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J. David Palmer
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October 30, 2024

Ms. Karen Shook, Secretary
Arkansas Public Service Commission
1000 Center Street
P. O. Box 400
Little Rock, Arkansas 72203

Re: Arkansas Public Service Commission Docket No. 07-016-U
Entergy Arkansas, LLC 2024 Integrated Resource Plan

Dear Ms. Shook:

Consistent with Section 6 of Attachment 1 to the Arkansas Public Service Commission (APSC or the Commission) Order No. 6 – Docket No. 06-028-R Resource Planning Guidelines for Electric Utilities (RPGs), Entergy Arkansas, LLC submits its 2024 Integrated Resource Plan and the Stakeholder Report that was prepared in accordance with Section 4.8 of the Commission's RPGs.

Should you have any questions concerning this filing, please call me at (501) 377-4455.

Sincerely,

/s/ J. David Palmer

JDP/et

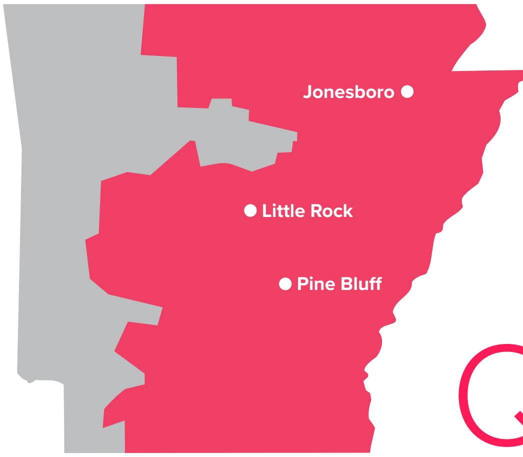
Enclosures

c: All Eligible Parties of Record

entergy

Entergy Arkansas, LLC

2024 Integrated Resource Plan



entergy
ARKANSAS

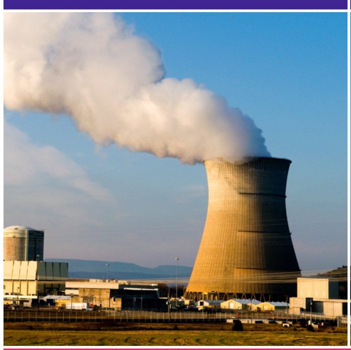
Quick Facts

110
years of service

728,000+
electric customers

63
counties served

2700
employees

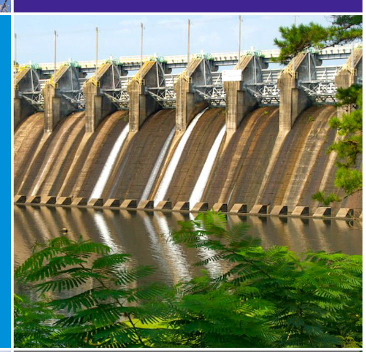


Fully Integrated
generation
transmission
distribution

~5500 MW
of power
generation
capacity

~3000 MW
of renewable generation
by 2030

Carbon Reduction
Target 50% reduction
by 2030
Net-zero by 2050



2
coal plants
will cease to
burn coal by 2030

Dow Jones Sustainability Index
21st consecutive year
1 of 4 electric utilities

Entergy Arkansas, LLC 2024
Integrated Resource Plan

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CHAPTER 1

Executive Summary

Introduction

The electric utility industry is in the midst of a seismic energy transition, and Entergy Arkansas, LLC ("EAL" or the "Company") is at the forefront of this change. Since the release of EAL's 2021 Integrated Resource Plan ("IRP"), unprecedented changes have occurred such as rising inflation, geopolitical disruptions, and increasing demand for cleaner, more reliable, and affordable energy. In this rapidly evolving environment, EAL remains steadfast in its commitment to providing safe, reliable, and affordable electricity to its customers in Arkansas. The Company continues to proactively plan for future resource needs while serving its diverse and growing customer base with a focus on affordability, reliability, and sustainability.

EAL recognizes that creating an affordable, reliable, and sustainable future for customers and their communities requires continued transformation of the Company's resource portfolio, and this IRP provides insights into EAL's planning process.

EAL integrates key objectives into its resource planning to benefit customers by focusing on several strategic initiatives, such as:

- Enhancing the energy portfolio through diversification, while maintaining strong nuclear performance;
- Maintaining and strengthening reliability through the addition of dispatchable generation, which will also reliably support the planned addition of renewable resources;
- Maintaining affordable electricity costs by adding new highly efficient or zero emissions generation resources that qualify for tax credits and strategically siting resources in areas where EAL can reduce cost;
- Addressing customer demand for clean energy by offering low-to-zero greenhouse gas resources and providing customer-specific tariffs such as Green Promise and Go ZERO to access green and clean energy attributes that are in high demand by customers;
- Investing in infrastructure to improve service reliability and resilience; and
- Actively engaging stakeholders to gather feedback and insights to drive continuous improvements and alignment.

Customers prioritize reliable, affordable, and sustainable power

Many of today's energy customers are looking for significant insight into how their energy is generated, delivered, and managed, including their energy sources. EAL actively works with its customers to understand their expectations and develop voluntary offerings that align with their needs and goals.

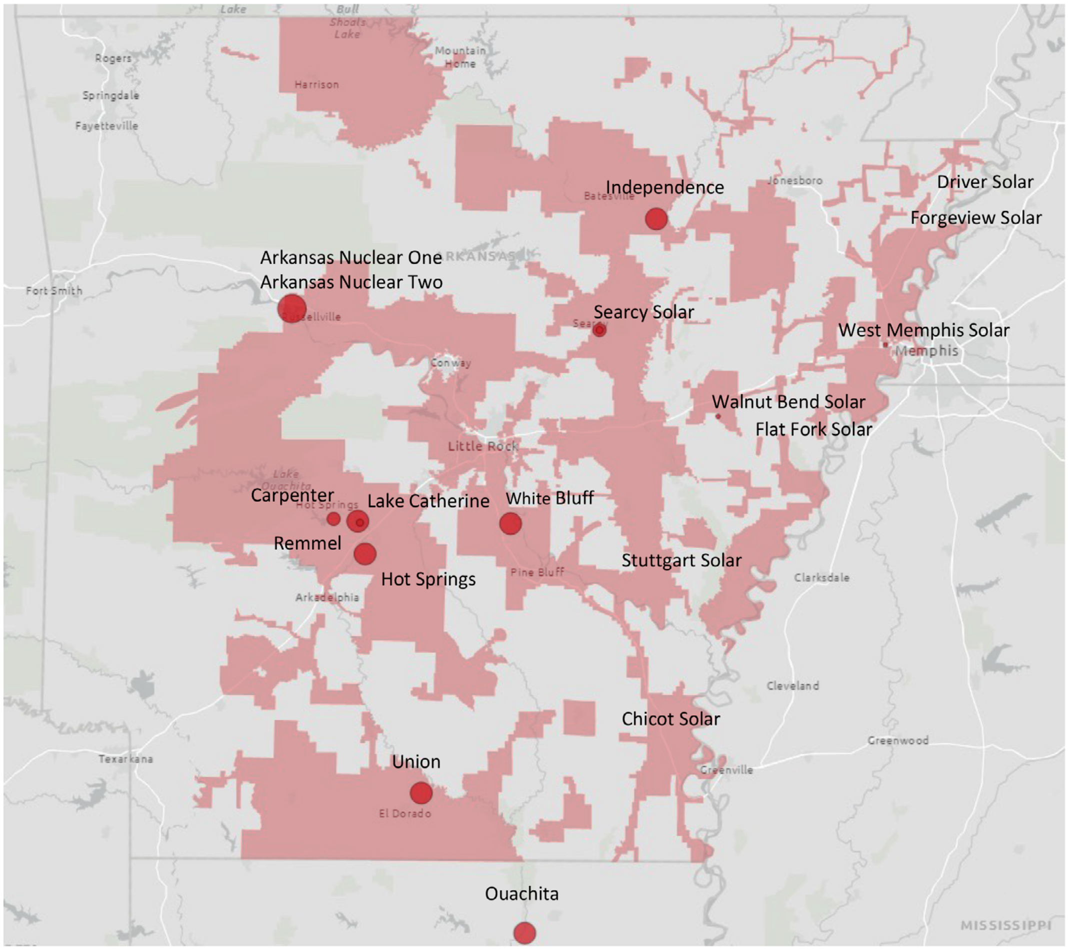


FIGURE 1: EAL'S SERVICE TERRITORY

EAL's customer base has grown to over 730,000 residential, commercial, industrial, and governmental customers located in 63 of Arkansas' 75 counties, which cover over 40,880 square miles. By combining an understanding of customer goals with sound and comprehensive planning, EAL can address customer needs while continuing to achieve the planning objectives of affordability, reliability, and sustainability.

EAL is able to meet its customers' reliability requirements with its existing nuclear, natural gas, and coal resources. EAL's objective of maintaining its existing fleet of dispatchable generation and adding dispatchable generation to replace the coal units will both support and strengthen reliability and support the deployment of planned renewable resources.

Existing Solar	Solar Additions in 2024	Solar Additions 2025-30
• Stuttgart 81 MW • Chicot 100 MW • Searcy 100 MW	• Walnut Bend 100 MW • Driver 250 MW • West Memphis 180 MW	• Flat Fork 200 MW • Forgeview 200 MW • 2022 RFP ~1000 MW • 2030 Solar 600 MW

FIGURE 2: EAL EXISTING AND PLANNED SOLAR ADDITION 2024-2030

To address customers' needs, EAL plans to add ~2.3 GW of solar resources by the end of 2030. EAL acquired Searcy Solar in January 2022 and recently completed the acquisitions of the Walnut Bend, Driver, and West Memphis solar facilities. Walnut Bend began commercial operations in September 2024, while Driver and West Memphis are expected to begin operations in the fourth quarter of 2024. Additionally, EAL received Arkansas Public Service Commission ("APSC" or the "Commission") approval for two 200 MW solar Purchase Power Agreements ("PPAs"), which were selected out of the 2021 Request for Proposals ("RFP"), with an in-service date of 2025. EAL issued another renewable RFP in June 2022, seeking up to 1,000MW of additional solar and/or wind resources.

The resources selected from this RFP will contribute to a diversified resource portfolio producing affordable energy under various conditions, to meet customers' desire for renewables and support EAL's own sustainability goals, which align with the sustainability goals of customers.

As the world shifts to a cleaner, greener economy, the electric grid will have to accommodate increased electrification and the increasing proportion of renewable generating resources. In addition to its growing renewable portfolio, EAL is evaluating proven and emerging technologies that can benefit customers, including but not limited to hydrogen-fueled generation, carbon capture and storage ("CCS"), and wind to integrate the intermittent nature of the renewable resources and increasing electrification to help ensure reliability, capacity and energy coverage that maximizes customer benefit. EAL will continue to pursue an "all-of-the-above" generation portfolio strategy to retain the benefits of maintaining the advantages of a mix of generating resources to strengthen reliability, affordability, and sustainability to benefit customers and meet their needs.

Environmental sustainability is a bedrock of EAL's resource planning

Entergy Corporation ("Entergy") has been an industry leader in voluntary climate action for over two decades, having been named to the Dow Jones Sustainability Index for twenty-one consecutive years. Building on its longtime legacy of sustainability, Entergy is enhancing its climate action strategy with a longer-term commitment: Entergy will work over the next three decades to reduce carbon emissions from its operations to net-zero by 2050. EAL intends to accomplish this by working with its regulators and other stakeholders to balance affordability, reliability, and sustainability. Building on the critical success already achieved on this front, EAL will continue working with regulators and key stakeholders to transform its portfolio, building a diverse generation fleet that maintains the grid's resilience and reliability and delivers on the shared sustainability commitments among EAL and its customers.

EAL offers affordable, reliable, and sustainable power to its customers.

EAL is tracking and working to reduce emissions over time by:

- Ceasing to use coal by the end of 2030;
- Deactivating other older, less-efficient generation assets as EAL is able to do so;
- Ensuring high performance of carbon-free nuclear assets;
- Deploying additional renewable capacity; and
- Evaluating feasible emergent technologies that offer sustainability benefits.

Before diving into 2024 IRP assumptions and results, it is imperative to understand what has changed since the last IRP analysis, the Mid-Cycle IRP, which was filed in Docket No. 07-016-U in December 2022.

What changed since the Mid-Cycle IRP Update?

- **Load growth** – EAL is experiencing higher peak loads predominantly due to increased growth in the large industrial classes among new and existing customers, and the increasingly greater number of larger load customers in the industrial, chemical, and crypto mining sectors. Arkansas' affordable electric rates, favorable tax and regulatory climate, and pro-business administrations have made Arkansas an attractive place to invest capital and create jobs. By 2026, EAL's energy sales forecast projects that 49 percent of the customer class will be industrial, more than a 10 percent increase from the 2023 customer mix shown in the Mid-Cycle IRP. The corresponding kilowatt hours in the industrial class benefit all customers.
- **Midcontinent Independent System Operator, Inc. ("MISO") capacity market reforms** – In August 2022, MISO shifted from an annual resource adequacy construct to a seasonal construct and modified its resource accreditation methodologies and offer requirements. Under the new construct, MISO established the planning reserve margin requirement ("PRMR") on a seasonal basis, and thermal resources are accredited using the Seasonal Accredited Capacity ("SAC") methodology instead of the unforced capacity ("UCAP") rating methodology. The UCAP is only impacted by forced outages, while the SAC is impacted by forced outages, derates, and non-exempt planned outages. For non-thermal resources such as solar, wind, and battery storage, the accreditation is based on performance in peak hours. Reductions in Effective Load Carrying Capability ("ELCC") for solar resources based on underlying forecasted solar penetration in the market reduce the capacity accreditation given to renewable resources, especially in the winter season. This approach establishes more granular, seasonal resource adequacy requirements to ensure sufficient resources are committed and obligated to be available when needed. However, this also means that more capacity is required to meet the seasonal PRMRs compared to the construct in place at the time of the Mid-Cycle IRP. Moreover, MISO's resource adequacy construct is still evolving. MISO recently conducted a stakeholder process to evaluate its proposal to replace the vertical demand curves with sloped demand curves in the Planning Resource Auction ("PRA"), a change that is expected to increase auction clearing prices and PRMs. The Federal Energy Regulatory Commission ("FERC") accepted this change in June 2024. MISO is now investigating changes to Load Modifying Resource ("LMR") accreditation to align with the thermal resource accreditation changes referenced above and proposed future changes to non-thermal resource accreditation that are currently before FERC in MISO's Direct Loss of Load ("DLOL") proposal, submitted to FERC in March 2024.

- **Technology costs** – Continued inflationary impacts driven by increases in labor and material cost, paired with higher demand for gas, renewable, and storage technologies due to growing load have resulted in higher technology costs compared to Mid-Cycle IRP assumptions.
- **Federal policies** – In April 2024, the Environmental Protection Agency ("EPA") released a final rule under the Clean Air Act ("CAA") Section 111 to establish new requirements for the control of CO_2 emissions from new and certain existing fossil-fired electric generating units ("EGUs"). Under this rule, EAL's coal-fired generating units are expected to qualify for an exemption. The most significant impact of EPA's final Section 111 rule would be for any new gas units that commence construction after May 23, 2023, and operating at greater than 40% annual capacity factor must limit their emissions intensity to 100 lb. CO_2/MWh beginning in 2032, a threshold based on the assumed use of CCS at an effectiveness of 90%. In one of the scenarios, the IRP models the impact of this rule along with the 45Q tax credit incentive that is part of the Inflation Reduction Act ("IRA") implemented in August 2022. Additionally, production tax credits ("PTCs") and investment tax credits ("ITCs") are modeled in all the IRP scenarios to offset investments required for new renewable and storage generation. The PTCs are based on the production of each kWh of electricity generated, whereas the ITC is based on the percentage of ITC-eligible capital investment post-construction.
- **Existing resource deactivation updates** – One of the action plans in the Mid-Cycle IRP was to effectuate the deactivation of Lake Catherine 4 ("LC4") in 2025; thus, the Mid-Cycle IRP assumed LC4 deactivating in 2025. However, in EAL's 2024 IRP, LC4 is assumed to be extended to 2027 to support resource adequacy needs. This IRP also assumes a combustion turbine ("CT") replaces LC4 and is operating within three years of LC4's deactivation. Additionally, in the Mid-Cycle IRP EAL's nuclear fleet reflected expiration of the operating licenses in 2034 for Arkansas Nuclear One ("ANO") Unit 1 and 2038 for ANO Unit 2 within the IRP study period, which resulted in decreased base load and load following capacity over the planning horizon as these units reach the expected end of their useful lives. However, in the 2024 IRP, Subsequent License Renewal ("SLR") is assumed for ANO Units 1 and 2, and thus the 2024 IRP extends their deactivation dates beyond the IRP study period of 2045.

About This Report

This IRP contemplates a study period of 2026-2045 and is intended to provide stakeholders insight into the Company's long-term planning process for meeting future demand and energy needs. Similar to EAL's Mid- Cycle IRP, certain fundamental uncertainties in this IRP remain, such as technological advances and their associated costs, growing customer preferences for renewable and emissions-free energy, and prospective changes in environmental regulations.

EAL's IRP guides long-term generation decisions

EAL recognizes that developing an affordable, reliable, and sustainable future for its customers and their communities requires a continued transformation of the Company's resource portfolio. This IRP provides insights into EAL's planning process, including an illustration to show how the planning principles are applied to long-term resource planning.

The IRP is a framework that provides foundational guidance to inform EAL management of the types of future generation resources to consider and when to start making decisions regarding the procurement process of those resources. The scenarios modeled withing the IRP framework provide overarching perspective to be considered, including external factors such as the need to capture economic development opportunities (which could be significant across Arkansas) and serving those loads. Concurrently, the IRP framework must reflect serving existing customers and ordinary growth, which also requires substantial investment in infrastructure in Arkansas. Potential economic development projects may involve customers with substantial demands for electricity and natural gas consumption at levels not previously seen in Arkansas, making improved timelines and recovery of such investments all the more essential. The starting point of EAL's strategic assessment is to understand its current capabilities. This includes accounting for existing fleet capacity, planned deactivation timelines, planned new resources schedules and capacity, and current load assumptions.

The next step involves identifying gaps by evaluating how current capabilities align with projected load growth and market uncertainties. Once the gaps have been identified, the focus shifts to determining how EAL can effectively address those gaps.

The results of this process are presented in the IRP, which provides a comprehensive projection of potential resource portfolios to bridge the gaps under various market uncertainties and sensitivity analyses. It is imperative to note that the IRP results are not intended as static plans or pre-determined schedules for resource additions or deactivations. Instead, the IRP is intended to support near-term decisions while guiding long term planning, accordingly, it is updated every three years to reflect changing conditions and needs.

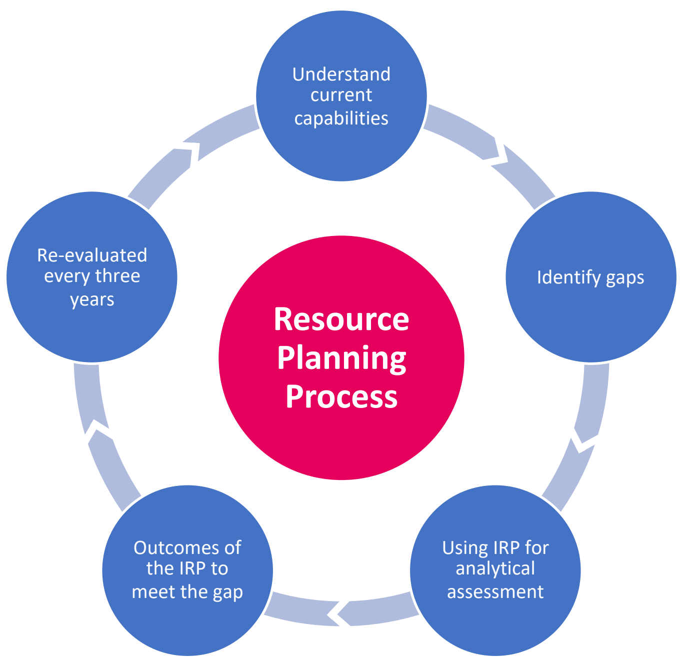


FIGURE 3: EAL'S RESOURCE PLANNING FRAMEWORK THROUGH IRP

The 2024 IRP employs a futures-based approach, consistent with the Company's recent IRPs. The approach involves constructing four futures designed to capture a broad range of uncertainties. In addition to the four futures, a sensitivity case was also analyzed to provide robustness and stress test the cases in a targeted manner.

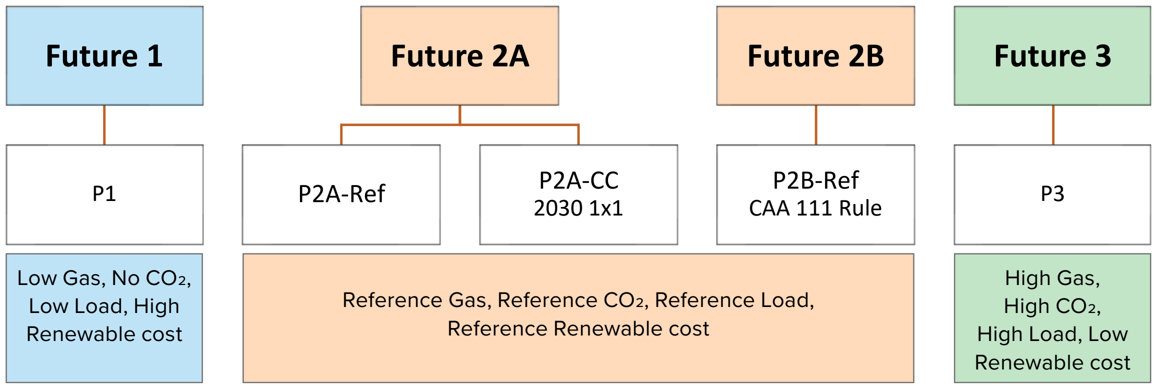


FIGURE 4: 2024 IRP FUTURE SCENARIO SUMMARY

EAL's Preferred Resource Plan

The results of the IRP analysis reasonably support that EAL's future supply-side resource additions will consist of a diverse portfolio mix of gas with hydrogen co-firing capability and renewable energy resources. EAL's preferred resource plan maintains the planning assumptions for existing units and begins adding dispatchable resources starting in the 2029-30-time frame, followed by incremental renewable and dispatchable resources to support the integration of renewable resources. The exact amount of each type of resource will ultimately be based on the real-time options and unique opportunities available to EAL and therefore may vary from the amounts in the Preferred Resource Plan.

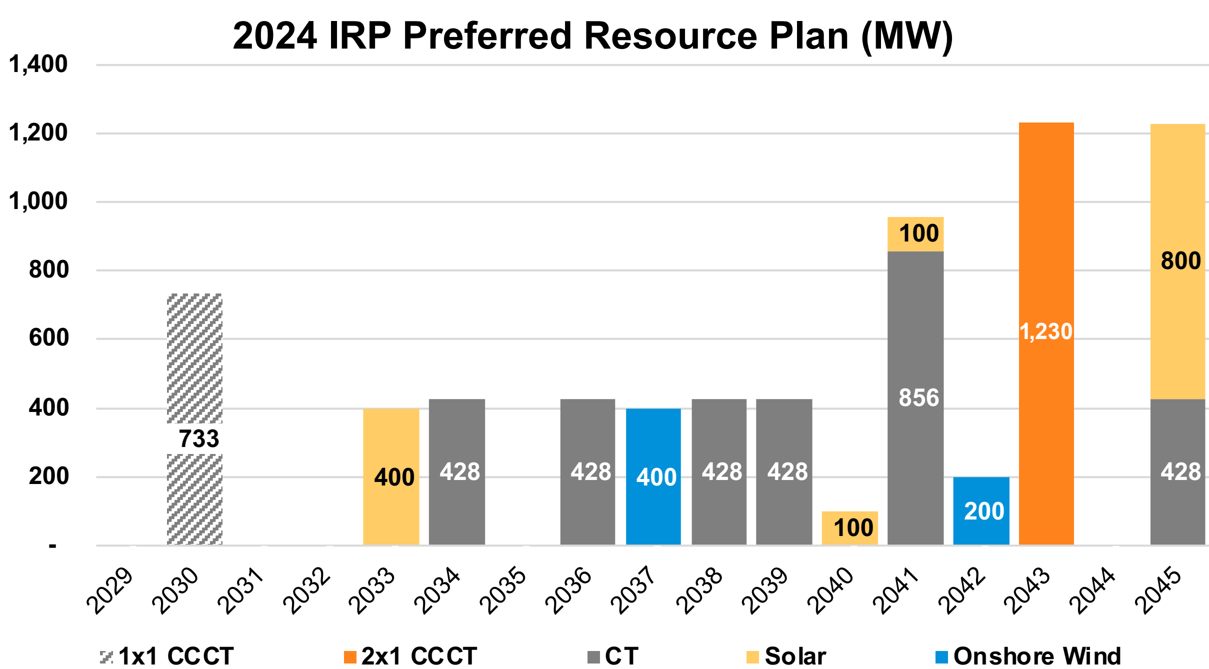
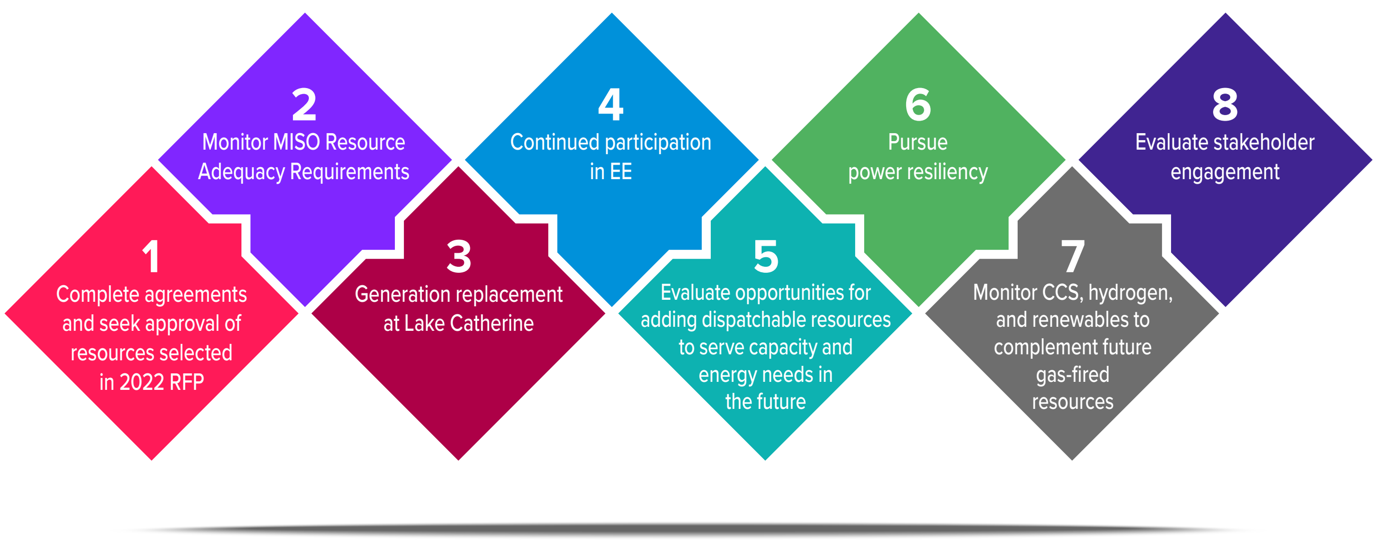


CHART 1: 2024 IRP PREFERRED RESOURCE PLAN

The Preferred Resource Plan is developed consistently with the Commission's Resource Planning Guidelines but does not represent planning decisions by EAL. Instead, the Company's specific long-term resource planning actions (e.g., capacity additions) are subject to review and approval by the Commission based on the unique characteristics of the resource. In the same respect, the IRP assumptions regarding the cost and availability of various supply-side resources do not reflect the actual cost or ownership structure for implementing those options. They are planning assumptions, with the actual costs and structures to be determined at the time of execution. In addition, while the IRP seeks to identify EAL's capacity needs and appropriate resources to fill those needs, this approach should not be read to foreclose the identification of a future resource that may be in the public interest for EAL's customers.

No approvals are sought for this IRP pursuant to the Commission's Resource Planning Guidelines. In any event, the Preferred Resource Plan and Action Plan outlined in Chapter 6 of the IRP reflect EAL's present expectations regarding the planning actions that may be expected over the next several years based on relevant and available information.

The 2024 IRP Action Plan consists of **eight action items**, which are summarized below and discussed in more detail in Chapter 6:



CHAPTER 2

Long-Term Resource Planning

Summary

- The APSC implemented the current Resource Planning Guidelines in 2006, requiring its jurisdictional utilities to file an IRP at least every three years; this is the sixth IRP filed by EAL.
- The EAL IRP process is guided by the twelve resource planning objectives, which were approved and instituted by the Company in 2012.
- Stakeholder engagement and feedback consistent with the Commission's guidelines have been key components of the IRP process since EAL's first IRP in 2006.
- EAL has made significant progress on the nine action items identified in its Mid-Cycle IRP Action Plan.

Introduction

The 2024 IRP covers the study period 2026-2045 and is the sixth IRP filed by EAL since the APSC adopted its Resource Planning Guidelines in Order No. 6 in Docket No. 06-028-R. Like the previous IRPs, EAL's 2024 IRP reflects that long-term resource planning is a dynamic and uncertain process, with no individual outcome providing absolute certainty as to the appropriate path for the utility to take. Potential costs and benefits, many of which are unforeseen, are assessed as they become known. In other words, the uncertainties that informed EAL's Mid-Cycle IRP update filed with the Commission on December 2022 (e.g., advances in renewable resource technology) remain but have been expanded to include other uncertainties, such as the impact and role of technology costs, growing role of renewable generation penetration in the market, and shifts in customer preferences and trends.

EAL's process for preparing this IRP considered potential future scenarios in which various resource plans could be evaluated. As with EAL's Mid- Cycle IRP update, this IRP was:

(i) developed by EAL's Resource Planning and Operations Staff,

(ii) reviewed by EAL's Resource Planning and Operations Committee ("RPOC"), and

(iii) approved by EAL's President and Chief Executive Officer ("CEO"), Laura R. Landreaux.

As indicated in Chapter 1 and consistent with the Commission's Resource Planning Guidelines, this IRP does not provide a fixed path for future EAL resource planning. Rather, EAL's specific long-term resource planning actions (e.g., capacity additions) are subject to review and approval by the Commission. The Action Plan contained within this IRP reflects EAL's current expectations regarding the planning actions the Company will take over the next several years and identifies a preferred portfolio. It is essential to understand that this is a snapshot in time based on the information available today and that a future IRP's preferred portfolio or EAL decision may deviate from this IRP's preferred portfolio based on new information or market influences.

Why does EAL need to plan for resources?

With various factors listed below, EAL needs to plan for resources to meet the growing demand and customer needs affordably, reliably, and sustainably.

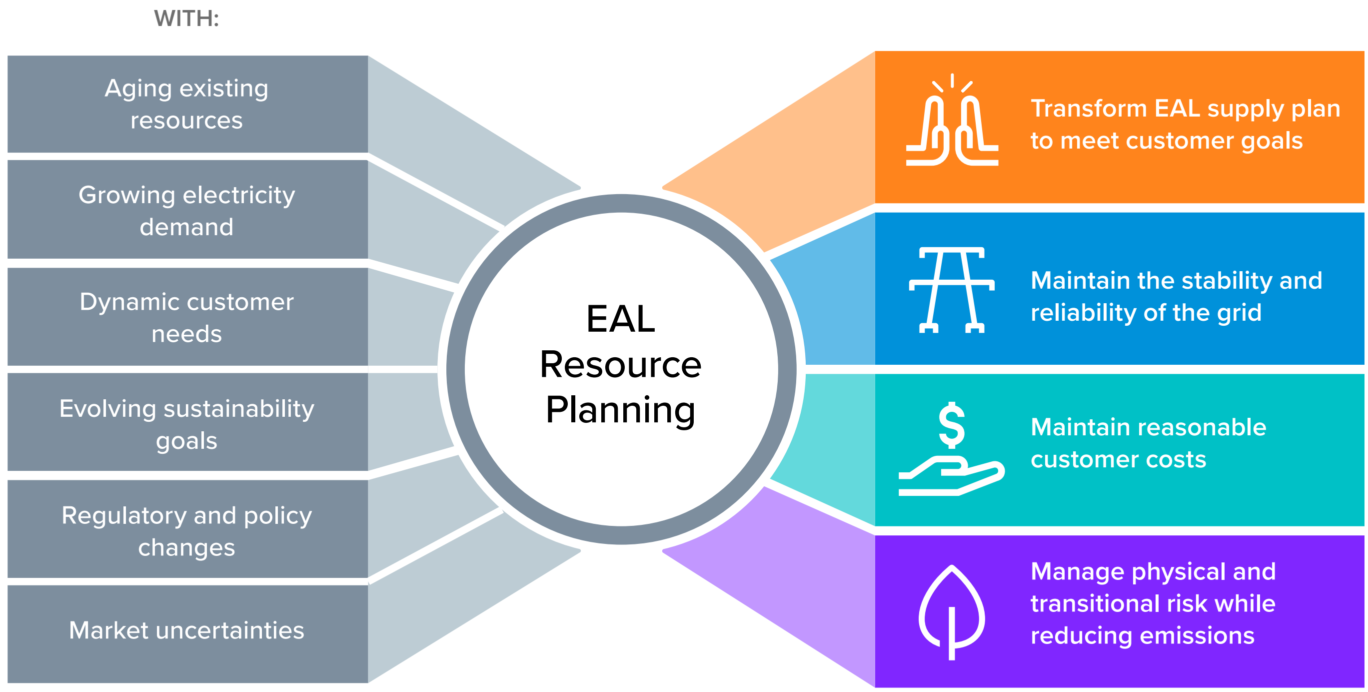


FIGURE 5: EAL NEED TO RESOURCE PLAN

Resource Planning Objectives

EAL has established a set of resource planning objectives to guide its development of the IRP. These planning objectives were recommended by the RPOC and approved by EAL's former President and CEO Hugh T. McDonald on May 16, 2012. Upon review of these planning objectives since the Mid-Cycle IRP, EAL maintains that the Company's key focus areas remain affordability, reliability, and sustainability. This balance looks at both the near-term and long-term benefits and risks associated with each key objective.

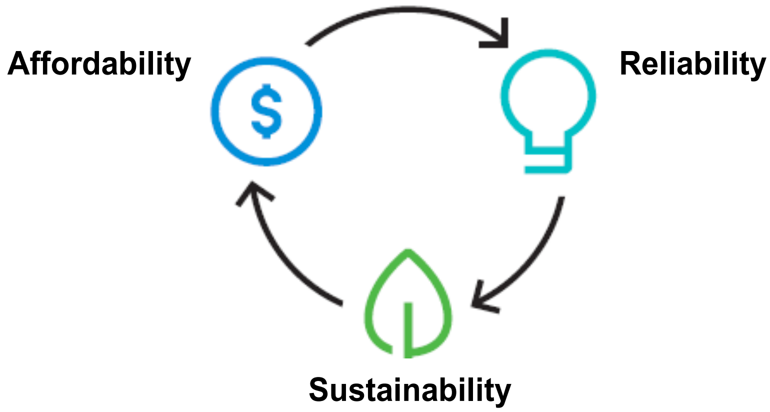


FIGURE 6: KEY PLANNING PRINCIPLES

In developing this IRP, EAL considered the resource planning objectives listed below to meet the requirements of the APSC Resource Planning Guidelines for Electric Utilities and outlined in more detail in Appendix A:

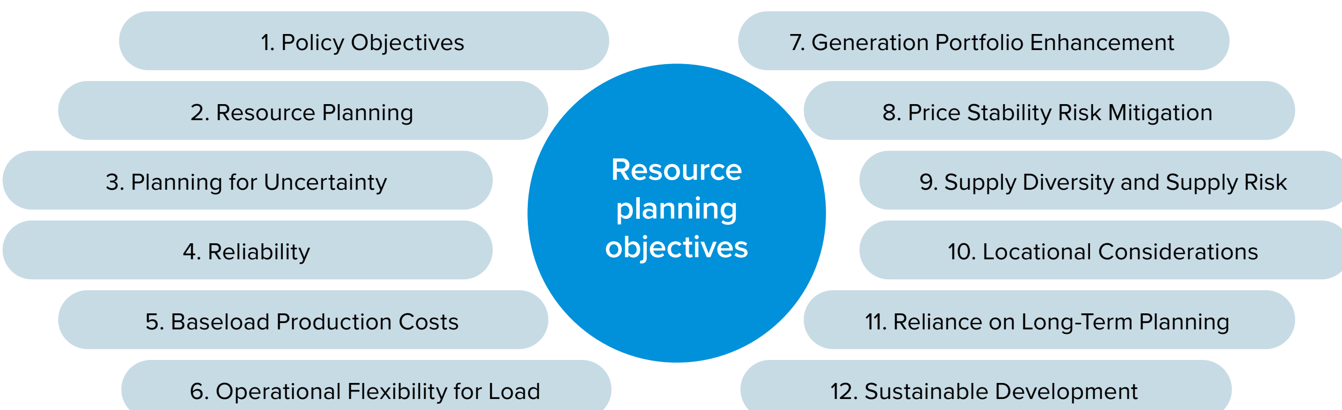


FIGURE 7: APSC RESOURCE PLANNING GUIDELINES FOR ELECTRIC UTILITIES

Long-Term Planning Challenges

EAL is committed to delivering reliable, affordable, and sustainable power for its customers. Achieving this balance is central to EAL's planning objectives, however, numerous planning challenges naturally arise due to a wide range of uncertainties.

One of the key challenges begins with forecasting future load, which is influenced by a multitude of dynamic factors. Changes in customer usage patterns, electrification, demand response ("DR") programs, economic growth, demand growth, accreditation changes, and weather variability all contribute to resource planning challenges. The widespread adoption of energy efficient appliances, smart home technologies, and customer usage behavior complicate load forecasting, especially as these trends alter peak times and energy needs. Moreover, extreme weather conditions such as heatwaves in summer or cold winters tend to drive short-term load fluctuations, causing sudden spikes in demand and energy, making it difficult to plan for sufficient generation capacity to meet demand during these high-stress periods.

Uncertainty also stems from evolving regulatory environments, which add layers of complexity to the planning process. As a member of MISO, EAL closely monitors and adapts to changing planning requirements, especially those pertaining to resource accreditation and reliability requirements. These changing planning requirements often impact capacity needs, which in turn require a quick response by utilities to meet the demand and minimize exposing customers to the risk of price volatility.

The addition of new resources presents its own set of challenges. While renewable energy is a key component of a sustainable power grid, its intermittent nature necessitates investments in dispatchable resources and storage solutions. Long term implementation of these generating resources is complex, involving different Engineering, Procuring and Construction ("EPC") timelines, logistics, and costs. Additionally, transmission planning must ensure the reliable and stable delivery of electricity. Growing interconnection queues further complicate the process of bringing new resources online.

EAL continuously strives to overcome these challenges and meet its commitment to customers by proactively managing uncertainties through robust planning processes.

Regulatory Context for EAL's IRP

In 2006, the Commission adopted an IRP rule requiring APSC-jurisdictional utilities to file an IRP at least every three years.[1] The rule required that utilities would immediately file their then-current resource plans. EAL met that obligation by filing the Strategic Supply Resource Plan that was in place then. EAL's next IRP was filed in 2009 and included the results and report of a stakeholder input process conducted for EAL's **2009 IRP**, as well as more comprehensive considerations of demand-side management ("DSM") and load control options. For EAL's **2012 IRP**, EAL modified its stakeholder process, reviewing actual study results with stakeholders rather than only reviewing high-level study assumptions and plans, deviating from what EAL did for its 2009 IRP. Stakeholders presented numerous questions at open meetings or in writing, which EAL addressed with written responses.

[1] See Order No. 6 in APSC Docket No. 06-028-R.

For the **2015 IRP**, EAL's stakeholder process proved to be far more interactive than prior stakeholder processes conducted by the Company, with numerous meetings and conference calls directed by the stakeholders with EAL participation and input. EAL notes the extensive work by the Stakeholder Group on the 2015 IRP, which is reflected in the stakeholder comments attached to the report. These comments reflected the diversity of the views held by various stakeholders.

For the **2018 IRP**, EAL's stakeholder process continued to evolve in response to increased stakeholder feedback and engagement. As part of multiple well-attended meetings and calls, stakeholders were provided with proposed assumptions, inputs, the IRP's modeling framework, and modeling results from all three IRP Futures. EAL also responded publicly to numerous stakeholder questions and hosted a technical discussion to gather and address feedback regarding EAL's modeling results. EAL again notes the extensive work undertaken by the Stakeholder Committee, which is reflected in the Stakeholder Report attached to the 2018 IRP.

