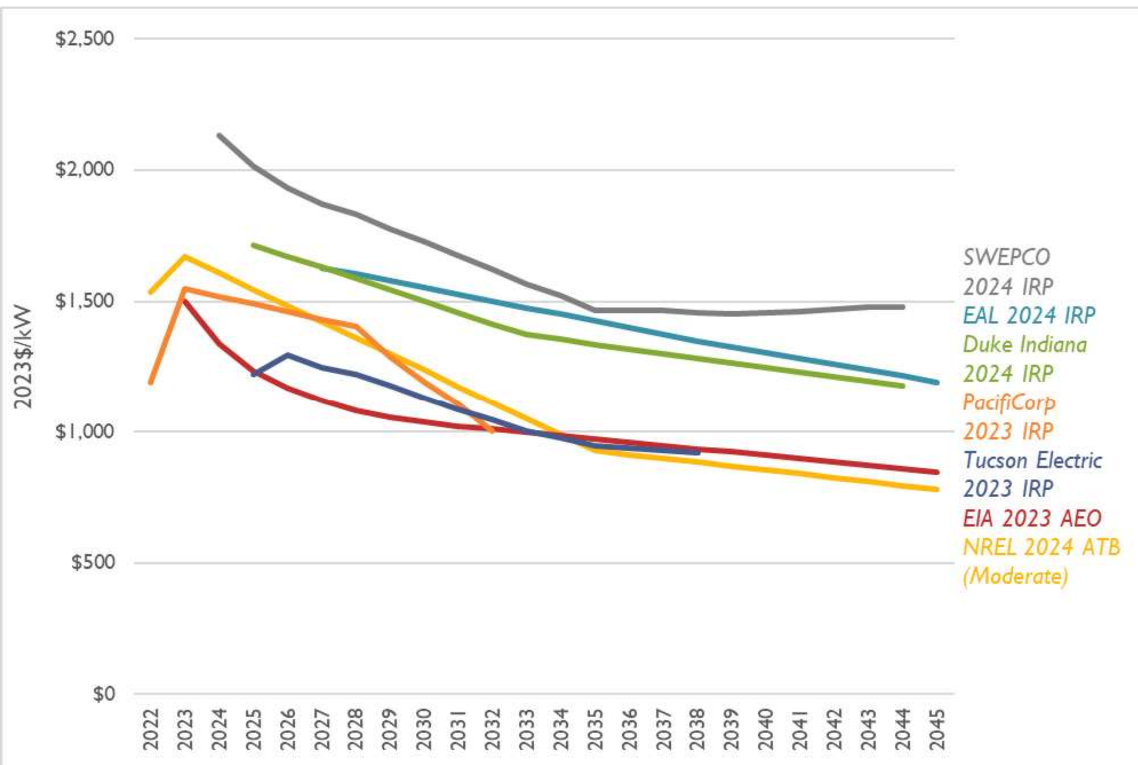


[2] *See Entergy Arkansas 2024 Integrated Resource Plan Stakeholder Meeting #2*, August 15, 2024, Slide 58, Preferred resource plan (showing EAL's plans to add 733 MW of gas in 2030, 400 MW of solar in 2033, 428 MW of gas in 2034, etc.).

[3] *Entergy Arkansas 2024 Integrated Resource Plan Stakeholder Meeting #2*, August 15, 2024; NREL ATB 2024; EIA Capital Cost and Performance Characteristics for Utility-Scale Electric Generating Power Technologies, January 2024; Lazard LCOE 2024.

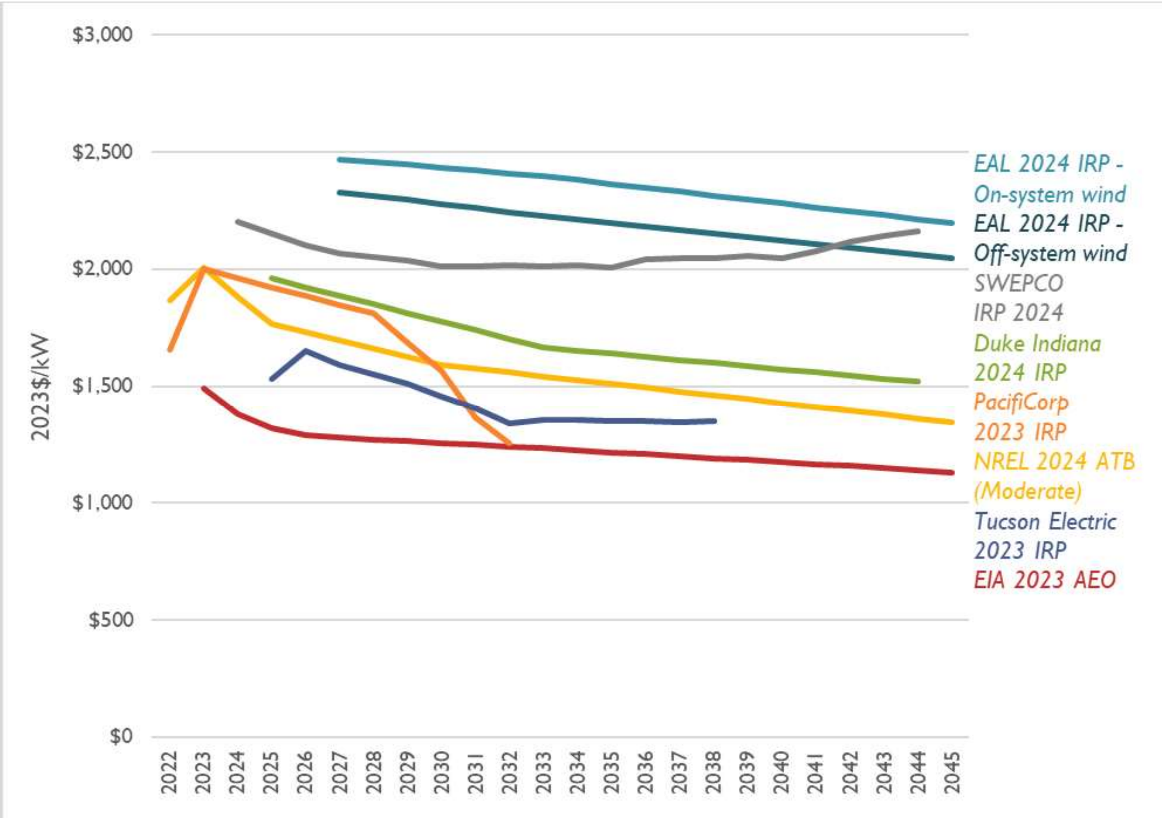
In Figure 2, Figure 3, and Figure 4 below, we compare Entergy's long-term cost estimates (now through 2045) for these same technologies to other industry forecasts. Entergy does assume that costs will decline over time due to technology maturation, but it uses the conservative learning curve assumptions from NREL's Annual Technology Baseline ("ATB").[4] Unless there is a clear justification for a slower rate of learning in Entergy's service area, it would be more reasonable for Entergy to use the ATB's moderate assumptions for planning purposes. Both because of the conservative learning curve and because its cost assumptions start above other sources we reviewed, Entergy's costs remain substantially higher than industry standard projections and other utility projections for the entire study period. Entergy's forecasts for solar PV, wind, and BESS are the highest, or among the highest, of all utilities we reviewed.

