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J. David Palmer
Director, Regulatory Affairs

October 29, 2021

Ms. Mary Loos, Secretary
Arkansas Public Service Commission
P. O. Box 400
Little Rock, Arkansas 72203-0400

Re: APSC Docket No. 07-016-U
Entergy Arkansas, LLC 2021 Integrated Resource Plan

Dear Ms. Loos:

Consistent with Section 6 of Attachment 1 to the Arkansas Public Service Commission ("Commission") Order No. 6 – Docket No. 06-028-R Resource Planning Guidelines for Electric Utilities, Entergy Arkansas, LLC submits its 2021 Integrated Resource Plan and the Stakeholder Report that was prepared in accordance with Section 4.8 of the Commission's Resource Planning Guidelines.

Should you have any questions concerning this filing, please call me at (501) 377-3571.

Sincerely,

/s/ J. David Palmer

DP/dh

Attachments
c: All Parties of Record

ATTACHMENT A

Entergy Arkansas, LLC

2021 Integrated Resource Plan

Submitted October 29, 2021

Chapter 1

Executive Summary

For more than a century, Entergy Arkansas, LLC ("EAL" or the "Company") has provided safe, reliable, and affordable electricity to its customers in Arkansas. EAL continues to serve its diverse, growing customer base by proactively planning for future resource needs while focusing on affordability, reliability, and environmental stewardship, while also considering risk.

EAL recognizes that creating a reliable and sustainable future for customers and their communities requires continued transformation of the Company's resource portfolio, and this Integrated Resource Plan ("IRP") provides insights into EAL's planning process.

Our Customers

Today's energy customers are using energy more efficiently than ever before, due to both an increasing emphasis on social responsibility and sustainability and advances in energy efficiency ("EE") standards. Customers are also seeking more options in the generation and delivery of energy, including how they interact with, understand, and manage their own energy use, as well as the actual sources from which their energy is derived. EAL is actively engaging its customers to obtain a better sense of those expectations and the ways in which EAL can bring offerings to the marketplace to meet those expectations.

EAL's customer base has grown to over 722,000 residential, commercial, industrial, and governmental customers located in 63 of Arkansas' 75 counties, covering over 40,880 square miles. By combining an understanding of what customers want with sound and comprehensive planning, EAL can deliver the type of service our customers expect while continuing to address the planning objectives of affordability, reliability, and environmental stewardship.

Environmental Sustainability

Entergy Corporation ("Entergy") has been an industry leader in voluntary climate action for two decades. Building on its longtime legacy of environmental stewardship, 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 reliability, affordability, and environmental stewardship. Looking ahead, EAL will continue to work 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 environmental commitments among EAL and its customers.

About This Report

This document describes EAL's long-term IRP for the study period 2023-2042 and is intended to provide stakeholders insight into the Company's long-term planning process for meeting future demand and energy needs. Similar fundamental uncertainties remain when compared to EAL's most recent IRP, which was filed with the Arkansas Public Service Commission ("APSC" or the "Commission") on October 31, 2018, in Docket No. 07-016-U. These uncertainties include advances in renewable technologies and their associated costs, growing customer preferences for renewable energy, and prospective changes in environmental regulations. Based on subsequent analysis, EAL's total generating capacity is forecasted to be nearly equal to its peak customer demand plus reserve margin target in 2025, coinciding with the assumed deactivation of the Company's Lake Catherine resource. The primary driver for the next significant capacity deficit after 2025 will coincide with the timing of the cease-to-use coal ("CTUC") efforts at White Bluff and Independence. That timing will be no later than 2028 for White Bluff and 2030 for Independence but could be sooner. The capacity deficit expands over time as forecasted customer demand increases and existing resources reach the end of their assumed useful lives.

As with the Company's most recent IRP, the 2021 IRP utilized a futures-based approach by which four future worlds were constructed to reasonably bookend a broad range of future uncertainties. The futures analysis was supplemented with sensitivity cases, which provide insight around the effect of possible changes to the time when EAL will cease to use coal in its portfolio. An economically optimized portfolio of both supply-side and demand-side resources was developed for each of the four futures, and four additional portfolios were created to support the sensitivity cases. Summaries of the modeled portfolios are shown in Chapter 6.