For the **2021 IRP**, EAL worked with stakeholders to address many issues and questions raised in the 2018 IRP's Stakeholder Report. Due to the COVID-19 pandemic, the stakeholder engagement process for this IRP was conducted virtually via multiple meetings and calls, including data postings and Q&A sessions at stakeholder request. As in the 2018 IRP cycle, stakeholders were provided with proposed assumptions, detailed inputs, the IRP's modeling framework, and modeling results from four IRP futures plus requested sensitivity portfolios. With the industry continuing to evolve towards decentralized and renewable resources, EAL added a fourth future for the 2021 IRP to more broadly account for a range of uncertainty. Additionally, EAL received multiple stakeholder comments and/or request letters as part of the IRP design process, to which the Company responded and endeavored to accommodate where feasible. EAL issued an update to the 2021 IRP called the **Mid-Cycle IRP**, which updated inputs such as the hourly load forecast as well as the Generation Verification Test Capacity ratings ("GVTC") for all existing resources, LMR capacity ratings, and PPA. The Mid-Cycle IRP aimed to refresh the implementation of the 2021 IRP Action Plan and align the preferred portfolio with changes in the inputs. Stakeholder engagement was part of the process, and EAL hosted a stakeholder meeting to review the mid-cycle IRP.

For the **2024 IRP**, EAL has implemented improvements based on previous IRP cycles and prioritized incorporating feedback from stakeholders both from the 2021 Stakeholder Report and input received from the current 2024 IRP process. This input was based on relevant questions raised during stakeholder meetings and post meetings as follow-up questions. As in the 2021 IRP and Mid-Cycle IRP, a future based approach was utilized with the addition of a reference scenario specifically focused on modeling compliance with the final CAA 111 rule. Additionally, in response to stakeholder comments regarding the renewable cost assumptions in the 2021 IRP, EAL included sensitivity cases for capital cost projections of renewables and battery energy storage systems ("BESS") in the 2024 IRP.

The Mid-Cycle IRP Action Plan

The Mid-Cycle IRP Action Plan contained nine action items, some of which are still in process. The current status of each action item is described below:

1. Complete the Acquisitions of Searcy, Walnut Bend, Driver, and West Memphis Solar Build-Own-Transfer ("BOT") Resources	EAL acquired Searcy Solar in January 2022, and the unit has been operational since then. Additionally, EAL completed the acquisitions of Walnut Bend, Driver, and West Memphis facilities in 2024. Walnut Bend achieved commercial operations in September 2024, Driver and West Memphis are expected to be online by the end of 2024.
2. Complete the 2021 Renewables RFP	In August 2021, EAL issued its 2021 Renewables RFP and completed the RFP in early 2022. The APSC approved the two 200 MW solar PPA resources selected from 2021 Renewables RFP, and they are currently under construction. The PPAs are expected to begin in 2025.
3. Effectuate the Deactivation of LC4 in 2025	In the prior IRP, LC4 was assumed to deactivate in 2025. However, EAL has since determined that LC4 is needed to operate through December 2027. This IRP also assumes a CT replaces LC4 and operates within three years of LC4's deactivation per MISO's generator replacement process. EAL will file for approval at the APSC for the replacement CT in the fourth quarter of 2024.
4. Identify DSM Opportunities	EAL's current portfolio includes DSM opportunities through agricultural irrigation load control, smart thermostats, residential direct load control program, and an interruptible tariff. Since the 2021 IRP Mid-cycle Update, EAL has added the Large Power High Load Density Service tariff (Crypto customers) which also receives capacity accreditation from MISO. EAL has begun assessing additional DSM opportunities through pilot offerings.
5. Continue Participation in Energy Efficiency ("EE")	After the 2020-2022 triannual EE program cycle, the APSC approved 2023 as a bridge year with the same targets and approved budgets as Planning Year ("PY") 2022. EAL's programs exceeded APSC savings targets in the four Program Years from 2020 through 2023. The APSC approved the next triannual EE programs for the program cycle for 2024-2026 in November of 2023.
6. Pursue Power Resiliency	Power Through represents EAL's initial power resiliency offering. In July 2024, EAL filed a compliance filing with the APSC that included EAL's revised proposed tariff consistent with the APSC's directives. EAL expects to begin offering Power Through service to its customers in 2025.
7. Implement Sustainable Solutions	Not only does EAL have five solar resources totaling 930 MW planned to achieve commercial operations between 2024 and 2025, but the Company also has developed two green tariffs to facilitate greater customer access to renewable resources across all customer classes, including low-income customers: Green Promise and Go ZERO.
8. Evaluate Stakeholder Engagement	As in prior IRP cycles, stakeholder engagement has been an integral part of the development of this IRP. As noted, EAL has taken steps to enhance the stakeholder engagement process and address some of the pertinent feedback raised in the 2021 IRP's Stakeholder Report. Additional details on the stakeholder engagement process are included in Chapter 7 of this report.
9. Complete the 2022 Renewable RFP	EAL completed the RFP issued In June 2022 for Renewable Resources. The RFP seeks to procure up to 1,000 MW of solar and/or wind resources with PPA deliveries and/or acquisitions starting in the 2025-26 timeframe.

CHAPTER 3

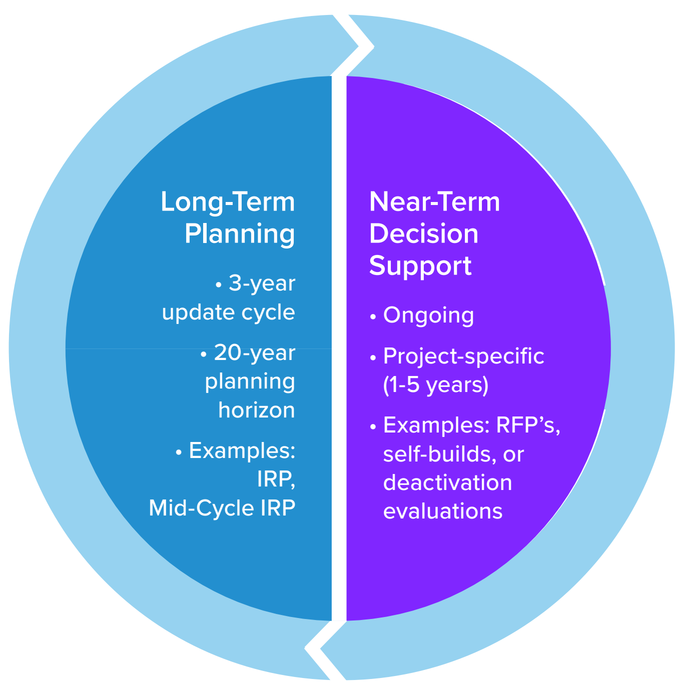
Integrated Resource Planning Process

Summary

- EAL's IRP strategy ensures that the Company is taking the necessary steps to continue to enhance affordability, reliability, and sustainability for its customers while providing flexibility to respond and adapt to a constantly shifting utility landscape.
- This strategy requires balancing many different variables, including evolution in technology and customer preferences, resource and transmission attributes, MISO resource adequacy requirements, and sustainability goals.

The IRP plays an important role in the iterative process of planning EAL's future resource portfolio by providing a comprehensive and transparent look at long-term themes and tendencies in designing and leveraging a diverse, balanced, and forward-thinking portfolio of resources to EAL planners and stakeholders. While these long-term and forward-looking indicators are important guides to resource planning, the IRP fulfills a distinctly different purpose and process from near-term, specific resource decisions that are presented to the APSC for approval. The IRP process guides the general direction of long-term resource planning. Specific resource selections are more akin to GPS coordinates of a specific location. Both are critical components of an integrated process.

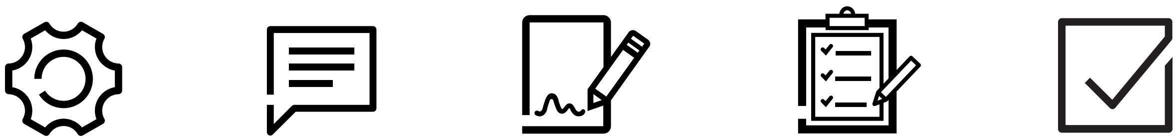
The considerations in this report are focused on efficiently meeting customers' ever-changing supply needs. EAL's IRP strategy ensures that EAL is taking the necessary steps today to continue to enhance affordability, reliability, and sustainability for its customers. This approach also provides the flexibility EAL requires to respond and adapt to a constantly shifting utility landscape.



The twenty-year study period for the 2024 IRP outlines the current energy landscape and the challenges and opportunities that lie ahead. A twenty-year study period was chosen for this IRP to evaluate long-term trends under a broad range of possible future outcomes. As in EAL's previous IRPs, the 2024 IRP is guided by EAL's Resource Planning Objectives, which focus on affordability, reliability, and sustainability. This IRP looks at the near-term and long-term benefits and risks associated with each key objective. The full details of the Resource Planning Objectives are available in Appendix A.

IRP Process

An IRP is a planning process and framework in which the costs and benefits of capacity and energy resources are evaluated to develop resource portfolio options that help meet EAL's planning objectives. Each component shown below in Figure 8 of the IRP process is key to creating an informative and effective IRP.



Planning and design	Stakeholder engagement	Modeling and analysis	Conclusions and action plan	Publishing and filing the report
Building future scenarios, assumptions, and ranges of risk factors	Sharing information and receiving feedback	Market modeling, EAL portfolio optimization, production cost projections	Identifying themes and opportunities, establishing a mid-term, actionable plan	Organizing information, displaying results, and communicating EAL's perspective

FIGURE 8: IRP PLANNING PROCESS COMPONENTS

The IRP serves as the foundational framework guiding EAL's long term generation decision and planning. EAL's long-term assessment starts with understanding the Company's current capabilities and capacity position. This includes accounting for existing generation capacity, existing resources deactivation timelines, planned new future resources schedules and capacity, and current load assumptions. The IRP analytics are then used to assess the gap.

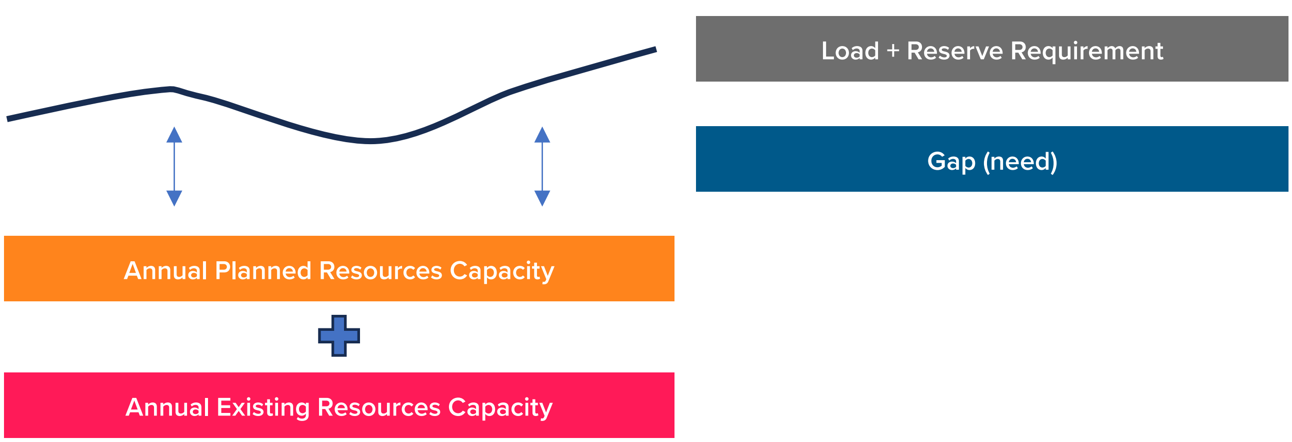


FIGURE 9: CAPACITY NEED ASSESSMENT

Existing Resources

EAL's customer base has grown to over 730,000 residential, commercial, industrial, and governmental customers in 63 of Arkansas' 75 counties, covering over 40,880 square miles. The Company currently controls, through ownership or through PPA, a diverse array of generating resources totaling approximately 5,479 MW of installed capacity ("ICAP") to serve these native load customers as of 2023.

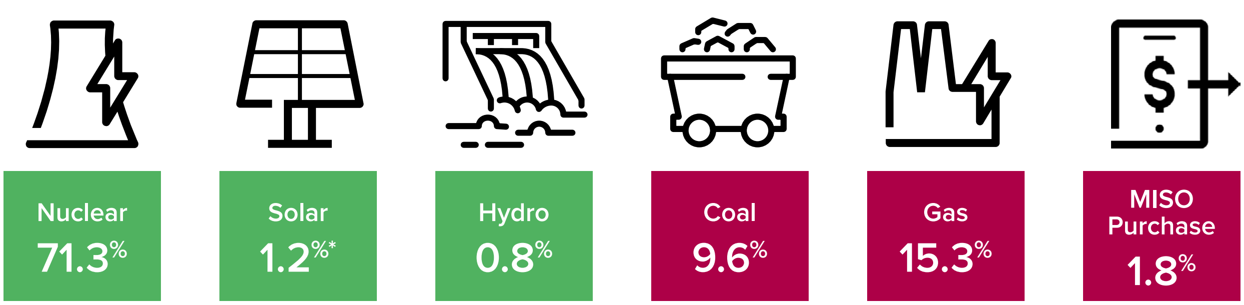
The Company fleet includes 37% of its clean capacity from the 1,726 MW of nuclear power resources from the two-unit ANO plant located near Russellville, Arkansas, as well as 303 MW from the Grand Gulf Nuclear Station ("Grand Gulf") near Port Gibson, Mississippi, which is under a long-term PPA.

EAL also utilizes 1,026 MW from coal-fired generation at White Bluff Steam Electric Station ("WB") and Independence Steam Electric Station ("ISES"), located near Redfield and Newark, Arkansas. EAL shares ownership of WB with the Arkansas Electric Cooperative Corporation ("AECC") and several municipal electric utilities; and shares ownership of ISES with AECC, Entergy Mississippi, LLC; Entergy Power, LLC; East Texas Electric Cooperative; along with several municipal electric utilities.

EAL relies on 2,070 MW of natural gas-fired generation that includes 563 MW from the Hot Spring Plant, 481 MW from the Ouachita Plant, and 504 MW from Union Power Station, which are modern combined cycle combustion turbine ("CCCTs"), as well as 522 MW from the LC4 plant.

EAL's generation fleet includes about 6% of renewable capacity with 73 MW of hydro-electric capacity along the Ouachita River Valley, 81 MW of solar from the Stuttgart Solar facility and 100 MW of solar from the Chicot Solar facility. Since the 2021 IRP, EAL added a 100 MW solar photovoltaic ("PV") and 10 MW of battery resource located near White County, Arkansas named Searcy Solar. The resource achieved commercial operation in December 2021 with EAL's BOT commencing on January 21, 2022. Additional information about EAL's existing resources is available in Appendix B.

Chart 2 below shows the percentage, by fuel type, of energy sources serving EAL's native load in 2023.



*SOLAR % EXCLUDES GREEN OFFERING SUBSCRIPTION OF ~0.07% SOLAR

CHART 2: 2023 EAL FUEL MIX

In addition to these generating resources, EAL's portfolio also includes resources that provide capacity value through reductions in customer load. These LMRs contributed nearly 485 MW combined of capacity including value associated with reduced line losses and reserves.

EAL also manages a portfolio of EE programs that produce both energy savings for customers and a reduction in load served by the Company. These programs have reduced the Company's load behind the customer meter by an incremental 272 MW since 2020 and an aggregate 772 MW since programs were introduced in 2014. The 2022 program year was designed to achieve 120% of a Commission-established target for achieved savings of 1.2% of 2018 retail sales. EAL exceeded that target with an overall achievement of 133% savings (1.59% of 2018 retail sales), which allows the programs to meet the performance incentive thresholds established by the Commission in Docket No. 13-002-U. Net program savings averaged 299 MWh for the 2020-2022 Program Years. In the 2024-2026 EE Plan, EAL expects to continue offering a Low-Income Program under Act 1102 of 2017 guidelines.

EAL's Gross Savings (ex ante)	302,315 MWh
As adjusted by Tetra Tech for Realization Rate (ex post)	301,059 MWh
As adjusted for Net-To-Gross ("NTG") ratios	292,926 MWh
EAL's MWh Target adjusted for Self Direct ("SD")	220,845 MWh
% of Target Achievement Based on Evaluated Energy Savings	133%

TABLE 1: 2022 EE PROGRAM METRIC

Future of Existing Resources

As indicated above, uncertainty is an ongoing issue that resource planners must consider in preparing long-term resource plans. In subsequent sections, EAL will review several factors that are assessed to guide and inform the portfolio design strategies and other issues facing EAL's planners.

Developing an IRP requires making assumptions about the future operating lives of existing generating units. Two key issues in this determination are the effective date of future environmental compliance requirements and whether the investments needed for EAL's older units to keep operating in compliance with those regulations are economical compared to alternative capacity resources. The IRP includes deactivation assumptions for existing generation to plan for and evaluate reasonable options for replacement capacity over the planning horizon. Based on the current design life assumptions incorporated into the IRP, some of EAL's existing generating units are anticipated to deactivate over the IRP planning horizon (2026-2045). During this planning period, the total reduction in EAL's generating capacity from the assumed unit deactivations grows to approximately 2,973 MW.

These deactivation assumptions do not constitute a definitive deactivation schedule but are used as planning tools and help to prompt cross-functional reviews and recommendations. It is not unusual for these assumptions to change over time given the dynamic use and operating characteristics of generating resources. The useful life for EAL's fleet of CCCT generators is based on historic operations and current conditions of each of the facilities. The IRP assumes EAL's CCCT generators may continue to cost-effectively generate energy well beyond the 30-year assumption in all four futures. Additionally, for EAL's nuclear fleet, the IRP assumes both units operate through the end of the modeling horizon.

As planned deactivation dates near, should significant equipment failure increase, or operating performance diminish, a reassessment of assumptions may be required. Unit-specific portfolio decisions, e.g., sustainability investments, environmental compliance investments, or unit deactivations, will be made at the appropriate time and will be based on economic and technical evaluations considering such factors as projected forward costs, anticipated operating roles, the reliability of the system, legal and environmental compliance, and the cost of supply alternatives. These factors are dynamic, and as a result, actual decisions may differ from planning assumptions as greater certainty is gained regarding legislative, regulatory, and relative economic requirements. Accordingly, EAL's IRP seeks to retain the flexibility to respond to changes in circumstances up to the time that a commitment is required to be made.

Planned Resources

Resource	Nameplate Capacity (MW)	Resource Type	COD[2]
Walnut Bend	100	Solar	2024
West Memphis	180	Solar	2024
Driver	250	Solar	2024
Flat Fork	200	Solar	2025
Forgeview	200	Solar	2025
2022 RFP	up to 1000 MW	Solar	Target 2027
2028 CT	446	Gas	Target 2028
2029 CCCT	733 Generic	Gas	Target 2029
2030 Solar	600 Generic	Solar	Target 2030
2030 Battery	350 Generic	Battery	Target 2030

EAL recently completed the acquisition of the Walnut Bend, Driver, and West Memphis facilities. Walnut Bend began commercial operations in September 2024, while Driver and West Memphis are expected to begin operations in the fourth quarter of 2024. Additionally, EAL received APSC approval for two 200 MW solar PPAs, which were selected out of the 2021 RFP and are planned to commence in 2025. EAL issued another renewable RFP in June 2022 that targeted procuring up to 1,000MW of additional solar and/or wind resources. Additionally, EAL is planning to replace LC4 with a CT at the same location to be online by winter 2028. As depicted in Figure 1 above, EAL is working on an additional CCCT for 2029 as well. Under the assumption that the planned resources described above proceed as planned, the 2024 IRP reflects approximately 7,269 MW of resources in EAL's portfolio by 2026 on an ICAP basis. The diversity of EAL's currently planned resource portfolio in 2026 is shown in Chart 3 below.

[2] All dates shown are targets and subject to change except for Walnut Bend, which achieved COD in September 2024.

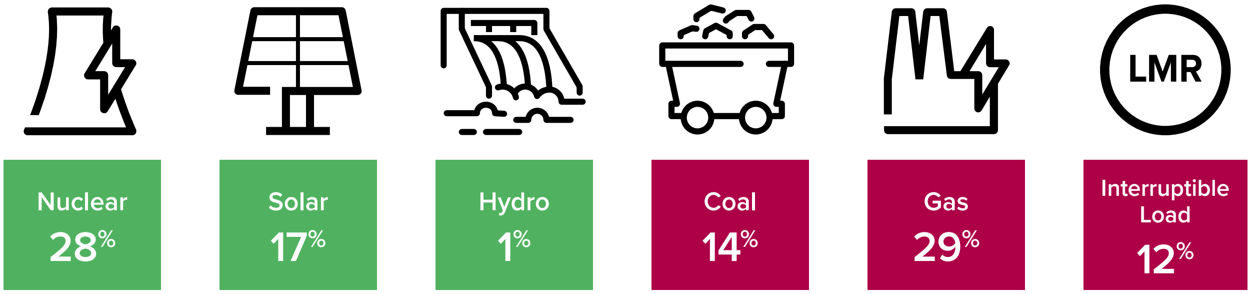


CHART 3: 2026 EAL CAPACITY MIX

Environmental Justice

EAL is mindful that public health impacts and Environmental Justice ("EJ") concerns are important considerations in the Company's daily operation. EAL respects the human rights of all individuals and defines human rights as those inherent to everyone, regardless of race, sex, nationality, ethnicity, language, religion, or other status. Everyone is entitled to these rights without discrimination, and EAL is committed to advancing and protecting human rights in all our operations.

EAL strives to minimize any potential adverse effects on the local communities the Company serves, including the communities of its low-income customers. EAL considers how EJ impacts its planning and policies to minimize adverse environmental effects and to sustain its communities. EAL maintains open communication and seeks opportunities to partner with its stakeholders on EJ concerns.

EAL aspires to be an industry leader in protecting the environment. Environmental laws, regulations and orders affect many areas of the Company's business, including restrictions on hazardous and toxic materials, air and water emissions, and waste disposal. EAL is committed to meeting or surpassing compliance with all environmental and applicable regulatory requirements and to enhance the communities it serves.

To that end, the following provides several examples of EAL's measures regarding potential public health impacts and EJ considerations. In developing new generation, EAL identifies candidate sites and then evaluates environmental factors and land use considerations for each site and its surroundings. This evaluation considers the presence of wetland areas, existing water quality in nearby water bodies, the potential presence of threatened or endangered species, cultural sites, and ambient air quality. Many of these factors are similar to the environmental indicators the EPA EJSCREEN tool considers. In addition, EAL conducts environmental due diligence reviews to identify any existing environmental conditions at or near a proposed site for generation development.

EAL employed the EPA EJSCREEN environmental and justice mapping tool to evaluate the proposed Driver Solar and West Memphis Solar projects to assess potential EJ issues that may warrant additional consideration and to inform outreach and engagement practices. Table 2 below reflects the EJSCREEN Demographic Index (average of low-income and minority population percentages) results for within a 1 mile and 10-mile radius of each site.

	Minority population			Low Income Population			Demographic Index		
Project	1-Mile	10-Mile	State Average	1-Mile	10-Mile	State Average	1-Mile	10-Mile	State Average
Driver	12%	54%	31%	64%	47%	41%	1.8	2.12	1.59
West Memphis	39%	60%	31%	34%	46%	41%	1.56	2.23	1.59

TABLE 2: EPA EJSCREEN RESULTS

The EPA EJSCREEN results indicate that the project sites are within an area with a demographic index of 2.12 and 2.23 for a 10-mile radius, which are above the state demographic index average of 1.59. For a 1-mile radius, the project sites are within an area with a demographic index of 1.8 and 1.56, slightly above and below the state average but not significantly so. These two solar sites will generate emissions-free renewable power and are not expected to affect minority or low-income populations disproportionately.

EAL continues to review and analyze best practices related to potential public health impacts and EJ considerations, including the use of EJSCREEN and other beneficial tools, in planning for the future. With the commitment to achieve net-zero carbon emissions by 2050, cease to use coal by 2030, and to conduct due diligence in its operations, it is apparent that EAL is striving not only to improve the environment but also to improve the communities EAL serves by reducing potential public health impacts.

Customer Preferences and Long-Term Planning

With advancements in technology and evolving priorities, both within and outside the traditional utility framework, customer expectations will continue to change. Today's customers are using energy more efficiently than ever before, due to both an increasing emphasis on social responsibility and sustainability and advances in EE standards. As specified in the Resource Planning Guidelines, EAL approaches EE with the broader goal of enhancing the generation, delivery, and use of energy, recognizing that a well-designed electric system, with the proper mix of generating resources, is just as important to reducing customer costs and bills as are programs aimed at educating customers how to efficiently manage their usage.

In response to customer demand and a business environment that is increasingly focused on sustainability and renewable energy goals, EAL sought and received APSC approval of its Green Promise tariff in Docket No. 21-054-TF and Go ZERO tariff in Docket No. 23-037-TF. These voluntary products provide participating customers with direct access to renewable and clean energy attributes and support economic development in Arkansas.

EAL is focused on achieving a better understanding of these evolving customer preferences, and the IRP is one set of inputs that helps EAL accomplish that goal and allows EAL to:

- Develop a comprehensive outlook on the future utility environment so EAL can more effectively anticipate and plan for customers' and the region's future energy needs;
- Incorporate new, smart technologies and advanced analytics to assess better where expanding resource alternatives can be leveraged, and plan for improvements and enhancements to the electrical grid; and

- Continue seeking cost-effective renewable resource additions to EAL's portfolio to support and expand renewable energy offerings to interested customers.

Advancing Technology - Technological advancements provide the energy industry with increased opportunities and alternative pathways to plan for and efficiently meet customers' energy needs and to partner with customers to accomplish those shared objectives. From improving the reliability and efficiency of energy production and delivery of that energy to customers, to more customer-facing opportunities, like storage, conservation, and advanced metering infrastructure ("AMI")-enabled options, these innovations can strengthen reliability and increase affordability for the homes, businesses, industries, and communities that EAL serves. These new technologies also support the continued development and expansion of sustainability efforts while addressing EAL's long-term planning objectives, outlined in further detail below.

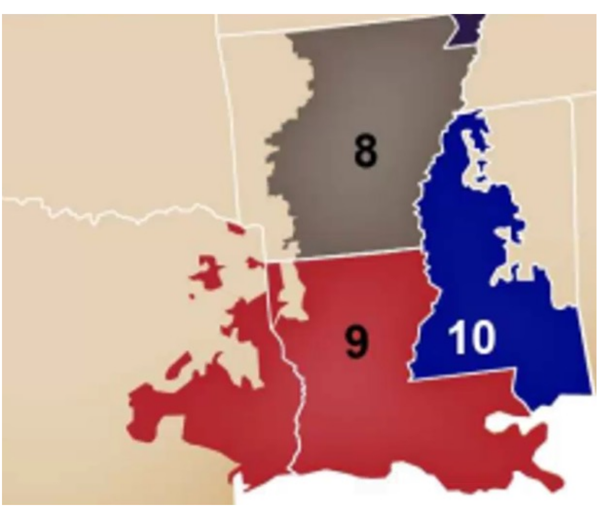
Increased Customer Value - By combining an understanding of what customers want with sound and comprehensive planning, EAL can deliver the type of services customers expect while continuing to address the planning objectives of cost, reliability, risk, and sustainability. Increasing the array of alternatives provides an opportunity to better meet EAL's planning principles by providing a diverse portfolio of resources to meet long-term service requirements. A diverse portfolio mitigates customer exposure to price volatility associated with uncertainties in fuel and power purchase costs and risks that may occur through a concentration of portfolio attributes such as technology, location, or supply channels. Additionally, by taking advantage of increased and evolving opportunities, EAL continues its practice of modernizing its supply portfolio.

MISO Resource Adequacy & Planning Reserve Requirements

EAL's Participation in MISO

EAL has been a market participant in MISO since December 19, 2013. Established in 2001, MISO operates as a nonprofit organization ensuring the reliability and efficiency of the electricity grid across 15 states and the Canadian province of Manitoba with over 500 Market Participants.

As shown in Figure 10, EAL operates primarily within Local Resource Zone ("LRZ") 8, except for Ouachita 1 & 2 in LRZ 9 and Grand Gulf in LRZ 10 of the MISO footprint.



As a MISO member, Entergy Arkansas' stake-holders benefit from increased informational transparency regarding:

- Resource adequacy
- Transmission planning
- Congestion management
- Market price signals

FIGURE 10: MISO LRZS 8, 9, AND 10

Resource Adequacy

As a load serving entity ("LSE") within MISO, EAL is responsible for planning and maintaining a resource portfolio to meet its customers' power needs reliably. To this end, EAL must maintain the proper type, location, control, and amount of capacity in its portfolio. With respect to the amount of capacity, two considerations are relevant:

1. MISO Resource Adequacy Requirements
2. Long-Term Planning Reserve Margin Targets

Resource adequacy is the process by which MISO obligates participating LSEs to demonstrate sufficient short-term capacity by procuring zonal resource credits ("ZRCs") equal to their PRMR. These ZRCs carry an obligation for the underlying resource to provide energy offers into MISO's markets or energy in emergency conditions to ensure regional reliability. ZRCs are provided by both supply-side generation and demand side alternatives. An LSE's PRMR is based on its forecasted load coincident with MISO's forecasted peak load, plus a planning reserve margin established by MISO annually for the MISO footprint and a transmission loss factor.

MISO's PRA is not and should not be relied upon as a long-term source of capacity. MISO is not authorized to build or procure generating capacity to ensure there is an ample supply; therefore, MISO relies on LSEs and retail regulators like the APSC to ensure each LSE has an appropriate amount of long-term physical capacity to support resource adequacy. If ZRCs submitted in the planning auction are less than the PRMR, the planning auction will clear at the Cost of New Entry ("CONE"). Notably, ZRCs are not sold through the planning resource auction. Rather, utilities participating in the auction merely make a payment, up to CONE, that fulfills their obligations vis-a-vis their respective PRMRs. Reasonable and responsible resource planning requires a long-term plan for physical resources that provides coverage of near-term resource adequacy requirements and supports regional reliability. EAL's long-term planning process aims to achieve those goals while leveraging the MISO capacity market to balance near-term short or long positions for the benefit of customers.

MISO market constructs, rules, and methodologies continue to evolve, including items that impact resource adequacy requirements and capacity accreditation. In November of 2021, MISO filed a proposal at FERC that shifts the annual resource adequacy construct to a seasonal construct including modification to the way requirements and accreditation are derived. FERC accepted MISO's proposed tariff changes in August of 2022, which have been implemented as of the 2023/2024 PY.

Considering the recent tariff changes, EAL's long-term planning approach is currently being re-evaluated to determine what updates, if any, are needed to accommodate MISO's new resource adequacy construct. Additionally, as capacity accreditation methodologies for non-thermal resources, such as solar, wind, and battery, are updated by MISO and approved by the FERC (assuming the FERC approval), EAL will align its long-term planning strategies with these updates. With anticipated increases in renewable penetration, MISO and EAL anticipate that the capacity value contribution of solar and wind will evolve.

Under MISO's resource adequacy process, the MISO-wide seasonal planning reserve margins are determined annually by November 1st prior to the upcoming planning year (June - May). Table 3 shows the MISO seasonal reserve margin targets for the 2024/2025 PY.

	Summer	Fall	Winter	Spring
Seasonal Reserve Margin Target	9.0%	14.2%	27.4%	26.7%

TABLE 3: MISO 2024/2025 PY SEASONAL RESERVE MARGIN TARGETS

Through MISO's annual resource adequacy process, MISO determines the amount of physical capacity needed within a particular region or LRZ based on load requirements, existing generation capability, and import capability of the LRZ. Those capacity requirements are called Local Clearing Requirement ("LCR") for the LRZ in each season of the Planning Year. Through MISO's proposed changes to the methodology for setting each LRZ's LCR, MISO has sent signals emphasizing the need for in-zone resources to contribute to LRZ resource adequacy.

Utilizing these seasonal reserve margin targets, EAL can assess the resource needs throughout the IRP period. Because the seasonal reserve margin targets are set annually, EAL will incorporate any target updates in future analyses.

At present, the MISO Resource Adequacy process is a short-term construct. Requirements are set annually and apply only to the upcoming year. Similarly, the cost of ZRCs, as determined annually through the MISO auction process, applies only to the upcoming year. Both the level of required ZRCs and the cost of those ZRCs are subject to change from year to year. In particular, the cost of ZRCs can change quickly because of variables such as changes in market participant bidding strategies, the availability of generation within MISO and a specific LRZ, or an LRZ's LCR. For example, if existing LRZ 8 generation is deactivated and replaced with generation outside of LRZ 8, there will be an increased risk of higher ZRC prices when in-zone generation is insufficient to meet the LRZ 8 LCR.

MISO's resource adequacy process considers only one year of load forecast uncertainty; thus, EAL plans beyond the immediate one-year requirement. The development of new capacity resources is a multi-year process, and load forecast uncertainty increases over that multi-year period in the future.

It should also be noted that the MISO resource adequacy construct is constantly evolving. Recently, MISO conducted a stakeholder process on its proposal to replace the vertical demand curve with a sloped demand curve in the PRA. EAL was engaged and participated in this stakeholder process. On June 27, 2024, FERC approved a downward-sloping Reliability Based Demand Curve, which will replace MISO's previous vertical demand curve. Implementation is scheduled for the 2025/2026 PY. EAL will adapt its long-term planning efforts and strategies to align with the resulting market design change.

Long-Term Planning Reserve Margin Targets - The Aurora model utilized summer and winter reserve margin targets based on MISO's 2024/2025 PY Loss of Load Expectation study applied to EAL's forecasted summer and winter coincident peak loads for each study year. Candidate resources received seasonal capacity credit consistent with this framework. While MISO's resource adequacy construct establishes reserve margins for each season, modeling the summer and winter reserve margin constraints captures the meaningful seasonal variations in performance and accreditation between candidate resources (e.g., solar, wind, and gas in summer vs. winter). Adding fall and spring reserve margin constraints would increase modeling complexity without any expected improvement in the capacity expansion portfolios. EAL is evaluating its long-term planning reserve margin targets for future IRPs in light of MISO's transition to a seasonal resource adequacy construct and its reliability-based demand curve ("RBDC") and DLOL accreditation proposals.

Resource Needs

Several factors are assessed to understand and determine EAL's resource needs. The next step is to identify capacity and energy gaps by evaluating how current capabilities align with projected load growth and market uncertainties. Once these gaps are identified, the IRP analysis is conducted to determine how EAL can address them effectively, leading to the selection of a preferred portfolio which is identified and described in Chapters 5 and 6.

Long-Term Capacity Requirements – As briefly described in the capacity need assessment framework in Chapter 3, EAL is projected to need new generating capacity throughout the 20-year IRP period to continue to serve customers reliably. Considering deactivation assumptions and load growth, EAL could see a winter deficit as early as 2027 and a summer deficit by 2028. This need may grow to over 8,300 MW by the end of the 20-year planning horizon in the high-load growth future. The charts below show EAL's portfolio of existing resources, including generating units and demand side capacity, and planned resources, as described above, compared to EAL's peak load plus the appropriate seasonal planning reserve margin. An assumption for future energy savings due to continued and expanded EE programs is included in the peak load. The deficit expands as expected loads increase and older generating units reach an assumed end of their useful life.

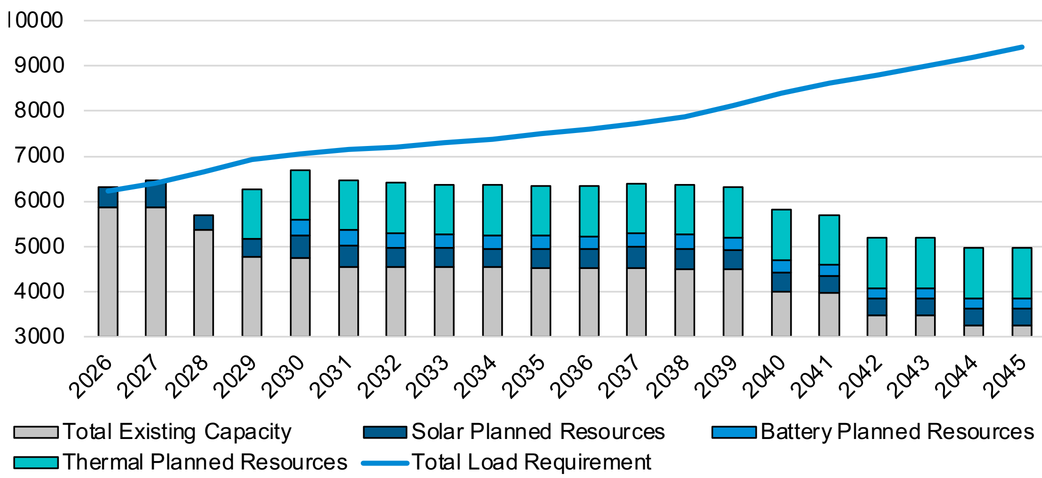


CHART 4: EAL CAPACITY POSITION SUMMER

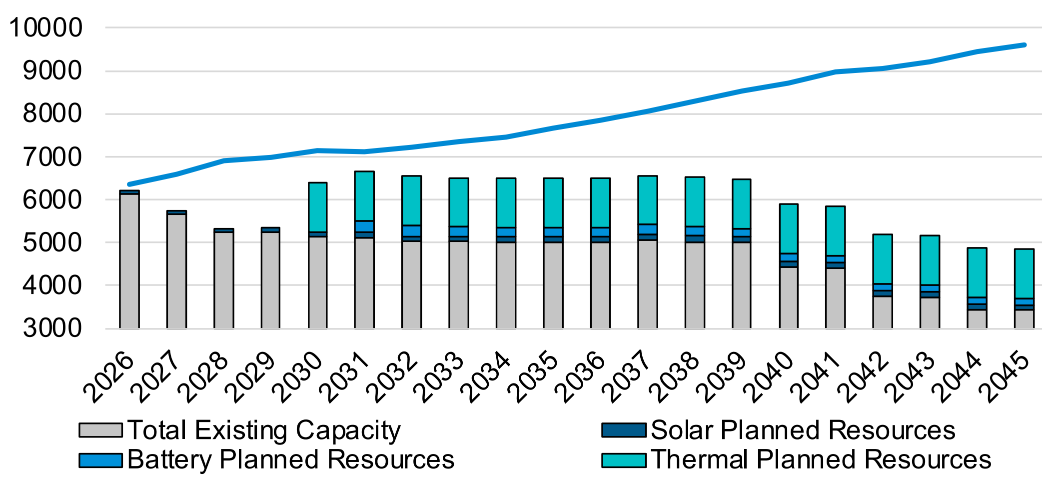


CHART 5: EAL CAPACITY POSITION WINTER

Energy Requirements – Besides addressing long-term capacity requirements, EAL regularly assesses how the current generating fleet is expected to align with its long-term energy requirements. Based on the current planning model projections and absent any changes to deactivation assumptions or approved resource additions, beginning in 2028, EAL is expected to fall short of effectively meeting its long-term energy requirements without significantly relying on the MISO market. However, the amount of energy produced by owned generation is subject to change based on fuel prices, market conditions, and unit operations.

Through the technology assessment and the IRP analytics, EAL evaluates energy-producing resources like renewable energy and small dispatchable natural gas resources to meet capacity and energy requirements over the long-term planning horizon. As resources deactivate and capacity requirements increase, EAL will balance energy producing and peaking generation to meet customer requirements effectively and efficiently.

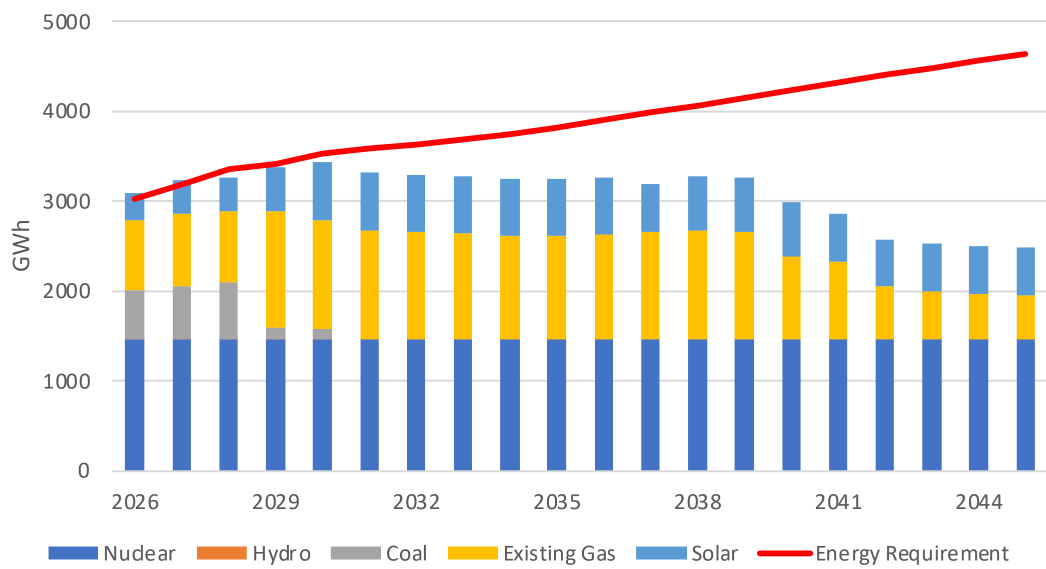


CHART 6: ENERGY COVERAGE SUMMER (AUGUST)

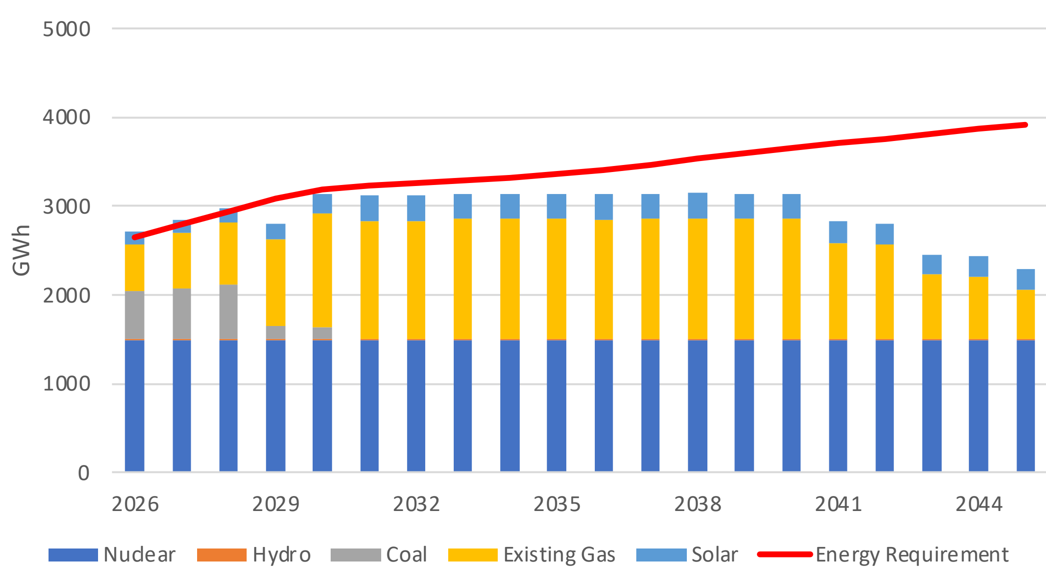


CHART 7: ENERGY COVERAGE WINTER (JANUARY)

Customer Usage – Unquestionably, capacity and energy resource needs are driven by customers' consumption and preferences. Customer conservation efforts, some of which are currently driven by EE programs, have already directly affected resource needs, as discussed further in Chapter 4. The type, size, and timing of future resource needs will be impacted as customers gain additional resources to manage consumption.