Figure 2: Solar cost trajectories for Entergy compared to other utilities and industry sources[5]



[4] *Entergy Response to Question 4, Set 5.*
[5] *Entergy Response to Question 4, Set 5*; NREL ATB 2024; EIA Capital Cost and Performance Characteristics for Utility-Scale Electric Generating Power Technologies, January 2024, adjusted using trajectory from EIA Annual

Figure 3: Wind cost trajectories for Entergy compared to other utilities and industry sources[6]

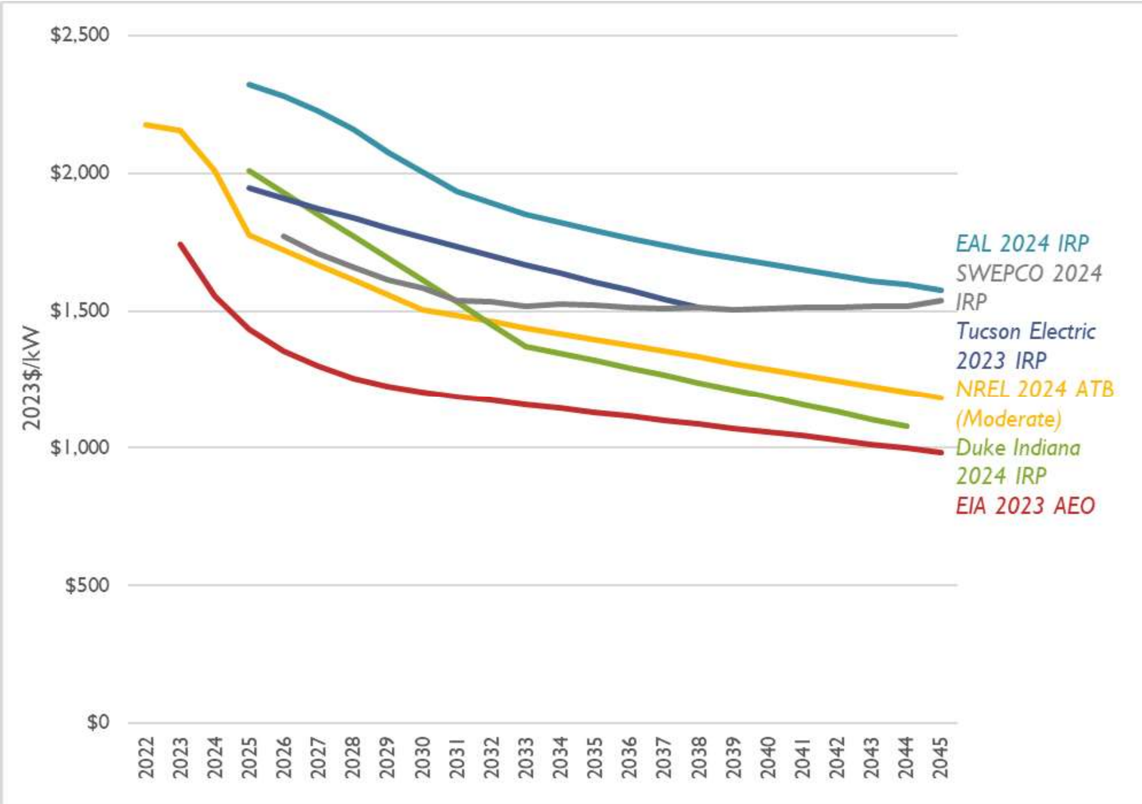


Notes: On-system wind refers to wind resources located in MISO South. Off-system wind refers to wind resources located in the Southest Power Pool (SPP).

Energy Outlook 2023; Lazard LCOE 2024; SWEPCO 2024 IRP; TEP 2023 IRP; PacifiCorp's 2023 IRP; Duke Energy Indiana IRP Stakeholder Meeting 2, April 29, 2024.

[6] *Entergy Response to Question 4, Set 5*; NREL ATB 2024; EIA Capital Cost and Performance Characteristics for Utility-Scale Electric Generating Power Technologies, January 2024, adjusted using trajectory from EIA Annual Energy Outlook 2023; Lazard LCOE 2024; SWEPCO 2024 IRP; TEP 2023 IRP; PacifiCorp's 2023 IRP; Duke Energy Indiana IRP Stakeholder Meeting 2, April 29, 2024.

Figure 4: BESS cost trajectories for Entergy compared to other utilities and industry sources[7]



ii. Entergy's capacity accreditation of batteries is unrealistically low.

Entergy is using declining effective load carrying capability ("ELCC") metrics to credit the capacity for each tranche of BESS and is using noticeably lower ELCCs in the winter than in the summer as shown in the table below.[8]

Table 1: Battery Energy Storage ELCC by tranche[9]

Tranche	Tranche size (GW)	Summer ELCC	Winter ELCC
Tranche 0	0–6 GW	95%	43%
Tranche 1	6–13 GW	62%	25%

[7] *Entergy Response to Question 4, Set 5*; NREL ATB 2024; EIA Capital Cost and Performance Characteristics for Utility-Scale Electric Generating Power Technologies, January 2024, adjusted using trajectory from EIA Annual Energy Outlook 2023; Lazard LCOE 2024; SWEPCO 2024 IRP; TEP 2023 IRP; PacifiCorp's 2023 IRP; Duke Energy Indiana IRP Stakeholder Meeting 2, April 29, 2024.
[8] Entergy Arkansas response to Stakeholder question 72.
[9] *Source: Entergy Arkansas response to Stakeholder question 72, Set 3; Entergy Arkansas response to Stakeholder question 10b, Set 5.*

Tranche 2	13–20 GW	41%	18%
Tranche 3	20+ GW	19%	11%

These results are concerning, as many of the assumptions behind the results were not provided to stakeholders. The ELCCs were calculated in an external study conducted by Astrapé based on 2022 data and published in September 2023. The study evaluated the ELCCs for BESS, solar PV, and wind. For BESS, Entergy reported that ELCCs decline quickly after Tranche 0, which covers the first 6 GW. There are several aspects of Entergy's use of the ELCC study (and assumptions) that are concerning:[10]

1. The numbers that Entergy provided in the table below were not directly cited in the Astrapé report, so it is unclear exactly what scenario / model result they represent.
2. The workbook that went along with the report was not provided to stakeholders.
3. The ELCCs, especially for winter, are substantially lower than what Astrapé has calculated in other regions and there is no explanation for why.
4. The base modeling includes no solar or wind on the system.
5. The tranche sizes are unnecessarily large and result in artificially low average ELCCs for the first several GW of BESS.[11]

To expand on several of the points above, Entergy's model seems to be crediting BESS with lower ELCCs than is justified. Astrapé has conducted ELCC studies for numerous other utilities. The study it conducted for Duke Energy Progress ("DEP") and Duke Energy Carolinas ("DEC")[12], for example, found much higher winter ELCCs for 4-hour BESS than Entergy has reported. While it is reasonable to expect variations across different regions, Entergy provided no explanation for the very low winter ELCC it used. Astrapé's study also found that average ELCC for BESS alone were lower than when they included the synergistic value from adding solar PV (i.e., the reliability benefits from having solar added available with storage). Specifically:

- DEP winter ELCCs for 450 MW - 4,800 MW BESS

[10] We are not questioning the accuracy of Astrape's ELCC study results, but rather the scope of the study, the input assumptions, and how Entergy is using and presenting the results.
[11] Astrape ELCC study, Figure 25.
[12] Duke Energy Carolinas and Duke Energy Progress Effective Load Carrying Capability (ELCC) Study, Prepared for Duke Energy by Astrape. 4/25/2022 at 10-11.

  - Without solar: 100% - 55.3%[13]
  - With solar: 100% - 64.5%
- DEC winter ELCCs for 300 MW - 3,200 MW BESS
  - Without solar: 99.5% - 73.5%
  - With solar 99.9% - 88.6%

The ELCC study assumed 0 MW of BESS, solar, and wind as the base assumption for the study year of 2028.[14] This means that the BESS ELCC values Entergy is using are based on modeling that assumes no solar and no wind on the system. Further, it assumes BESS is only used to arbitrage market energy or fossil generation. It also means Entergy is calculating an ELCC for the 2028 grid and applying it to the entire study period. As a result, Entergy is undercounting the likely capacity value that BESS can provide as the grid transitions in the future and more solar PV and wind is deployed. Based on the study from DEP and DEC's systems, we would expect to see higher ELCCs with solar and wind deployed alongside BESS on the system.