The results of the IRP analysis reasonably support that EAL's future supply-side resource additions primarily will consist of renewable energy resources. EAL's preferred resource plan maintains the planning assumptions for existing units and begins adding renewable resources starting in 2025 consistent with Sensitivity Portfolio 4, though the exact amount of each type of renewable resource will be based on a market solicitation and may vary from the amounts in Sensitivity Portfolio 4.

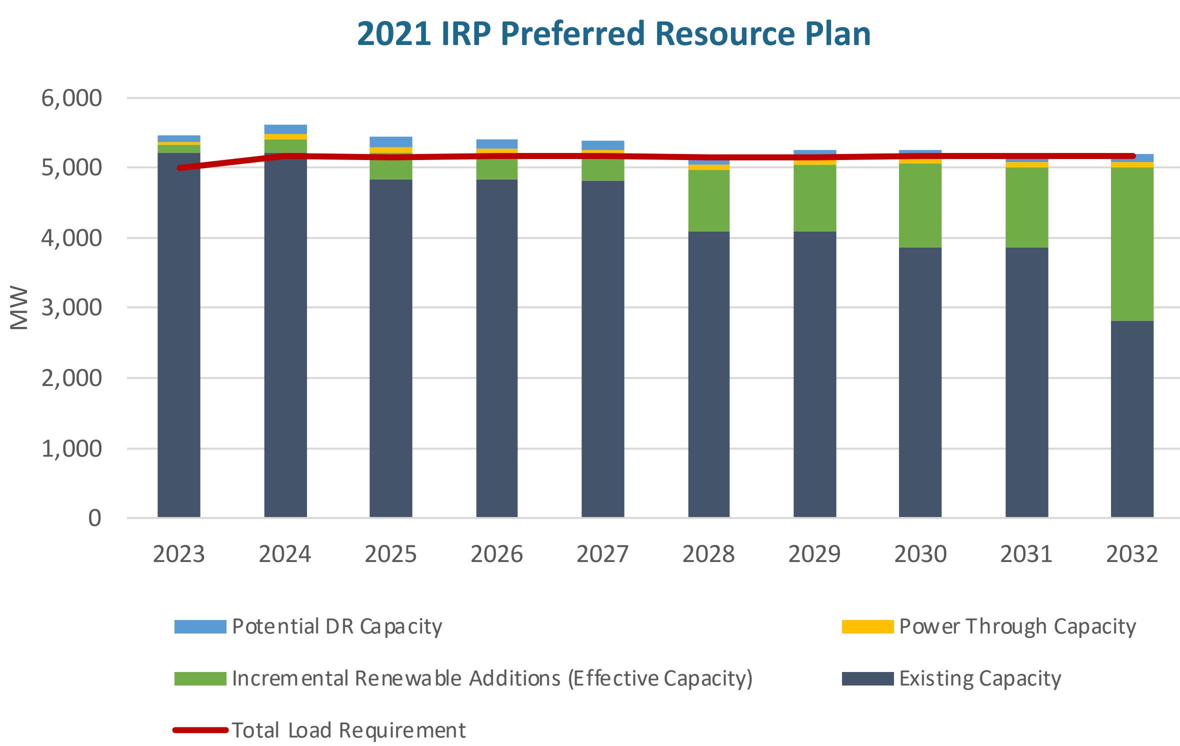


Chart 1: 2021 IRP Preferred Resource Plan

The IRP's future resource portfolios are developed consistent with the Commission's Resource Planning Guidelines but do not represent planning decisions by EAL. Rather, the Company's specific long-term resource planning actions (e.g., capacity additions) are subject to review and approval by the Commission. In the same respect, the IRP's assumptions regarding the cost and availability of various supply-side resources do not reflect the actual cost or ownership structure for implementing those options. They are planning assumptions, with the actual costs and structures to be determined at the time of execution, likely through a market solicitation. In addition, while the IRP seeks to identify EAL's capacity needs and appropriate resources to fill those needs, this approach should not be read to foreclose the identification of a future resource which may provide significant energy value to EAL's customers.