EAL's long-term planning process and the evaluation outlined in this IRP help inform how EAL will meet its future capacity and energy requirements needed to continue reliably serving its customers. Consistent with the resource planning objectives outlined in Chapter 2, EAL's planning approach is to employ a diverse portfolio of energy-generation resource alternatives, located in relatively proximity to customer load to help provide sufficient capacity during peak demand periods as well as adequate reserves. These practices ensure that EAL can continue providing safe and reliable service at a just and reasonable rates for customers.

Supply Role Needs – As discussed previously in the existing resource section, EAL's CCCT generation fleet provides customers base load and load-following energy supply. The IRP reflects useful life assumptions for existing CCCTs that have been based on historic operations and current conditions of each of the facilities. These deactivation assumptions as well as EAL's near-term cease to use coal dates result in a significant decrease in base load and load following capacity towards the end of the planning horizon.

EAL's current generating fleet also includes its LC4 gas unit, which continues to provide a large amount of ICAP and serves to meet reliability needs over seasonal peaks. However, the deactivation of LC4 early in the IRP planning horizon (2027) will reduce EAL's peaking resource capability if it is not replaced. As a result, in this IRP, a replacement CT is added starting in 2028 to support resource adequacy needs.

Locational Considerations – The location of resources significantly impact the electric grid. Resources, both supply-side and demand-side, effect the pattern of power flowing on the transmission system and on the voltage at the substations in the vicinity of the resource. Adding a generating resource injects power into the electric grid; this additional power might help alleviate congestion on the electric grid, but the incremental power might also result in thermal constraints that may have to be alleviated with transmission upgrades. The addition of resources may also add reactive power into the system that can provide voltage regulation. This effect on the electric grid is particularly beneficial for large industrial loads and other similar loads that impose reactive power demands. Deactivations of resources can similarly change the power flow through the electric grid and may result in overloads or voltage constraints, and any resource additions or replacements in lieu of resource deactivations may be strategically located on the electric grid to minimize any detrimental impacts. Finally, the location of resources also has a broader impact on the MISO capacity auction. A location within an LRZ allows a resource to contribute to the LCR of an LRZ in the MISO PRA.

Flexibility Considerations – The portfolio design analytics explore the value of renewable energy projects, energy storage, peaking, and CCCT capacity. Based on these analyses, the long-term planning horizon will likely include additions of renewable and energy storage technologies to EAL's portfolio. As intermittent resource additions increase and individual resources in EAL's legacy fleet wind down, EAL also may see increased value in additional flexible peaking and quick-response capability more indicative of spinning technologies, such as Reciprocating Internal Combustion Engines ("RICE") and Aero-derivative CT technologies. EAL is also committed to exploring clean, alternative fuel sources to ensure longevity of these resources.

EAL will continue to assess the likely increasing capacity, energy and operational flexibility required over the long-term planning horizon. This on-going assessment of the generation supply plan against dynamic factors like capacity requirements, operation roles, grid reliability and evolving technologies will enable EAL to improve efficiencies to develop solutions to address its customers' needs while mitigating risk.

Transmission Planning

Transmission planning ensures that the transmission system:

(1) remains compliant with applicable North American Electric Reliability Corporation ("NERC") reliability standards, and related Southeastern Electric Reliability Council and EAL's local planning criteria, and

(2) is designed to deliver energy to end-use customers efficiently and at a reasonable cost.

Since December 2013, EAL has been a Transmission Owning member of MISO, a Regional Transmission Organization ("RTO"). MISO was approved as the nation's first RTO in 2001 and is an independent nonprofit member-based organization that supports the delivery of wholesale electricity and operates energy and capacity markets in 15 U.S. states and the Canadian province of Manitoba. In cooperation with stakeholders, MISO manages 75,000 miles of high voltage transmission and 191 GW of ICAP across its footprint. Since joining MISO, EAL has planned its transmission system in accordance with the MISO tariff.

A key responsibility of MISO is the development of the annual MISO Transmission Expansion Plan ("MTEP"). EAL is an active participant in the MISO MTEP development process, which is currently in development of the MTEP 25 cycle. Participation in the MISO MTEP process is how EAL's transmission plan is incorporated into the annual MTEP document. The overall planning process can be described as a combination of "Bottom–Up" projects identified in the individual MISO Transmission Owner's transmission plans, which address issues more local in nature and are driven by the need to provide service safely and reliably to customers and projects identified during MISO's "Top-Down" studies, which address issues more regional in nature and provide economic benefits or address public policy mandates or goals.

Through these MTEP-related activities, EAL works with MISO, other MISO Transmission Owners, and stakeholders to promote a robust and beneficial transmission system throughout the MISO region. EAL's participation helps ensure that opportunities for system expansion that would benefit EAL customers are thoroughly examined. Combining Bottom-Up and Top-Down planning helps ensure all issues are addressed effectively and efficiently.

EAL's transmission strategy is centered on meeting the evolving needs of its customers for safe and reliable energy. Each year the EAL transmission system is thoroughly studied to verify that it will continue to provide customers with reliable and safe service through compliance with all applicable NERC reliability standards and local planning criteria and guidelines.

These studies identify potential system conditions where reduced reliability may occur in the future. Additional studies are then performed to develop projects and determine what, where, and when system upgrades are required to address future reliability concerns. This annual review identifies any transmission system reinforcements necessary to provide reliable and safe service in response to changing system conditions. These studies consider the effects of overall system load growth, retirements of existing generation resources, implementation of new generating resources, the adequacy of new and existing substations to meet local load, the expected power flows on the bulk electric system, and the resulting impacts on the reliability of the EAL transmission system.

These reliability studies result in projects presented annually to the EAL RPOC and ultimately must be approved by EAL's President and CEO. Once approved, these reliability projects are submitted to MISO for regional study to 1) verify that the reliability need exists, 2) verify that the proposed solutions solve the reliability need, and 3) provide stakeholders the opportunity to propose alternatives. Additionally, MISO performs other yearly studies to consider planning issues including, Market Efficiency Projects, Multi-Value Projects, and customer driven projects, such as those driven by generator interconnection requests, and opportunities for interregional projects with neighboring planning regions.

The result of the MISO MTEP process is a compilation of transmission projects that are needed to address system reliability requirements, improve market efficiency, and/or provide specific system benefits as delineated in the MISO Tariff. The MTEP identifies solutions to meet regional transmission needs and to create value opportunities through the implementation of a comprehensive planning approach.

Each MTEP document is identified by the year in which it was completed. Appendix A of each MTEP cycle lists and briefly describes the transmission projects that have been evaluated, determined to be needed and subsequently approved by the MISO Board of Directors. Since joining MISO in 2013, EAL has submitted projects into MTEP 14 through MTEP 25. The EAL projects that were approved for inclusion in Appendix A of MISO's MTEP 23 cycle are provided in Appendix C - Table I. Also, submitted Target Appendix A projects for MTEP 24 are in Appendix C - Table II, and projects for Target Appendix A of MTEP 25 are in Appendix C -Table III. These future transmission projects and other transmission plans developed during the next three years will be essential inputs to consideration of future resource needs.

Integration of Transmission and Resource Planning – The availability and location of current and future generation on the transmission system can significantly impact the long-term transmission plan, requirements for meeting NERC reliability standards, and efficiently delivering energy to customers at a reasonable cost. Optimal construction of generating resource and transmission facilities, both in terms of location and timing, and the continued maintenance of this integrated electric network is crucial to the functioning of an efficient and reliable electric network capable of delivering value to customers. Generating resources and the transmission grid serve complementary roles: while the transmission system conveys power to customers, the generating resources help meet the energy and capacity requirements of the grid. Moreover, like transmission, new generation must be planned well in advance of activation. Due to the interrelationship of generation and transmission planning, looking far enough into the future and addressing potential generation needs is critical to meet EAL's planning objectives of maintaining affordability, reliability, and sustainability.

The continued evaluation and condition of EAL's generation fleet must be considered for integrated generation and transmission planning. EAL's planning assumption includes deactivating existing generation resources during the planning horizon, which could impact transmission reliability without the proper siting of replacement generation. Likewise, the location of planned transmission facilities on the bulk electric system, particularly those at higher operating voltages, significantly impact the siting, timing, size, and type of planned resources to address the generation needs of a particular area.

Distribution Planning & Grid Modernization - Through its distribution planning process, EAL's efforts will continue to maintain and improve the reliability of the distribution lines and distribution line infrastructure, while aiming to minimize customer outages. Customers directly benefit from improvements in line maintenance, infrastructure, vegetation management, and substation reliability through reduced outages and outage duration. Customers also benefit from reducing costs by extending the life of distribution assets and minimizing maintenance costs concerning those assets.

Additionally, EAL's grid modernization efforts are aimed at continually upgrading and redesigning grid infrastructure to facilitate adding new technologies and intelligent devices that facilitate safe multi-directional energy flows, automate operations, enable remote control, increase operational efficiency, improve quality of service, increase reliability and resiliency, and expand options for customers.

This modernized grid infrastructure, including enhanced communications networks and broadband, is critical for day-to-day utility reliability needs and supports more significant deployment of advanced meters and related infrastructure, distributed energy resources ("DERs"), and other technologies. EAL's objective is to achieve a modernized distribution system over time that improves reliability to meet customers' evolving needs and expectations.

Integration of Transmission and Distribution Planning - While MISO operates an energy and ancillary services market, administers a transmission planning process and a resource adequacy process through an annual PRA, EAL, in its role as a load-serving entity, must integrate resource, transmission, and distribution planning to ensure that energy can be supplied to customers in a manner that is reliable, affordable, and environmentally responsible.

As discussed above in the "Distribution Planning and Grid Modernization" section, distribution investment will enable the interconnection of DERs and impact the system's reliability. Additionally, driven by customer-specific goals, or economically offsetting wire investments, distributed generation may be deployed across the EAL service territory. These investments impact the need for other transmission and generation investment.

Due to the interdependencies of the resource, transmission, and distribution long-term planning processes, coordinating and harmonizing these three planning processes are crucial to ensure that EAL's affordability, reliability, and sustainability objectives are met.

Sustainability Goals

Entergy has been an industry leader in voluntary climate action for over two decades. Building on its longtime legacy of sustainability, Entergy in 2020 enhanced its climate action strategy with a longer-term commitment, announcing that: Entergy will work over the next three decades to reduce carbon emissions from its operations to net-zero by 2050 as stated above. EAL intends to contribute to accomplishing this commitment by working with its regulators and other stakeholders to balance affordability, reliability, and sustainability. In 2001, Entergy was the first U.S. utility to limit its carbon dioxide emissions voluntarily. After beating this target by more than twenty percent, Entergy has renewed and strengthened this commitment twice. Entergy outperformed by eight percent its obligations through 2020 to maintain carbon emissions from Entergy owned facilities and controllable power purchases at twenty percent below year 2000 levels. In 2019, Entergy announced a goal to emit half the carbon emissions per MWh in 2030 versus 2000 and in 2020 announced its commitment to achieve net-zero emissions by the year 2050.

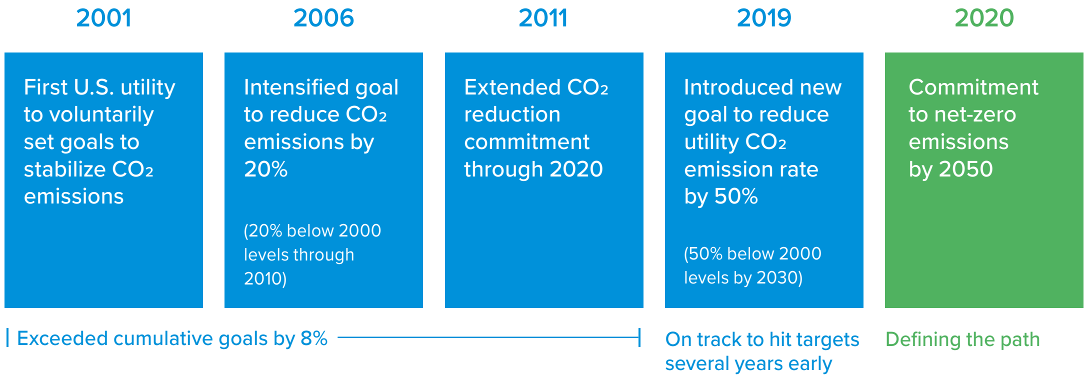


FIGURE 11: ENTERGY CLIMATE ACTION STRATEGY

Entergy is taking action now toward a carbon-free future. It is aiming to achieve its net-zero 2050 commitment by enhancing its transformation strategy with emerging technology options, working with customers, key suppliers, and partners to advance new technologies necessary to reduce emissions. Entergy continues to engage with partners and gain experience on enhancing natural systems like forests and wetlands that absorb carbon, while partnering with customers to electrify other sectors like transportation and industry for net emissions reductions and community benefits.

Additional details are available in Entergy's 2023 Performance Report and in the most recent climate report from 2022.[3]

[3] Entergy 2023 Performance Report PDF

2022-Climate.pdf (entergy.com)

CHAPTER 4

Model Inputs and Assumptions

Summary

- **EAL's IRP strategy ensures that the Company is taking the necessary steps today to continue to enhance affordability, reliability, and sustainability for its customers while providing flexibility to respond and adapt to a constantly shifting utility landscape.**
- **This strategy requires balancing many different variables, including evolution in technology and customer preferences, resource and transmission attributes, MISO resource adequacy requirements, and sustainability goals.**

Resource Planning Considerations

Guided by its Resource Planning Objectives, EAL's resource planning process seeks to maintain a portfolio of resources that affordably, reliably, and sustainably meet customers' power needs at a just and reasonable cost while minimizing risk exposure. The landscape within the electric utility industry is changing, and this IRP offers early insight into opportunities to respond to this evolving environment. EAL strives for a planning process that provides the flexibility needed to better respond to this constantly evolving environment. This planning approach includes modeling scenarios with various inputs to study market outcomes.

Load Forecasting Methodology

Each year, EAL develops a load forecast for financial and resource planning. That forecast is often used as the starting point or reference case for scenario analysis such as the IRP process. That reference case is developed sequentially starting with a forecast of monthly billed sales, which is then converted to a calendar month view and subsequently converted into hourly loads across each month. Other scenario forecasts are then developed similarly, starting with monthly energy and then converting those levels to hourly loads. Based on the timing of the EAL IRP cycle, the most recent forecast used as a starting point for developing the IRP future scenarios was developed in mid-2023. As such, for the 2024 IRP, the 2023 starting point forecast is considered the low case. Accordingly, EAL developed two futures forecasts based on the low case forecast for the 2024 IRP. The future scenarios are discussed in detail further below.

Load Forecast Uncertainty

Electric load in the long term will be affected by a range of factors, including:

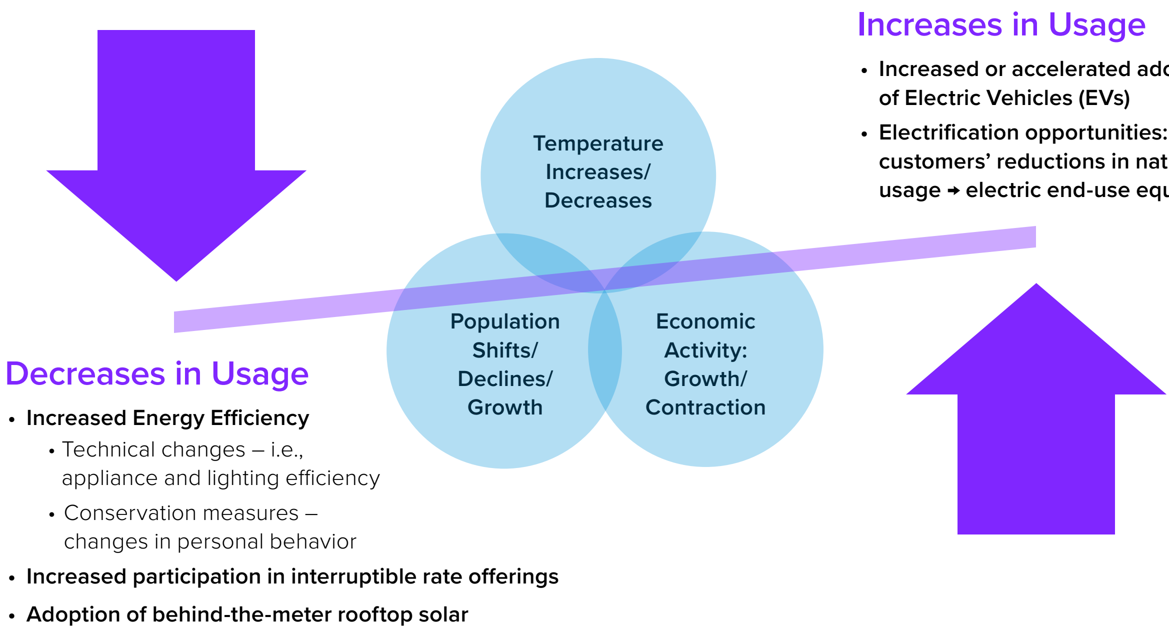


FIGURE 12: LOAD FACTOR UNCERTAINTY

These factors have varying effects on hourly consumption patterns across each day in the study period. This can create higher or lower annual peak loads and shifts in time-of-day peaks.

Low Case Energy Forecast

The low case forecast was developed using a bottom-up approach by customer class: residential, commercial, industrial, and governmental. The forecast was developed using historical sales volumes, customer counts, and temperature inputs from January 2010 through April 2023, as well as future estimates for normal weather (based on 20-year averages) and EE. In addition, the forecast includes estimates for changes in customer counts, future growth in large industrial usage, estimates of future consumption growth from electric vehicles ("EVs"), and declines due to future rooftop solar adoption.

Regression Models for Non-Large Industrial Forecasts

The sales forecasts for the residential, commercial, small industrial, and governmental classes are developed individually using statistical regression software and a mix of historical and forward-looking data. The historical data primarily includes monthly sales volumes by class and temperature data expressed as cooling degree days ("CDDs") and heating degree days ("HDDs"). Some of the forecasts also use historical indices for elements such as population, employment, and levels of end-use consumption for things such as heating/cooling, refrigeration, and lighting. These historical data are used in Itron's Metrix ND® forecasting software. This software is used to develop statistical relationships between historical consumption levels and explanatory variables such as weather, economic factors, and month-of-year, and those relationships are applied going forward to estimates of normal weather, economic factors, and the month-of-year to develop the forecast. Explanatory variables are typically included in each class-level forecast model if the statistical significance is greater than 95%.

Residential Forecasts for EAL

The long-term residential forecast projects an increase in electricity consumption with 1.4%/yr. Compound Annual Growth Rate ("CAGR") for 2026-2045. This forecasted increase is largely due to increasing average Use Per Customer ("UPC") in the long-term periods, reflecting EV adoption increases, slightly offset by nearly flat customer count growth. The customer counts are projected based on S&P Global's county level economic data for EAL's service territory.

The monthly model for residential UPC, taking into account expected efficiency is:

	Energy	Customers	UPC
2027	-0.2%	0.1%	-0.3%
2030	0.3%	0.1%	0.3%
2033	1.5%	0.1%	1.4%
2036	2.2%	0.0%	2.2%
2039	2.0%	-0.1%	2.1%
2042	2.2%	0.0%	2.2%
2045	2.0%	-0.1%	2.1%
2026-2045 CAGR	1.4%	0.0%	1.4%

TABLE 4: YOY GROWTH RESIDENTIAL

Residential UPC per day =
Heating Degree Days * Heating end-use index * Heating coefficient +
Cooling Degree Days * Cooling end-use index * Cooling coefficient +
other use coefficient * other end-use index

Table 4 shows the year-over-year changes and CAGRs in residential energy, customer counts, and UPC.

The residential forecasts use variables for individual months instead of heating or cooling indices with monthly values across a year, allowing for greater precision with each monthly result. The regression uses actual historical weather, and the resulting coefficients are applied to estimates for trended normal weather levels in the future.

Commercial Forecast for EAL

The long-term commercial forecast projects an increase in electricity consumption with 3.3%/yr. CAGR for 2026-2045. This forecasted increase is largely due to a slightly increasing customer count and higher usage driven by estimated increases for electrification modifications and EV adoption levels in the commercial sector. Since the prior IRP, the EV adoption curve was revised significantly, based on announced plans at the time from auto manufacturers and other positive news around vehicle charging. Industry trends combined with refining the EV forecast methodology, using vehicle registration data and resulted in a higher EV forecast. Similarly, more electrification opportunities are expected since the last IRP.

The commercial sales forecast is developed using a methodology similar to the residential forecast with the exception being that the commercial sales are forecasted in total, rather than by UPC. This is because of the diversity of commercial customers, such as a large hospital versus a small office. Otherwise, the commercial forecast accounts for organic EE, primarily from heating, ventilation, air conditioning ("HVAC") and refrigeration as well as Company-sponsored DSM programs, which are discussed further below.

Year	Energy	Customers
2027	1.6%	0.5%
2030	2.5%	0.4%
2033	3.1%	0.3%
2036	5.0%	0.1%
2039	4.5%	0.0%
2042	3.4%	-0.1%
2045	2.7%	-0.2%
2026-2045 CAGR	3.3%	0.1%

TABLE 5: YOY GROWTH COMMERCIAL

The monthly model for Commercial Sales:
Heating Degree Days * Heating efficiency index * Heating coefficient +
Cooling Degree Days * Cooling efficiency index * Cooling coefficient +
other use coefficient * other use efficiency index

Governmental Forecast for EAL

Governmental energy usage is forecasted to be relatively flat with only a slight increase for 2026-2045 with a CAGR of -0.1/yr. This is due largely to a slight decrease in customer counts, offset by a modest increase in UPC.

Small Industrial Forecast for EAL

The small industrial forecast includes industrial sales not forecasted individually in the large industrial forecast, further described below. Forecasts are based on historical trends and IHS economic indices such as labor force, refining, and chemicals. Small industrial sales can be volatile and are generally not temperature related.

Large Industrial Growth

The 2026-2045 CAGR for EAL's large industrial sales is 0.2%. Due to their sizes, customers in the large industrial class are forecasted individually. Existing large industrial customers are forecasted based on historical usage, known or expected future outages, and information about expansions or contractions. Forecasts for new or prospective large industrial customers are based on information from the customer and from EAL's Economic Development team as to each customer's expected MW size, operating profile, and ramping schedule. The forecasts for new large industrial loads are also risk-adjusted based on the customer's expected likelihood and progress towards achieving commercial operation.

Year	Sales
2027	0.6%
2030	2.8%
2033	0.0%
2036	0.0%
2039	0.0%
2042	0.0%
2045	0.0%
2026-2045 CAGR	**0.2%**

TABLE 6: YOY LARGE IND GROWTH

Energy Consumption by Class

EAL's energy consumption comes mostly from the industrial and residential customer classes who account for 49% and 29%, respectfully, of the forecasted sales for 2026.

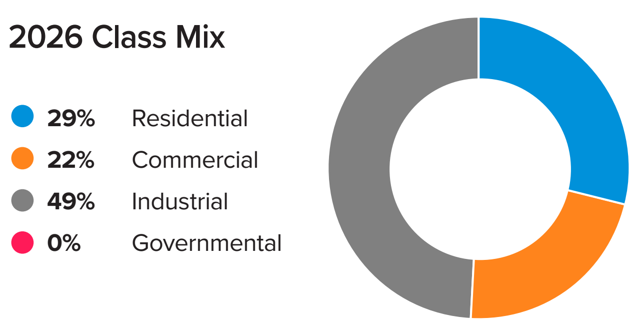


CHART 8: 2026 ENERGY CLASS MIX

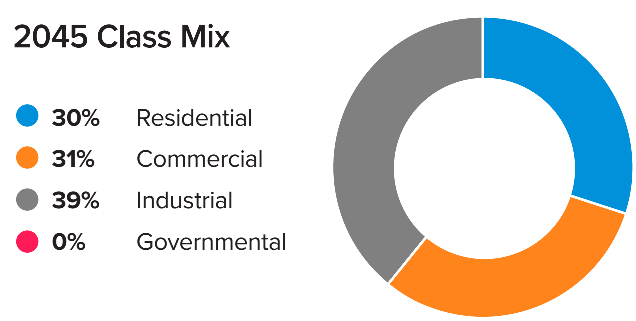


CHART 9: 2045 ENERGY CLASS MIX

This consumption mix by class shifts throughout the study period, namely an increase in commercial sales from incremental EV and Electrification over time, offsetting generally flat industrial sales in the long-term. See Chart 9 for the projected 2045 energy mix by customer class.

Energy Efficiency

EE comes from consideration of two sources: (1) the effects of naturally occurring or organic EE and (2) the effects of EAL's Commission-approved EE and DSM programs. The naturally occurring EE includes customers replacing older HVAC systems or appliances with newer, more efficient units, replacing incandescent lighting with LED lighting, and the growth in numbers of new multi-family (apartments) residences over single-family residences. Data for the naturally occurring EE are the Statistically Adjusted End Use estimates from Energy Information Administration to reflect expected changes in EE codes and standards as well as adoption and turnover rates for each end use. EAL's EE programs help customers make the same types of efficiency improvements and help move the timeline forward from when the naturally occurring efficiency would occur. Together, organic EE and the Commission-approved EE programs result in EAL's customers using less electricity on a per-customer basis than what would have otherwise been consumed. As shown in the graphic below, these programs have effects in the program year, which accumulate and carry forward creating impacts on future periods as well.

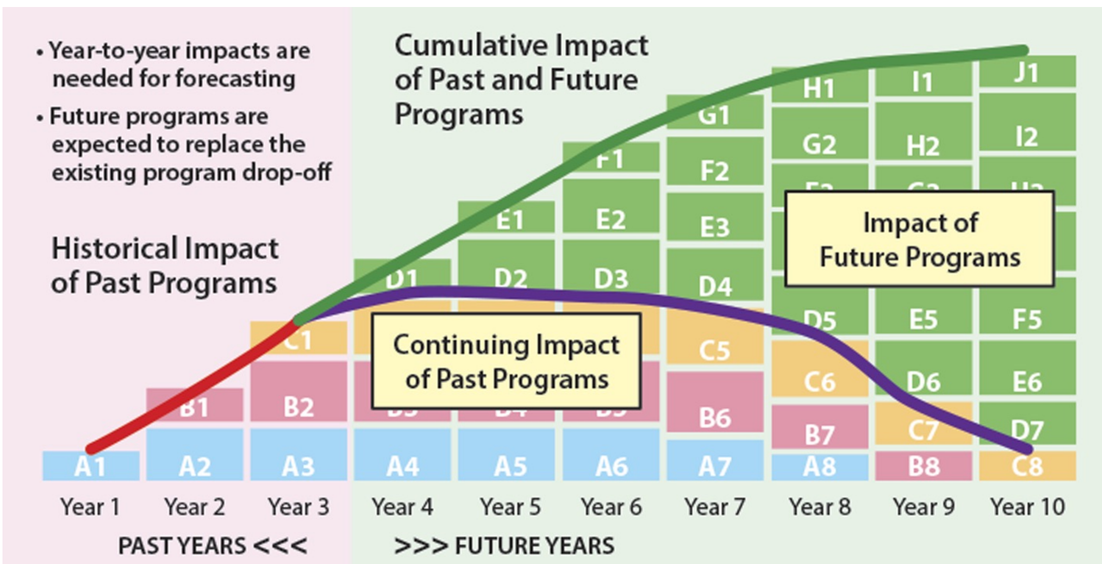


FIGURE 13: CHRONOLOGICAL DSM IMPACT

Solar

The low case forecast includes a decrement for estimated future customer solar installations. A separate set of forecast models estimates these future solar installations using technical, economic and market potential, combined with cumulative historical adoption trends in the EAL service territory.

The technical potential is based on a report from the National Renewable Energy Laboratory ("NREL") that assesses the percentage of sales potentially offset by rooftop solar, derived from the number of buildings and rooftops that are suitable in each state. The potential used for EAL's service area (MISO South) is 30% for residential and 39% for commercial which, in effect, becomes the ceiling for the number of customers adopting rooftop solar.

The economic potential comes from the results of a payback model, which considers factors including installed panel costs, tax incentives, and electricity prices. The installed panel cost curve is based on estimates from IHS. The assumed installed cost for rooftop solar can be seen below.

Cost for Rooftop Solar (in $/Wdc)

Customer Class	2023	2024	2025
Residential	2.76	2.72	2.63
Commercial	1.53	1.52	1.44

TABLE 7: COST FOR ROOFTOP SOLAR

The power prices are based on EAL's forecasted retail rates going out five years and are scaled based on annual zonal Locational Marginal Price ("LMP") estimates for the long term. For residential and commercial customer installations, it is assumed that there is a federal tax credit of 30%, which begins to taper by 2030 to 22% by 2045.

The market potential is developed using a customer adoption model that considers how new technologies are adopted over time.

Solar adoption rates over time are then calculated using a combination of the potential impacts described above and EAL historical solar adoption trends. The resulting future solar adoption estimate is allocated to monthly megawatt hours levels based on assumed average installation sizes and hourly profiles of the solar intensity for EAL's region (MISO South) using solar profiles from NREL.[4]

From 2026 forward, the low case forecast includes relatively small effects from rooftop solar adoption from residential customers, as payback periods exceed 10 years. The commercial forecast has a higher impact on total sales reduction, due to the assumed panel sizes being higher for larger sites and lower payback periods. A number of customers are also assumed to install solar for non-economic reasons.

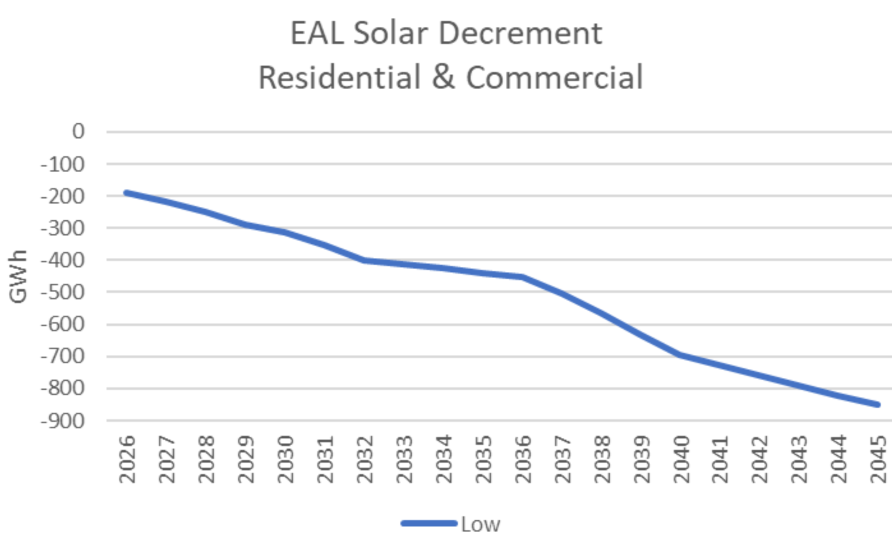


CHART 10: EAL SOLAR DECREMENT [5]

[4, 5] http://pvwatts.nrel.gov/

Electrification and Conversions

The Low Case forecast includes an assumption for company-run sales growth programs to encourage electrification. The programs include both on-road and non-road conversions, such as fleet electrification and commercial process electrification, respectively. Based on estimates from 2023, these projects are expected to add nearly 1.9 TWH to commercial sales by 2050.

Trended Normal Weather

The temperature assumptions used for long-term planning are based on “Normal” weather, which is customary utility forecasting practice. For EAL’s planning, this is an average based on twenty years of temperature history. The use of 20 years strikes a reasonable balance between longer periods (30 years), which may take longer to pick up changing weather trends and shorter periods (10 years), which may not provide enough data points to smooth out volatility.

Analysis of historical data reveals that trends in average temperatures, expressed as CDDs and HDDs, have not been flat over the last few decades, and there is no evidence at this time to support an assumption of future temperatures remaining flat. As such, EAL has calculated a “Trended Normal” assumption for long-term energy planning using trends in 20-year rolling averages of monthly temperatures from 2003 - 2022. Those trends are applied to the base level of the 20-year normal temperatures, and the trended normal result is used in the forecasts. By 2045, the effect of the trended normal temperature assumption increases summer (July - September) residential and commercial energy consumption by 58 GWh (1%) and decreases winter (December - February) energy consumption by 38 GWh (-1%).

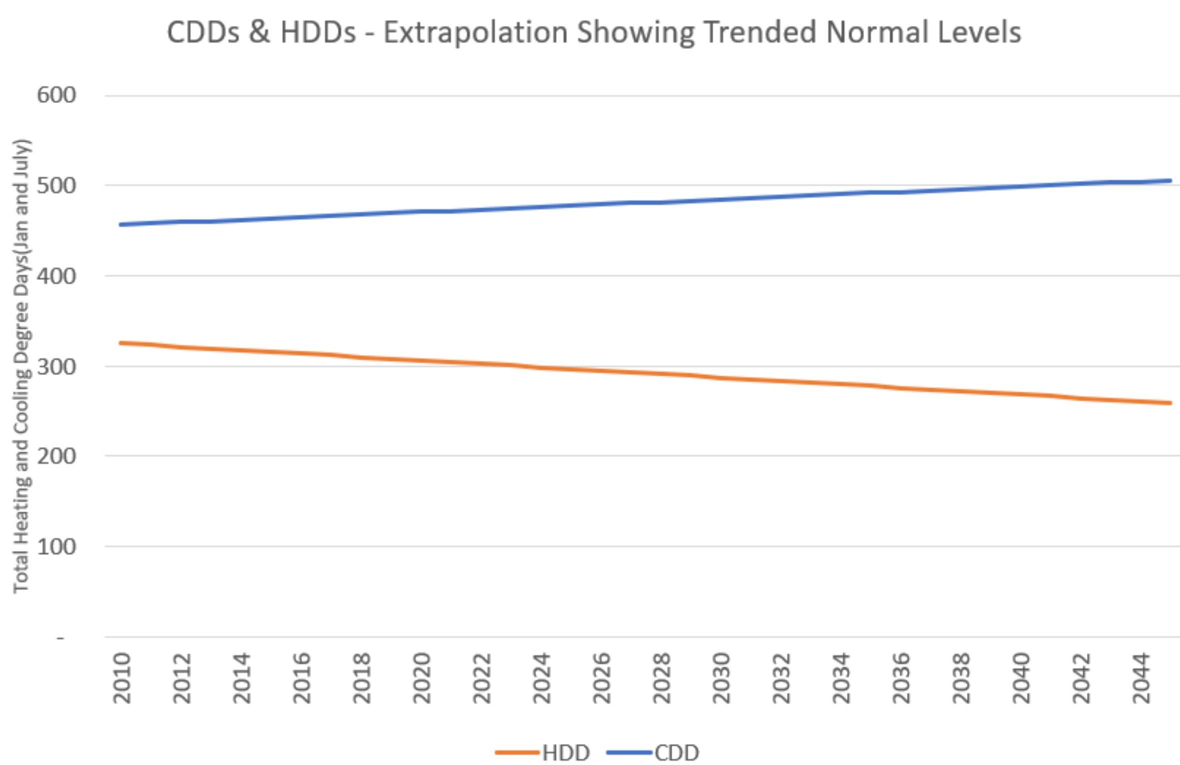


CHART 11: CDDS AND HDDS – EXTRAPOLATION OF 20 YEAR ROLLING

Hourly Load Forecast

Methodology

The load forecast combines three elements: the volumes from the monthly sales forecasts described above, the estimated monthly peak loads, and the hourly consumption profiles or shapes. These elements are developed using Itron's Metrix ND® software.

The forecasted monthly sales provide the monthly MWh volume for the load forecasts and reflect the expected effects of a few elements, such as customer growth or declines, new large industrial loads, and EE. The monthly volumes are also used to develop the peak forecasts and are estimated based on the historical relationship of peaks to energy, while also considering the effects of weather. Hourly load shapes are developed from historical hourly load by customer class and in total. Those historical shapes are used along with historical weather data (HDD and CDD), calendar data to account for differences in usage on weekends or holidays, and other data to develop "typical load shapes" by customer class to be used for the forecast period.

The final step in producing the hourly load forecasts is to combine – or calibrate – the monthly energy, monthly peak, and the hourly shapes described above. Using Itron's Metrix LT® software, the energy volumes, the estimated peaks, and the typical hourly shapes are calibrated such that the three elements fit together in a way that the final result preserves the volume of energy while fitting it to the hourly profiles while maintaining, as closely as possible, the relationship of peak MW to monthly MWh. This process also reallocates the forecasted solar and EV energy using specific profile hours for each product technology. The result is a set of hourly load values, by class, for the forecast period from which a peak level can be determined, as shown below.

Reference Case Peak Comparison to Previous IRP

Since EAL's 2021 IRP cycle, there have been increases in the peak load forecast levels. This increase is primarily due to estimated growth in the large industrial class, driven by large new loads.

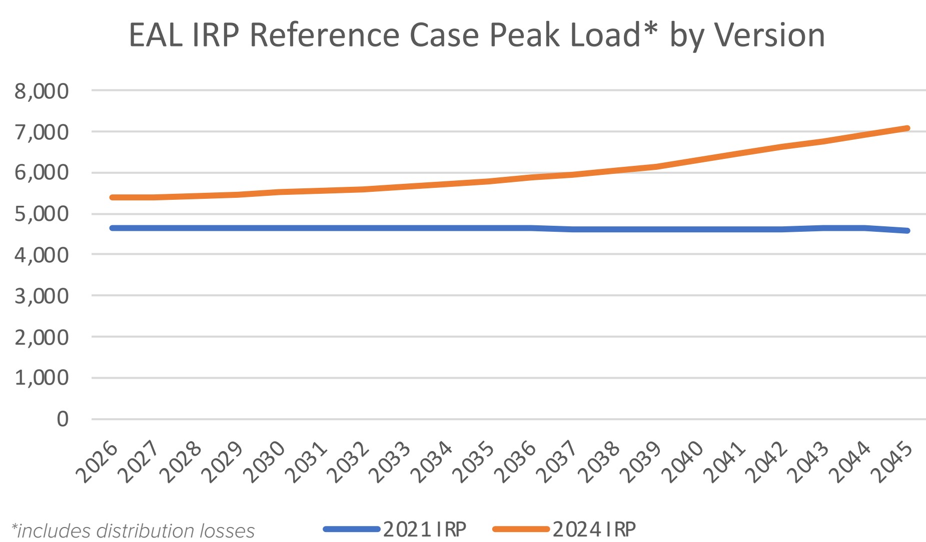


CHART 12: EAL IRP REFERENCE CASE PEAKS BY VERSION

IRP Load Scenarios - Load levers by Future

In past IRP iterations, EAL would create "high" and "low" sensitivity forecasts by adjusting a Reference Case up or down to reflect a range of load possibilities. For this IRP, EAL started with a low scenario and then adjusted specific levers to produce the reference and high scenarios. This process modification was driven primarily by potential industrial growth not included in the business plan load forecast approved in mid-2023. A summary of the levers used is shown below and described in each of the future scenarios:

Adjustments to low case by Scenario

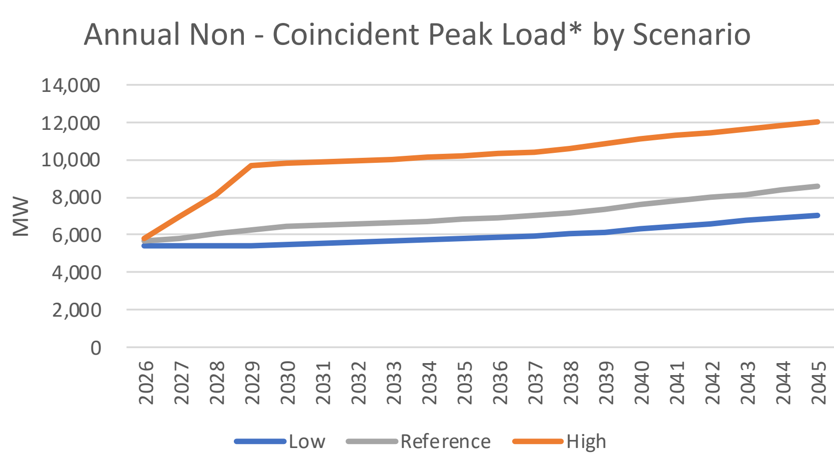
Lever	Reference	High
EVs	Higher	Higher *(equal to Reference)*
Building Electrification	Higher	Higher *(equal to Reference)*
Energy Efficiency	Lower	Higher *(equal to Reference)*
Customer Growth (Industrial)	Higher	Higher
Customer Usage (Industrial)	Higher	Higher

TABLE 8: LOAD LEVERS BY FUTURE

In the low scenario, there is assumed to be less year-over-year growth among residential and commercial customers. Additionally, the average UPC was decreased to lower levels, accounting for the potential of greater effects from EE. To further reduce the energy in the low scenario, EV adoption was also lowered. Industrial customer growth was held steady.