Additionally, by making the tranches so large and relying on average ELCCs for the entire tranche, Entergy is undervaluing the capacity from the first several GW of BESS added. If the model was deploying a large quantity of BESS, this would eventually balance out with the second part of the tranche (that will be over-valued). But critically, if the BESS is credited too low initially to be selected by the model at all then you will never get to the second part of the tranche. This is seen in Future 1 (the low load scenario) and Future 2A (the reference scenario without the U.S. Environmental Protection Agency's Greenhouse Gas Standards and Guidelines for Fossil Flue-Fired Power Plants promulgated under Section 111 of the Clean Air Act ("111 Rule")),[15] where

---

[13] These values correspond to the range of battery capacities shown in the bullet above. The first 450 MW of battery storage on the system have an ELCC of 100 percent. By the time there is 4,800 MW of battery storage on the system, the average capacity value declines to 55.3 percent.
[14] Resource adequacy and Effective Load Carry Capability (ELCC) Study, Prepared for Entergy by Astrape, September 26, 2023 at 10 and 14.
[15] 89 Fed. Red. 39,798 (May 9, 2024); *See also* Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants | US EPA

zero BESS is built. The model does add BESS in the reference scenario with 111 (2 GW) and the high load scenario (26 GW).

iii. **As a result of renewable cost and accreditation assumptions, Entergy's modeling assumptions do not match reality in MISO.**

Entergy's MISO market build results for many of its scenarios do not match what we would expect based on the resources currently in the MISO queue and resource plans developed by other MISO utilities. Specifically, in portfolio 2A, Entergy adds over 100 GW of new gas across MISO during the study period, 40 GW of solar, 11 GW of wind, and zero MW of BESS, hybrid or otherwise (Table 2). Looking at the MISO interconnection queue, there is over 160 GW of solar and over 110 GW of BESS, hybrid or stand-alone that is active in the queue.

Table 2. Comparison of MISO interconnection queue and Entergy MISO capacity expansion results[16]

Resource	Total capacity added in Portfolio 2A 2024-2045 (MW)	Total active capacity in MISO interconnection queue (MW)	Active capacity in queue with study (MW)
2x1 CCCT	92,273	15,005	3,982
CT	8,556		
Solar	40,000	163,688	68,217
Battery Storage	0	60,590	23,723
Battery Hybrid	0	53,713	26,383
Wind	11,600	40,436	16,140

While it is likely that some of the resources in the queue will not materialize, it's unrealistic to assume that *no* storage will be built and significantly less solar than is already past the study phase of the interconnection queue will be built over the entire study period. It's concerning that Entergy did not attempt to calibrate its reference scenarios against what is actively known about resource additions and the interconnection queue in MISO. The Entergy-specific modeling is

[16] Sources: MISO. "Interactive Queue." Accessed September 12, 2024. Available at: https://www.misoenergy.org/planning/resource-utilization/GI_Queue/gi-interactive-queue/ and 2024 Integrated Resource Plan Stakeholder meeting #2, August 15, 2024 at 28.

similarly skewed against renewables and in favor of gas resources. In the Refence Scenarios, Entergy modeled zero MW of BESS (hybrid or otherwise) over the entire study period, 700 MW of solar, 600 MW of wind, and over 5 GW of new gas. To connect these findings to the ELCC discussion above, the lack of BESS across MISO or the Entergy system is likely driven in part by the low BESS ELCCs that Entergy modeled.

iv. Entergy arbitrarily failed to model the "energy community" 10% adder that is available to it under the Inflation Reduction Act. Entergy's modeling therefore may overstate the costs of new clean energy projects.

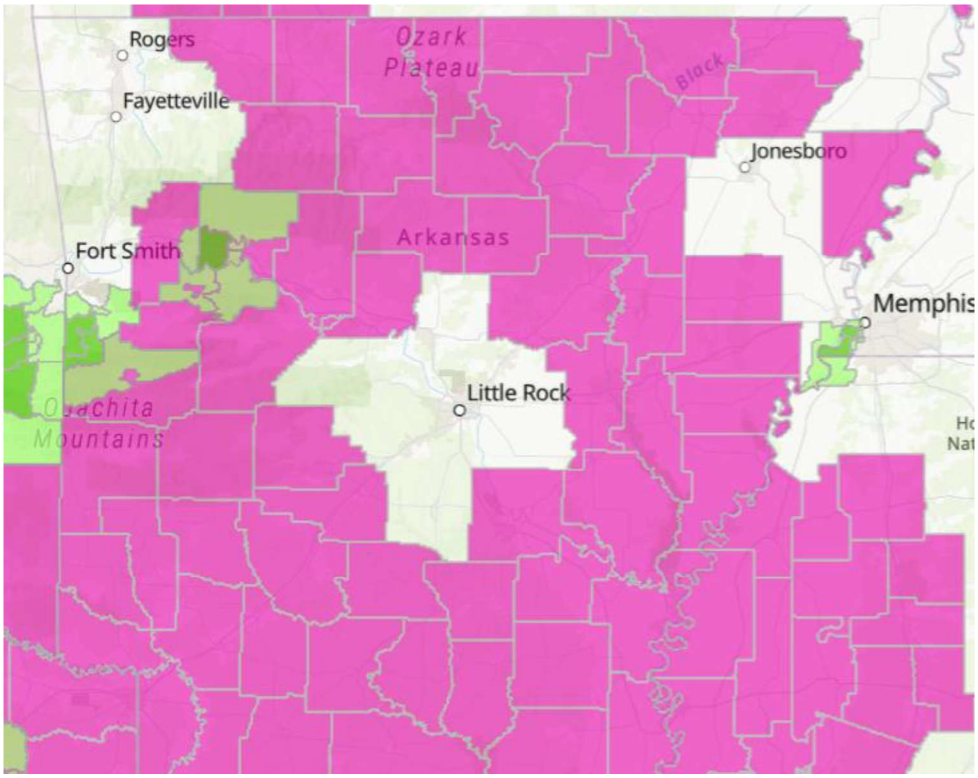
Under the Inflation Reduction Act, solar, battery, and wind projects that are located in an "energy community," as defined under the Act, are entitled to a 10% increase in the value of the production or investment tax credit (each project developer may elect either the PTC or ITC but not both). In the modeling for this 2024 IRP, Entergy Arkansas has refused to include this 10% adder, which means that its modeling likely overstates the cost of new clean energy investments. Entergy's stated reason for not including the "energy community" adder in its 2024 IRP modeling—that the location of solar, battery, wind projects is unknown[17]—is unreasonable given the circumstances.

First, nearly all of Entergy Arkansas's service area is currently considered by the IRS to be an "energy community" under the IRS. In other words, a randomly sited solar project in Arkansas would have a high probability of being located in an "energy community." But, in addition, there

[17] EAL 2024 IRP Q&A No. 36 ("Q. 36. [] How is EAL modeling the energy community bonus production tax credit in its planning assumptions? A. 36. EAL is not incorporating the energy community adder into the quantitative analysis given that the site locations are not known and qualification for this credit cannot be determined with certainty until a new generation unit is placed in service; as such, this adder is not part of the IRP modeling. See https://www.irs.gov/creditsdeductions/frequently-asked-questions-for-energy-communities#losestatus.")

is no reason to expect developers to randomly site solar project when they know that a project located in an "energy community" is 10% cheaper for a utility purchaser.

Figure 1, Map of "Energy Communities" in Arkansas as of Oct. 2024[18]



Second, when Entergy retires the first White Bluff coal-burning unit, the census tract in which White Bluff is located and all adjoining census tracts, will become "energy communities" under the Act. The same creation of an "energy community" will occur when the first Independence coal-burning unit is retired. A battery project or solar-battery hybrid project located at White Bluff or Independence (or in any adjoining census tracts) would qualify for a 10% increase in the value of tax credits. Because these coal plant sites would likely be a suitable location for a new battery storage project, Entergy's ability to take advantage of the adder for batteries is likely within its own control.

---

[18] U.S. Internal Revenue Service Energy Community Bonus Tax Credit map, available at: https://arcgis.netl.doe.gov/portal/apps/experiencebuilder/experience/?id=a2ce47d4721a477a8701bd0e08495e1d.

Simply put, Entergy is wrong to exclude the 10% "energy community" adder from its modeling in this IRP, when it is likely that such increase in the tax credits will be available for Arkansas-located solar projects, and it is even more likely that that such credit increase would be available for a storage project located at the site of its own retired coal units, a siting decision that is within Entergy's control. Entergy should be required to update its modeling to include consideration of these tax credits.

v. Entergy Arkansas should consider applying for a US DOE Energy Infrastructure Reinvestment program loan to reduce the cost to customers of retiring coal units and/or building new clean energy projects.