EAL recognizes that creating a reliable and sustainable future for its customers and their communities requires continued transformation of the Company's resource portfolio, and 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. Looking ahead, EAL will continue to work 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 environmental commitments among EAL and its customers.

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

The 2021 IRP Action Plan consists of eight action items, which are summarized below and discussed in more detail in Chapter 6:

1. Complete the Acquisitions of Searcy, Walnut Bend, and West Memphis Solar Build-Own-transfer Resources	EAL will complete the acquisitions of the Searcy, Walnut Bend and West Memphis facilities from 2021 through 2023 as construction is completed for each facility.
2. Complete the 2021 Renewables RFP	In August 2021, EAL issued its 2021 Renewables RFP and is expected to be completed in early 2022. The RFP is seeking to procure up to 500 MW of solar and/or wind resources with PPA deliveries starting and/or acquisitions starting in the 2024-25 timeframe.
3. Effectuate the Deactivation of Lake Catherine 4 in 2025	In preparation for the assumed deactivation of Lake Catherine Unit 4 in 2025, EAL will initiate the processes necessary to reliably support the end of commercial operation.
4. Identify Demand-side Management Opportunities	EAL is researching DR devices for compatibility with AMI communications to expand the Company's DR offerings. Evaluation of potential offerings is planned to take place in 2022.
5. 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 the updated targets adopted in EAL's 2020-2022 EE Program Plan as filed in Docket No. 07-085-TF.
6. Pursue Power Resiliency	EAL will develop and implement customer-centric power resiliency solutions. Power Through represents EAL's initial power resiliency offering. Upon APSC approval, EAL will offer Power Through to its customers starting in 2022.
7. Implement Sustainable Solutions	Develop and implement customer-centric sustainability solutions. Green Promise is a green tariff designed to assist residential (including low-income) and nonresidential customers in the achievement of their sustainability objectives. Following APSC approval, EAL will offer Green Promise to its customers. Also, in conjunction with Action Plan Item #2, additional customer-centric sustainability solutions will be considered once additional renewable resources are selected.
8. Evaluate Stakeholder Engagement	Stakeholder engagement has been an important part of the development of this IRP. An immediate priority will be for EAL to closely review the stakeholder report, which can be found in Appendix H of this report and continue taking steps to address concerns in the Company's IRP process.

Chapter 2

Long-Term Resource Planning

Introduction

Summary

- In 2006, the APSC adopted an IRP rule requiring its jurisdictional utilities to file an IRP at least every three years; this is the fifth IRP filed by EAL since the APSC adopted its Resource Planning Guidelines.
- The IRP process follows EAL's twelve resource planning objectives, which were approved and instituted by the Company in 2012.
- EAL has made significant progress on the seven action items identified in its 2018 IRP Action Plan.

This document describes EAL's long-term IRP for the period 2023 - 2042. This is the fifth IRP filed by EAL since the APSC adopted its Resource Planning Guidelines in Order No. 6 in Docket No. 06-028-R. Similar to prior IRPs, EAL's 2021 IRP reflects the fact that uncertainty remains an issue that must be considered in long-term resource planning, with no outcome providing absolute certainty as to the appropriate path for the utility to take. In other words, the uncertainties that dominated EAL's 2018 IRP filed with the Commission on October 31, 2018 (e.g., advances in renewable resource technology) remain but have been expanded to include other uncertainties, such as the impact and role of more significant amounts of renewable generation in the market and changes in customer preferences, something that EAL intends to continue identifying and addressing.

EAL's process for preparing this IRP considered potential future scenarios in which various resource plans could be evaluated. As with EAL's 2018 IRP, 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) typically 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 based on information available today.