The main cause of changes in the high scenario is the addition of even more large industrial customers with large load additions. This was driven by a recent significant increase in interest from large customers in EAL's service area.

The results of these volumetric changes provide forecasted sales, which are converted to hourly loads to model estimated impacts to EAL's peaks, as shown below.



includes distribution losses

CHART 13: EAL IRP PEAK LOAD FORECAST BY FUTURE

EVs

The low case forecast includes an assumed level of additional energy consumption resulting from the adoption of EVs, as well as growth of total on-road vehicles over time, as overall adoption is expected to continue to increase. Overall, the additional GWh volumes from the EV forecast in the low case are minimal in the near term with growth to the residential and commercial consumption volume estimated to start increasing more in the late-2030s. The low case assumes 99% market saturation by 2070. These usage levels were then assumed to increase by an additional 25% for the EV forecast inputs for the reference and high scenarios.

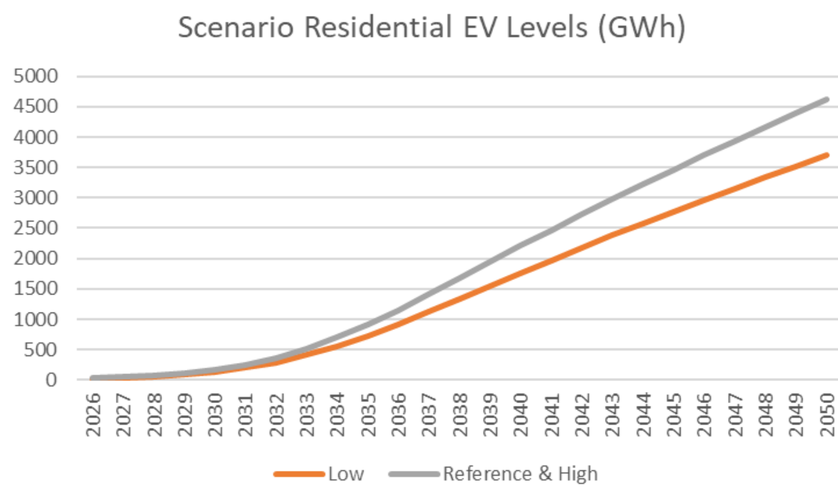


CHART 14: RESIDENTIAL EV LEVELS

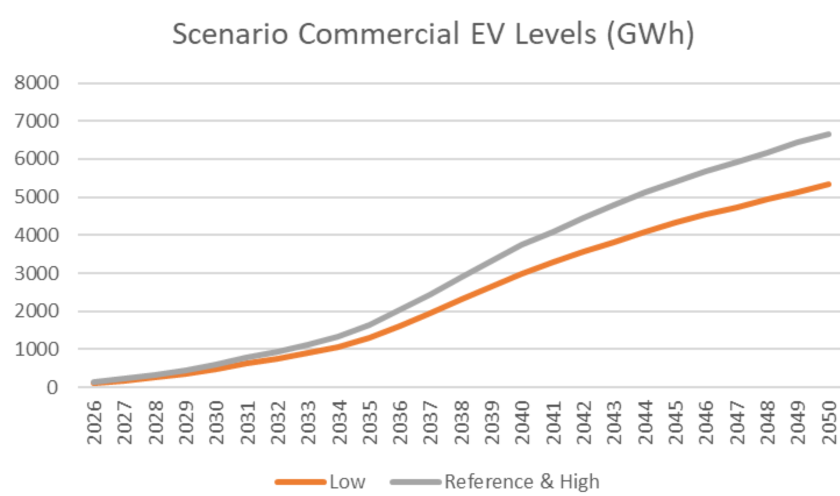


CHART 15: COMMERCIAL EV LEVELS

Industrial Growth

Regarding industrial growth, the low scenario assumes increases in usage driven by existing customer expansions and the anticipation of new customers. Reference and high scenarios include even higher potential industrial growth, based on a recent significant increase in interest from large customers in EAL's service area.

Capacity Resource Options

Generation Technology Assessment - As part of its long-standing sustainability and as the operator of one of the cleanest generation fleets in the nation, Entergy's commitment to reduce utility emissions by 50% below 2000 levels and achieve net-zero emissions by 2050 requires a continued transformation of its generation portfolio. EAL's IRP process evaluates available generation alternatives to meet customer energy needs per the planning objectives. As part of this process, the generation and storage technology assessment was prepared to identify a range of potential supply-side resource alternatives that merit more detailed analysis due to their potential to meet EAL's planning objectives of balancing affordability, reliability, and sustainability.

Technology Evaluation and Selection - As illustrated in Figure 14, EAL evaluated the cost-effectiveness and feasibility of deployment for many potential supply-side resources. The three-phased (i.e., Technical, Economic, Technology Selection) process to select generation alternatives considers qualitative and quantitative criteria and results in a final selection of supply-side resources that are best positioned to meet customer energy needs consistent with EAL's planning objectives.

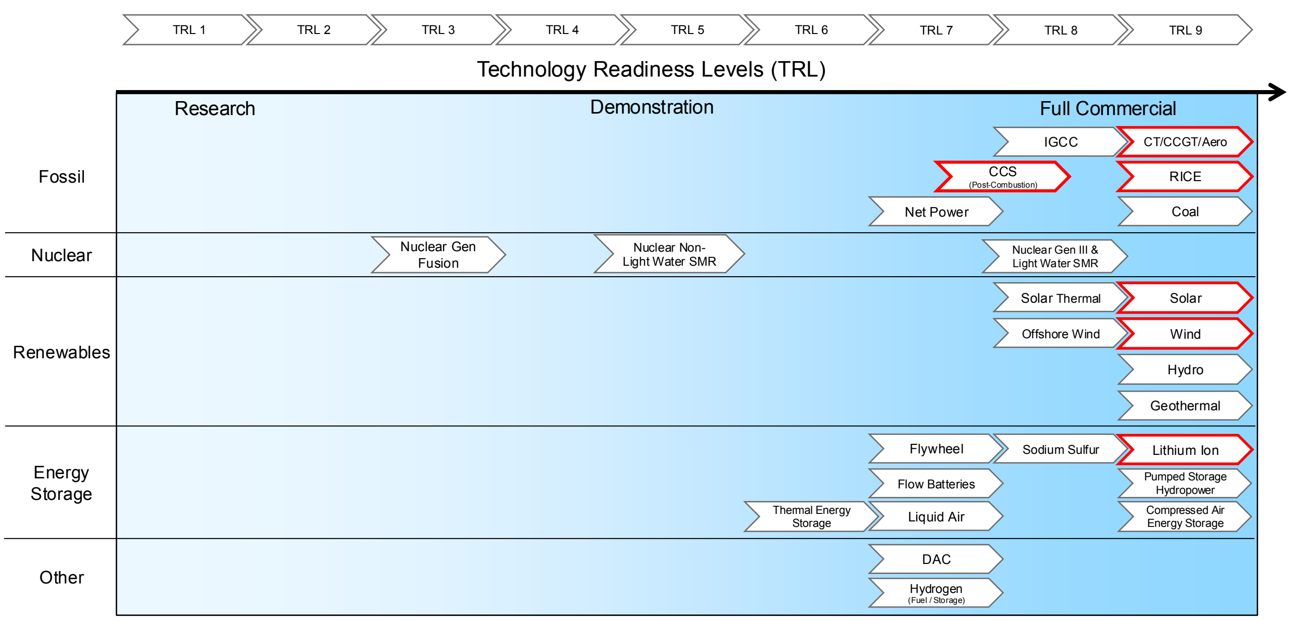


FIGURE 14: POTENTIAL SUPPLY-SIDE RESOURCE ALTERNATIVES (TECHNICAL SCREENING)

In the technical evaluation, potential supply-side resources were evaluated relative to technology maturity, environmental impact, operational characteristics, fuel availability, and feasibility of deployment to serve EAL's service area. In the economic evaluation, EAL developed and compared technology alternatives relative to capital, and operation and maintenance ("O&M") cost estimates. The alternatives included renewable, energy storage, and conventional generation with carbon capture and hydrogen co-firing pathways options. Following the economic screening, the supply-side resources selected for inclusion in the capacity expansion models are those deemed to be the most feasible to serve EAL's generation needs based on comparative cost and performance parameters, deployment risks (cost/schedule certainty), and emerging commercial, technical, and policy trends. Notwithstanding the technologies discussed specifically in this IRP, and included in the capacity expansion models, EAL will continue to evaluate existing, new, and emerging technologies to inform deployment decisions and build a balanced generation portfolio that optimizes its planning objectives. Figure 15 lists the technologies selected for inclusion in the capacity expansion models.

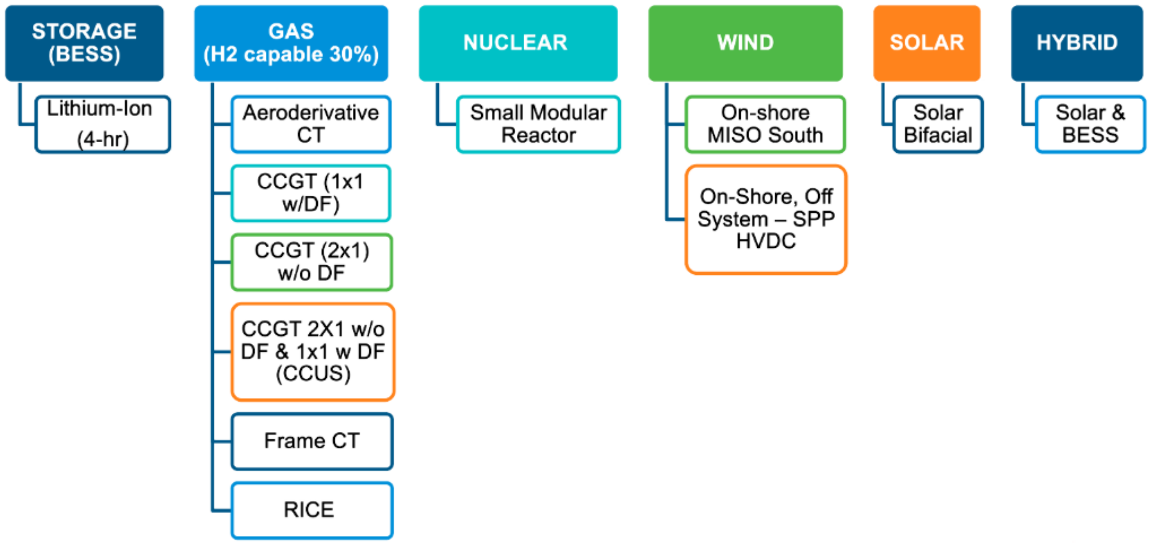


FIGURE 15: TECHNOLOGIES SELECTED FOR CAPACITY EXPANSION MODEL

Conventional Generation - Natural gas-powered generation technologies are a competitive supply-side resource alternative due to historically relatively lower natural gas prices in EAL's service area and suitability to serve a variety of supply roles (baseload, load-following, limited peaking). These technologies offer synergies with the existing EAL fleet, including supply chain economies of scale and deep-rooted operational expertise. CCS is feasible within EAL's service territory. CCS can be seen as an alternative to hydrogen in producing low-carbon electricity, particularly in regions lacking hydrogen infrastructure. CCS is more economically viable with the expanded tax credits provided by the IRS Section 45Q. As this technology becomes more widely deployed, it could allow for 24/7 low-carbon dispatchable assets. EAL continues to evaluate the options for deploying CCS with the new and existing generation, as well as investigate integrated solutions that can provide substantial capital cost avoidance.

The long-term suitability of dual fuel natural gas and hydrogen powered generation technologies to meet EAL's planning objectives is largely dependent on natural gas prices, technology improvements, and advancements in infrastructure investment. The two main pathways to decarbonization for conventional generation resources include CCS and hydrogen firing/co-firing.

CCS involves capturing roughly 95% of the CO_2 emitted from the plant, generally through contact with an amine based liquid solvent, and permanently stores it in geologic formations deep underground. Portions of Arkansas likely possess the geology necessary to store CO_2 gas, as visualized in the U.S. Geological Survey map below in Figure 16. The expanded tax credits provided by the IRS Section 45Q have spurred significant carbon storage investments throughout the country, particularly in regions with a heavy industrial presence and adequate geology. The EPA's final revision to the EPA CAA Section 111(b) rules for new gas generation is another driver for CCS investments in the region to the extent that the rule does not cause a bottleneck in the supply chain, labor availability, and other resources.

Hydrogen firing/co-firing can also provide decarbonization solutions due to the lack of a carbon presence in the gas. The newest large frame turbines have the capability to run with up to 30% or higher co-blending, if a hydrogen supply is available and the balance of plant equipment is designed to accommodate. The turbine original equipment manufacturers ("OEMs") are actively working to achieve commercial viability for firing with 100% hydrogen. For wider deployment of this hydrogen firing through a turbine, necessary advancements that need to be made, include, but are not limited to, building hydrogen production and delivery infrastructure, combustor systems, and emission reduction technologies for Nitrogen Oxide ("NOx"). As OEMs advance, EAL will continue to evaluate the development of hydrogen fueled power generation technology.

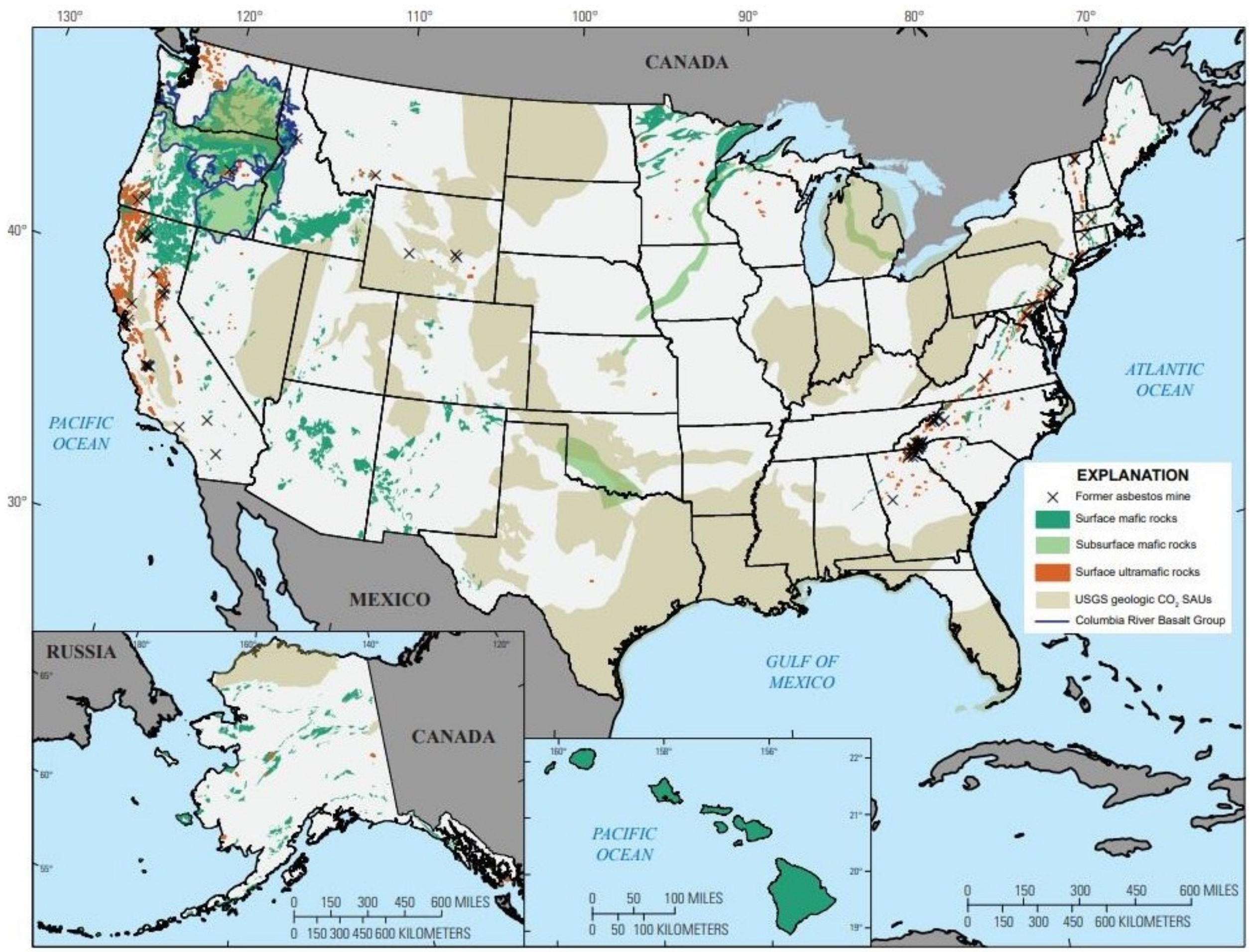


FIGURE 16: GEOLOGIC CARBON STORAGE POTENTIAL IN THE UNITED STATES [6]

[6] https://www.usgs.gov/media/images/geologic-carbon-storage-potential-united-states

Technology	MW *(Summer)*	Installed Capital Cost *(Nominal $/kw-ac)*	Fixed O&M *(L. Real 2024$/MWh)*	Variable O&M *(L. Real 2024$/kw-yr)*	Levelized Cost of Electricity *(L. Real 2024$/kw-yr)*
CT	428	$1,543	$7.85	$6.76	$184
CCCT (1x1) w/ duct firing	733	$1,752	$14.26	$4.70	$57
CCCT (2x1)	1,230	$1,487	$10.91	$4.22	$51
Aeroderivative CT	88	$4,285	$26.93	$9.21	$183
RICE	129	$2,171	$36.18	$13.83	$164

TABLE 9: NATURAL GAS GENERATION

Combined Cycle Combustion Turbines - Driven by economies of scale and relatively low historic gas prices, CCCT fleet operators have remained competitive, from a $/MWh perspective, when compared to solar and wind resources. CCCTs are suitable to serve as load-following baseload efficiently, while simultaneously offering plant flexibility. In this analysis, CCCT units included are comprised of either one or two frame CTs and a steam turbine that recovers thermal energy from the CTs, which provides an efficient heat rate and moderate flexibility. CCCTs can be combined with CCS technology to reduce carbon emissions without many retrofits however, this assumes sufficient land is available for the capture facility. Achieving greater volumes for hydrogen co-firing is conditional on the technological development of hydrogen fired CTs. Depending on the relative hydrogen co-firing volume, system modifications would be required in the CT and steam system of the plant. In addition to advancements in CT technology, potential modifications for a future hydrogen fueled CCCT plants could include, but are not limited to, modifications to the heat recovery steam generator system and post-combustion NOx control systems.

Frame Combustion Turbine with 30% Hydrogen Firing Capability - Historically, CTs have functioned as the technology of choice to support peaking applications, resulting from consistent technological improvements supported by relatively lower natural gas prices. Over time, renewable resources have become an economically competitive source of capacity. While renewable resources are expected to play a larger share of the role for peaking applications, CTs can support integrating renewable resources and build a balanced, reliable, portfolio by offering quick-start (~30 minutes) backup power when renewables cannot meet peak demands.

Most dry, low-NOx designs can accommodate hydrogen blends in the range of 20%-30% with advanced dry, low-NOx technologies under development to enable higher blend rates up to 100% hydrogen fired systems. Achieving higher hydrogen firing rates depend on the availability of fuel supply and combustor designs as well as other system modifications, for example, fuel management systems/compression, CT enclosures, and control system updates.

Aeroderivative Combustion Turbine ("AERO CT") with 30% Hydrogen Firing Capability - AERO CTs have gained market share in applications to serve peak and intermittent power, offering inherent flexibility as a product of applications from the aviation to power industry. Traditionally, AERO CTs provide higher flexibility than frame CTs due to their hot start time (10 minutes), minimum up/down time, and ramp rate.

AERO CT OEMs are continuing to develop combustion systems to enable higher hydrogen blend rates. Current dry, low-NOx systems utilized within AERO CTs enable blending of hydrogen in the range of 30% with ongoing development of advanced combustor systems to enable higher blending rates, up to 100%.

Reciprocating Internal Combustion Engine – As renewable penetration increases, RICE units may be leveraged to support the integration of renewable generation. RICE units can support increased demand for reliability through dispatchable power that can be placed online rapidly with the ability to frequently start/stop in response to changing load conditions.

RICE OEMs have demonstrated that existing models can accompany blends of hydrogen. Technology advancements and the necessary plant modifications required to increase the hydrogen blend capability above 25% are under development. RICE OEMs are also working to develop models compatible with other potential low-carbon fuels.

Renewable and Energy Storage Systems - Over the past decade, driven by technological improvements that result in lower costs and improved performance, renewable and energy storage technologies have been increasingly deployed worldwide, particularly utility-scale solar, followed by onshore wind and BESS. Renewable energy resources add fuel diversity and play a distinct role in building a balanced resource portfolio. Due to the intermittent nature of renewable generation, a balanced portfolio must maintain the ability to meet the changing instantaneous nature of customer usage and renewable production curves. In response to stakeholder feedback from the 2021 IRP, this IRP includes hybrid cost savings for all batteries in the capacity expansion analysis, recognizing that cost savings may be achieved by locating batteries at existing renewable resource sites to potentially reduce interconnection and network upgrade costs.

The IRP total relevant supply cost ("TRSC") analysis incorporates key renewable energy provisions included in the IRA. These IRA provisions include tax credits investment offsets for clean energy technology, with the goal of reducing carbon emissions. The tax credits include full PTCs of $27.50/MWh (real 2022$) for solar, offshore wind, onshore wind, and hybrid solar, and assume the PTCs are realized at 90% through the cash conversion or monetization process permitted in the IRA. The analysis includes ITCs at 30% for standalone and hybrid battery resources, which are applied to 90% of total resource cost. Consistent with the IRA provisions, the tax credits are phased out over the IRP evaluation period, beginning in 2036.

Technology	MW *(Summer)*	Installed Capital Cost *(Nominal $/kw-ac)*	Fixed O&M *(L. Real 2024$/MWh)*	Assumed Capacity Factor	Life *(years)*	DC/AC Ratio	Degradation
Utility-Scale Solar	100	$1,763	$17.07	25.3%	30	1.3	0.5% per year
Hybrid: Solar + BESS	100 MW Solar, 50 MW / 200 MWh BESS	$2,889	$23.08	25.3%	30 (Solar) 20 (BESS)	1.3	0.5% per year

TABLE 10: SOLAR AND HYBRID ENERGY STORAGE RESOURCE ASSUMPTIONS

Solar - Across the U.S., the deployment of solar energy resources has continued to grow rapidly. As the underlying economics have improved for solar resources, solar has become a central resource in building a balanced portfolio. While the cost of solar has recently increased, resource alternatives have also increased in cost; fortunately, PTCs for solar have helped to offset some of the increase. Therefore, despite the near-term market issues, solar remains an economical addition to EAL's portfolio, and EAL's point of view ("POV") remains that beyond 2030, project costs are expected to remain relatively flat as the industry continues to mature. In addition to cost impacts from the industry maturing, new module designs and configurations continue to be developed to improve efficiency and offset costs due to demand and inflation. However, because solar energy production is variable, grid flexibility and dispatchable generation are necessary to ensure reliability. Additionally, as part of the planning considerations for utility-scale facilities, land size requirements and site-specific needs must be evaluated. Consistent with the prior stakeholder feedback regarding solar cost assumptions and data sources, EAL has included a variety of sources of solar cost data as noted on slide 45 of the 2024 EAL IRP Stakeholder Kickoff Meeting.

Technology	MW *(Summer)*	Installed Capital Cost *(Nominal $/kw-ac)*	Fixed O&M *(L. Real 2024$/MWh)*	Assumed Capacity Factor	Life *(years)*
On-shore, MISO South	100 – 200 MW	$2,672	$37.54	32.1%	30
On-shore, Off-system (Southwest Power Pool ("SPP"))	100 – 200 MW	$2,521	$35.09	44%	30

TABLE 11: WIND ENERGY STORAGE RESOURCE ASSUMPTIONS

Onshore Wind - Onshore wind resources have gained momentum in the US and international markets, driven by technology improvements that reduced capital costs. Taller wind turbine hub heights have rapidly entered the market and are anticipated to benefit the economics of lower wind speed territories. EAL is evaluating the reliability, cost, and executability tradeoffs between the potential deployment of onshore and offshore wind resources located in its service area and imported from neighboring markets.

EAL is actively evaluating cost effective ways to integrate wind resources into its portfolio. However, some aspects of wind energy, which is local to the area served by EAL, are currently challenging compared to wind energy that serves some nearby regions. For example, wind energy in MISO South has an estimated capacity factor of ~32%, compared to those in MISO North (~46%) and SPP (~44%). However, EAL's wind resource options may include some local wind and wind energy imports from nearby regions with a stronger wind resource. In response to prior stakeholder feedback regarding modeling SPP wind resources, EAL included assumptions for SPP wind delivered via HVDC line in the 2024 IRP. However, EAL elected not to include existing or new-build AC interconnected SPP wind as an alternative due to the lack of available hedging mechanisms available to EAL for such resources.

Offshore Wind - In the U.S., the offshore wind industry has been developing with its first commercial offshore wind farm becoming operational in Rhode Island in 2016 (30 MW Block Island Wind Farm). At this time, while most of the U.S. industry is concentrated in the northeastern United States, potential projects have been developing across the U.S. with more widespread maturity having been achieved in Europe. Offshore wind technologies are comprised of fixed and floating foundations, and in recent years, turbine capacity has significantly increased with OEMs offering larger diameter systems. In 2023, the U.S. Bureau of Ocean Energy Management held lease sales in August 2023, which had limited interest with RWE winning one lease auction and no bidders in the other wind area auction. Assuming technology improvements (particularly advancements in resiliency to withstand major hurricane force wind speeds) and cost declines are achieved, conditions in the Gulf of Mexico and current economics show that fixed turbines may be suitable for deployment, particularly in areas with relatively shallower depths. Development of offshore wind projects would need to be evaluated further with respect to whether they may reasonably be determined to be in the public interest for EAL's customers.

Technology	MW *(Summer)*	Installed Capital Cost *(Nominal $/kw-ac)*	Fixed O&M *(L. Real 2024$/MWh)*	Round-trip Efficiency	Life *(years)*
Storage (4hr, Li-Ion)	50 MW / 200 MWh	$2,417	$15.03	85%	20

TABLE 12: STAND-ALONE STORAGE ENERGY STORAGE RESOURCE ASSUMPTIONS

Battery Energy Storage Systems - Utility-scale BESS capital costs have held steady in recent years, balanced by lithium cost declines and labor and material cost increases. Current use cases of battery technology are applied to discharge times that are four-hours or less to provide peak shaving capabilities. When strategically and efficiently integrated into the electric grid, BESS have the potential to provide transmission and distribution grid benefits by avoiding investments required due to line overloads that occur under peak conditions. In addition to these peak-shaving applications, BESS can provide voltage support, which mitigates the effects of electrical anomalies and disturbances. If paired together, BESS have the potential to deliver solar energy production into late afternoon hours, mitigating the ramping requirement created by the daily decline in solar energy production.

In addition to the above, BESS have the potential to offer additional value through MISO markets to benefit customers by effectively enabling an intra-day temporal shift between energy production and energy use. Through this process, energy can be absorbed and stored during off-peak/low-cost hours and discharged during on-peak/high-cost hours. When dispatched advantageously, the spread (i.e., cost difference) between the time periods can create cost savings for customers. BESS qualify in some markets for various ancillary service applications such as frequency regulation, reserves, voltage regulation, and given enough discharge duration, can qualify for MISO's capacity market. As the industry learns more and further deploys this technology, safety considerations and practices are becoming clearer, including a renewed focus on fire prevention.

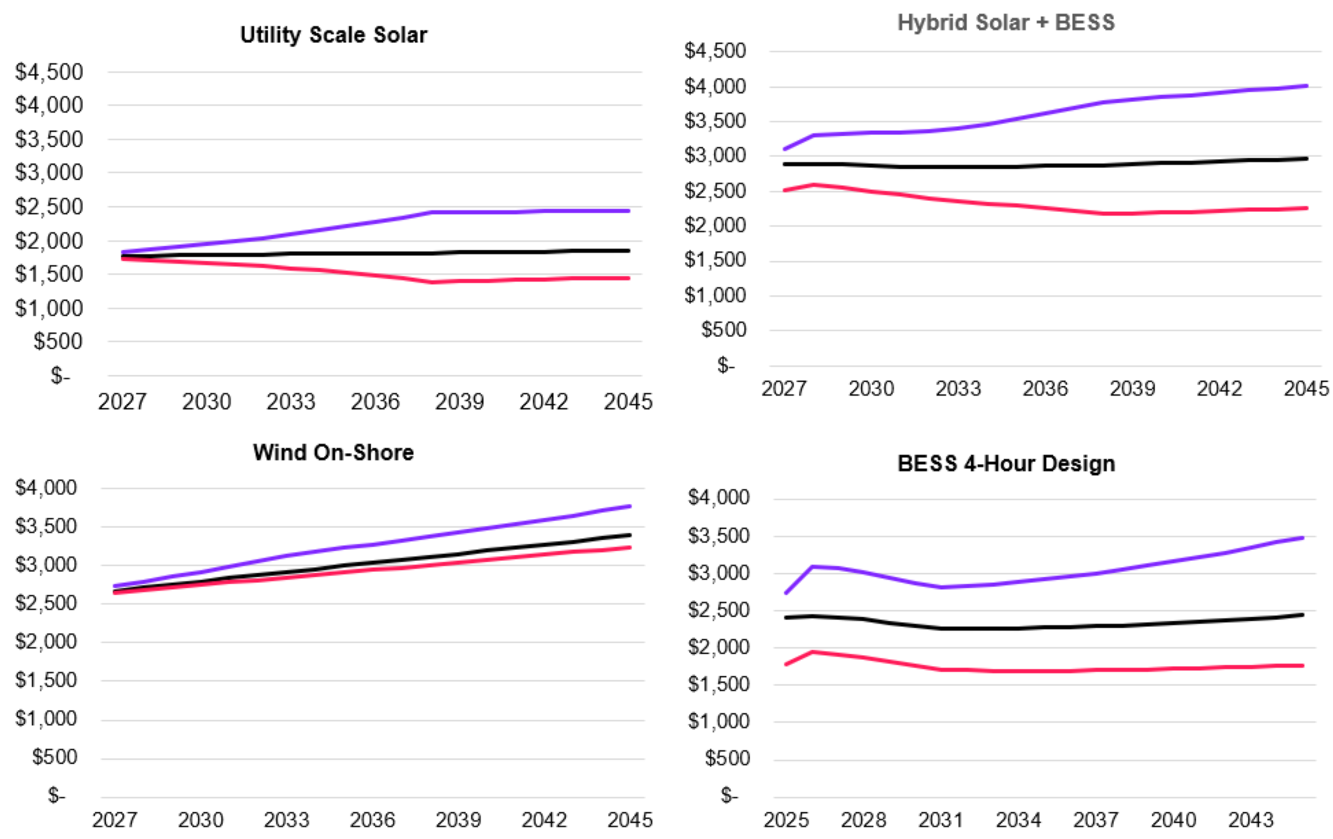


CHART 16: RENEWABLE AND ENERGY STORAGE INSTALLED CAPITAL COST WITH SENSITIVITY

Pumped Storage Hydroelectric – In 2022, pumped storage hydroelectric was the largest source of grid connected energy storage in the US and can provide large-scale, long duration energy storage. In 2022, the US had approximately 22 GW of pumped storage hydroelectric capacity. Pumped storage hydroelectric systems require two reservoirs, an upper and lower. During periods of excess energy production, water is pumped from the lower reservoir to the upper. When energy production is required, flow is reversed, and water can flow from the upper reservoir to the lower. During this process the flowing water turns a turbine that turns a generator to convert the energy into electricity. The average efficiency of pumped hydro storage efficiency is typically near 80%. However, one of the deployment challenges with developing pumped storage hydroelectric facilities is the requirement of suitable natural formations.

Advanced Nuclear Technology and Small Modular Reactors - Nuclear energy is a key component for meeting EAL's long-term resource planning objectives. As EAL continues to operate its existing nuclear fleet, it continues to observe industry developments in Advanced Nuclear Technology and Small Modular Reactors ("SMRs") to meet customer needs. SMRs may potentially offer several benefits, including being physically smaller, reduced capital investments and opportunities for incremental power additions, as well as supplying base load electricity including system "inertia" that is lacking in inverter-based resources. In addition, SMRs generally rely on passive safety systems, requiring no manual intervention or externally applied forces to shut down safely. Pairing SMRs with renewable resources would provide complementary technology that does not depend on climate and time of day. The Company will continue to monitor the development of this technology.

Transmission Interconnection Costs – The costs below are additional costs for a point of interconnection onto the transmission system. The information includes, the cost required to interconnect to the existing transmission network via either a new transmission substation or existing transmission substation. Additional network upgrades are excluded due to their highly site -specific nature. Transmission substation interconnection costs are largely determined by the transmission voltage class but can also be reflected by MW size. The table below summarizes the assumptions.

New POI Cost

Project Size (MW)	Cost ($ millions)	Description
X<399 MW	15	(115,138,161 kV) = POI substation (3 breaker ring) + t-line adjustments (cut-ins) + remote end work (line panels)
399≤X≤799	20	(230 kV) = POI substation (3 breaker ring) + t-line adjustments (cut-ins) + remote end work (line panels)
X>799	50	(500 kV) = POI substation (3 breaker ring) + t-line adjustments (cut-ins) + remote end work (line panels)

Brownfield POI Cost

Project Size (MW)	Cost ($ millions)	Description
X<399 MW	7	(115,138,161 kV) = POI Add node to existing substation
399≤X≤799	9	(230 kV) = POI Add node to existing substation
X>799	15	(500 kV) = POI Add node to existing substation

Summary of Emerging Supply Trends and Implications - Advancement in generation technologies provide new opportunities to meet customer needs reliably, affordably, and sustainably, increasingly rendering new supply-side generation alternatives as viable options to address planning objectives. EAL's planning processes strive to understand these technological changes to enable the Company to design a portfolio of resources and services that meet customers' needs and wants, while maintaining a reliable grid.

Renewable and energy storage system technologies continue to be economical alternatives. The increased deployment of intermittent generation will need to be balanced with flexible, dispatchable, and diverse supply alternatives. Smaller, more modular resources, such as Aero-CT, RICE, and battery storage, provide an opportunity to reduce risk and better address locational, site-specific reliability requirements while continuing to support overall grid reliability. Combining these trends provides additional opportunities to meet EAL's planning objectives.

Environmental Regulations

Another key driver to changes in future resource needs is the various environmental regulations that potentially impact the long-term viability of EAL's existing generating units. Five key areas of regulations are discussed here: Regional Haze Rule, Cross-State Air Pollution Rule, Coal Combustion Residuals ("CCR") Rule, Effluent Limitation Guideline Rule, and Potential Greenhouse Gas Regulation. The uncertainty associated with each area varies. For example, the Regional Haze requirements have been in place for some time and are far more developed, with greater certainty as to the compliance requirements and timing. Even so, the specifics that will be required for compliance with Regional Haze cannot be known fully at this time.

Regional Haze Rule – The current Regional Haze Program was established as part of the 1990 amendments to the CAA. This program is designed to protect visibility at certain federally designated Class I areas and to return visibility conditions in those areas to natural background visibility conditions by the year 2064. This is to be accomplished via a series of 10-year planning periods where each state is charged with surveying contributions from air emissions sources in that state and developing a Regional Haze State Implementation Plan ("SIP") to ensure that sufficient emission reductions occur during each planning period to remain on course to achieve natural background conditions in all Class I areas by 2064.

During each planning period, the State of Arkansas must evaluate contributions from sources within the state for potential impacts on visibility conditions at various Class I areas. For all states, a SIP for the regional haze second planning period, which spans from 2018 to 2028, was to be submitted to the EPA by July 31, 2021. While Arkansas did not meet this deadline, a final SIP was submitted to EPA for review on August 8, 2022, and this SIP submission was determined by the EPA to be complete on August 18, 2022. The SIP submitted by Arkansas incorporates EAL's commitment to cease burning coal at Independence Unit 1 and Unit 2 by no later than December 31, 2030, and it does not require the installation of additional air pollution controls on any EAL generating units. The EPA has yet to act on Arkansas's SIP and is subject to a consent decree deadline to do so by no later than August 31, 2026.

Cross-State Air Pollution Rule ("CSAPR") – The EPA finalized the CSAPR in 2011 under the "good neighbor" provision of the CAA to reduce transported pollution that significantly affects downwind non-attainment and maintenance problems for the 2008 ozone National Ambient Air Quality Standard ("NAAQS"). The rule was vacated and stayed on December 30, 2011, but in late 2014, the stay was lifted following a Supreme Court reversal of the lower court decision. Arkansas is subject to CSAPR for ozone-season (May 1 – September 30) emissions of NOx. Affected entities must hold one allowance for every ton of NOX and SO2 generated, depending on the programs in which their respective state must participate.

Phase I of CSAPR went into effect in May 2015 and Phase II went into effect in May of 2017. On September 7, 2016, the EPA issued a CSAPR update rule revising the CSAPR program. This 2016 update rule revised the total allowance pool for Arkansas sources, including a significant reduction in available allowances beginning with the 2018 ozone season.

In March of 2021, the EPA issued a revised CSAPR update rule published in the Federal Register on April 30, 2021. This rule established a new CSAPR Group 3 consisting of 12 of the 21 states that were previously in CSAPR Group 2. Arkansas, however, remained in CSAPR Group 2 and its CSAPR allowance allocations were not modified as part of the 2021 rule. Due to the reduction in the number of states remaining in CSAPR Group 2 (from 21 to 9) with the creation of Group 3, the overall size of the Group 2 emission allowance market was reduced with the issuance of the 2021 revised update rule.

In April 2022, the EPA issued a proposed Federal Implementation Plan ("FIP") finding that Arkansas has linkages to downwind maintenance receptors in two states. On February 13, 2023, the EPA published a final rule disapproving in whole or in part interstate transport SIP submissions for the 2015 8-hour ozone NAAQS for 21 states, including Arkansas.

Several state and industry petitioners filed petitions for review of the EPA's SIP disapprovals, with many also filing motions to stay the effectiveness of the SIP disapprovals pending judicial review. Regional circuit courts granted stays concerning the final SIP disapprovals, including Arkansas. On March 15, 2023, the EPA released a pre-publication version of the final FIP addressing the 2015 ozone NAAQS. The Final FIP was published on June 5, 2023, effective August 4, 2023. On July 2023, the EPA published an interim final rule addressing judicial stays of several states' interstate transport SIP disapprovals. The July 31, 2023, publication reiterated that the effectiveness of the final FIP will remain stayed in six states, including Arkansas while the respective states' judicially stayed SIP disapprovals are in effect. In June 2024, the US Supreme Court issued an order, in challenges filed in the DC Circuit, staying the enforcement of this FIP pending the DC Circuit Court's review of the rule.

EAL continues to comply with CSAPR requirements in place in Arkansas before the EPA's final FIP published June 5, 2023. EAL awaits court decisions with respect to the final SIP disapproval for Arkansas (Eighth Circuit) and the final FIP (DC Circuit).

Mercury and Air Toxics Standards – On February 16, 2012, the EPA finalized the Mercury and Air Toxics Standards ("MATS") rule. EAL's coal facilities are each subject to the MATS rule. On April 25, 2024, the EPA finalized a Risk and Technology Review ("RTR") to the rule. In the final RTR, the EPA finalized a revision to the fPM standard for coal-fired generating units reducing the fPM limit from 0.030 lb/mmBtu to 0.010 lb/mmBtu on a 30-day average. The revised standard is effective July 6, 2027. EAL is currently evaluating its coal units to determine whether additional controls are necessary to comply with this new lower standard.