Entergy should update its IRP to include consideration of the U.S. Department of Energy Infrastructure Reinvestment ("EIR") Loan Program to lower the cost of replacing its retiring coal units. To incentivize replacement of fossil fuel infrastructure with clean energy investments, U.S. DOE's Loan Programs Office ("LPO") has been allocated $250 billion in loan guarantee authority to fund "projects that retool, repower, repurpose, or replace energy infrastructure that has ceased operations"[19] for conditional project commitments through September 30, 2026. LPO's guidance on EIR eligibility illustrates several hypothetically-qualifying projects such as the replacement of retired coal and gas-fired power plants with renewable energy sources and storage, including environmental remediation efforts for on-site coal ash ponds as eligible activities.[20] Under the EIR, utilities such as Entergy Arkansas can receive loan guarantees at much lower interest rates than the utility's rate of return on the coal plant,[21] which can cover up to 80% of projects costs, with many

---

[19] Inflation Reduction Act, Section 1706(a)1-2.
[20] Department of Energy, Loan Programs Office, "Program Guidance for Title 17 Clean Energy Financing Program" at 28-30, (May 19, 2023), *available at:* https://www.energy.gov/lpo/articles/program-guidance-title-17-clean-energy-program#page=1.
[21] Christian Fong et al., "The Most Important Clean Energy Policy You've Never Heard About," Rocky Mountain Institute, (Sept. 13, 2023), *available at:* https://rmi.org/important-clean-energy-policy-youve-never-heard-about/.

applicants receiving loans to cover 50-70% of project costs.[22] Given that Entergy is already planning to retire coal units, it should take advantage of this opportunity for low-interest and relatively low-risk refinancing, which could lower the costs of retiring and replacing the units with clean energy sources. It would be a missed opportunity for Entergy to forgo applying to the EIR program to reduce costs.

B. Entergy's only near-term resource addition is hard-coded, and transparency into this decision is limited.

Entergy modeled a number of planned near-term resource additions that were selected as part of the last (2021) IRP. These include 950 MW (nameplate) of new solar resources in 2024 and 2025, another 100 MW of solar PV in 2027, and then 600 MW of solar and 250 MW of BESS in 2030. The planned resources also include 428 MW of combustion turbine (CT) capacity in 2028, and 733 MW of combined cycle combustion turbine (CCCT) in 2029.[23] Now, in the current IRP, Entergy is planning to add another large thermal resource. In Portfolio 2A the resource is an 856 MW CT[24], and in Portfolio 2A CC (the Preferred Portfolio) it is a 733 MW CCCT, added in 2030.[25]

Entergy acknowledged that the model selected CTs, but that it then hard-coded in a CCCT instead.[26] When asked why Entergy made that assumption, the Company cited several benefits of CCCT units: they have higher capacity factors than CTs, which would reduce customer exposure to market energy; are less capital intensive; require a single interconnection and single contract; are hydrogen-capable; and could be retrofitted with carbon capture and sequestration (CCS) equipment.[27] These answers are concerning for a number of reasons. First, it is not clear that

[22] Department of Energy, Loan Programs Office, "Program Guidance for Title 17 Clean Energy Financing Program" at 9, (May 19, 2023), *available at:* https://www.energy.gov/lpo/articles/program-guidance-title-17-clean-energy-program#page=1.
[23] Entergy Response to Stakeholder Request 63, Set 3.
[24] 2024 Integrated Resource Plan Stakeholder meeting #2, August 15, 2024 at 38.
[25] 2024 Integrated Resource Plan Stakeholder meeting #2, August 15, 2024 at 39.
[26] *Id.*
[27] Entergy Response to Stakeholder Request 6, Set 5.

Entergy needed the CCCT as an energy resource – in fact, the model selected CTs, and it is likely that solar and wind would be lower cost energy resources than a CCCT gas plant. Under the 111 regulations, CCCTs are limited to a 40 percent capacity factor without CCS in any case. Second, CTs should also be H_2 capable, so it is unclear why Entergy is citing that as a justification for the choice of the CCCT over a CT. Third, CCS would not be necessary with a CT or BESS. Finally, CTs and BESS are better suited to operate as capacity resources and help with the integration of renewables than CCCTs. CCCTs are energy resources, and while they can balance renewables, they are more economically operated as baseload units and not peaking units.

C. Large price discrepancies between portfolios prevent meaningful comparison, and Entergy's analysis conflates scenarios and portfolios.

All IRP modeling involves both scenarios (what Entergy calls "futures") and portfolios. Scenarios represent possible versions of the future and are meant to capture the range of conditions in the broader energy industry and regulatory environment that are outside of Entergy's control. In contrast, portfolios are potential combinations of resources that Entergy could use to reliably meet load in a given scenario.

For its 2024 IRP, Entergy modeled four scenarios: (1) Existing Fleet, (2A) Business as Usual, (2B) Clean Air Act 111, and (3) Accelerated Change.[28] All the scenarios assume that Entergy-owned coal will be deactivated by 2030. Futures 2A and 2B use reference case assumptions for load growth, renewable capital costs, and gas prices. The scenarios differ in their treatment of coal and steam gas generating units in MISO as a whole; Future 2B assumes that all these units deactivate by 2030, which is Entergy's method for representing the 111 Rules. Futures 1 and 3 are bookend scenarios of low and high paces of transition. In Future 1, load growth and gas prices are low, while renewable costs are high. Future 3 examines the reverse: high load growth

[28] 2024 Integrated Resource Plan Stakeholder meeting #2, August 15, 2024 at 17.

and gas prices and low renewable costs. Future 1 does not include a carbon price while Future 3 includes a high cost of carbon.

Entergy's analysis uses a nearly 1:1 relationship between scenarios and portfolios.[29] The only exception is Future 2A, which has two corresponding portfolios, one of which adds two CTs in 2030 and the other has a hardcoded CCCT in 2030.[30] As a result of this 1:1 mapping, when Entergy compares the cost and risk of various portfolios, it is actually comparing the cost and risk associated with very different versions of the future—not the risk associated with different actions the Company could take. This does not yield much insight, because the factors that distinguish the futures (e.g., load growth, gas prices, resource costs, and the status of the 111 Rule) are outside of Entergy's control, and therefore the modeling results cannot meaningfully inform the Company's action plan.

A key metric that Entergy uses to compare the portfolios is total relevant supply cost ("TRSC"). TRSC includes variable supply costs, levelized fixed costs of the incremental resource additions in each portfolio, bill credit associated with the production tax credit, and the cost of market capacity purchases.[31] In other words, it includes all forward-going costs associated with the portfolio except for the fixed costs of existing generators.[32] Table 3 presents the TRSC for the five portfolios that Entergy modeled.

Table 3. Total relevant supply cost results from Entergy modeling[33]

	TRSC (millions 2024$)	Percent difference from Preferred Portfolio
Portfolio 1	$7,571	-48%
Portfolio 2A	$14,602	1%

[29] 2024 Integrated Resource Plan Stakeholder meeting #2, August 15, 2024 at 18.
[30] Entergy Response to Stakeholder Request 6, Set 5.
[31] 2024 Integrated Resource Plan Stakeholder meeting #2, August 15, 2024 at 45.
[32] Entergy Response to Stakeholder Request 34, Set 2.
[33] Source: 2024 Integrated Resource Plan Stakeholder meeting #2, August 15, 2024 at 45.

Portfolio 2A with CC	$14,514	0%
Portfolio 2B	$12,623	-13%
Portfolio 3	$42,664	194%

The TRSC results vary widely between scenarios, mainly because the different load growth assumptions drive drastically different levels of resource builds. For example, the TRSC of Portfolio 3 is nearly three times greater than the Portfolio 2A-CC (the preferred portfolio). By 2030, the winter peak load in Future 3 is already 3.5 GW higher than in Future 2, and the model correspondingly builds 3.6 GW more gas capacity in 2030 in Portfolio 3 than in Portfolio 2A-CC, along with 2 GW of wind and 350 MW of battery storage (Table 4). Total capacity additions in 2030 are nine times higher in Portfolio 3 than in Portfolio 2A-CC, and cumulative capacity additions 2030–2045 are 2.7 times higher in Portfolio 3.

Because the renewable resource costs and gas prices also vary between scenarios, it is difficult to draw any conclusions about the relative advantages of each resource mix. Portfolio 3 initially appears to be a more renewable-heavy portfolio, but it is impossible to distinguish the cost impact of increased renewable buildout from the cost impact of all the other variables that differ between the scenarios.

The differing input assumptions also lead to distortions in Entergy' s risk modeling, discussed in more detail below. For example, Portfolio 3 scores poorly on energy market risk,[34] primarily because it has very high market exposure in 2029.[35] None of the portfolios include new resources in Entergy's service area until 2030, so the high load growth prior to 2030 appears as an increase in market purchases.

[34] 2024 Integrated Resource Plan Stakeholder meeting #2, August 15, 2024 at 50.
[35] 2024 Integrated Resource Plan Stakeholder meeting #2, August 15, 2024 at 49.

Table 4. Comparison of load and new resource builds in Portfolio 2A with CC and Portfolio 3[36]

Metric	Preferred portfolio: Portfolio 2A-CC	Portfolio 3	Percent Difference
Winter peak load in 2030 (MW)	5,483	8,958	63%
Total resource additions in 2030 (MW)	733	6,634	805%
Gas - CT	-	856	-
Gas - CC	733	3,428	368%
Solar	-	-	-
Wind	-	2,000	-
Battery	-	350	-
Winter peak load in 2045 (MW)	7,366	10,842	47%
Total resource additions 2030-2045 (MW)	6,957	18,622	168%
Gas - CT	2,995	2,995	0%
Gas - CC	1,963	3,428	75%
Solar	1,400	4,200	200%
Wind	600	5,800	867%
Battery	-	2,200	-

Overall, Entergy's scenario framework is not set up in a way that answers any specific questions about actions the Company could take or portfolios it should consider. To improve its framework, Entergy should develop multiple portfolios under the same scenario, and it should focus on comparing the cost and risk of portfolios that share a common set of scenario assumptions. Importantly, this will enable accurate comparison of TRSCs, because it will isolate the impact of Entergy's build decisions from external factors such as load growth. Entergy should then look for no-regrets actions—those that appear across multiple portfolios—with a focus on the next 5 to 10 years and incorporate these actions into its short-term action plan.

[36] Source: Peak load values are from Stakeholder Request 5, Set 5. Resource builds are from 2024 Integrated Resource Plan Stakeholder meeting #2, August 15, 2024 at 39 and 42.

D. Entergy's risk analysis is overly simplistic and should be replaced with iterative resource adequacy modeling.

Entergy includes five categories in its risk assessment: energy market risk, reliability, executability and optionality, fuel supply diversity, and sustainability.[37] It displays the score in each category as a pie chart, and the results of the risk analysis are a series of five pie charts for each portfolio.[38] Below, we describe specific concerns with Entergy's definition of reliability and executability and optionality, as well as the need for Entergy to complete more comprehensive resource adequacy modeling rather than relying on qualitative rankings.

i. Entergy's reliability and executability metrics bias the results of the risk assessment towards fossil resources.

Reliability: Entergy calculates reliability scores for each resource type by ranking the resources across six primary and five secondary metrics and then summing the total score.[39] The first tier of reliability attributes includes modularity, energy duration, dispatchability, outage rate, operational flexibility, and fast start capability. The second tier includes automatic generation control (AGC) capability, non-inverter inertia, reactive power (VAR) support, fuel independence, and black start capability.

Figure 5 shows the scores that each resource type receives. Aeroderivative combustion turbines (Aero CT), reciprocating internal combustion engine (RICE) units, and four-hour batteries receive the highest reliability scores, while solar and onshore wind receive the lowest scores. Combined cycle and J Frame CT units fall in the middle. Entergy uses these scores to rank the portfolios based on their capacity mixes.[40]

---

[37] 2024 Integrated Resource Plan Stakeholder meeting #2, August 15, 2024 at 47.
[38] 2024 Integrated Resource Plan Stakeholder meeting #2, August 15, 2024 at 48.
[39] 2024 Integrated Resource Plan Stakeholder meeting #2, August 15, 2024 at 52.
[40] 2024 Integrated Resource Plan Stakeholder meeting #2, August 15, 2024 at 53.

Figure 5. Entergy methodology for developing reliability scores by resource type[41]

	Reliability Score per 100 MW of UCAP							
	2x1 CCCT	1x1 CCCT	CT (J Frame)	Aero CT	RICE	Battery [2]	Solar	Onshore Wind
	Tier 1 (0 - 5)							
Modular Capacity	1	2	3	5	5	5	5	5
Energy Duration	5	5	3	4	4	1	1	1
Dispatchability	3	3	5	5	5	5	1	1
Planned & Forced Outages	3	3	1	1	3	5	5	5
Operational Flexibility	2	2	3	5	4	3	0	0
Fast Start	1	1	3	5	5	5	0	0
	Tier 2 (0 - 3)							
AGC Capable	3	3	3	3	3	3	0	0
Inertia (non-inverter)	3	3	2	1	1	0	0	0
VAR support	3	3	3	3	3	3	1	1
Fuel Independence	0	0	0	0	0	3	3	3
Black Start	0	0	0	3	3	1	0	0
Total score per 100 MW of Unforced Capacity (UCAP)	**24**	**25**	**26**	**35**	**36**	**34**	**16**	**16**

This is an overly simplistic analysis for the reliability of a system with renewables and battery storage in addition to fossil resources. Entergy needs to design balanced portfolios with enough complementary resources to ensure energy and capacity adequacy in all hours of the year, and it needs to assess the reliability of each portfolio as a whole, rather than developing generic scores for resource types in isolation. To achieve this, it should complete iterative resource adequacy modeling (discussed in more detail below). This would allow Entergy to better capture the reliability benefits that renewable resources can provide.

Executability and Optionality: Entergy scores executability and optionality based on a number of subjective criteria related to the feasibility of procuring new resources and the adaptability of the portfolio to changes in load or technological availability. For example, Entergy scores portfolios that do not add new resources until the late 2030s higher because of the greater "lead time available prior to initiating procurement."[42] It ranks CT and CCCT units high on adaptability, because they could be converted to burn a hydrogen blend in the future. It favors portfolios that add fewer new resources overall, and views wind builds as a negative, because they

[41] Source: 2024 Integrated Resource Plan Stakeholder meeting #2, August 15, 2024 at 52.
[42] 2024 Integrated Resource Plan Stakeholder meeting #2, August 15, 2024 at 54.

"are not currently widely available to EAL, and if procured in large quantities, may require excessive reliance on off-system resources, which may entail transmission cost."[43] Finally, the reliance on CCS in the 111 scenario presents a risk because the geology of Arkansas is not amenable to carbon sequestration.

This is a highly subjective metric that emphasizes certain aspects of executability and optionality while omitting others, overall biasing scores towards fossil resources. For example, Entergy scores portfolios with large quantities of new gas resources higher, because gas resources "may change supply roles," i.e., are compatible with hydrogen blending.[44] This ignores the far greater benefit that clean energy resources such as wind, solar, and BESS provide—these resources won't *need* to change supply roles in the future, because they are not vulnerable to emissions regulations. Entergy also should not favor portfolios that require few resource additions and that delay procurement, unless those are truly the most economic for ratepayers. Frequent and early procurement will signal to the market that Entergy is interested in renewables and will allow the Company to gain experience incorporating these resources into its system gradually. Similarly, Entergy should not dismiss wind resources just because they could hypothetically require transmission investments; it should study the transmission investments to determine if they are cost-effective for ratepayers, and if so, should pursue them.

ii. Entergy should be integrating capacity expansion modeling with resource adequacy modeling

Entergy's reliability analysis is not sufficiently robust in this IRP. The Company modeled a 9 percent reserve margin in the summer and a 27.4 percent reserve margin in the winter,[45] but did no subsequent modeling to assess the sufficiency or reasonableness of its resulting portfolios.