Coal Combustion Residuals Rule – EAL operates CCR units at White Bluff and Independence, which are subject to the CCR rule. In April 2015, the EPA published the final CCR rule regulating coal ash from coal-fired generating units as non-hazardous wastes under Resource Conservation and Recovery Act ("RCRA") Subtitle D. The final regulations became effective on October 19, 2015, and created new compliance requirements for CCR management including modified storage, new notification and reporting practices, product disposal considerations, ongoing monitoring requirements and CCR unit closure criteria. In December 2016, the Water Infrastructure Improvements for the Nation Act was signed into law, authorizing the EPA to enforce the CCR rule rather than leaving primary enforcement to citizen suit actions. On August 21, 2018, the D.C. Circuit Court vacated and remanded several of the CCR rule provisions relating to inactive and unlined surface impoundments. On August 28, 2020, the EPA issued a final rule with a revised date of April 11, 2021, that unlined surface impoundments and units that failed the aquifer location restriction must cease receiving waste and initiate closure.

EAL operates CCR units at Independence and White Bluff that are subject to the CCR rule, including two recycle ponds and a landfill at each location. In 2020, EAL completed the installation of revised bottom ash handling systems at both Independence and White Bluff. These new systems eliminated the need for the recycle ponds at each site. EAL commenced closure of the two recycle ponds at Independence in August of 2020 and February of 2021, respectively. At White Bluff, closure of one of the two recycle ponds commenced in October of 2018, prior to the installation of the new bottom ash handling system, and closure of the remaining recycle pond commenced in February of 2021. The recycle ponds at both plants were certified as closed on October 2, 2023.

On May 18, 2023, the EPA published in the Federal Register proposed revisions affecting the remaining CCR units at Independence and White Bluff. On May 8, 2024, the EPA published in the Federal Register a final revised CCR rule. The new rule included the addition of regulatory requirements for newly defined CCR Management Units ("CCRMUs"). CCRMUs determined to be over 1,000 tons will be included as CCR units under the EPA CCR Program. EAL continues to work with various industry organizations to determine the best compliance path.

EAL anticipates that on-site disposal options will remain available at its facilities, to the extent needed for CCR that cannot be transferred for beneficial reuse.

Effluent Limitation Guideline Rule – Updates to the Effluent Limitation Guideline rule ("ELG") were finalized by the EPA on November 3, 2015. These revisions apply to White Bluff and Independence and require coal-fired electric generating units to have a zero discharge of bottom ash transport water. The requirement was originally scheduled to become effective between November 1, 2018, and December 31, 2023, with the exact date to be determined by the permitting authority (ADEQ). On September 17, 2017, the EPA finalized a revision to the ELG rule that modified the earliest possible compliance date from November 1, 2018, to November 1, 2020. In this action, the EPA also indicated its intent to reconsider other aspects of the 2015 ELG rule, including bottom ash transport water requirements.

Revised National Pollution Discharge Elimination System ("NPDES") permits were issued to White Bluff and Independence by ADEQ and were effective on March 1, 2020, and on November 1, 2020, respectively. These permits established an ELG zero-discharge compliance date of December 30, 2023, for bottom ash transport water.

On October 13, 2020, the EPA issued a further revision to the final rule allowing plants that agree to cease firing coal on or before December 31, 2028, to take advantage of a regulatory exemption permitting unlimited discharge of bottom ash transport water for the remaining life of the facility, and for limited discharges of bottom ash transport purge water under certain defined circumstances for other facilities. To ensure these operational flexibilities, modified NPDES permits were issued to Independence and White Bluff in 2023, incorporating the regulatory operational allowances from the 2020 reconsideration rule.

On March 29, 2023, the EPA published in the Federal Register a proposed revised ELG rule, which removes much of the operational flexibility from the reconsideration, which was effective December 14, 2020, and includes new requirements and discharge limits for ash landfill leachate.

On May 8, 2024, the EPA published in the Federal Register a final revised ELG rule. This revised ELG established BPJ and non-zero limits for Combustion Residual Leachate ("CRL") at facilities retiring prior to 2034. The ELG also established BPJ limits for legacy wastewaters for closed facilities. The ELG established that chemical precipitation is the required technology for CRL discharges after closure and all legacy wastewater discharges. This revised ELG also creates a new subcategory for units that discharge bottom ash transport purge water and plan to permanently cease coal-fired operations by no later than December 31, 2034. EAL continues to evaluate the best compliance path for the revised ELG requirements.

GHG Regulation Under Section 111 of the CAA – On April 25, 2024, the EPA released a final rule under CAA Section 111 to establish new requirements for controlling CO_2 emissions from new and certain existing fossil-fired EGUs. The existing unit requirements of this final rule are not expected to impose any new substantive requirements on existing EAL generating units. EAL's coal-fired generating units are expected to qualify for an exemption. Similarly, the final rule does not impose any CO_2 emission limits for existing gas steam generating units until January 1, 2030. EAL's only such unit is LC4, which is committed to deactivate by no later than December 31, 2027. The final rule does not include any requirements for existing gas turbine units, though EPA has announced plans to propose requirements for such units at a later date.

The most significant impact of the EPA's final 111 rule would be for any new gas turbine generating units. The final rule defines a unit as "new" if construction of the unit is commenced after May 23, 2023. The EPA's rule divides the requirements for new gas turbine generating units into three subcategories based on the annual capacity factor of the new generating unit. Low load CTs (<20% annual capacity factor) which combust natural gas are subject to a heat input-based CO_2 emission standard of 120 lb CO_2/MMBtu, which is achievable by any unit that burns pipeline-quality natural gas. Intermediate load CTs, which are those that operate at annual capacity factors of greater than 20% but less than 40%, are subject to an output-based CO_2 emissions efficiency standard of 1,170 lb CO_2/MWh-gross, which is expected to be achievable by the most efficient commercially available simple-cycle CT designs. Base load CTs (>40% annual capacity factor) are subject to phased emission standards, with a Phase 1 standard of 800 lb CO_2/MWh-gross [7], and a Phase 2 standard of 100 lb CO_2/MWh-gross. The Phase 1 standard applies once a new base load turbine unit begins operation, and the Phase 2 standard applies beginning January 1, 2032, with the possibility of a single 1-year extension to this date if necessary due to factors outside the control of the EGU owner/operator. Compliance with EPA's Phase 2 standard for new base load CT units is expected to require the application of CCS at an effectiveness of 90% or greater.

Fuel Price Forecasts

Natural Gas Price Forecasts

Three natural gas price forecast scenarios were used to develop the 2024 IRP. The first year of the natural gas price forecast is based on NYMEX Henry Hub forward prices, which are market future prices as of November 2023. Because the NYMEX futures market becomes increasingly illiquid as the time horizon increases, NYMEX forward prices are not a reliable predictor of future prices in the long term. Due to this limitation, the long-term POV regarding future natural gas prices utilizes an average across several independent, third-party consultant forecasts. Gas markets are influenced by multiple complex forces; consequently, long-term natural gas prices are highly uncertain. Therefore, EAL presents and uses three alternatives for natural gas prices to address this uncertainty. In levelized 2024 dollars per MMBtu throughout the IRP period, the reference case natural gas price forecast is $4.34/MMBtu, the low case is $2.99/MMBtu, and the high case is $5.76/MMBtu.

[7] This emission standard applies to any new base load combustion turbine with a maximum heat input rating of greater than 2,000 MMBtu/hr. EPA's final rule includes a formula to calculate the applicable Phase 1 emission standard for units with a maximum rating of less than 2,000 MMBtu/hr, up to a maximum emission standard of 900 lb CO_2/MWh-gross for the smallest units.

Described in more detail later in Chapter 5, each of the IRP Futures assumes the natural gas price forecast sensitivity appropriate for the future world envisioned.

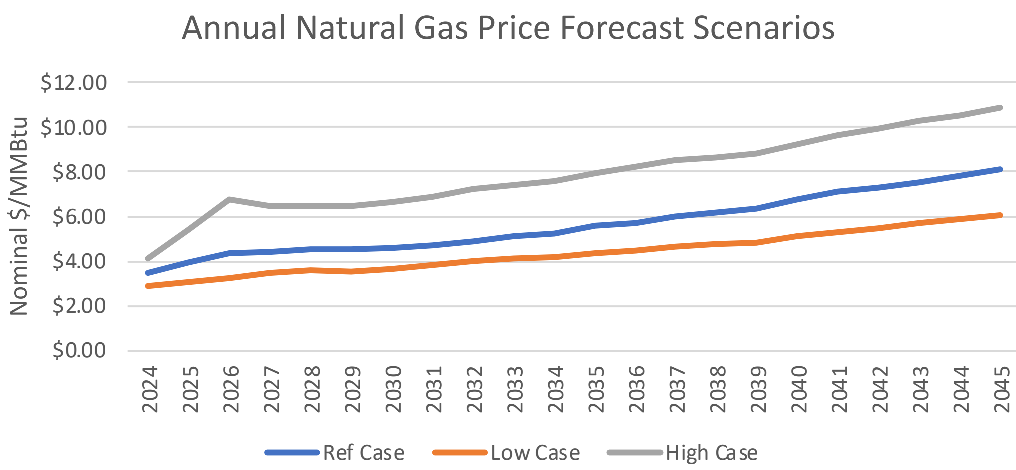


CHART 17: ANNUAL NATURAL GAS PRICE FORECAST SCENARIOS

Coal Price Forecasts

The delivered to plant coal price forecast for White Bluff and Independence is based on a weighted average price of coal commodity and coal transportation commitments under contract and third-party consultant forecasts of Powder River Basin coal prices for any open coal commodity position. In addition, railcar expenses and appropriate plant specific coal handling cost adders are included. Current transportation rates are escalated by the All-Inclusive Less Fuel index and current fuel surcharges are escalated by the diesel fuel price index. Current plant specific delivery component costs are escalated based on an appropriate index to forecast the future year component cost. In levelized 2024 dollars per MMBtu throughout the IRP period, the delivered coal price is $2.52 in the reference gas case, $2.48 in the low gas case, and $2.52 in the high gas case. The delivered coal price forecast for non-Entergy plants comes directly from the Aurora default input database provided by Energy Exemplar and prices vary by plant.

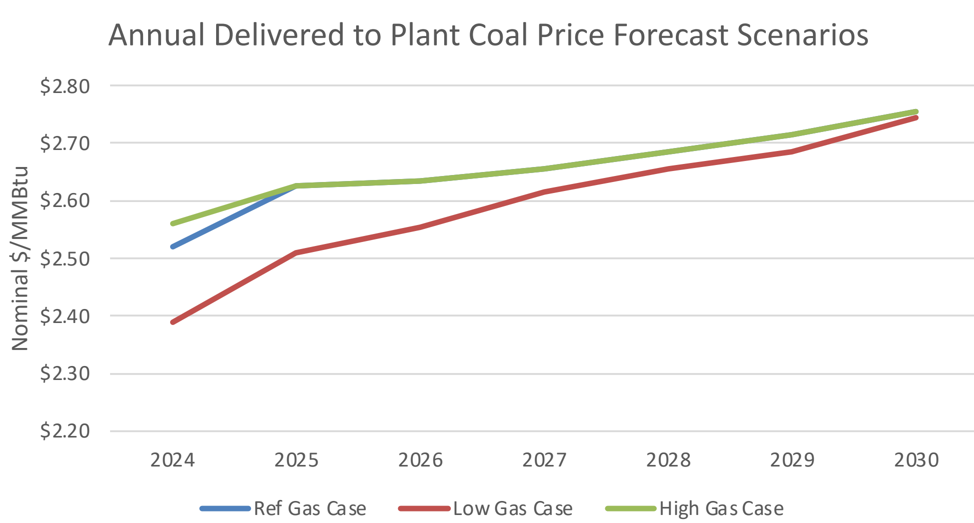


CHART 18: ANNUAL DELIVERED TO PLANT COAL PRICE FORECAST SCENARIOS

CO_2 Price Forecasts - EAL's POV on a potential carbon price recognizes the uncertainty of national carbon regulation by considering a range of potential policies and timing. The Company's CO_2 price forecast is based on the following four cases from the ICF International, Inc. ("ICF") Q3 2022 Core CO_2 Price Trajectory issued in September 2022 by ICF [8] :

- "No CO_2" case, in which the power sector does not face a CO_2 price.
- "Regulatory" case, in which prices representative of action under CAA are utilized.
- "80% Reduction" case, in which prices consistent with a national cap and trade program that begins in 2035 and targets an 80% reduction from 2020 levels by 2050 are utilized.
- "Legislative" case, in which high prices consistent with the Climate Leadership Council's Carbon Dividend proposal are utilized.

The CO_2 price projections for each of ICF's four cases are weighted using the following probabilities, according to ICF's professional judgement and based on the likelihood of the outcomes, to arrive at EAL's POV price assumption.

Case	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
No CO_2	100%	100%	100%	100%	100%	80%	75%	75%	75%	35%	25%	15%
Regulatory	-	-	-	-	-	20%	25%	25%	25%	25%	25%	25%
80% Reduction	-	-	-	-	-	-	-	-	-	30%	30%	30%
Legislative	-	-	-	-	-	-	-	-	-	10%	20%	30%

TABLE 13: CO_2 PROBABILITY WEIGHTINGS

EAL's low case assumes no CO_2 price, the medium case assumes EAL's point of view CO_2 price (i.e., the weighted average of the four ICF cases described above), and the high case assumes ICF's Legislative case as shown below:

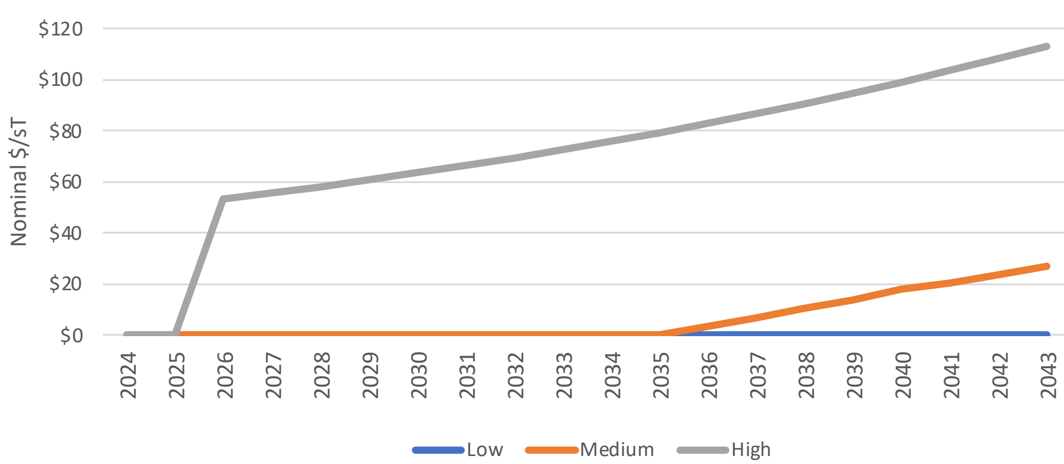


CHART 19: CO_2 PRICE FORECAST SCENARIOS

[8] ICF provides professional services and technology-based solutions to governmental and commercial clients, including management, marketing, technology, and policy consulting and implementation services. Additional information can be found at https://www.icf.com/.

CHAPTER 5

Modeling Framework

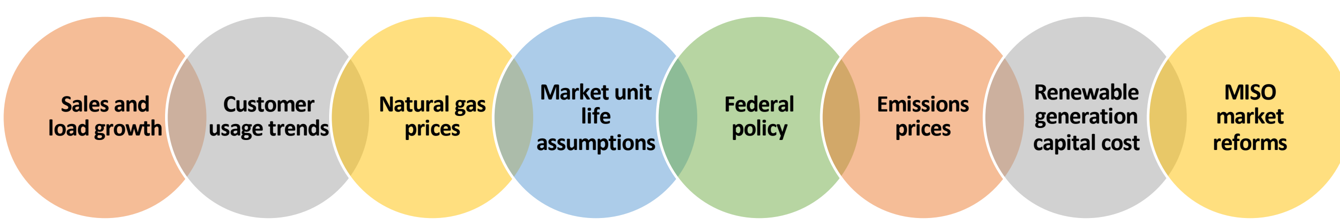
Summary

- As with previous IRPs, a futures-based approach was employed for the 2024 IRP. Four futures were modeled to bookend a broad range of uncertainties.
- A second scenario modeled around Future 2A was developed to capture the uncertainties around EPA Rule CAA 111 and how that could impact resources for EAL.
- Due to the recent implementation of the MISO seasonal construct, the 2024 IRP winter and summer seasons were modeled to represent MISO's new Planning Resource Auction.
- In comparison to previous IRPs, because of the new MISO seasonal construct, the model favored gas resources as they provide consistent capacity accreditation levels in both the summer and winter seasons.

Futures-Based Approach

Instead of analyzing and planning for one set of outcomes, EAL's IRP uses a futures-based approach to evaluate portfolios across a broad range of potential future conditions. Long-term outcomes result from many variables, and futures are designed as different combinations of assumptions that could coexist together resulting in a range of market outcomes.

Major areas of uncertainty



The 2024 EAL IRP considers four scenarios, depicted in Table 14 below.

	Future 1	Future 2A	Future 2B	Future 3
Peak Load & Energy Growth	Low	Reference	Reference	High
Natural Gas Prices	Low	Reference	Reference	High
MISO Coal Deactivations	All ETR cease to use coal by 2030 All MISO coal aligns with MTEP Future 1 (46 year life)	All ETR cease to use coal by 2030 All MISO coal aligns with MTEP Future 2 (36 year life)	All ETR cease to use coal by 2030 All MISO coal by 2030	All ETR cease to use coal by 2030 All MISO coal aligns with MTEP Future 3 (30 year life)
MISO Natural Gas CC Deactivations	50 year life	45 year life	NGCC by 2035	35 year life
MISO Natural Gas Other Deactivation	46 year life	36 year life	Steam gas generating units by 2030	30 year life
Carbon Tax Scenario	No Cost	Reference Cost	Reference Cost	High Cost
Renewable Capital Cost	High Cost	Reference Cost	Reference Cost	Low Cost
Narrative	Lower growth from the residential and industrial sector is forecasted which reduces the need to transition from the existing fleet. Renewable cost assumed to be high.	Moderate amount of industrial growth forecasted which would drive the need for new development.	Entergy and utilities across MISO deactivate existing units early to be compliant with proposed changes to CAA Section 111(d). New resources built would comply with proposed changes to 111(b).	High energy growth from both industrial and residential sectors forecasted. Renewable cost assumed to be low due to more efficient supply chain.

TABLE 14: IRP FUTURES ASSUMPTIONS

The four futures vary key modeling parameters, contemplating three distinct load paradigms, three commodity price sensitivities, and three renewable cost sensitivities are modeled. In Future 1, the EAL load forecast reflects the lowest load growth of all the scenarios modeled. Futures 2A and 2B utilize a moderate growth load profile. The highest load modeled is employed in Future 3 with a high industrial growth assumption. This set of scenarios was designed to demonstrate the impact of differences in load forecasts (such as quicker-than-expected industrial growth) on capacity expansion portfolios. Once the capacity expansion for these four futures was complete, the TRSC was computed, and a qualitative risk assessment was performed for each portfolio. Chapter 6 describes the scenario comparisons.

Market Modeling and EAL Portfolio Optimization

The development of the 2024 IRP relied on the Aurora Energy Market Model to develop optimized portfolios for the MISO energy market and EAL under a range of possible futures. Aurora is a production cost and capacity expansion optimization tool that simulates energy market operations using hourly demand and individual resource operating characteristics in a chronological dispatch algorithm and uses projected market economics to determine the optimal long-term resource portfolio under varying future conditions including fuel prices, available generation technologies, environmental constraints, and future demand forecasts. Aurora's optimization process identifies the set of future resources that most economically meets the identified requirements given the defined constraints. Aurora's logic seeks to build the most valuable resources to the system based on the combination of fixed and variable costs as well as energy revenue from the hourly dispatch for the whole simulation period. The capacity expansion analysis does not explicitly consider transmission constraints within the EAL or MISO study regions when developing the optimized portfolios. Transmission considerations and other site-specific factors are considered when evaluating specific resource options.

Gas resource capacity credit – The capacity credit assumption for gas resource alternatives in the IRP is based on MISO's 2024/2025 PY Schedule 53 class averages (ISAC[9]/ICAP[10]) published February 23, 2024, and Seasonal UCAP[11] /ISAC Ratio published February 21, 2024. The class average is multiplied by the UCAP/ISAC ratio for each season for each gas resource technology type to arrive at the assumed capacity credit for the IRP.

Technology	Summer capacity credit [%]	Winter capacity credit [%]
CCCT (1x1 M501JAC)	98	97
CT (M501JAC)	96	88
AERO CT (LMS100PA)	95	99
RICE (7x Wartsila 18V50SG)	95	99

TABLE 15: SEASONAL ACCREDITATION FOR GAS ALTERNATIVES

[9] ISAC = Intermediate Seasonal Accredited Capacity.

[10] ICAP = Installed Capacity.

[11] UCAP = Unforced Capacity.

Renewable Capacity Credit - The solar and wind capacity accreditation used in the IRP was calculated using the Dynamic Peak credit function within Aurora. This function instructs Aurora to calculate the peak credit for each type of renewable resource for each iteration of the long-term capacity expansion run based on the penetration of total renewables in the previous iteration. The top 3% of the peak load hours per month, net of solar, wind, and hydro resource output is used to determine how much PRM contribution a resource type will have in a season. EAL incorporated this modeling technique in part to address prior stakeholder feedback regarding ELCC modeling assumptions.

The battery storage capacity credit used is based on an internal ELCC study, which examined the expected change in the reliability contribution of battery resources as more battery capacity is added in MISO South. This ELCC assumption was assigned in tranches to account for the expected decline in capacity accreditation with increased battery penetration. The initial battery capacity credit is assumed to be 95%.

Reserve margin targets – The Aurora model utilized summer and winter reserve margin targets based on MISO's 2024/2025 PY Loss of Load Expectation study applied to EAL's forecasted coincident peak loads for each season of each study year. Candidate resources received seasonal capacity credit consistent with this framework. While MISO's resource adequacy construct establishes reserve margins for each season, modeling the summer and winter reserve margin constraints captures the meaningful seasonal variations in performance and accreditation between candidate resources (e.g., solar, wind and gas in summer vs. winter). Adding fall and spring reserve margin constraints would increase modeling complexity without any expected improvement in the capacity expansion portfolios. EAL continues to evaluate its long-term planning reserve margin targets in light of MISO's transition to a seasonal resource adequacy construct, RBDC, and its DLOL accreditation proposal, currently pending at FERC.

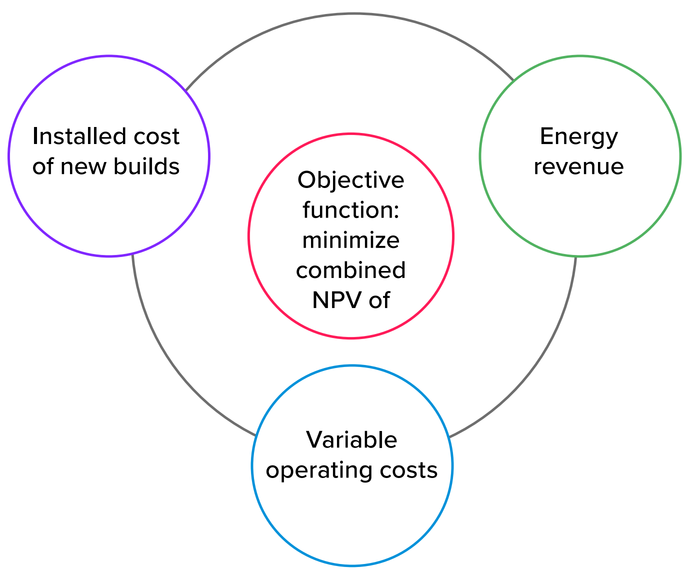


FIGURE 17: AURORA CAPACITY EXPANSION LOGIC

Aurora long-term capacity expansion logic was used to identify economic type, amount, and timing of supply-side resources needed to meet EAL's and the MISO market's future capacity needs. The results of this process are portfolios of supply-side resources that produce the lowest total supply cost to meet the identified need within the constraints defined in each of the four futures (the "optimized portfolios").

Optimized Portfolio for Future 1

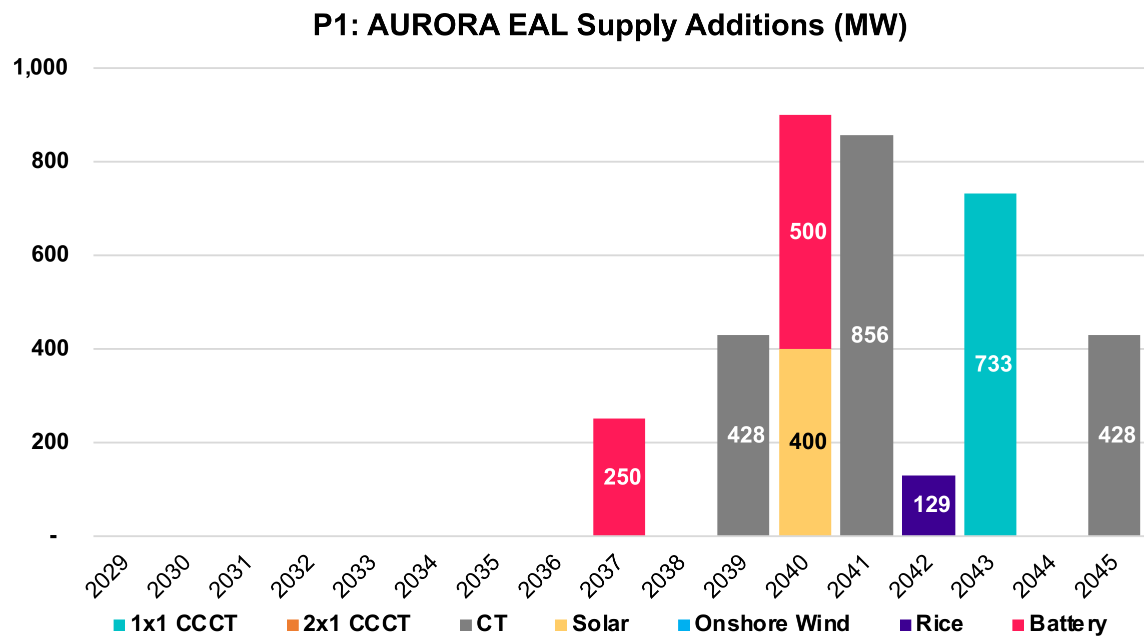
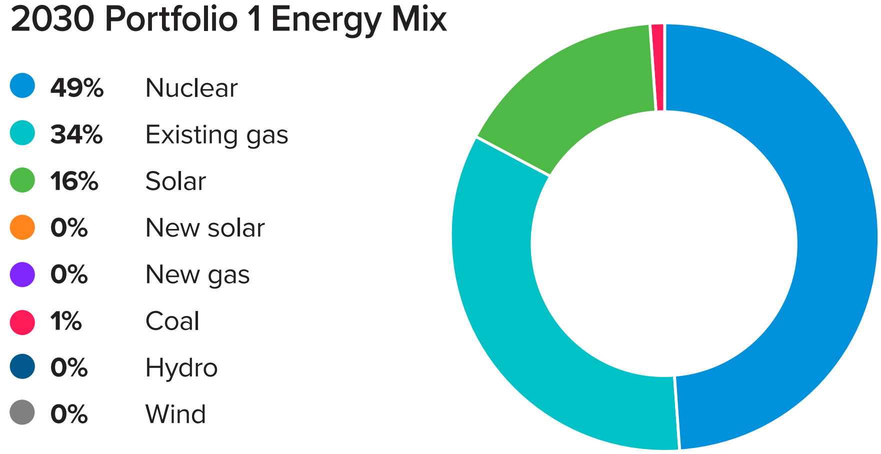


CHART 20: FUTURE 1 EAL OPTIMIZED PORTFOLIO (P1)

EAL Technology by 2045	P1 installed summer MW	P1 effective summer MW	P1 installed winter MW	P1 effective winter MW
1x1 CCCT	733	720	778	708
2x1 CCCT	0	0	0	0
CT	1,711	1,651	1,838	1,510
AERO CT	0	0	0	0
RICE	129	123	129	128
Single axis tracking solar	400	135	400	72
Coupled Battery	750	480	750	208
On-shore wind	0	0	0	0
Off-system wind	0	0	0	0
SMR	0	0	0	0
Total supply side additions	**3,723**	**3,109**	**3,895**	**2,626**

TABLE 16: SEASONAL ACCREDITATION FOR RESOURCE ALTERNATIVES

2030 Portfolio 1 Energy Mix



2045 Portfolio 1 Energy Mix

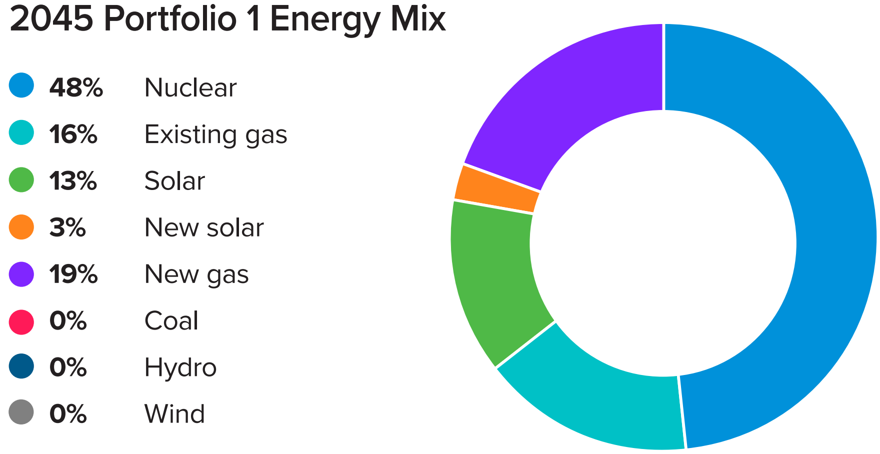


CHART 21: EAL PROJECTED P1 ENERGY MIX

From EAL's energy coverage below, EAL stayed around full energy coverage throughout the study. The energy coverage metric shown in this report is a forecast of EAL's generation as a result of economic dispatch under the assumptions for each future and does not reflect the availability of that generation to meet EAL's load.

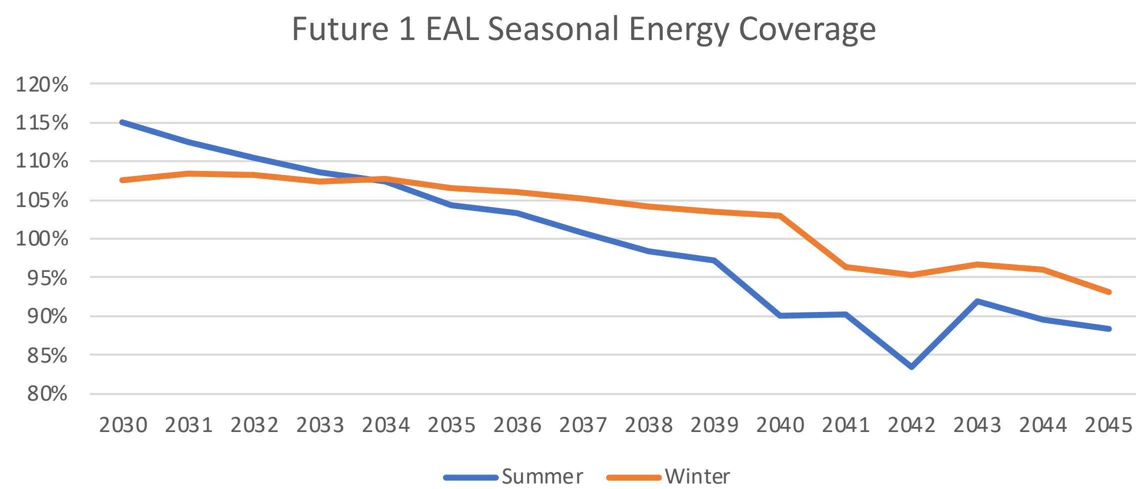


CHART 22: FUTURE 1 EAL SEASONAL ENERGY COVERAGE (P1) [12]

Future 1 is defined by the lowest load growth, low gas prices, no CO_2 prices, and high forecasted renewable costs. Economically, this environment favors gas powered dispatchable resources. The optimized portfolio, P1, includes predominantly dispatchable resources including some energy storage.

In Portfolio 1, 2.7 GW of thermal capacity and 750 MW of energy storage were added within the planning horizon and 400 MW of solar additions. In this portfolio, no capacity or energy deficit was observed until 2037, due to the low load growth. With sufficient energy producing resources existing in the early study period, the resource additions selected mid-study horizon are mostly peaking resources, such as batteries, CTs, and RICE. Later in the study, a 1x1 CCCT was selected in 2043 to replace the assumed deactivation of a large energy producing gas unit. In addition, EAL was more capacity constrained during the winter seasonal, which deterred the model from selecting solar resources due to the low winter capacity accreditation. With this portfolio, by 2045, the overall EAL energy mix will be 48% nuclear, 35% thermal and 16% from solar resources and 88% of the overall capacity has the potential to be low-carbon capable. Low-carbon capable gas resources include newly constructed CCCTs, CTs and AERO CT resources, as they can potentially burn hydrogen or utilize CCS in the future. This portfolio resulted in full energy coverage throughout most of the study period. The TRSC for the Future 1 portfolio is $7,571 million on a net present value basis (2024 dollars). More detail on the TRSC estimate for each portfolio can be found in Appendix F.A similar build trend was observed for the MISO Market in Future 1. The majority of the resource alternative selections were gas-powered dispatchable resources due to the low gas prices, no CO_2 prices, high renewable costs, and the volatility of renewable ELCC across seasons. EAL's market seldomly utilized the MISO market in Future 1 because dispatchable resources were readily available in both markets. The MISO market build chart and resource alternative table can be found in Appendix E.

[12] The energy coverage metric shown in this report is a forecast of EAL's generation as a result of economic dispatch under the assumptions for each future and does not reflect the availability of that generation to meet EAL's load.

Optimized Portfolio for Future 2A

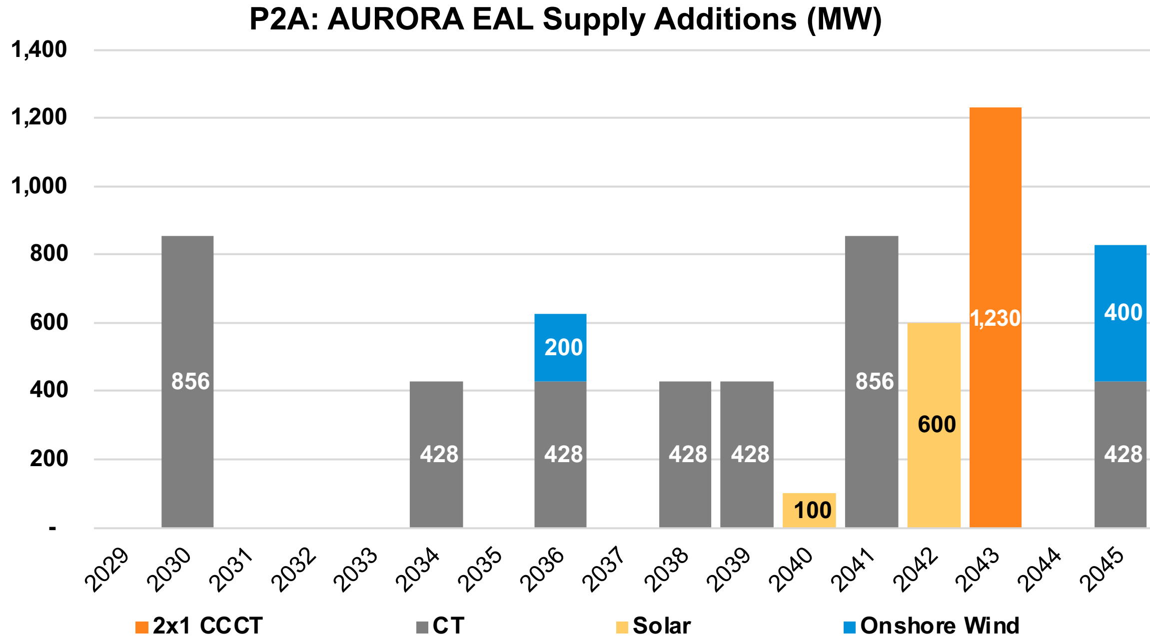


CHART 23: FUTURE 2A EAL OPTIMIZED PORTFOLIO (P2A)

EAL Technology by 2045	P2A installed summer MW	P2A effective summer MW	P2A installed winter MW	P2A effective winter MW
1x1 CCCT	0	0	0	0
2x1 CCCT	1,230	1,210	1,305	1,189
CT	3,850	3,715	4,135	3,398
AERO CT	0	0	0	0
RICE	0	0	0	0
Single axis tracking solar	700	262	700	33
Coupled Battery	0	0	0	0
On-shore wind	600	212	600	275
Off-system wind	0	0	0	0
SMR	0	0	0	0
Total supply side additions	**6,381**	**5,399**	**6,740**	**4,896**

TABLE 17: SEASONAL ACCREDITATION FOR RESOURCE ALTERNATIVES

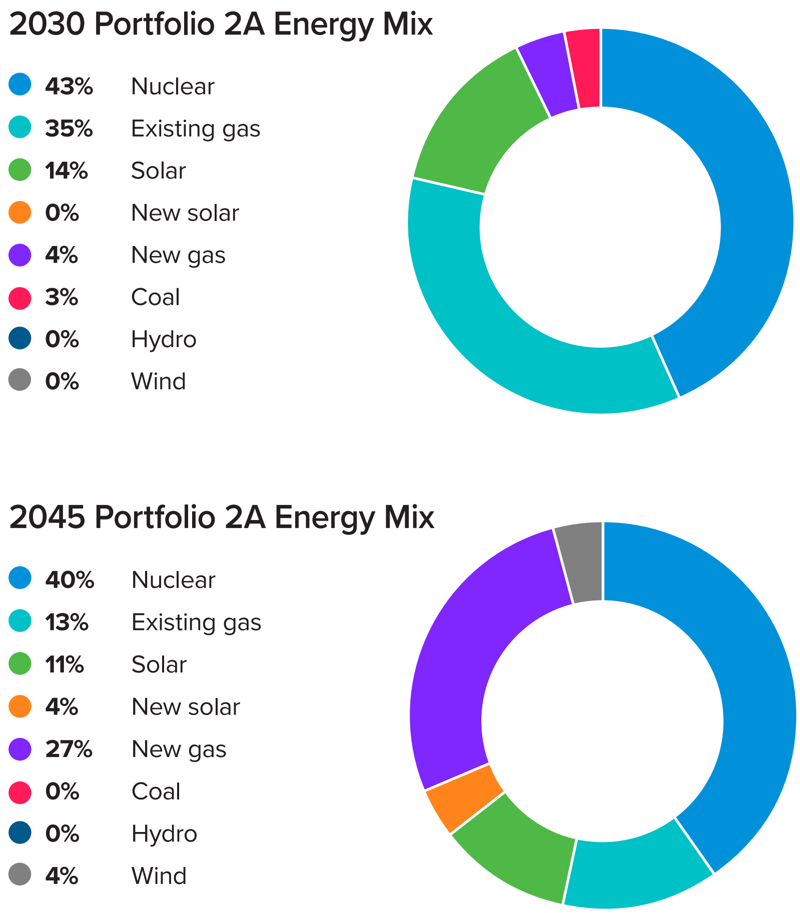


CHART 24: EAL PROJECTED P2A ENERGY MIX

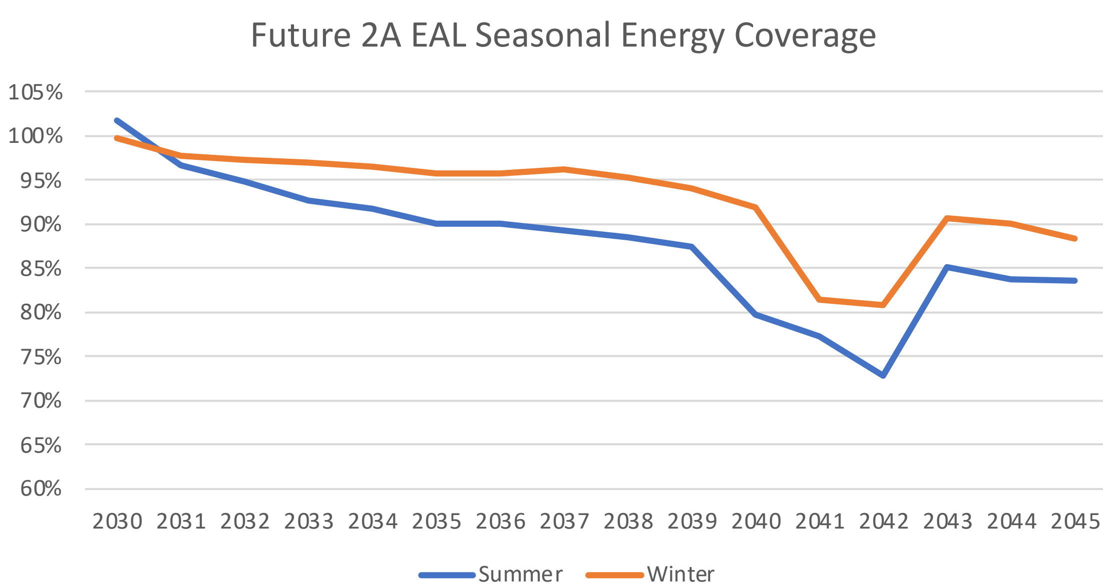


CHART 25: FUTURE 2A EAL SEASONAL ENERGY COVERAGE (P2A)

Future 2A is defined by medium load growth, reference gas prices, reference CO_2 prices, and reference capital install costs. The optimized portfolio using these assumptions includes a diverse mix of dispatchable and renewable energy resources.

In Future 2A, 5.8 GW of thermal capacity and 1.3 GW of renewable capacity were added within the planning horizon. In the optimized portfolio, a capacity deficit driven by load growth is met with two CTs for their peaking capacity characteristics. This is followed by wind resource additions starting in the middle of the study period and gas resources in the later years to replace retiring gas generation. With this portfolio, by 2045, the overall EAL energy mix will be about 40% nuclear, 40% gas thermal, and 19% carbon-free renewable resources and 91% of the overall capacity has the potential to be low-carbon capable. Low-carbon capable gas resources include newly constructed CCCTs, CTs and Aeroderivative resources, as they can potentially burn hydrogen or utilize CCS in the future. Concerning energy coverage, EAL dipped below 100% energy coverage at the beginning of the study and trended upwards as a new CCCT was selected. The TRSC for the Future 2A portfolio is $14,602 million on a net present value basis (2024 dollars). More detail on the TRSC estimate for each future can be found in Appendix F.

A similar build trend was observed for the MISO Market in Future 2A. CCCTs were selected throughout the study to replace the deactivated units. Solar and wind resources were also selected to help meet the energy and demand requirements. EAL's market utilized the MISO market more frequently in Future 2A because fewer generating units were selected in EAL's market. The MISO market build chart, and resource alternative table can be found in Appendix E.

Optimized Portfolio for Future 2B

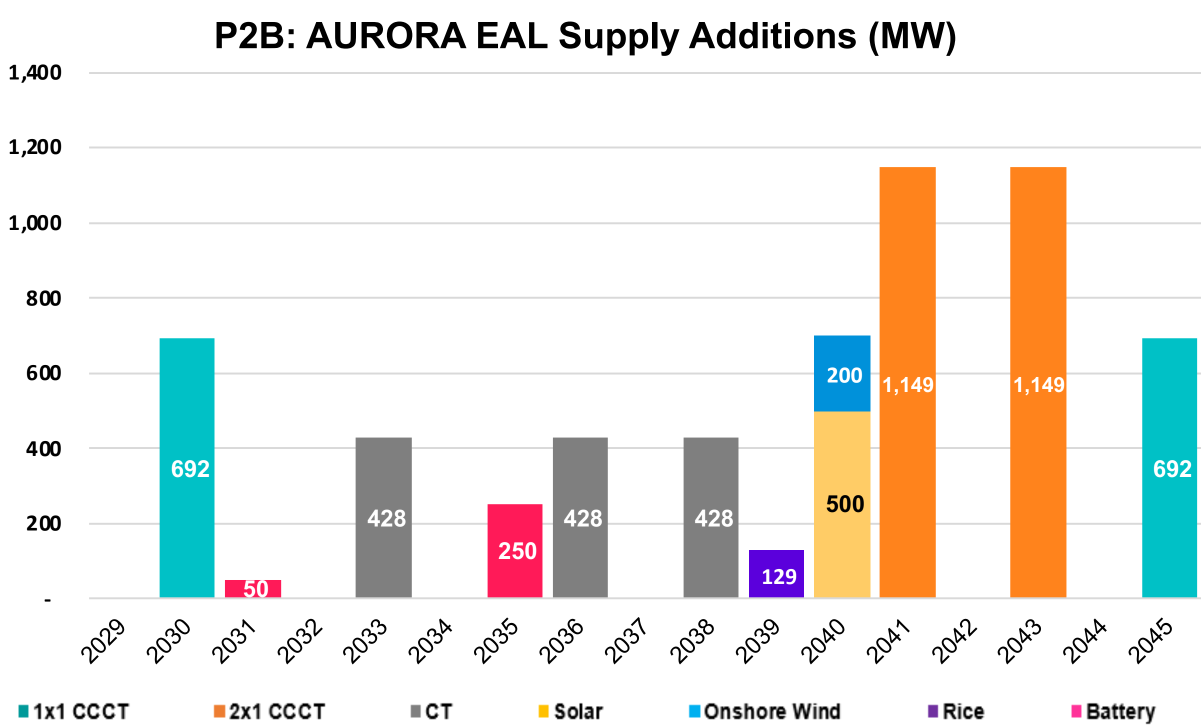


CHART 26: FUTURE 2B EAL OPTIMIZED PORTFOLIO (P2B)

EAL Technology by 2045	P2B installed summer MW	P2B effective summer MW	P2B installed winter MW	P2B effective winter MW
1x1 CCCT	1,383	1,360	1,469	1337
2x1 CCCT	2,298	2,260	2,438	2,222
CT	1,283	1,238	1,378	1,133
AERO CT	0	0	0	0
RICE	129	123	129	128
Single axis tracking solar	500	94	500	27
Coupled Battery	300	253	300	111
On-shore wind	200	77	200	77
Off-system wind	0	0	0	0
SMR	0	0	0	0
Total supply side additions	**6,094**	**5,404**	**6,414**	**5,035**

TABLE 18: SEASONAL ACCREDITATION FOR RESOURCE ALTERNATIVES

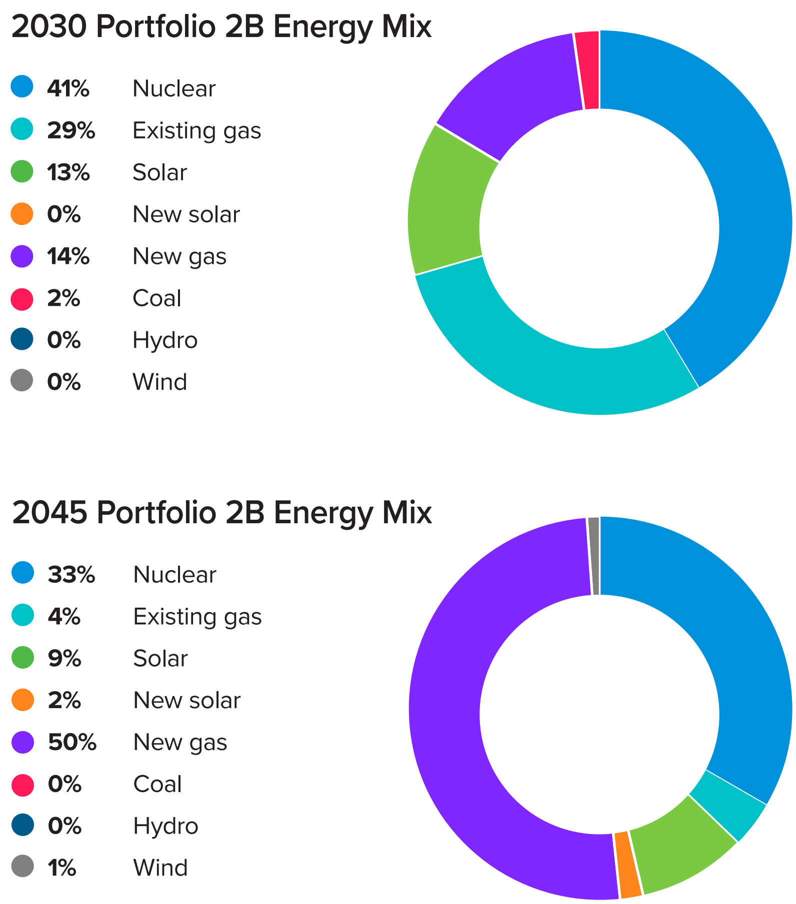


CHART 27: EAL PROJECTED P2B ENERGY MIX

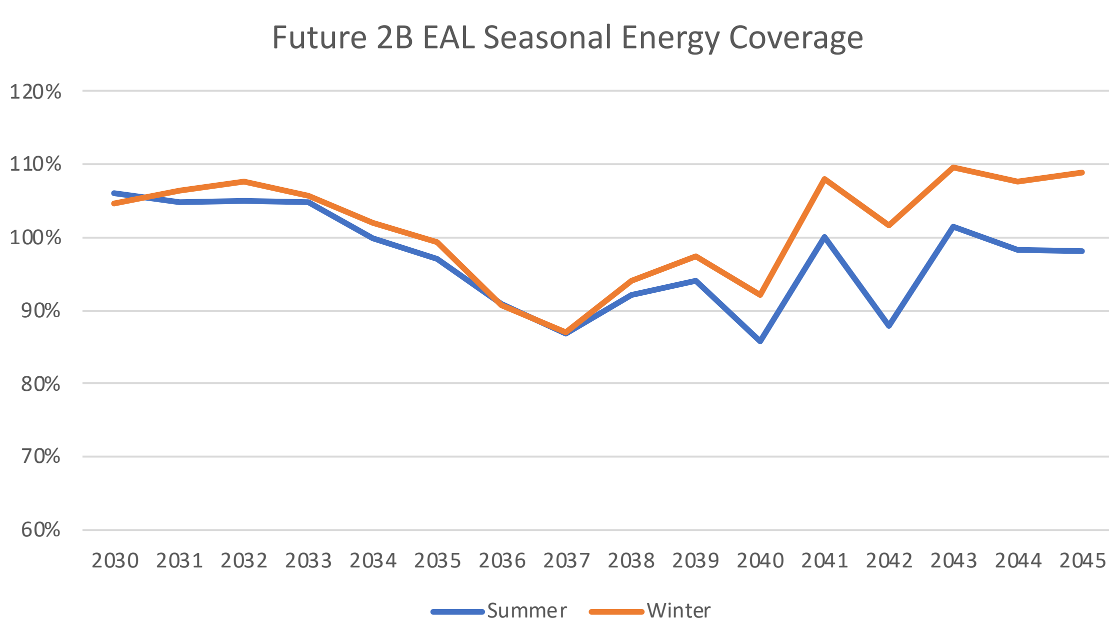


CHART 28: FUTURE 2B EAL SEASONAL ENERGY COVERAGE (P2B)

Similar to Future 2A, Future 2B is defined by reference load growth, reference gas prices, reference CO_2 prices, and reference capital installed costs. As summarized in Table 14, Future 2B includes assumptions around Clean Air Act Section 111. To comply with CAA 111, CCCT units installed in this future are assumed to have CCS attachments with 95% carbon capture. Aurora modeling reflects a derate to CCCT capacity to account for the CCS auxiliary load. Energy offers include the 45Q tax credit and additional CCS Variable Operating and Maintenance expenses. All existing coal and steam gas units are assumed to cease to use coal or deactivate by 2030 in lieu of modeling the various Best Systems of Emissions Reduction ("BSERs") identified in the May 2023, proposed rule or the April 2024 111(d) final rule, such as natural gas co-firing, CCS, or capacity factor restrictions. Under the final rule, the identified BSERs vary based on the operating horizon of the unit. The compliance pathway ultimately selected will likely vary according to unit-specific economics and other factors. Existing CTs were limited to a 20% maximum capacity factor by 2030 and existing CCCTs were limited to a 50% maximum capacity factor by 2035. The optimized portfolio using these assumptions resulted in a relatively higher need for baseload or units capable of producing large amounts of energy.

In Portfolio 2B, 5.3 GW of thermal capacity, 300MW of battery storage and 700 MW of renewable capacity were added within the planning horizon. In the optimized portfolio, a deficit due to the capacity factor limit on existing gas units is met with a 1x1 CCCT addition in 2030. As the load grows, CTs were added to meet the capacity need and as existing gas generation deactivates, two 2x1 CCCTs with CCS were selected for those replacements. Additionally, some solar, wind, and battery were selected throughout the study period. With this portfolio, by 2045, the overall EAL energy mix will be about 33% nuclear, 54% gas resource, and 12% carbon-free renewable resources and 80% of the overall capacity has the potential to be low-carbon capable. Concerning energy coverage, EAL imported energy from the MISO market in the summer in this portfolio due to wind resources producing less energy and exported energy to the MISO market in the winter, when wind resources produce more energy. The TRSC for the Future 2B portfolio is $12,623 million on a net present value basis (2024 dollars). More detail on the TRSC estimate for each future can be found in Appendix F.

A similar build trend was observed for the MISO Market in Future 2B. CCCTs were selected throughout the study to replace the deactivated units and provide additional energy due to energy limitations on existing units under the CAA III assumptions. EAL's market more frequently exported energy to the MISO market in Future 2B because more generating units were available in EAL's market selection. The MISO market build chart and alternative resource table can be found in Appendix E.

Optimized Portfolio for Future 3

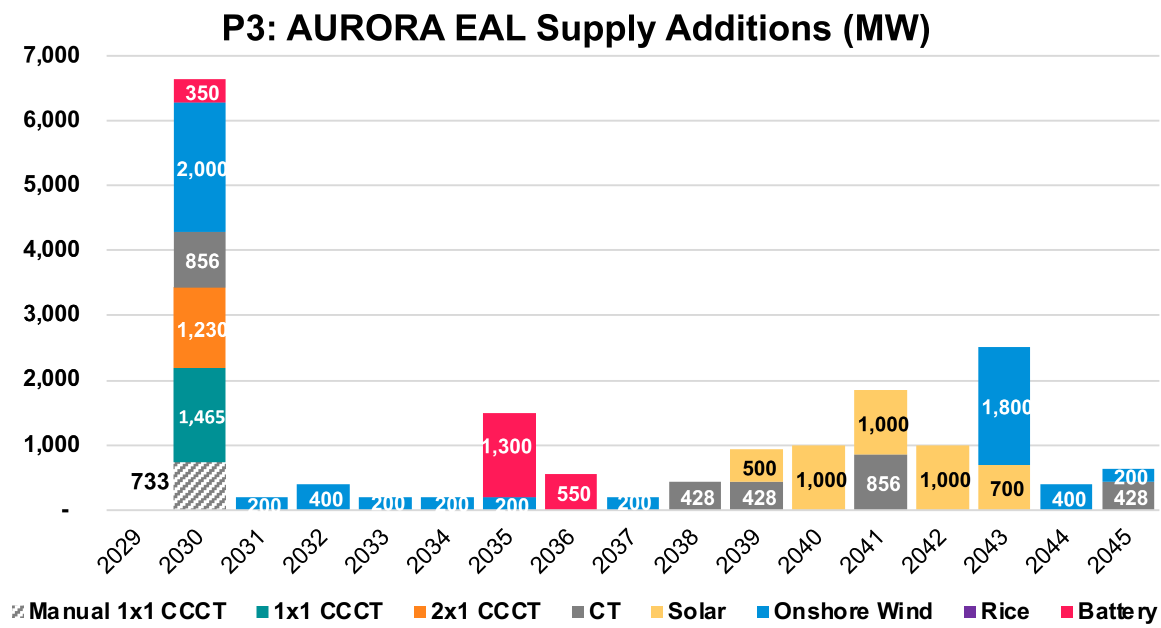


CHART 29: FUTURE 3 EAL OPTIMIZED PORTFOLIO (P3)

EAL Technology by 2045	P3 installed summer MW	P3 effective summer MW	P3 installed winter MW	P3 effective winter MW
1x1 CCCT (Manual)	733	720	778	708
1x1 CCCT	1,465	1,441	1,556	1,416
2x1 CCCT	1,230	1,210	1,305	1,189
CT	2,995	2,889	3,216	2,643
AERO CT	0	0	0	0
RICE	0	0	0	0
Single axis tracking solar	4,200	707	4,200	136
Coupled Battery	2,200	774	2,200	371
On-shore wind	5,800	2,049	5,800	2,977
Off-system wind	0	0	0	0
SMR	0	0	0	0
Total supply side additions	**18,623**	**9,789**	**19,055**	**9,441**

TABLE 19: SEASONAL ACCREDITATION FOR RESOURCE ALTERNATIVES

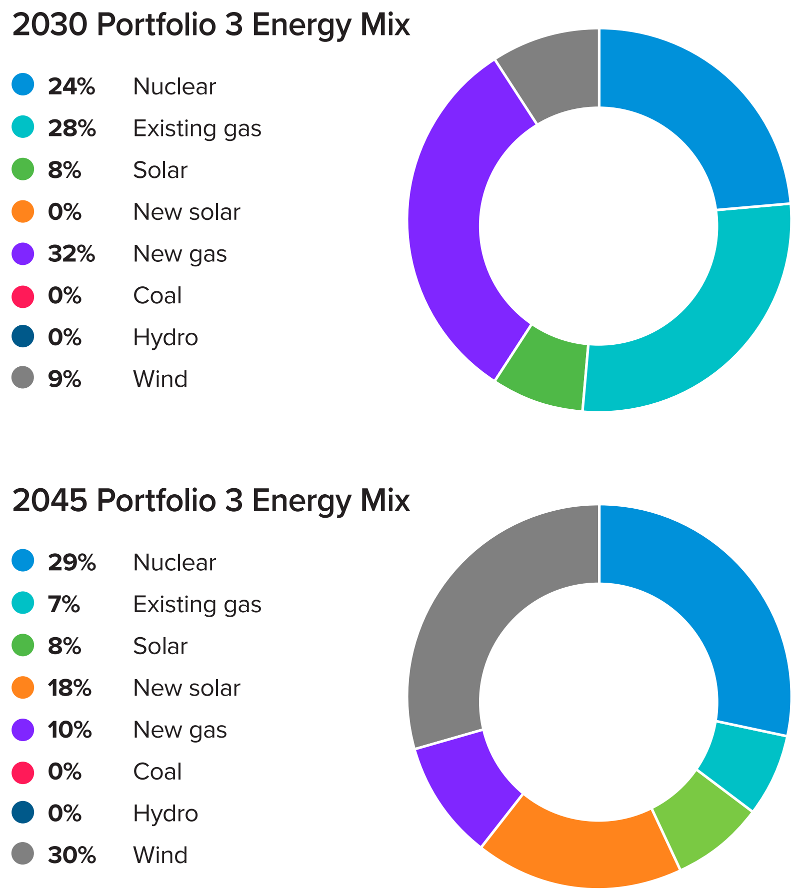


CHART 30: EAL PROJECTED P3 ENERGY MIX

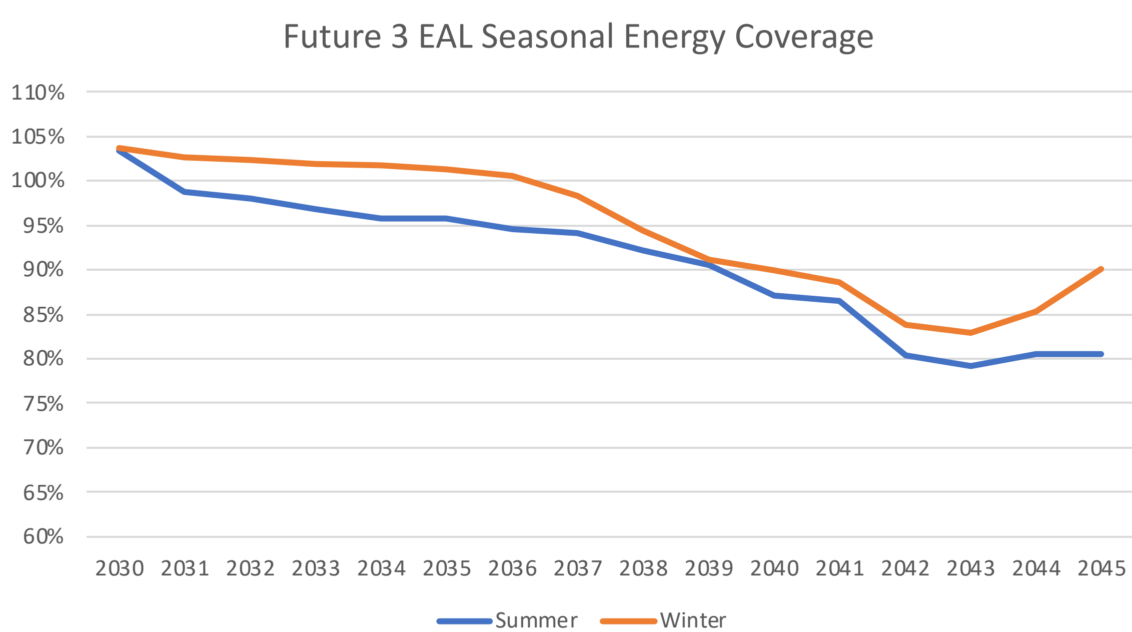


CHART 31: FUTURE 3 EAL SEASONAL ENERGY COVERAGE (P3)

Future 3 is defined by high load growth, high gas prices, high CO_2 prices, and low renewable costs. The optimized portfolio using these assumptions consists of higher levels of renewable resource additions. In Portfolio 3, 4.4 GW of thermal capacity, 2 GW of wind, and 350MW of battery storage were added in the year 2030 to meet the high load-factor demand growth before 2030. The greatest amount of renewable capacity is added in Future 3 due to the high CO_2 price assumption, paired with high natural gas prices, and low renewable resource cost assumptions, making renewable energy a more economical option than natural gas. Gas resources are still needed to meet the capacity and energy needs in 2030 and to replace deactivating gas generation in the later years. With this portfolio, by 2045, the overall EAL capacity mix will be about 31% gas resources and 65% carbon-free resources and 95% of the overall capacity has the potential to be low-carbon capable. Concerning energy coverage, EAL imported energy from the MISO market both in the summer and winter seasons. The TRSC for the Future 3 portfolio is $12,623 million on a net present value basis (2024 dollars). More detail on the TRSC estimate for each future can be found in Appendix F.

A similar build trend was observed for the MISO Market in Future 3, where mostly renewables were selected to meet the demand and energy requirements for the MISO Market, driven by the high gas prices and high CO_2 prices. Due to the amount of non-dispatchable resources selected in the MISO market, EAL frequently imported MISO excess energy from the market when available. The MISO market build chart and resource alternative table can be found in Appendix E.

Sensitivity Portfolio Future 2A CC

In addition to the optimized portfolio for each future shown above, a sensitivity case within Future 2A was added. This sensitivity case resulted in P2A CC which replaces two CTs added in 2030 in P2A with a 1x1 CCCT in 2030, and then optimizes the rest of the portfolio. The 1x1 CCCT in 2030 was added manually to improve EAL's energy coverage metric.

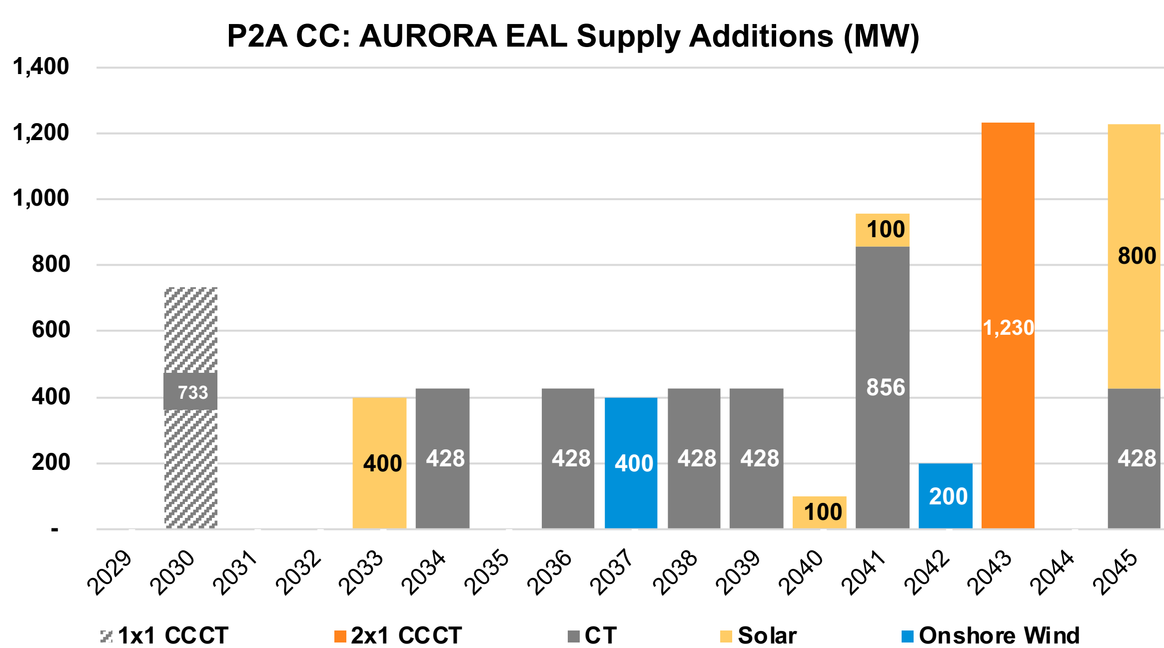
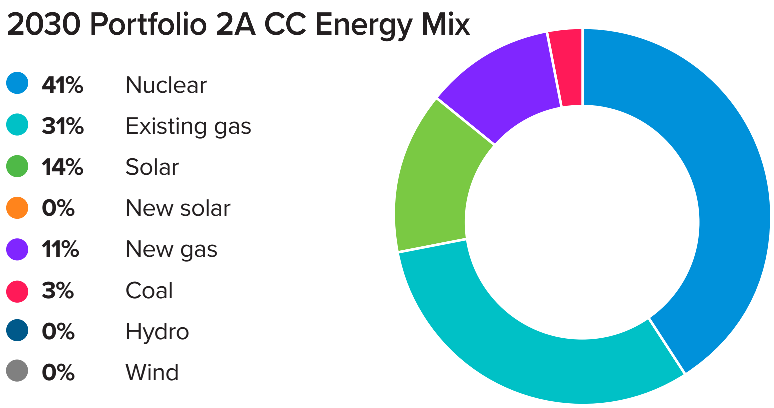


CHART 32: FUTURE 2A CC EAL OPTIMIZED PORTFOLIO (P2A CC)

EAL Technology by 2045	P2A CC installed summer MW	P2A CC effective summer MW	P2A CC installed winter MW	P2A CC effective winter MW
1x1 CCCT (Manual)	733	721	778	708
2x1 CCCT	1,230	1,210	1,305	1,189
CT	2,995	2,889	3,216	2,643
AERO CT	0	0	0	0
RICE	0	0	0	0
Single axis tracking solar	1,400	525	1,400	66
Coupled Battery	0	0	0	0
On-shore wind	600	212	600	279
Off-system wind	0	0	0	0
SMR	0	0	0	0
Total supply side additions	**6,957**	**5,556**	**7,299**	**4,886**

TABLE 20: SEASONAL ACCREDITATION FOR RESOURCE ALTERNATIVES



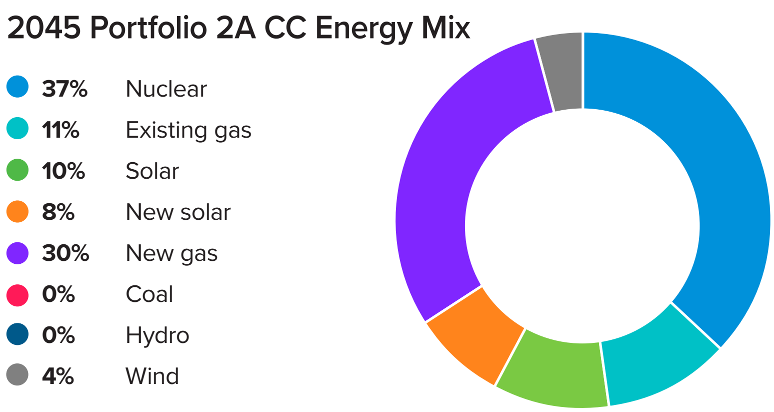


CHART 33: EAL PROJECTED P2A CC ENERGY MIX

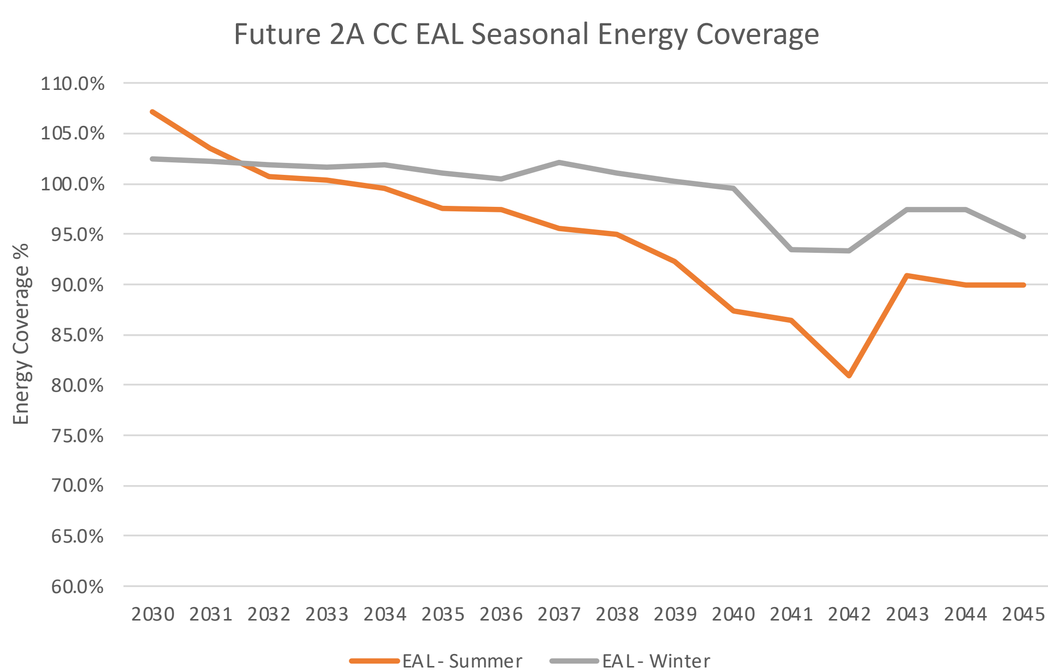


CHART 34: FUTURE 2A CC EAL SEASONAL ENERGY COVERAGE (P2A CC)

In Future 2A CC with the addition of a 1x1 CCCT in 2030 in lieu of two CTs, the winter energy coverage stays above 100% until 2040 and the summer energy coverage averaged 95% between 2030 and 2045. Compared to portfolio 2A, which has an annual average energy coverage of 90%, Portfolio 2A CC relied less on the MISO market for energy.

In Future 2A CC, similar to Portfolio 2A, 5.1 GW of thermal capacity and 2 GW of renewable capacity were added within the planning horizon. In the sensitivity portfolio the remainder of the CTs and CCCTs were added onto the system identical to Portfolio 2A. The only change observed is slightly more solar added to fill in the difference in capacity between the two CTs versus the 1x1 CCCT. The TRSC for the Future 2A CC portfolio is $14,514 million on a net present value basis (2024 dollars). More detail on the TRSC estimate for each future can be found in Appendix F. A similar build trend was observed for the MISO Market in Future 2A CC as in Future 2A.

Results -Capacity Expansion & Total Relevant Supply Cost Metric (shows all Futures)

The TRSC for each portfolio, as shown in Table 21, was calculated for the scenario for which it was developed. The TRSC is calculated using:

- **Variable supply cost** – The variable output from the Aurora model for all of EAL's fleet, which includes fuel costs, variable O&M, emissions costs, startup costs, energy revenue, make-whole payments, uplift revenue, and 45Q tax credits for CCS units where applicable.
- **Levelized-real non-fuel fixed costs** – Return of and on capital investment, fixed O&M, and property taxes for the incremental resource additions in each portfolio, calculated on a levelized real basis.
- **PTC Benefits** – Benefits associated with EAL's ratemaking treatment.
- **Capacity purchases/(sales)** – The capacity above or below the target reserve margin in each scenario multiplied by the assumed capacity value.

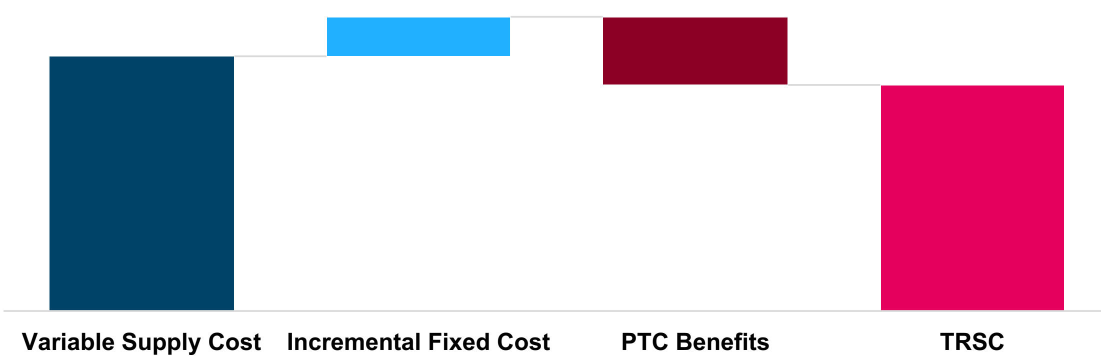


FIGURE 18: TRSC COMPONENTS

Each EAL portfolio is run through the Aurora production cost model for the relevant future and combined with other spreadsheet-based cost components to produce the TRSC. The results of the analysis are summarized below.

Portfolio	Gas/CO_2 price scenario	TRSC ($MM, 2024$ NPV)
Portfolio 1	Low gas, No CO_2	$7,571
Portfolio 2A	Ref gas, Ref CO_2	$14,602
Portfolio 2A CC	Ref gas, Ref CO_2	$14,514
Portfolio 2B	Ref gas, Ref CO_2	$12,623
Portfolio 3	High gas, High CO_2	$42,664

TABLE 21: TRSC RESULTS

Qualitative Risk Characteristics

The results of the EAL IRP are not intended as static plans or pre-determined schedules for resource additions and deactivations. As EAL nears execution decisions regarding its resource portfolios, it will be important to understand the relative risk that contemplated portfolios may bring. In response to stakeholder feedback regarding adding an objective metric to determine the preferred plan, in this IRP, EAL added a scorecard assessing qualitative risk factors. The following factors are intended to give EAL an indication of the qualitative risk characteristics that may contribute to future portfolio decisions:

Market Factors - Reviewing market relative energy coverage within the MISO market metrics allows EAL to assess the level of exposure to market prices for a portfolio. A portfolio forecasted to generate less or more energy relative to their demand relies on the MISO energy market to make up its need, resulting in a higher energy price risk if LMPs are higher than anticipated, or higher fixed-cost risk if LMPs are lower than anticipated.

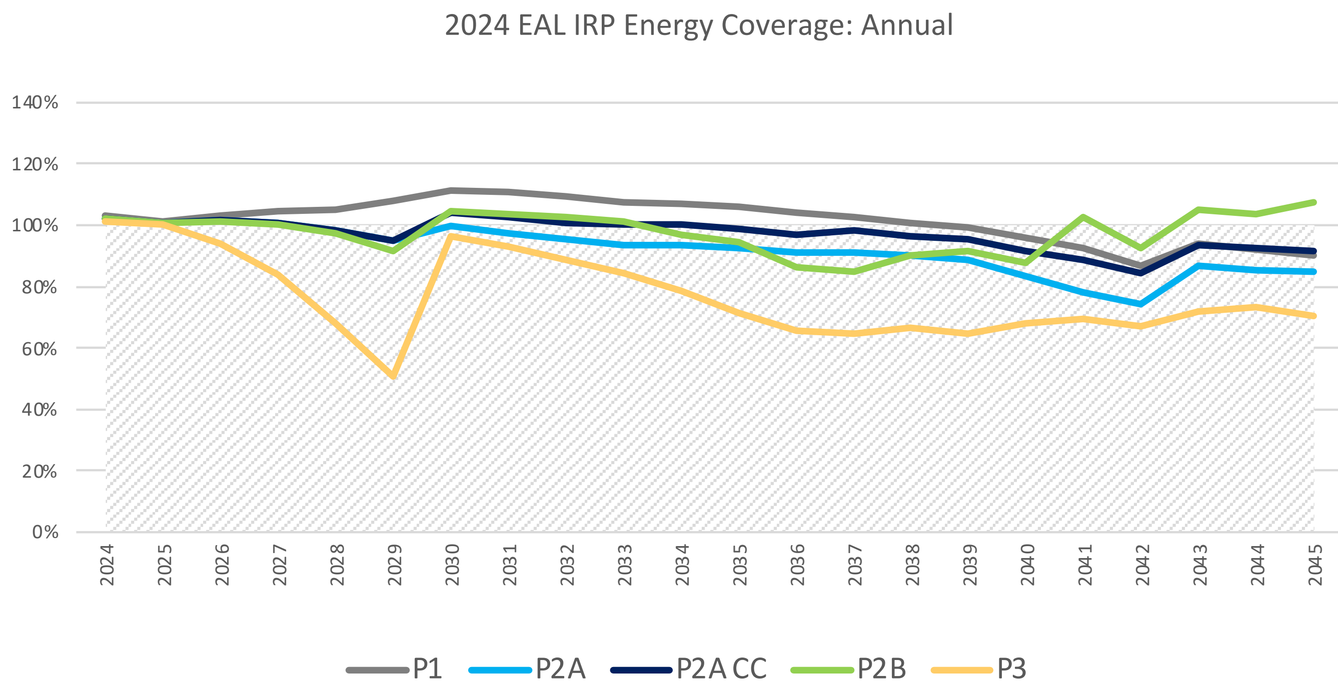


CHART 35: ANNUAL ENERGY COVERAGE

Measuring energy coverage allows EAL to assess the level of exposure to market prices for each portfolio. The energy coverage metric does not perfectly account for the physical hedge provided by the ability for the resources in each of the EAL IRP portfolios to increase beyond the optimal economic dispatch levels of the resources, if system conditions merit doing so. However, it does indicate the extent to which each portfolio's variable supply cost relies on the simulated market LMPs.

Portfolios 1, 2A, 2A CC, and 2B provide similar levels of estimated energy coverage annually and reasonably match up with EAL's seasonal demand, with 2B being more closely aligned to the 100% coverage line.

Portfolio 3 energy coverage dips drastically in 2029 and in the outer years relative to P1, P2A, and P2B, indicating higher reliance on the MISO energy market.

Portfolio 1	Portfolio 2A	Portfolio 2A CC	Portfolio 2B	Portfolio 3

TABLE 22: MARKET RISK PORTFOLIO SCORES

Reliability - Performing a reliability analysis provides EAL the ability to understand the relative reliability attributes of a portfolio for reasonably balancing regional requirements related to capacity, transmission, and reliability.

A qualitative analysis was performed on the following list of reliability attributes to assess the reliability performance of each portfolio:

Reliability Attribute	Tier	Description
Modular Capacity	1	Ability for resource capacity to be sited in smaller increments or to enter partial outage configurations, lessening single point of failure risk
Energy Duration	1	Ability to provide energy continuously throughout the day
Dispatchability	1	Ability to respond to directives from system operators regarding its status and output
Planned & Forced Outages	1	Ability to be operationally available due to minimal planned outages and forced outages
Operational Flexibility	1	Ability to cycle on and off, ramp up and down quickly, and have low minimum uptimes
Fast Start	1	Ability to quickly respond from an offline state to an online state
Automatic Generation Control (“AGC”) Capable	2	Ability to be placed on Automatic Generation Control, allowing output to be ramped up or down automatically to respond immediately to system changes
Inertia (non-inverter)	2	Ability to stabilize the system using large rotating machinery (turbines, shafts, stators, exciters, etc.)
Voltage-Ampere Reactive (“VAR”) support	2	Ability to send VARs out onto the system or consume excess VARs to control voltage
Fuel Independence	2	Ability to operate without reliance on a fuel deliverability system or the ability to store fuel onsite
Proximity to Customers	2	Ability to be sited near customers; Operating Company specific conditions may influence scoring for this attribute
Black Start	2	Ability to help with system restoration after a widespread system outage

Tier 1 attributes are considered to have greater impact on system reliability than Tier 2 attributes. Tier 1 attributes are scored on a zero to five scale and tier 2 attributes are scored on a zero to three scale. Analysis is focused on resources’ physical reliability attributes and does not consider specific MISO ancillary service requirements.

Each technology type is given a score on a per 100 MW of UCAP basis for the various reliability attributes.

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 UCAP	**24**	**25**	**26**	**35**	**36**	**34**	**16**	**16**

TABLE 23: RELIABILITY SCORING CRITERIA

Portfolio 1 consists of a mix of gas, battery, and solar resource types, earning the highest relative reliability score.

Portfolios 2A, 2A CC, 2B, and 3 perform similarly, with P2A achieving a slightly higher score partially driven by the higher number of CT additions.

Portfolio 3 relies on a heavy buildout of wind and solar resources, resulting in lower VAR, inertia, and AGC scores.