[43] *Id.*
[44] *Id.*
[45] 2024 Integrated Resource Plan Stakeholder meeting #2, August 15, 2024 at 34.

Instead, the Company performed the "qualitative risk assessment"[46] discussed above to supplement its capacity expansion modeling.

Best practices in resource planning require reliability assessments to be conducted iteratively with resource planning. A reserve margin is simply a starting point and resulting portfolios are subsequently tested against historical weather data to assess how well they are likely to perform in extreme weather. In this way reliability analysis is not simply a static evaluation metric, but instead an input to the system. This is critical both for assessing how individual portfolios perform, and whether additional resources are needed to meet reliability requirements. It is also useful for accurately assessing how different portfolios perform relative to one another. Entergy should be evaluating the reliability of its portfolios in a resource adequacy model, rather than just qualitatively assessing each portfolio after the fact using a subjective ranking system.

E. Entergy Arkansas arbitrarily failed to include the full costs of new gas plants in its modeling for the 2024 IRP.

In this IRP, Entergy Arkansas has not included the costs for new pipeline construction when estimating the costs for new thermal plants. Nor has Entergy included the contract cost of assuring firm gas service for any new gas generation.[47] Excluding these costs means that Entergy Arkansas is underestimating the full cost of investing in new gas generation.

A new gas plant has no value for Entergy's customers if it is not served by a gas pipeline. Further, the MISO capacity accreditation for any new gas generation will be low if Entergy has not contracted for firm gas service. These costs can be significant. As one example, in a recent

[46] 2024 Integrated Resource Plan Stakeholder meeting #2, August 15, 2024 at 51-53.
[47] EAL 2024 IRP Q&A No. 1. ("Q1: Do the costs for new thermal plants shown here include the cost of new pipeline construction, firm pipeline service, both, or neither? From reading the footnotes, I would guess that these costs are not included, but was hoping to confirm that. A1: The costs for new thermal plants do not include the costs for new pipeline construction. They also do not include any firm transportation costs associated with the delivery of natural gas.").

Indiana combustion turbine pre-approval docket, the utility estimated that these gas transportation costs at $27 million *per year*, which exceeded the annualized cost of constructing the two combustion turbines themselves (assuming a 20 year useful life).[48] Entergy should update its modeling to include these known, quantifiable costs. Otherwise, its 2024 IRP modeling will understate the costs of new gas generation.

F. Multiple other modeling limitations bias Entergy's modeling towards coal and gas resources

In addition to the issues outlined above, a number of other concerns are still outstanding:

- Entergy limits the resources available to the model, and critically does not allow the model to select long duration energy storage ("LDES") – that is, BESS with 10-100+ hour ratings, even later in the modeling period. There are more than half a dozen LDES pilot projects around the country. For example, Form Energy has 100-hour BESS pilots proposed or underway in the states of Georgia, Virginia, New York, Colorado, and Minnesota (there are two in MN). Some of these pilots are already demonstrating several critical advancements that were identified as necessary by the U.S. Department of Energy report for LDES to become commercially available as soon as the 2030s. Additionally, other utilities, including Xcel, have started to model LDES as a resource option in their planning processes. Half a dozen utilities and resource authorities have found the LDES technology to be mature and commercially developed enough to deploy pilots as part of their grid. Entergy should also allow the model to select long-duration BESS as part of its resource portfolio by at least 2030. Further, modeling LDES would be consistent with Entergy's approach to modeling small modular reactors,[49] another nascent technology that currently lacks commercial deployments at scale.

---

[48] *See* Indiana Utility Regulatory Commission, Cause No. 45564, Final Order dated June 28, 2024, page 23.

[49] 2024 Integrated Resource Plan Stakeholder meeting #2, August 15, 2024 at 8.

- While the 111 Rule by and large is irrelevant for Entergy's coal plants, based on prior settlement agreements with Sierra Club, it does impact future gas builds. Entergy does not model the 111 Rule as part of its reference or base scenario, but instead models the 111 Rule as a separate scenario. In the 111 Rule scenario, the model builds 733 MW of CCCT capacity in 2030 – which would be subject to a 40 percent capacity factor cap, or else would need to install CCS to comply with the 111 Rule. Entergy assumes that CCCT units in the 111 Rule scenario comply with the 111 Rule by installing CCS.[50]

G. Conclusions and recommendations for resource modeling

- Entergy should revise its renewable cost assumptions to align with industry standard values such as NREL's Annual Technology Baseline or justify why costs in its service area are higher.

- Entergy should use an ELCC for BESS that reflects the solar and wind on the system, and should use smaller and more reasonable tranches. The Company should clearly document how it derives these values from the Astrapé ELCC study.

- Entergy should adjust its modeling scenario structure to enable comparison of multiple portfolios that correspond to the same scenario.

- In place of its qualitative risk analysis, Entergy should perform iterative resource adequacy modeling.

II. Transmission Planning and Modeling Recommendations

A. Introduction and Background

Transmission connectivity for new generation resources is a critical piece of an IRP, as economics depend on resource location. EAL declines to identify locations for new generation resources ["the resources were not site-specific but rather a generalized assumption for the cost to

[50] Entergy Response to Stakeholder Request 1, Set 5.

install the resource within the MISO South footprint, or for the on-shore wind SPP, in SPP"].[51] EAL further declines to consider transmission new generation may require, apart from interconnection costs ["projected transmission projects are outside the scope of this proceeding"][52] notwithstanding the requirement by the Arkansas Public Service Commission that "the [transmission plan] 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."[53] EAL even acknowledges this requirement but refuses to adhere to it, except to introduce an un-needed and costly 600 mile HVDC transmission line to SPP as a strawman hindering the consideration of other, more economic options.[54]

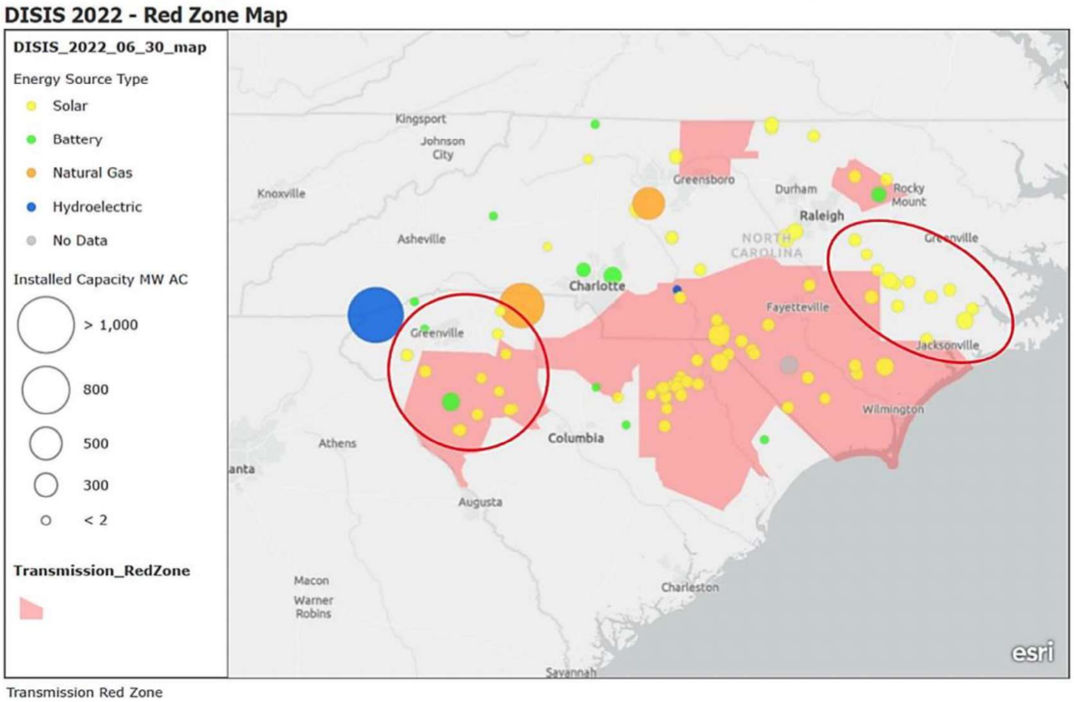
B. Comparison with Transmission Planning in other Southern States' IRPs