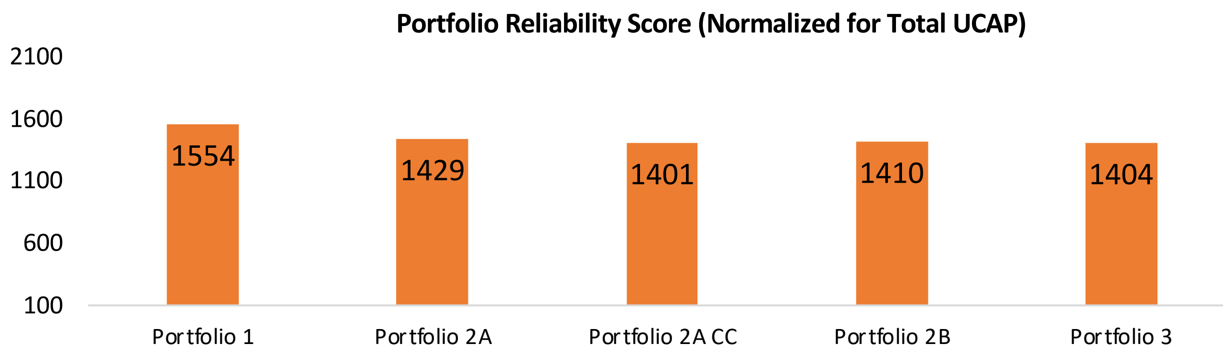


CHART 36: PORTFOLIO RELIABILITY SCORES

Portfolio	2x1 CCCT	1x1 CCCT	CT (J Frame)	Aero CT	RICE	Battery	Solar	Onshore Wind	Total Portfolio Score	Variance to Top Score	Final Score
1	-	463	1071	-	114	443	44	-	2135	0	
2A	447	-	1444	-	-	-	46	26	1963	172	
2A CC	438	272	1099	-	-	-	91	25	1926	210	
2B	822	510	442	-	-	97	67	-	1938	197	
3	252	312	631	-	-	438	157	140	1930	206	

TABLE 24: PORTFOLIO RELIABILITY SCORES

Economic, reliability, and risk evaluation - The analysis of TRSC, which represents the incremental fixed costs and total variable supply costs to reliably serve customers' resource needs under the assumptions of a particular Portfolio through the planning horizon, used cross-testing to identify a 20-year revenue requirement for each of the 3 optimized Portfolios in all three Futures. Information on the TRSC and risk analysis can be found in Appendix E.

Executability and optionality - Assessing the executability of a portfolio allows EAL to evaluate the relative risks associated with procuring single or multiple resources within the timeframe needed. This assessment aims to highlight the potential time and cost risks associated with procuring a potential portfolio of resources such as: interconnection/deliverability, MISO queue process, procurement process and negotiations, construction, etc. Optionality considers the adaptability of a portfolio which enables EAL to adjust to various market conditions, including how soon resources must be procured within the portfolio, the portfolio's capability to use hydrogen, or the portfolio's ability to adapt its supply role.

- Portfolios are assessed based on:
    - Overall feasibility of procurement and execution of resources within the portfolio (e.g., availability of resources, lead time prior to initiating procurement)
    - Adaptability (e.g., ability of the portfolio to adjust to unforeseen changes in load or retirements) and optionality associated with resource types (e.g., supply role adaptability such as hydrogen-capable CTs and CCCTs that may change supply roles)
- Portfolio 1 does not build its first resource until 2037, which increases the lead time available before initiating procurement. It contains one of the lowest number of resources. It also includes hydrogen-capable CTs and CCCTs that may change supply roles to increase adaptability.
- Portfolio 2A and 2A CC will start building resources in 2030, shortening the lead time required to begin procuring resources. Similarly, they both require the execution of relatively few resources, making it more feasible than the other portfolios.
- Portfolio 3 contains many resources starting in 2030 and consists of a mix of gas, battery, solar, and wind throughout the planning period. The development lead time and regulatory requirements for such a large portfolio reduces this portfolio's score. Wind resources are not currently widely available to EAL, and if procured in large quantities would likely require excessive reliance on off-system resources, which may entail additional transmission costs.
- Portfolio 2B has a similar number of resources to P1 and P2A starting in 2030.
- Portfolio 2B includes the construction of a 1x1 CCCT within the timeframe that allows the resource to be eligible to receive 45Q tax credits under the IRA for the associated CCS infrastructure, which will lower the costs of implementing the CCS significantly. However, depending on resource location, the state's geology could make the execution of a CCS project challenging, especially the storage of the captured carbon, reducing the executability score of the portfolio.

Portfolio 1	Portfolio 2A	Portfolio 2A CC	Portfolio 2B	Portfolio 3
				

TABLE 25: EXECUTABILITY AND OPTIONALITY SCORES

Fuel Supply Diversity - Fuel supply diversity assesses the level of exposure to fuel supply concerns, such as commodity constraints.

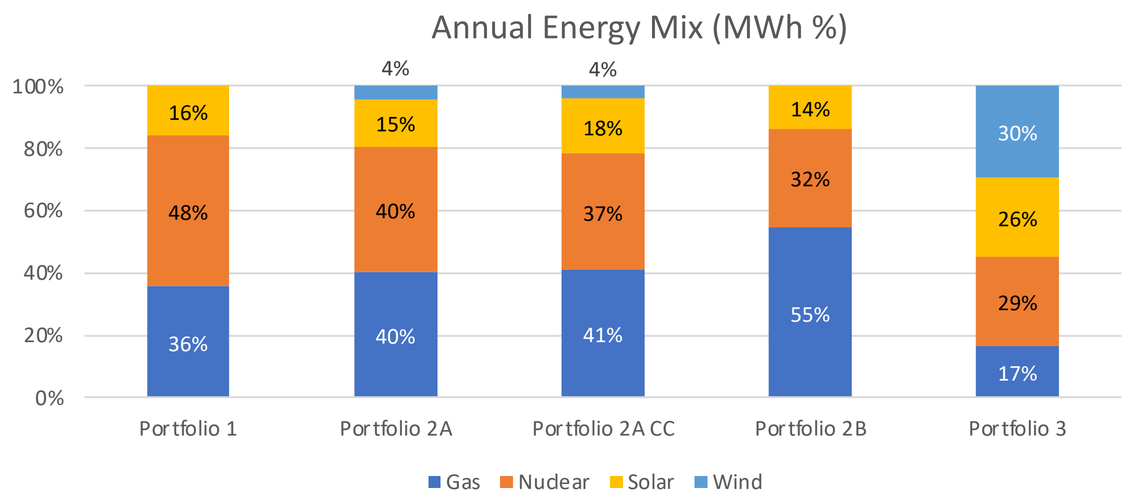


CHART 37: ANNUAL ENERGY MIX

Portfolio 1	Portfolio 2A	Portfolio 2A CC	Portfolio 2B	Portfolio 3

TABLE 26: FUEL DIVERSITY SCORES

Environmental - Analyzing the relative CO_2 emissions impact of a portfolio allows EAL to understand the risks associated with changing laws, regulations, and environmental market pressures.

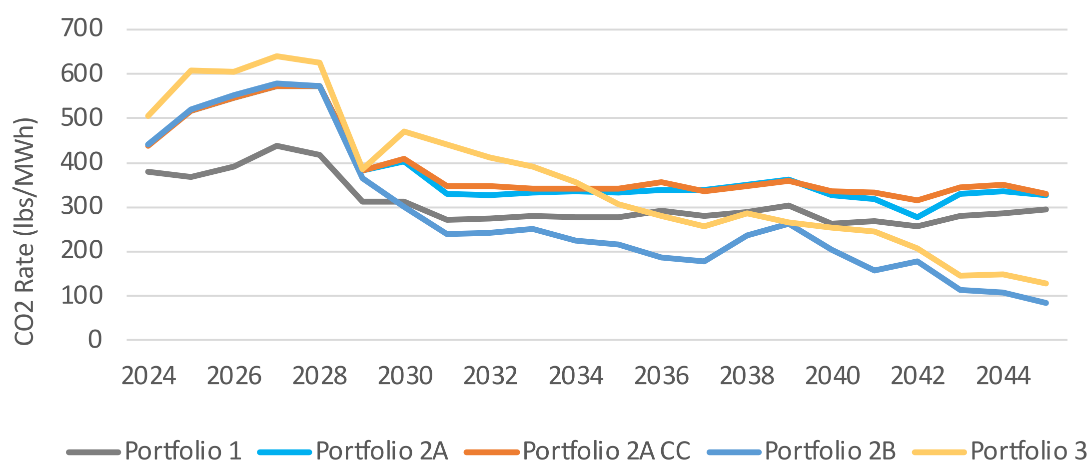


CHART 38: ANNUAL CO_2 RATE

Portfolio 1	Portfolio 2A	Portfolio 2A CC	Portfolio 2B	Portfolio 3

TABLE 27: ENVIRONMENTAL SCORES

CHAPTER 6

Action Plan

Summary

- **Peaking capacity, such as a CT, is favored across all scenarios in the near term to meet winter capacity needs and integration of renewables.**
- **Any substantial load growth will require thermal resources that provide year-round, dispatchable capacity and energy. However, if renewable costs decrease, a mix of gas and renewable resources would be ideal to serve the load growth.**
- **Battery storage may also be cost-effective peaking capacity if built alongside renewables to realize capital, O&M, land, and interconnection cost savings.**
- **The Preferred Resource Plan features a balanced mix of renewable, baseload, and peaking capacity.**

Findings & Conclusions

Findings across Futures – As stated in the previous chapters of the report, EAL used a futures-based approach accompanied by the Aurora capacity expansion process to evaluate the various needs in the future given the market uncertainties. This process resulted in optimized resource portfolios projected to meet the future need economically. Four futures and a sensitivity to the reference future 2A were evaluated resulting in five distinct portfolio mixes. When reviewing the results of the five resource portfolios across the futures, the many varying inputs across the futures must be considered. The portfolios developed based on this broad range of uncertainties reflected in the IRP Futures may provide insight into the types of resources that can be cost effective over this range of possible outcomes; however, caution must be taken when comparing results between the futures. Table 33 below summarizes key results for each future.

	Portfolio 1	Portfolio 2A	Portfolio 2A CC	Portfolio 2B	Portfolio 3
Solar	400	700	1,400	500	4,200
Battery Hybrid	750	- -	300	2,200	
Onshore wind	-	600	600	200	5,800
CCCT	733	1,230	1,963	3,681	3,428
CT	1,711	3,815	2,995	1,283	2,995
RICE	129	-	129	-	
Total MWs built	3,723	6,380	4,517	15,918	9,612
Thermal %	69%	79%	71%	84%	34%
Renewable %	11%	20%	29%	11%	54%
Hybrid Storage %	20%	0%	0%	5%	12%

TABLE 28: PORTFOLIO RESULTS SUMMARY (SUMMER INSTALLED MW)

Results Overview

Portfolio 1

In Future 1, removing anticipated load growth and assuming low gas costs, no CO_2 tax, and high renewable costs, Aurora modeling indicated no near-term addition will be needed until 2037, provided EAL's planned resource additions through 2030 are achieved.

However, this portfolio presents risk related to limiting EAL's ability to respond to incremental load growth, creating long lead times before new larger customers can be served, or existing larger customers can expand loads. This delay, often about five or more years, could impede economic development in Arkansas, particularly in territories with lower electricity prices. This portfolio would likely hinder growth and opportunity in Arkansas.

Portfolios 2A, 2A CC and 2B

In all the Future 2 portfolios, assuming medium load growth, Aurora modeling results indicate that there are incremental gas resource(s) needed starting in 2030.

The key difference between the P2A, P2A CC and P2B build in 2030, is the gas technology selected. Two CTs were selected in 2030 in P2A while in P2B selected a 1x1 CCCT. For a robust evaluation of 2030, P2A was re-optimized with the manual adjustment of a 1x1 CCCT in lieu of the two CTs. All portfolios yielded similar capacity surplus and deficit outcomes. However, regarding energy coverage P2A CC and P2B provided higher energy coverage relative to P2A. The two portfolios with the CCCT in 2030 resulted in lower TRSC than P2A with two CTs.

Additionally, when comparing the two portfolios with a CCCT in 2030, P2A CC and P2B, which includes CCCT with CCS, resulted in lower TRSC driven by 45Q tax credit lowering cost. CAA 111 portfolios include the full 12-year period of 45Q tax credits within the VSC, whereas the resource addition costs only account for the levelized cost of the years within the evaluation period. Notably, only levelized costs through the evaluation period, 2045, are picked up. This methodology tends to favor the CAA 111 portfolios over the regular portfolios. However, the long-term availability of 45Q tax credit is subject to uncertainties, as political changes in administration or policy priorities could affect its availability and introduces risks to its long-term viability.

Moreover, the availability of CO_2 storage sites is geographically limited which poses a location risk. This limitation could impact the feasibility and cost effectiveness of deploying CCS depending on the proximity of storage sites and the pipeline distance required. Transportation and storage costs may be understated as siting is not assessed in the IRP analysis; and certain sites within EAL service territory are unsuitable for CO_2 storage and may require additional transportation cost.

Portfolio 3

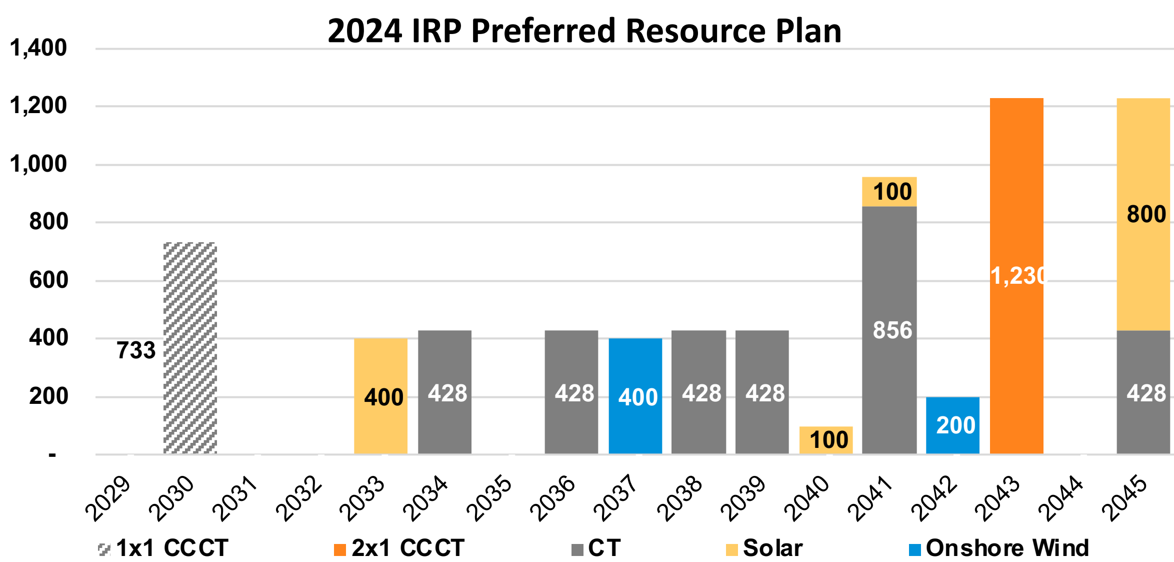
Given high load growth potential and assuming low renewable cost in Future 3, Aurora modeling results indicate higher level of renewable additions. As a result, EAL would need to explore opportunities for integrating wind and battery to complement existing solar in the current mix. A significant risk in this portfolio is this potential for overbuilding in 2030 where the high load growth does not materialize.

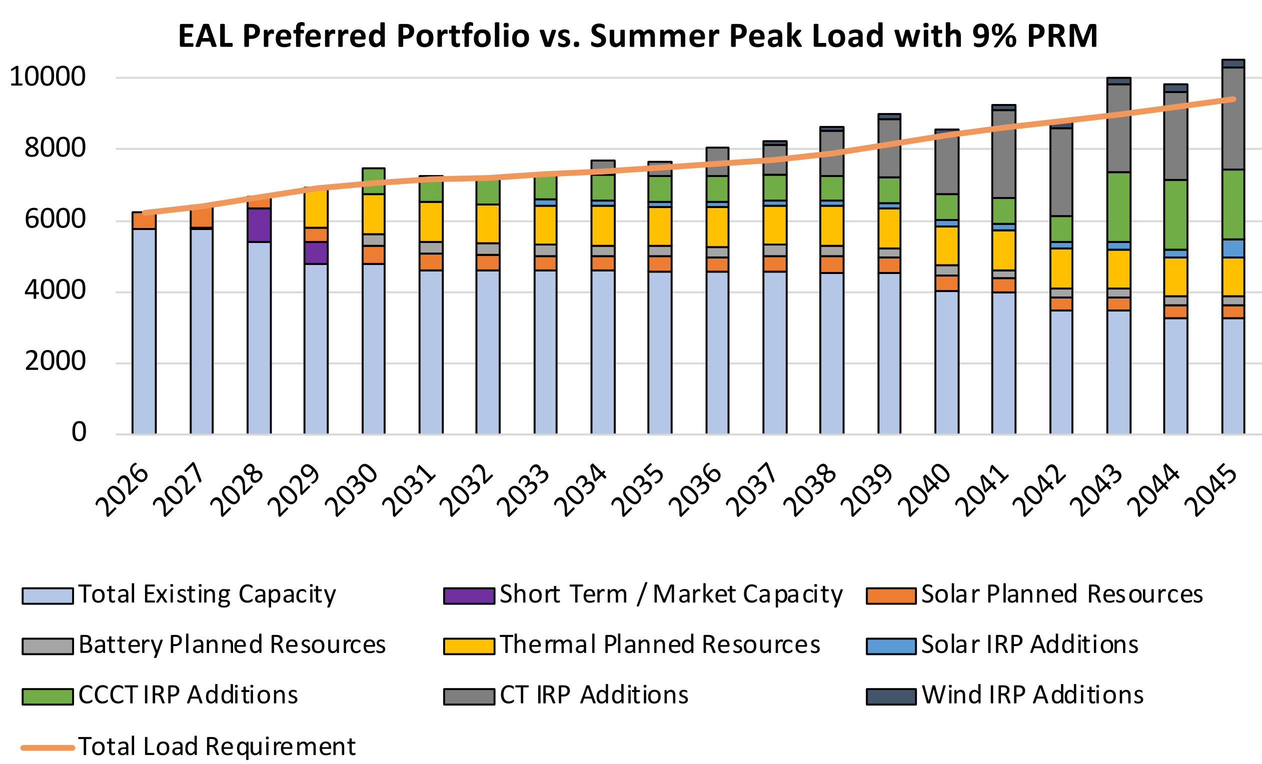
Observations across the portfolios

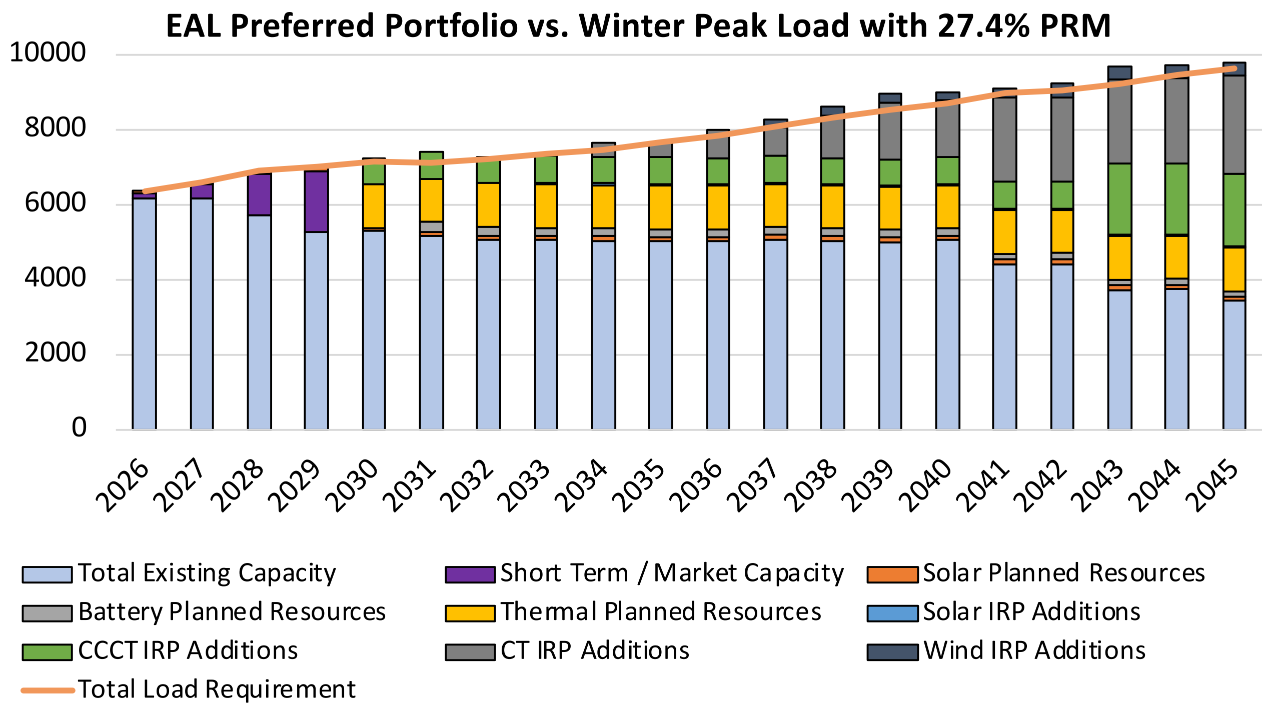
- Dispatchable peaking capacity is favored across all scenarios to meet winter capacity needs. In general, EAL mainly built CTs for capacity needs when its energy position was long, and then built renewables and CCCTs for energy and capacity as bigger deficits were seen from existing gas deactivations after 2040.
- Any substantial load growth for EAL will require thermal resources that provide year-round capacity and energy.
- Battery storage can be cost effective if built alongside renewables to realize capital, O&M, land, and interconnection cost savings.
- Growth should be served with a mix of gas and renewable resources.

2024 IRP Preferred Resource Plan

Based on the modeling, analysis and findings discussed above, the EAL concludes Portfolio 2A CC as the Preferred Portfolio for the 2024 IRP.







The preferred portfolio is one of three portfolios modeled under Future 2 market assumptions that are similar in the first ten years, specifically, Aurora identified the need for dispatchable generation in 2030 in all three Future 2 portfolios.

The preferred portfolio features a balanced mix of renewable, baseload, and peaking resources, supporting EAL's load growth. The CCCT instead of two CTs in 2030 provides better energy coverage, mitigating market exposure. Moreover, the CCCT offers a pathway for lower carbon operations with hydrogen-capable technology, aligning with Entergy's future carbon goals.

The results support the conclusion that EAL's initial future supply-side resources should be focused on a combination of new dispatchable CT and CCCT resources as well as renewable energy resources. The near-term addition of CTs and a CCCT are needed to meet the large capacity, and energy needs due to industrial growth and continued steady residential growth. Ensuring these dispatchable resources are hydrogen capable and CCS enabled will help to mitigate environmental risks and ensure the resources are best positioned to provide sustained value for customers in the future. In the near-term, renewable resource additions will be made based on specific project proposals. Including renewable resources also increases fuel supply diversity, lowers environmental cost risk, and responds to customers' preferences for renewable energy, while also making progress toward meeting Entergy's announced sustainability goals. Over the long-term, the amount and timing of capacity needs cannot be known completely. Load requirements, commodity prices, environmental policy considerations, technology adoption, and other factors may impact the resources needed to serve customers. The 2024 EAL IRP shows that a mix of resources and resource types enhances the adaptability of EAL's portfolio to changes, such as rapidly evolving customer demand and sustainability requirements. In the near term, resource additions will be made based on specific projects. EAL's preferred resource plan maintains the planning assumptions for existing and planned resources and begins adding gas resources starting in the 2029-30, time frame followed by renewable resources and CTs to support the integration of renewable resources.

2024 IRP Action Plan

The action items below represent a pragmatic approach to EAL's integrated planning over the coming three years. By necessity, the integrated resource planning process is subdivided into work streams, each with its own process and timeline.

1. Complete agreements and seek approval of resources selected in the 2022 Renewable RFP	In June 2022, EAL issued its 2022 Request for Proposals for Renewable Resources seeking to procure up to 1,000 MW of solar and/or wind resources via long-term PPA, acquisition or self-build project. EAL will complete negotiations with selected proposals and seek approval of the agreements from the APSC.
2. Monitor MISO Resource Adequacy Requirements	EAL will continue to monitor its capacity position and potential need for incremental short-term capacity to address the seasonal capacity deficit from 2026 to 2029.
3. Generation replacement at Lake Catherine	EAL will seek approval from the APSC to construct a CT with a plan to commence commercial operations in Q4 2028, but no later than three years after the deactivation of Lake Catherine Unit 4. EAL will also continue to evaluate utilization of the remaining interconnection rights from Lake Catherine Unit 4.
4. Continue Participation in EE	EAL will continue to offer cost effective EE and DR programs within the Commission's Rules for Conservation and EE Programs and subsequent future Commission orders as provided through Arkansas law, including targets adopted in EAL's 2024-2026 EE Program Plan as filed in Docket No. 07-085-TF.
5. Evaluate opportunities for adding dispatchable resources to serve capacity and energy needs in the future	EAL will seek to develop a diverse mix of resources to meet its customers capacity and energy needs post-2028. The mix is expected to include a combination of solar, battery and gas resources to ensure capacity, energy, and reliability in supporting integration of renewable resources, and will be evaluated in the future IRPs.
6. Pursue Power Resiliency	EAL will develop and implement customer-centric power resiliency solutions. Power Through represents EAL's initial power resiliency offering. On July 11, 2024, EAL made a compliance filing with the APSC that explicitly conforms with Commission Order Nos. 11 and 13 in Docket No. 20-049-U. EAL requested approval of the compliance tariff by August 12, 2024. Upon APSC approval, EAL will offer Power Through to its customers.
7. Monitor CCS, Hydrogen, and Renewables to complement future gas-fired resource additions	EAL will continue to monitor the 45Q credit amid political uncertainties. Additionally, EAL will assess geographic locations to find opportunities for suitable CCS storage sites. As political changes and policy priorities shift, EAL will evaluate the availability of the tax credit and adjust its long-term strategy.
8. Evaluate Stakeholder Engagement	The stakeholder engagement for the 2024 IRP has been robust and an important component of the process. EAL will closely review the stakeholder report, which can be found in Appendix G of this report and continue taking steps to address concerns in the continuing IRP process.

CHAPTER 7

Stakeholder Engagement

According to the APSC Resource Planning Guidelines, one component of the development of the IRP is engaging with stakeholders in EAL's long-term planning process. As defined in the APSC Resource Planning Guidelines for Electric Utilities, stakeholders include representatives of retail and wholesale customers, independent power suppliers, marketers, and other interested entities in EAL's service area. As noted in Chapter 2, EAL worked diligently with stakeholders to address feedback provided in the 2021 IRP's Stakeholder Report and feedback received during the 2024 IRP's planning cycle.

The stakeholder engagement process began in September 2023 with a public Preliminary Information Posting to EAL's IRP website.

In January 2024, EAL held a virtual Stakeholder Kickoff Meeting to provide a comprehensive overview of its planning processes and objectives, including preliminary assumptions and inputs for the IRP modeling. The meeting was well attended, with participation from diverse groups of stakeholders, representing various educational and professional backgrounds, and bringing a wide range of industry experience and expertise.

Following the meeting, in February 2024, EAL posted its Set 1 Q&A document, addressing questions raised during and after the Stakeholder Kickoff Meeting. In March 2024, EAL received about 115 additional questions from the Stakeholder Committee covering input assumptions, IRP processes, and modeling. EAL responded to these inquiries and posted the responses as Set 2 Q&A to the EAL IRP website. In response to Set 2 Q&A, the Attorney General and Arkansas Electric Energy Consumers, Inc. on behalf of the Stakeholder Committee for the 2024 IRP submitted another set of questions, which EAL answered in Set 3 Q&A as to applicable questions. Subsequently, in August 2024, the Southern Renewable Energy Association submitted additional questions related to Set 3 responses. EAL responded to these queries and posted them as Set 4 Q&A.

In August 2024, EAL held a second virtual meeting, which provided detailed updates on several key topics:

- Technology cost and performance data updates
- Futures overview used for the 2024 IRP
- Capacity expansion results
- TRSC
- Qualitative risk assessment
- EAL's recommended preferred portfolio
- Outline of the 2024 IRP Action Plan

This meeting was well-attended, and EAL posted the presentation material on the EAL IRP website. Following the meeting, stakeholders submitted further questions regarding the information to which EAL responded by posting Set 5 Q&A. In September 2024, EAL received additional questions regarding responses in Set 5 and subsequently posted answers to applicable questions in Set 6 Q&A. EAL received the stakeholder report in October and is available in appendix G.

Abbreviations & Definitions

AECC	Arkansas Electric Cooperative Corporation
AERO CT	Aeroderivative Combustion Turbine
AGC	Automatic Generation Control
AMI	Advanced Metering Infrastructure
ANO	Arkansas Nuclear One
APSC	Arkansas Public Service Commission
BESS	Battery Energy Storage Systems
BOT	Build-Own-Transfer
CAA	Clean Air Act
CAGR	Compound Annual Growth Rate
CCCT	Combined Cycle Combustion Turbine
CCR	Coal Combustion Residuals
CCRMU	CCR Management Units
CCS	Carbon Capture & Storage
CDD	Cooling Degree Days
CEO	Chief Executive Officer
CO_2	Carbon Dioxide
CONE	Cost Of New Entry
CRL	Combustion Residual Leachate
CSAPR	Cross-State Air Pollution Rule
CT	Combustion Turbine
DC/AC	Direct Current/Alternating Current
DERS	Distributed Energy Resources
DF	Duct Firing
DLOL	Direct Loss of Load
DR	Demand Response
DSM	Demand-Side Management
EAL	Entergy Arkansas, Inc.
EE	Energy Efficiency
EGU	Electric Generating Unit
EIA	Energy Information Administration
EJ	Environmental Justice
ELCC	Effective Load Carrying Capability
ELG	Effluent Limitation Guideline Rule
EPA	Environmental Protection Agency
EPC	Engineering, Procurement, & Construction
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FIP	Federal Implementation Plan
GW, GWh	Gigawatt, Gigawatt Hour
HDD	Heating Degree Days
HVAC	Heating, Ventilation and Air Conditioning
HVDC	High Voltage Direct Current
ICAP	Installed Capacity
ICF	ICF International, Inc.
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
ISAC	Intermediate Seasonal Accredited Capacity
ISES	Independence Steam Electric Station
ITC	Investment Tax Credit
kW, kWh	Kilowatt, Kilowatt Hour
LC4	Lake Catherine 4
LCR	Local Clearing Requirement
LMP	Locational Marginal Price
LMR	Load Modifying Resource
L. Real	Levelized Real
LRZ	Local Resource Zone
LSE	Load Serving Entity
MATS	Mercury and Air Toxics Standards
MISO	Midcontinent Independent System Operator
MMBTU	Metric Million British Thermal Unit
MTEP	MISO Transmission Expansion Plan
MW, MWh	Megawatt, Megawatt Hour
NAAQS	National Ambient Air Quality Standard
NERC	North American Electric Reliability Corporation
NOx	Oxides of Nitrogen
NPDES	National Pollution Discharge Elimination System
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
O&M	Operation and Maintenance
OEMS	Original Equipment Manufacturers
P2A	Portfolio 2A
P2B	Portfolio 2B
POV	Point of View

PPA	Power Purchase Agreement
PRA	Planning Resource Auction
PRMR	Planning Reserve Margin Requirement
PTC	Production Tax Credit
PV	Photovoltaic
RBDC	Reliability Based Demand Curve
RCRA	Resource Conservation and Recovery Act
RFP	Request For Proposal
RICE	Reciprocating Internal Combustion Engine
RPOC	Resource Planning and Operations Committee
RTO	Regional Transmission Organization
RTR	Risk and Technology Review
SAC	Seasonal Accredited Capacity
SD	Self Direct
SIP	State Implementation Plan
SLR	Subsequent License Renewal
SMR	Small Modular Reactors
SO2	Sulfur Dioxide
SPP	Southwest Power Pool
TRSC	Total Relevant Supply Cost
TWH	Terawatt Hours
UCAP	Unforced Capacity
UPC	Usage Per Customer
VAR	Voltage-Ampere Reactive
WB	White Bluff Steam Electric Station
Wdc	Watt Direct Current
YoY	Year-over-Year
ZRC	Zonal Resource Credit

Appendix A – Resource Planning Objectives

Purpose:

The purpose of this document is to establish resource planning objectives to guide Entergy Arkansas, LLC. resource planning and operations staff in development of EAL's IRP and to meet the requirements of the APSC Resource Planning Guidelines for Electric Utilities.

Objectives:

In developing EAL's IRP, EAL's resource planning and operations staff should consider the following objectives:

1. **Policy Objectives** – The development of the IRP should reflect policy and planning objectives reviewed by the EAI RPOC and approved by EAI's President and CEO. Those policy and planning objectives will consider and reflect the policy objectives and other requirements provided by EAI's regulators.
2. **Resource Planning** – The development of the IRP will consider generation, transmission, and demand-side (e.g., demand response, energy efficiency) options.
3. **Planning for Uncertainty** – The development of the IRP will consider scenarios that reflect the inherent unknowns and uncertainties regarding the future operating and regulatory environments applicable to electric supply planning, including the potential for changes in statutory requirements.
4. **Reliability** – The IRP should provide adequate resources to meet EAI's customer demands and expected contingency events in keeping with established reliability standards.
5. **Baseload Production Costs** – The IRP should provide baseload resources that provide stable long-term production costs and low operating costs to serve baseload energy requirements.
6. **Operational Flexibility for Load Following** – The IRP should provide efficient, dispatchable, load-following generation and fuel supply resources to serve the operational needs associated with electric system operations and the time-varying load shape levels that are above the baseload supply requirement. Further the IRP should provide sufficient flexible capability to provide ancillary services such as regulation, contingency and operating reserves, ramping, and voltage support.
7. **Generation Portfolio Enhancement** – The IRP should provide a generation portfolio that over time will realize the efficiency and emissions benefits of technology improvements and that avoids an over-reliance on aging resources.
8. **Price Stability Risk Mitigation** – The IRP should consider factors contributing to price volatility and should seek to mitigate unreasonable exposure to the price volatility associated with the major uncertainties in fuel and purchased power costs.
9. **Supply Diversity and Supply Risk Mitigation** – The IRP should consider and seek to mitigate the risk exposure to major supply disruptions such as outages at a single generation facility or the source of fuel supply.

10. **Locational Considerations** – The IRP should consider the uncertainty and risks associated with dependence on remote generation and its location relative to EAI's load so as to enhance the certainty associated with the resource's ability to deliver power to EAI's customers.

11. **Reliance on Long-Term Resources** – EAI will meet reliability requirements primarily through long-term resources, both owned assets and long-term power purchase agreements. While a reasonable utilization of short-term purchased power is anticipated, the emphasis on long-term resources is to mitigate exposure to supply replacement risks and price volatility and ensure the availability of resources sufficient to meet long-term reliability and operational needs. Over-reliance on limited term purchased power (i.e., power purchased for a one-to-five-year term) exposes customers to risk associated with market price volatility and power availability.

12. **Sustainable Development** – The IRP should be developed consistent with EAI's vision to conduct its business in a manner that is environmentally, socially, and economically sustainable.

Appendix B – EAL Portfolio of Resources

Owned Generation	Total Installed Capacity (MW)	Ownership (%)	Retail Capacity (MW)	Commercial Operations Date
Arkansas Nuclear One Unit 1	833	100%	788	1974
Arkansas Nuclear One Unit 2	992	100%	938	1980
Carpenter Unit 1	17	100%	17	1932
Carpenter Unit 2	12	100%	12	1932
Hot Spring	563	100%	563	2002
Independence Unit 1	824	31.5%	260	1983
Lake Catherine 4	521	100%	521	1970
Ouachita Unit 1	236	100%	236	2002
Ouachita Unit 2	245	100%	245	2002
Remmel Units 1,2 & 3	10	100%	10	1925
Searcy Solar	100	100%	100	2022
Union 2	504	100%	504	2003
White Bluff Unit 1	815	57.0%	466	1980
White Bluff Unit 2	823	57.0%	468	1980

Purchased Generation	Total Installed Capacity (MW)	Retail Capacity (MW)	Commercial Operations Date
Grand Gulf	1,393	303	1985
Stuttgart Solar	81	81	2017
Chicot Solar	100	100	2020

Demand – side Resources	Reduction During Peak Load Hours (MW)
Interruptible Load	485

Appendix C - MISO MTEP Submissions

TABLE I: EAL PROJECTS SUBMITTED AS TARGET APPENDIX A IN MTEP23

Project Driver	Project Name	Current Projected ISD
Asset Management	2024 EAL Asset Renewal Program	12/31/2024
Generator Interconnection	Hamrick 161kV J1842: Cut-in Switching Station	2/1/2025
Customer Driven	Driver - Hybar 230kV: New transmission line	5/1/2025
Baseline Reliability	Dell 161kV Breaker Upgrades	6/1/2025
Baseline Reliability	Dumas - Reed 115kV: Rebuild Line	6/1/2025
Generator Interconnection	Flat Lake 161kV J1562: Cut-in Switching Station	10/31/2025
Generator Interconnection	Prairie Creek 161kV: POI for J1816	11/1/2025
Generator Interconnection	Aurelle 115kV: POI for J1612	4/1/2026
Baseline Reliability	McNeil 500kV Relay Improvement SPOF	12/1/2026
Baseline Reliability	Keo 500kV Bus Reconfigure	12/1/2027
Enhanced Transmission Reliability	Gum Springs 115kV: Build Breaker Station	6/1/2028

TABLE II: EAL PROJECTS SUBMITTED AS TARGET APPENDIX A IN MTEP24

Project Driver	Project Name	Current Projected ISD
Generator Interconnection	J1437 Nimbus Wind FCA	3/31/2025
Customer Driven	Grand Prairie 115kV: New substation	4/1/2025
Generator Interconnection	Doylestown 115kV: Cut in Switching Station (J1577 & J1607)	5/1/2025
Asset Management	2025 EAL Asset Renewal Program	12/1/2025
Baseline Reliability	Arklahoma 115kV Bus Relay Improvement SPOF	12/1/2025
Baseline Reliability	Champs 115kV: New Substation Phase 1	12/1/2025
Baseline Reliability	Frazier Pike 115kV: New Substation	12/1/2025
Generator Interconnection	Kinder 161kV: New POI J1558	4/1/2026
Generator Interconnection	Morrilton East 161kV: POI for J1559	4/1/2026
Generator Interconnection	J1670 Crooked Lake 2 GIA upgrades	4/3/2026
Generator Interconnection	Wheatley 500kV: New POI J1710 J1819 J1820 J1821	9/13/2026
Customer Driven	Galet 500/230kV New Substation	9/30/2026
Generator Interconnection	West Memphis 500/161kV Auto Replacement	12/5/2026

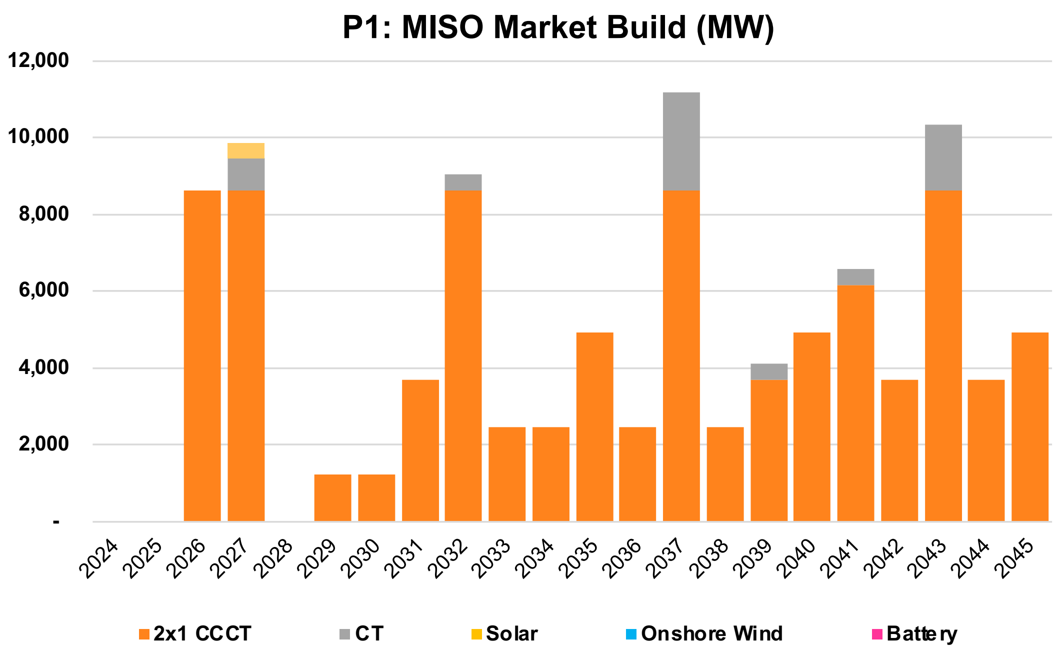
TABLE III: EAL PROJECTS SUBMITTED AS TARGET APPENDIX A IN MTEP25

Project Driver	Project Name	Current Projected ISD
Generator Interconnection	MPFCA Replace Sherwood 115kV Breakers	3/13/2026
Customer Driven	Wrightsville 115kV: Build two 115kV lines	2/26/2027
Baseline Reliability	Everton Road - Harrison East 161kV: Rebuild Line	6/30/2028
Baseline Reliability	Saint Joe - Everton Road 161kV: Rebuild Line	12/30/2029
Baseline Reliability	Hilltop - Saint Joe 161kV: Rebuild Line	6/30/2027
Baseline Reliability	El Dorado Donan - El Dorado Monsanto 115 kV: Rebuild Line	6/30/2027
Baseline Reliability	Hot Springs 500kV SPOF	1/30/2026
Asset Management	2026 EAL Asset Renewal Program	12/30/2026

Appendix D - Scope of AURORA Market Model

The shaded areas shown on the map are modeled in Aurora. These areas include MISO-South, and MISO Classic (MISO-Central and MISO-North).