As an example of an IRP of a comparable southern state that considers transmission options adequately to enable solar energy at lower cost than combined cycle generation, Duke Energy indicates promising locations for up to 8 GW of solar energy development in a transmission-constrained area that has high viability for solar and solar paired with storage facilities known as

[51] 4th stakeholder question set, response 1 b.
[52] 3rd stakeholder question set, response 27.
[53] Arkansas PSC Resource Planning Guidelines for Electric Utilities, approved in docket 06-028-R, section 4.7
[54] Entergy IRP Stakeholder meeting #2, p. 10; Stakeholder questions Response 105.

a “red-zone” region, with numerous interconnection requests.[55] Duke details required transmission upgrades in the filing, as set forth in the following Figure L-2:[56]

Figure L-2: 2022 DISIS Phase 1 Interconnection Requests



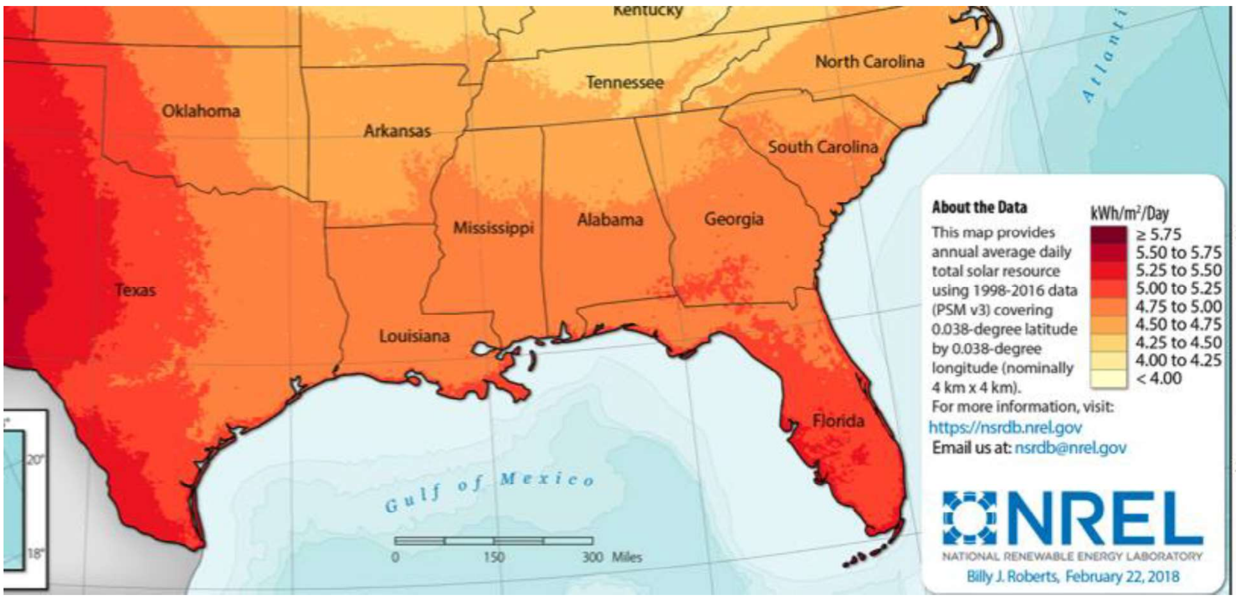
Duke (Duke Energy Company, and Duke Energy Progress) quantifies the transmission costs associated with increased utility scale solar, as illustrated in the following Table:[57]

Table 2-12: Transmission Cost of Solar and Solar Paired with Storage

	Transmission Overnight Cost (2023 $/W)	
	DEC	DEP
Solar and Solar Paired with Storage	$0.35	$0.21

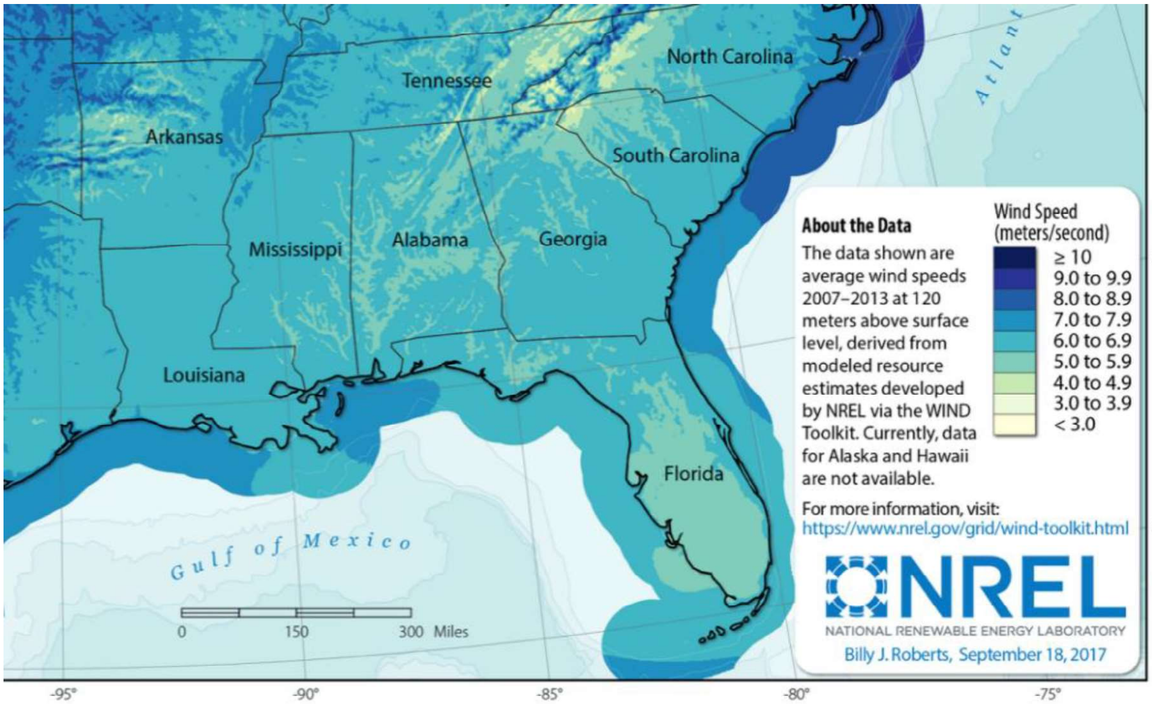
[55] Duke Energy IRP, Appendix L, Transmission System Planning and Grid Transformation at 24, https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/appendix-l-transmission-system-planning.pdf?rev=c6cf1bc1ac9c4c878ec4a5d2307c4532.
[56] *Id.* at Figure L-2.
[57] Duke Energy IRP, chapter 2, Figure 2-12 https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/chapter-2-methodology-and-key-assumptions.pdf?rev=44036eb8cc98429c92e7ac00bea5f445.

Duke indicates an all-in cost for solar (including transmission) approximately equal to EAL's; however, solar resources in southern and southeastern Arkansas exceed North Carolina's, according to resource maps from NREL, which indicates that solar economics for Arkansas and imports from Entergy Louisiana would be more favorable than Duke North Carolina's, depending on resource location:[58]



Wind resources are distributed much less evenly than solar resources, underlying the need for considering transmission in detail for an IRP:[59]

[58] NREL, Global Horizontal Irradiance, https://www.nrel.gov/gis/assets/images/solar-annual-ghi-2018-usa-scale-01.jpg.
[59] NREL, Wind Resource of the United States https://www.nrel.gov/gis/assets/images/wtk-10m-2017-01.jpg.