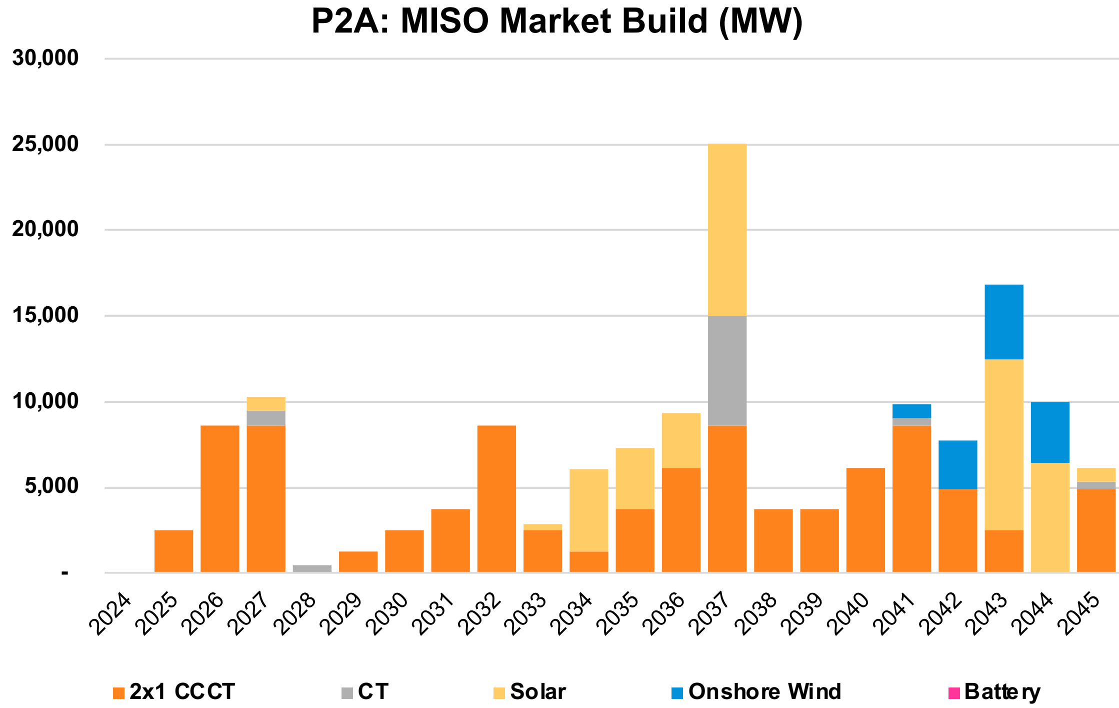
Appendix E - MISO Build



Future 1 MISO seasonal accreditation for resource alternatives

MISO Technology by 2045	P1 installed summer MW	P1 effective summer MW	P1 installed winter MW	P1 effective winter MW
2x1 CCCT	91,042	89,549	96,596	88,018
CT	6,417	6,191	6,892	5,664
Single axis tracking solar	400	135	400	72
Coupled Battery	0	0	0	0
On-shore wind	0	0	0	0
Total supply side additions	**97,859**	**95,875**	**103,888**	**93,754**

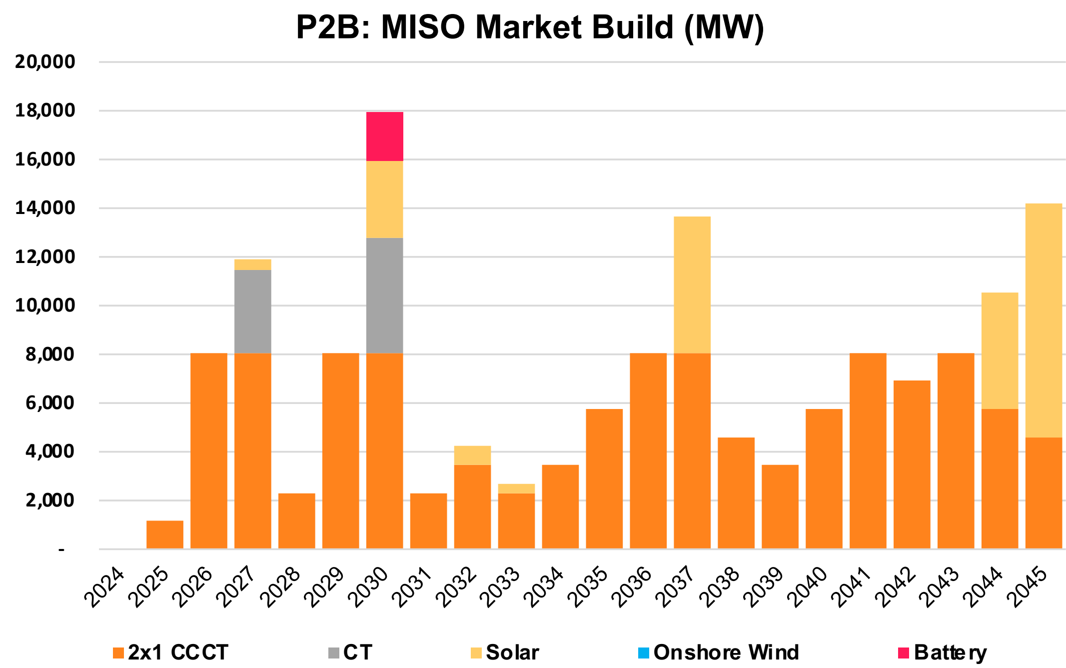
Future 2A MISO Optimized Portfolio (P2A)



Future 2A MISO seasonal accreditation for resource alternatives

MISO Technology by 2045	P2A installed summer MW	P2A effective summer MW	P2A installed winter MW	P2A effective winter MW
2x1 CCCT	92,273	90,759	97,901	89,207
CT	8,556	8,255	9,189	7,552
Single axis tracking solar	40,000	14,949	40,000	1,886
Coupled Battery	0	0	0	0
On-shore wind	11,600	4,106	11,600	5,317
Total supply side additions	**152,429**	**118,068**	**158,690**	**103,962**

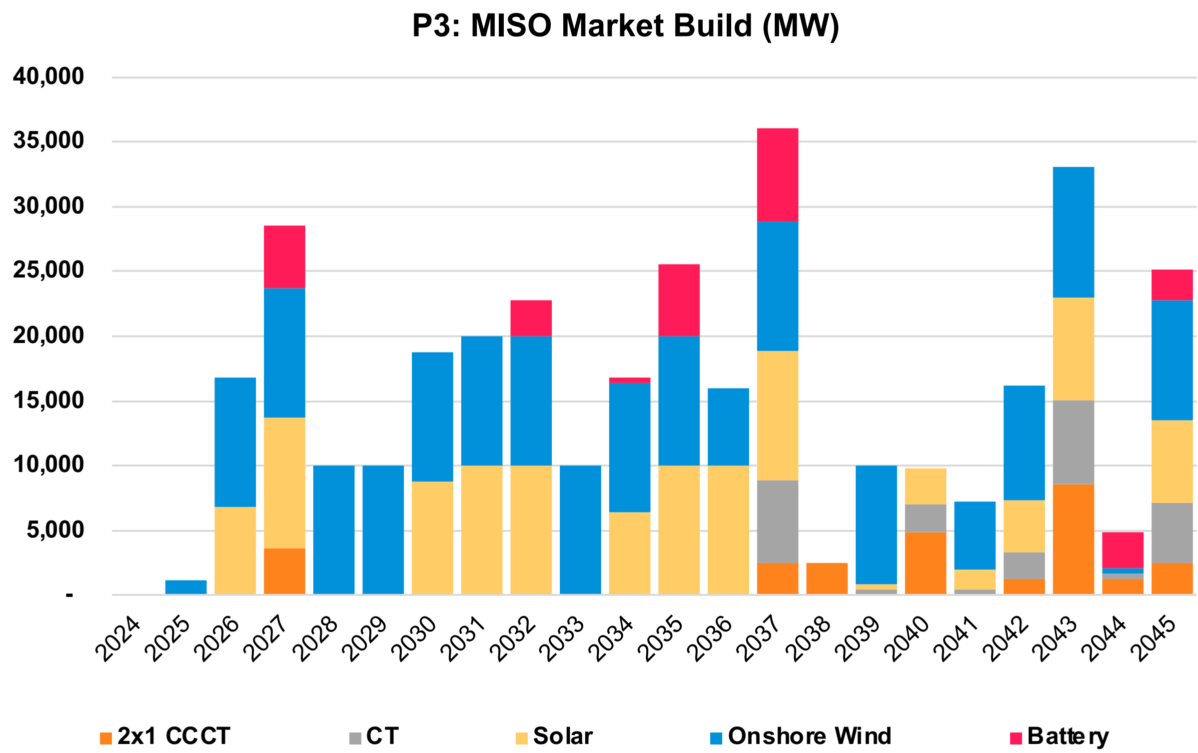
Future 2B MISO Optimized Portfolio (P2B)



Future 2B MISO seasonal accreditation for resource alternatives

MISO Technology by 2045	P2B installed summer MW	P2B effective summer MW	P2B installed winter MW	P2B effective winter MW
2x1 CCCT	116,049	114,146	123,128	112,194
CT	8,128	7,842	8,730	7,174
Single axis tracking solar	24,800	4,663	24,800	1,338
Coupled Battery	2,000	1,900	2,000	860
On-shore wind	0	0	0	0
Total supply side additions	**150,977**	**128,551**	**158,658**	**121,566**

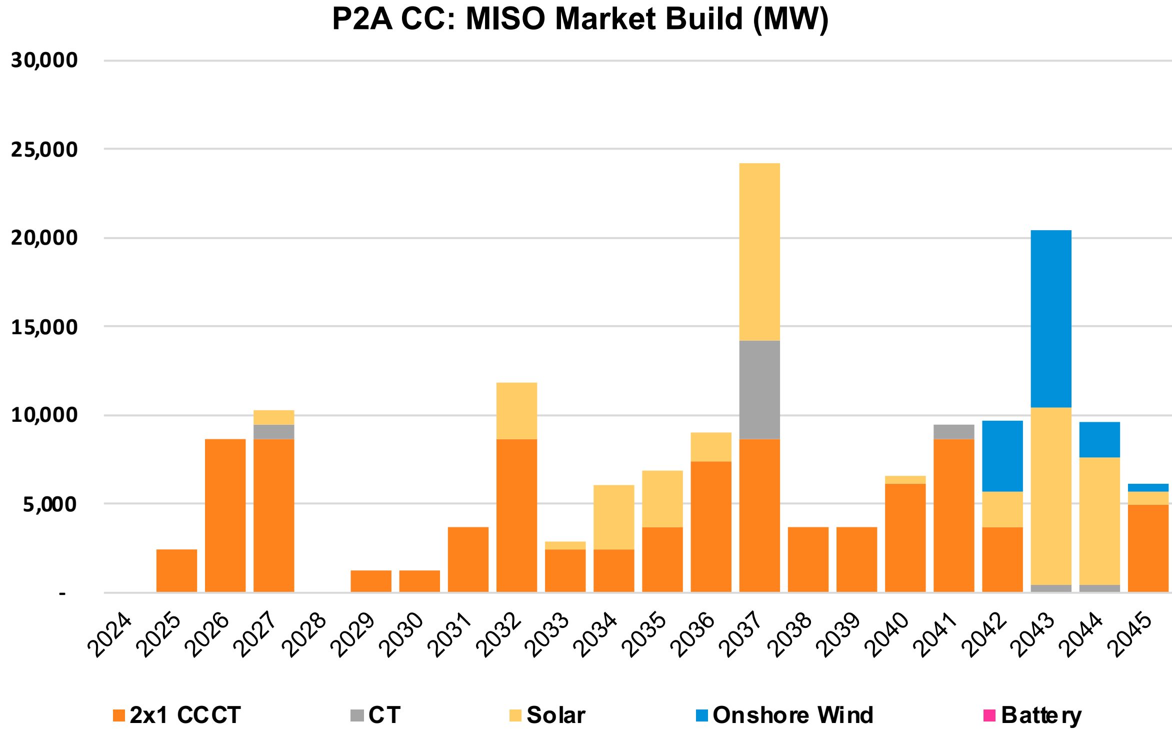
Future 3 MISO Optimized Portfolio (P3)



Future 3 MISO seasonal accreditation for resource alternatives

MISO Technology by 2045	P3 installed summer MW	P3 effective summer MW	P3 installed winter MW	P3 effective winter MW
2x1 CCCT	30,758	30,253	32,634	29,736
CT	22,246	21,463	23,892	19,634
Single axis tracking solar	124,000	14,803	124,000	1,974
Coupled Battery	42,400	16,882	42,400	7,925
On-shore wind	140,000	51,553	140,000	72,155
Total supply side additions	**359,403**	**134,954**	**362,925**	**131,424**

Future 2A CC MISO Optimized Portfolio (P2A CC)



Future 2A CC MISO seasonal accreditation for resource alternatives

MISO Technology by 2045	P2A CC installed summer MW	P2A CC effective summer MW	P2A CC installed winter MW	P2A CC effective winter MW
2x1 CCCT	89,812	88,339	95,209	86,829
CT	8,128	7,842	8,730	7,174
Single axis tracking solar	43,200	16,211	43,200	2,037
Coupled Battery	0	0	0	0
On-shore wind	16,400	5,770	16,400	7,628
Total supply side additions	**157,540**	**118,162**	**163,620**	**103,667**

Appendix F - TRSC Analysis Results

TRSC Analysis Results

The TRSC for each portfolio was calculated for the future for which it was developed. The total relevant supply cost is calculated using multiple component that were explained in Chapter 5. Below is the TRSC for each future portfolio broken into the components.

FUTURE 1 OPTIMIZED PORTFOLIO TRSC RESULTS

	Cost ($MM, 2024$ NPV)
Net Variable Supply Cost (Benefit)	$7,062
Resource Additions Levelized Fixed Costs [1/1 COD]	$1,250
Bill Credits (Solar and Wind PTCs)	$0
Capacity Purchases (Sales)	($741)
TRSC	$7,571

FUTURE 2A OPTIMIZED PORTFOLIO TRSC RESULTS

	Cost ($MM, 2024$ NPV)
Net Variable Supply Cost (Benefit)	$12,133
Resource Additions Levelized Fixed Costs [1/1 COD]	$2,754
Bill Credits (Solar and Wind PTCs)	($23)
Capacity Purchases (Sales)	($263)
TRSC	$14,602

FUTURE 2A CC OPTIMIZED PORTFOLIO TRSC RESULTS

	Cost ($MM, 2024$ NPV)
Net Variable Supply Cost (Benefit)	$11,666
Resource Additions Levelized Fixed Costs [1/1 COD]	$3,302
Bill Credits (Solar and Wind PTCs)	($92)
Capacity Purchases (Sales)	($362)
TRSC	$14,514

FUTURE 2B OPTIMIZED PORTFOLIO TRSC RESULTS

	Cost ($MM, 2024$ NPV)
Net Variable Supply Cost (Benefit)	$8,078
Resource Additions Levelized Fixed Costs [1/1 COD]	$4,903
Bill Credits (Solar and Wind PTCs)	$0
Capacity Purchases (Sales)	($358)
TRSC	$12,623

FUTURE 3 OPTIMIZED PORTFOLIO TRSC RESULTS

	Cost ($MM, 2024$ NPV)
Net Variable Supply Cost (Benefit)	$28,330
Resource Additions Levelized Fixed Costs [1/1 COD]	$14,334
Bill Credits (Solar and Wind PTCs)	($836)
Capacity Purchases (Sales)	$836
TRSC	$42,664

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

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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.

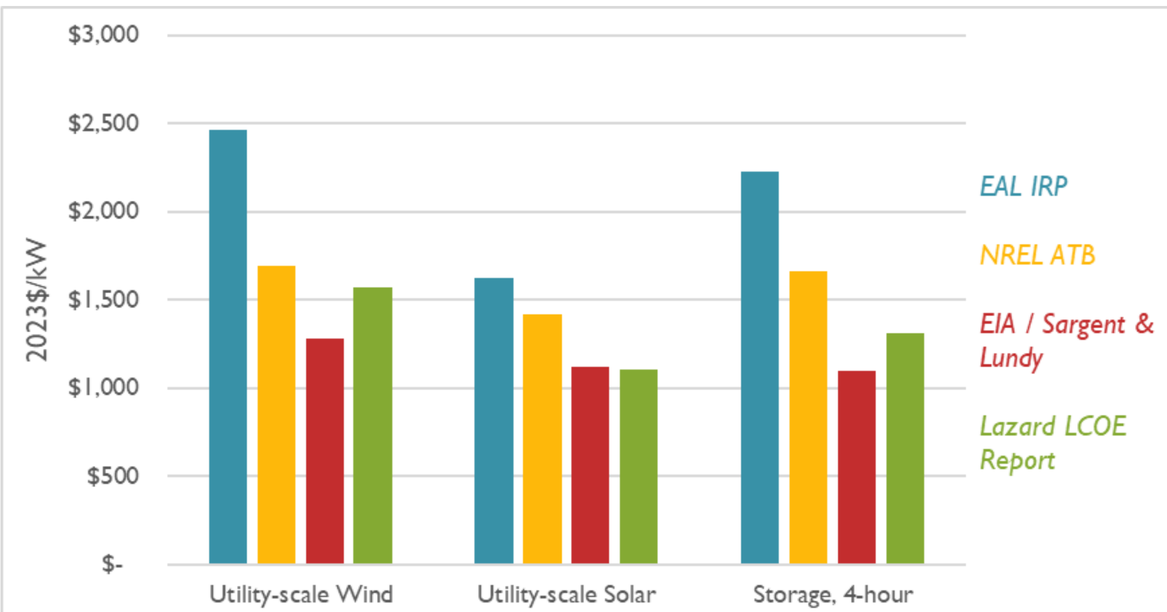
The input data provided by Entergy for the IRP shows capital cost estimates for new solar, wind, and storage resources that are substantially higher than expected both now and going forward. The Company's estimated costs are higher than other utility cost data and higher than leading industry cost data 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]

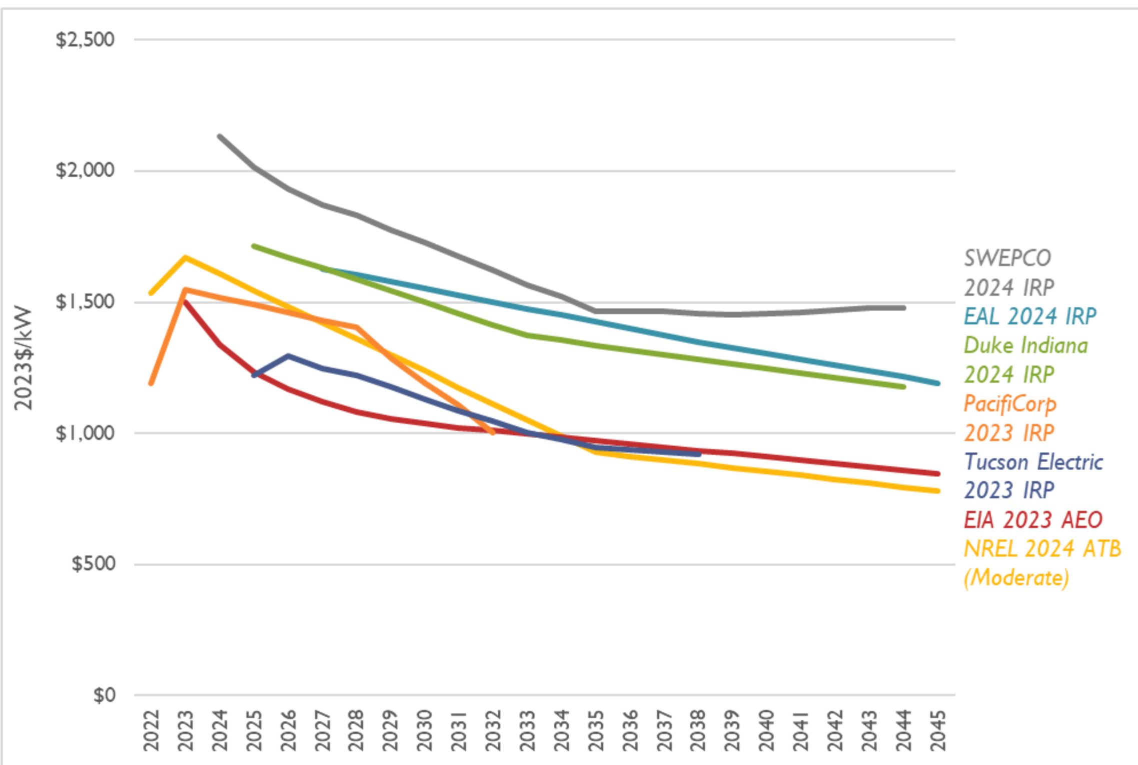


[2] *See Entergy Arkansas 2024 Integrated Resource Plan Stakeholder Meeting #2*, August 15, 2024, Slide 58, Preferred resource plan (showing EAL's plans to add 733 MW of gas in 2030, 400 MW of solar in 2033, 428 MW of gas in 2034, etc.).

[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.

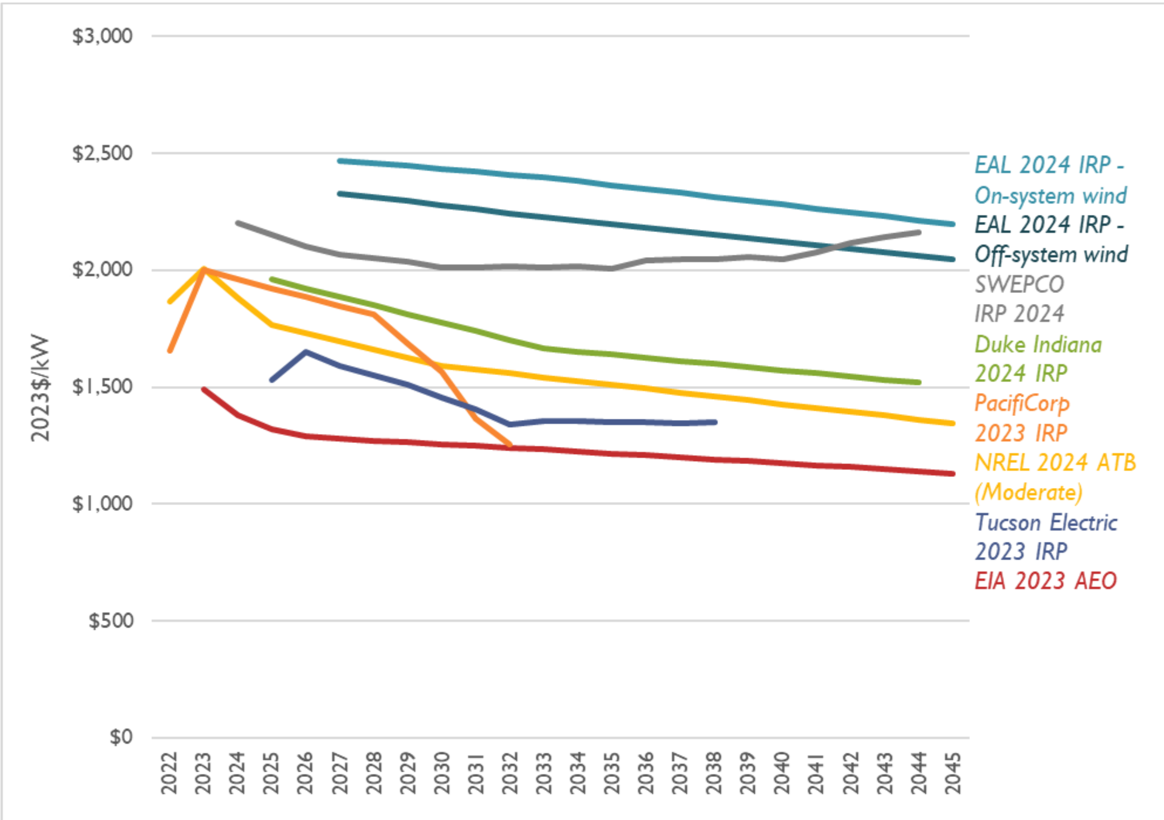
In Figure 2, Figure 3, and Figure 4 below, we compare Entergy's long-term cost estimates (now through 2045) for these same technologies to other industry forecasts. Entergy does assume that costs will decline over time due to technology maturation, but it uses the conservative learning curve assumptions 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]

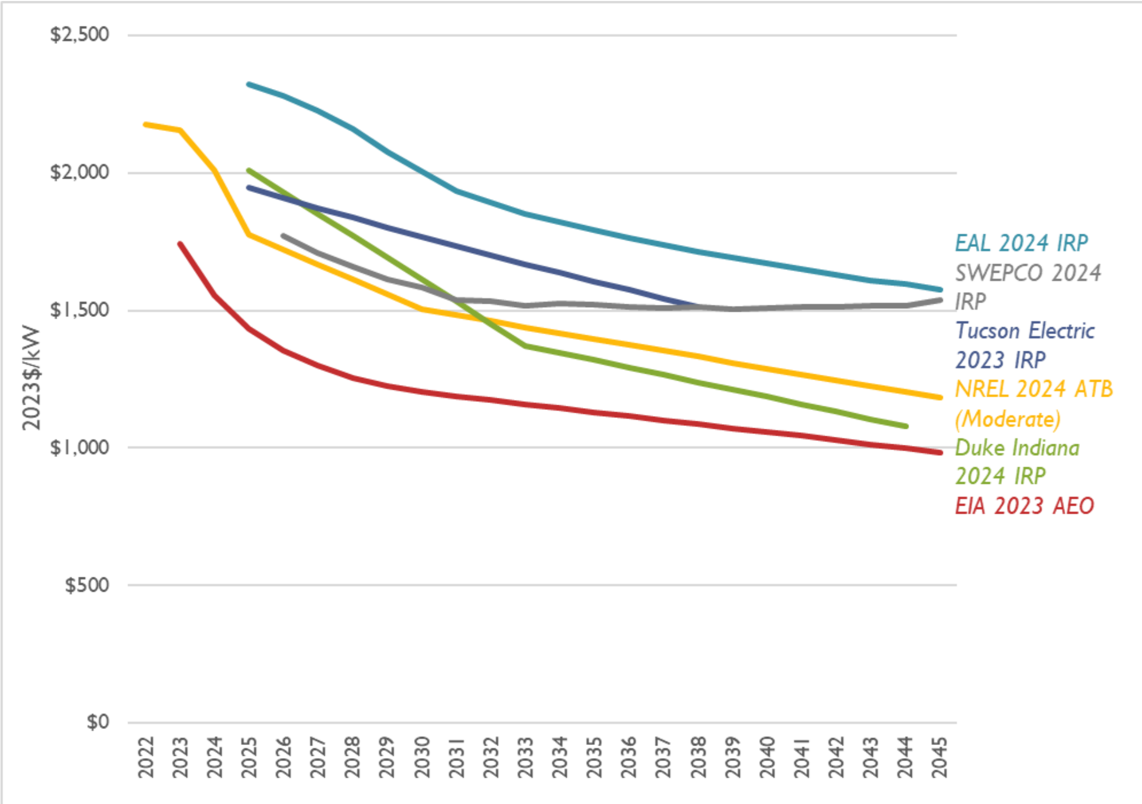


Notes: On-system wind refers to wind resources located in MISO South. Off-system wind refers to wind resources located in the Southest Power Pool (SPP).

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.

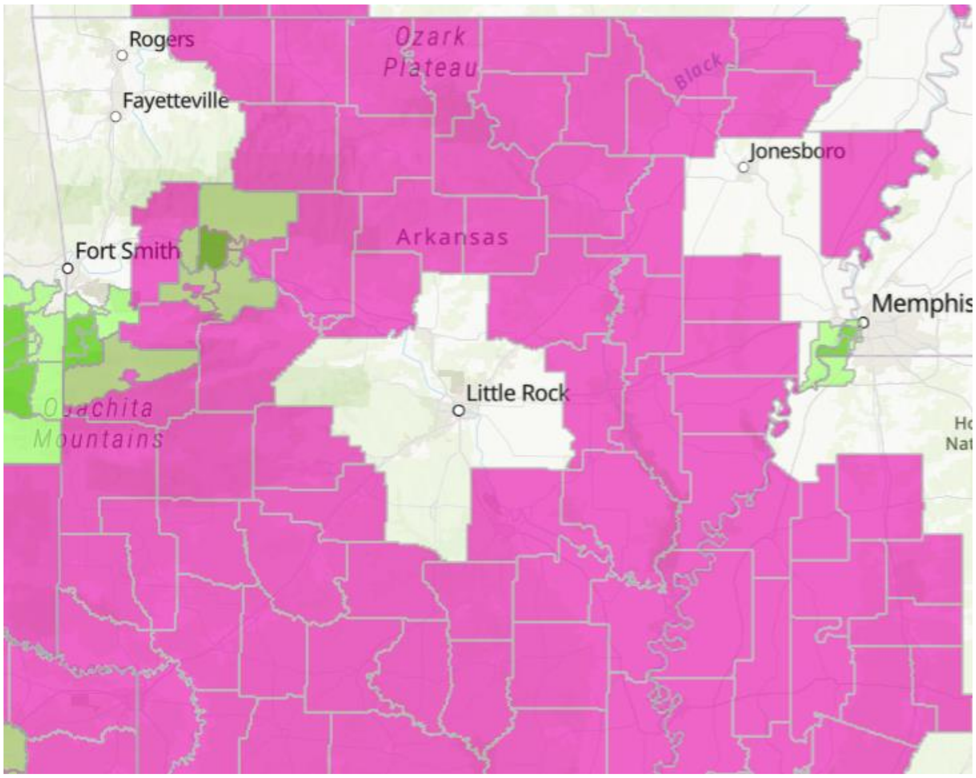
Under the Inflation Reduction Act, solar, battery, and wind projects that are located in an "energy community," as defined under the Act, are entitled to a 10% increase in the value of the production or investment tax credit (each project developer may elect either the PTC or ITC but not both). In the 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.

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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

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[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

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[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]

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[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.

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[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]

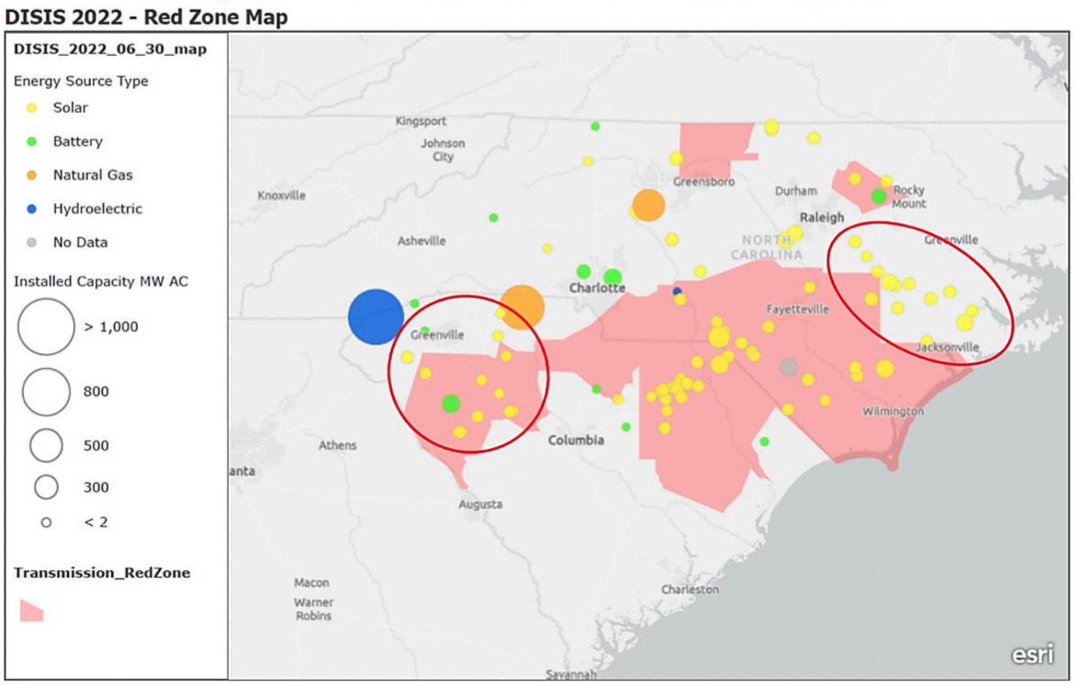
B. Comparison with Transmission Planning in other Southern States' IRPs

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



Transmission Red Zone

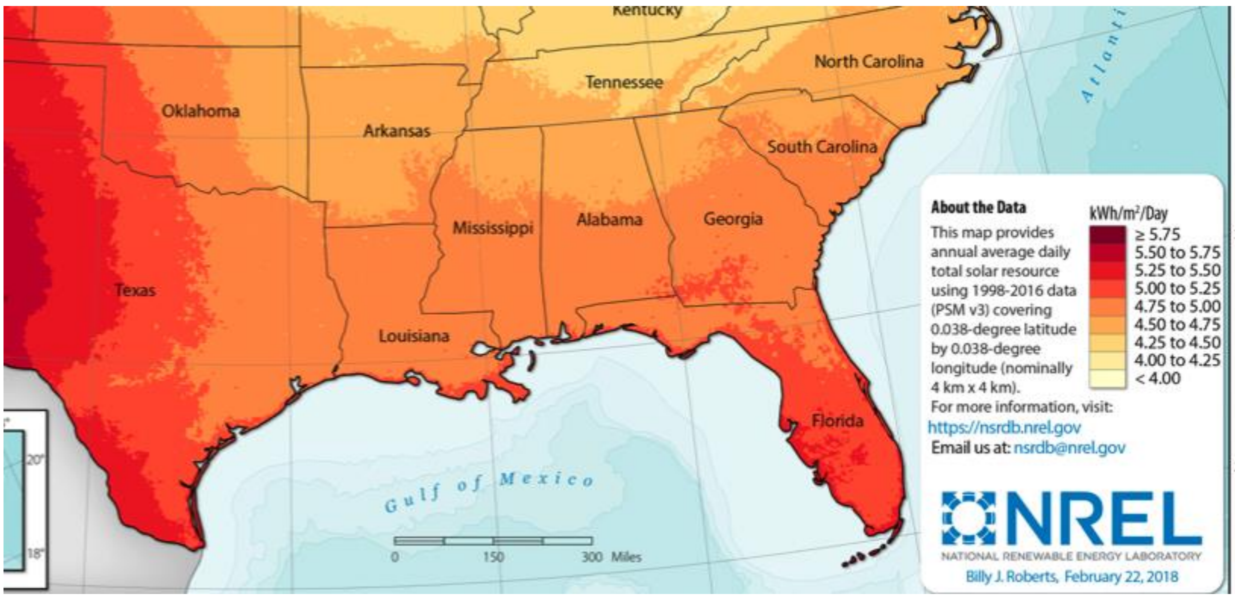
Duke (Duke Energy Company, and Duke Energy Progress) quantifies the transmission costs associated with increased utility scale solar, as illustrated in the following Table:[57]

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

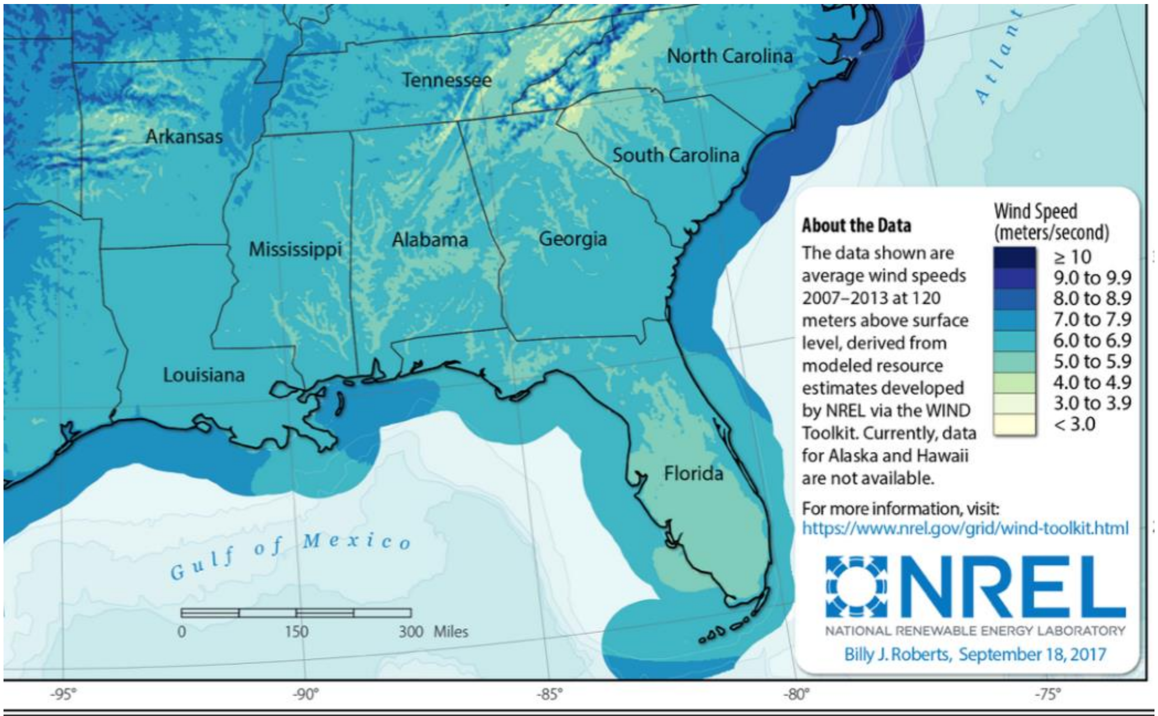
[55] Duke Energy IRP, Appendix L, Transmission System Planning and Grid Transformation at 24, https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/appendix-l-transmission-system-planning.pdf?rev=c6cf1bc1ac9c4c878ec4a5d2307c4532.
[56] *Id*. at Figure L-2.
[57] Duke Energy IRP,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



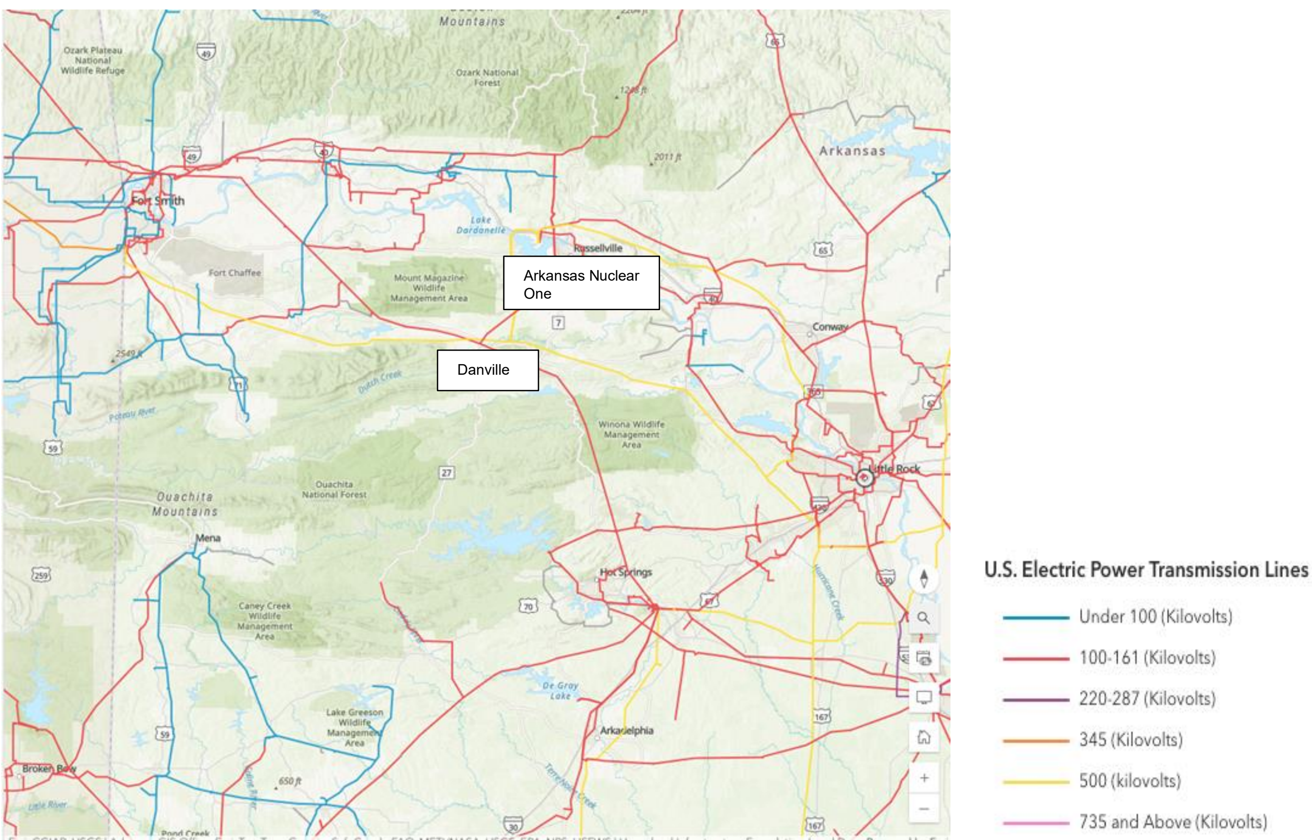
EAL claims importing power from the wind resource in SPP requires a 600-mile HVDC line but provides no evidence such a line would be needed. To the contrary, a NREL wind map shows western Arkansas and eastern Oklahoma have promising resource regions in mountainous areas comparable to western Oklahoma, 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.

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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,

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