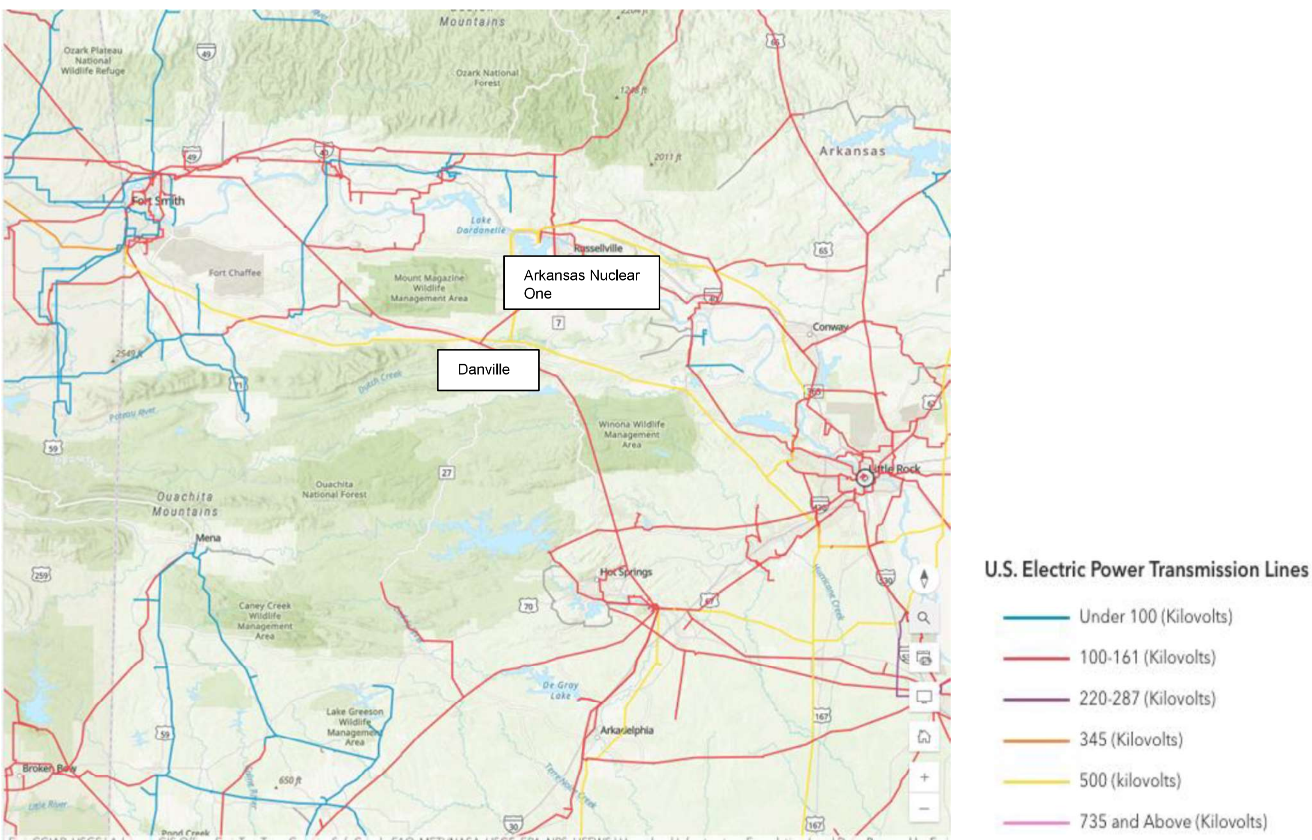
EAL claims importing power from the wind resource in SPP requires a 600-mile HVDC line but provides no evidence such a line would be needed. To the contrary, a NREL wind map shows western Arkansas and eastern Oklahoma have promising resource regions in mountainous areas comparable to western Oklahoma, indicating the viability of wind development close to the Entergy footprint without needing a 600-mile line. When asked about wind from western Arkansas at the August 15, 2024 stakeholder conference, EAL simply responded "that location was not feasible because trees would require high hub heights." This ignores the long-term trend to high hub heights, and thus was not a credible engagement with stakeholders.

The Entergy System has 14,000 MW of interconnections with SPP.[60] If there are constraints limiting off-system imports, EAL provides no evidence. Any such constraints could be alleviated incrementally at low cost with grid enhancing technologies. They could be removed at scale by

[60] FERC Docket EC12-145 Protest of SPP, pp. 8-9, filed Jan 22 2013; Protest of SPP TO's, p. 19, filed Jan 11 2013; *See also*, Bruce W. Radford, *Entergy's Power Play: The ITC member and link-up with MISO*, FORTNIGHTLY MAGAZINE, March 2023, available at https://www.fortnightly.com/fortnightly/2013/03/entergys-power-play?authkey=fc44fde8ab462c9ed7169ced78f2278279eeb4fa51764326ec5a5714f608fb36.

reconductoring lines far more economically than building a 600-mile HVDC line. However, EAL uses the high cost of the HVDC option as a strawman to block importing energy from SPP rather than as a serious resource proposal.

A public domain transmission map[61] shows the presence of strong interconnection capacity between western Arkansas and SPP with 500kV lines (yellow in the map) originating at the 1,800 MW Arkansas Nuclear One power station, ostensibly flowing power west through Danville towards Fort Smith, suggesting there could be available capacity from Western Arkansas wind regions or from SPP into Danville where power flows would be in the opposite direction from the nuclear station. Elsewhere, interties at the EHV New Madrid substation connect to multiple regions, Southern Arkansas has connections through Louisiana to SPP among others.



[61] https://www.arcgis.com/apps/mapviewer/index.html?layers=d4090758322c4d32a4cd002ffaa0aa12.

Accordingly, EAL's IRP fails to consider resource and transmission options in sufficient depth to discover their economics. Therefore, EAL's transmission planning analysis (or lack thereof) is inconsistent with the Commission Resource Planning Guideline that transmission planning "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."[62]

C. Conclusions and recommendations for transmission planning and modeling

Entergy is not sufficiently integrating transmission planning into its resource planning process. The Company states that projected transmission projects are outside the scope of this proceeding, and that the Aurora model does not include transmission constraints of future projects. Model selection should not excuse Entergy from conducting robust resource planning that includes transmission requirements. While it is true that transmission planning analysis is inherently a separate exercise, Entergy can and should still consider transmission alternatives and integrate the results from the separate transmission studies into its IRP processes.

***

The Stakeholder Committee appreciates the opportunity to participate in EAL's IRP process pursuant to Section 4.8 of the Commission's Resource Planning Guidelines. The Stakeholder Committee respectfully requests that EAL incorporate the recommendations provided in this Report into EAL's 2024 IRP. The Stakeholder Committee submits that its recommendations will be particularly helpful to aid EAL in identifying a preferred Resource Plan pursuant to Section 4.5 of the Resource Planning Guidelines, as well as developing an action plan pursuant to Section 4.6. The Stakeholder Committee reserves that right to file comments regarding the IRP process and results pursuant to Section 4.8 of the Commission's Resource Planning Guidelines.

[62] Resource Planning Guidelines, Section 4.7, Transmission Plan.

Respectfully submitted,

Arkansas Electric Energy Consumers, Inc.

By: /s/ M. Shawn McMurray
M. Shawn McMurray (ABN 92250)
Shawn@TheMcQueenFirm.com

Christina L. Baker (ABN 2016001)
CBaker@TheMcQueenFirm.com

The McQueen Firm, PLLC
P.O. Box 241814
Little Rock, AR 72223
Office: (501) 690-3017

Arkansas Advanced Energy Association, Inc.

By: /s/ Lauren Waldrip
Lauren Waldrip
Executive Director
Arkansas Advanced Energy Association
411 S. Victory St. #207 Little Rock, AR 72201
c: 870.295.8454
lwaldrip@arkansasadvancedenergy.com

Sierra Club

By: /s/ M. Shawn McMurray
Tony Mendoza
Senior Attorney
Sierra Club Environmental Law Program
2101 Webster St., 13th Floor
Oakland, CA 94612
(415) 977-5589
tony.mendoza@sierraclub.org

Southern Renewable Energy Association

By: /s/ Simon Mahan
/s/ Whit Cox
Simon Mahan, Executive Director
Whit Cox, Regulatory Director
11610 Pleasant Ridge Road, Suite 103 #176
Little Rock, AR 72223
simon@southernwind.org
whit@southernrenewable.org

University of Arkansas System

By: /s/ Sherri L. Robinson
Sherri L. Robinson
Sr. Associate General Counsel
4301 W. Markham, #860
Little Rock, AR 72201
SLRobinson@uams.edu