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 McDonald on May 16, 2012. Upon review of these planning objectives since the 2018 IRP, EAL maintains that the Company's key areas of focus remain: affordability, reliability, and environmental stewardship. EAL's resource planning objectives are listed below and outlined in more detail in Appendix A:

1. Policy Objectives
2. Resource Planning
3. Planning for Uncertainty
4. Reliability
5. Baseload Production Costs
6. Operational Flexibility for Load Following
7. Generation Portfolio Enhancement
8. Price Stability Risk Mitigation
9. Supply Diversity and Supply Risk Mitigation
10. Locational Considerations
11. Reliance on Long-Term Planning
12. Sustainable Development

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 ("SSRP") that was in place at that time. 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 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, as EAL did for its 2009 IRP. In addition, EAL addressed numerous questions from stakeholders, presented at open meetings or in writing to EAL, with written responses provided for all such questions.

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 that were attached to the report. These comments reflected the diversity of the views held by various stakeholders, which to their credit appear to have been resolved in an amicable manner.

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 has worked with stakeholders to address many of the issues and concerns raised in the 2018 IRP's Stakeholder Report. Due to the COVID-19 pandemic, the stakeholder engagement process for this IRP has been conducted on a virtual basis 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 has received multiple Stakeholder comments and/or request letters as part of the IRP design process, to which the Company has formally responded and endeavored to accommodate where feasible.

The 2018 IRP Action Plan

The 2018 EAL IRP Action Plan contained seven action items, some of which are still in process. The current status of each action item is described below:

1. **Completion of the Build-Own-Transfer ("BOT") of Solar PV:** Searcy Solar, approved by the Commission in Order No. 7 in Docket No. 19-019-U, is currently in the final phases of construction and expected to achieve commercial operation by the end of 2021. Additionally, EAL sought Commission approval of a tax equity partnership ("TEP") ownership structure for Searcy Solar that will increase net economic benefits to customers. EAL's request was approved by the Commission in Order No. 3 in Docket No. 21-028-U.
2. **Supply-side Resource Additions:** Since the 2018 IRP was filed, EAL has continued to monitor its load and capability position and has taken steps to add cost-effective renewable resources that take advantage of the highest-available level of Investment Tax Credit for its customers. The Company's 2019 Request for Proposals for Solar Photovoltaic Resources resulted in two resource selections: Walnut Bend Solar, a 100 MW solar resource, approved in Order No. 8 in Docket No. 20-052-U and West Memphis Solar, a 180 MW solar resource, approved in Order No. 8 in Docket No. 20-067-U.

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

3. **Potential 2025 Capacity Need:** Lake Catherine 4 will deactivate in 2025 and the resulting capacity need in 2025 is mitigated by three solar resources expected to achieve commercial operation between 2021 and 2023. In Docket No. 13-028-U, the APSC approved the sustainability project that would extend the useful life of Lake Catherine Unit 4 through 2024. The facility has subsequently accomplished all related corrective actions to mitigate reliability issues, and no life extension projects have been performed that would significantly increase reliability up to and extend operation of the facility beyond 2025. A glide-path maintenance program has been implemented that is intended to reduce overall costs while supporting safe and reliable operations up to Lake Catherine Unit 4's planned deactivation date. Any deviation from the present deactivation assumption in 2025 would require immediate and significant capital investments in the unit's boiler and generator to extend its useful life. Additionally, the Clean Air Visibility Rule ("CAVR") requires Lake Catherine Unit 4 to cease operations in 2027. The aforementioned costs to extend the life of the unit and unwind the glide-path maintenance program would be incurred for a maximum of two additional years of unit operation.
4. **Demand-side Resource Additions:** EAL will evaluate the cost-effectiveness and feasibility of potential projects to gain energy efficiencies in addition to EAL's existing Arkansas EE Program Portfolio. EAL is researching Demand Response ("DR") devices for compatibility with Advanced Metering Infrastructure ("AMI") communications to expand its DR offerings. Demonstrations of potential devices are scheduled for 2022 with potential integration of successfully vetted devices as a pilot in EAL's 2024-2026 Program Plan.
5. **Continued Participation in EE:** EAL has continued 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 the updated targets adopted in EAL's 2020-2022 EE Program Plan as filed in Docket No. 07-085-TF. On a net MWh basis, EAL expects to save 286 GWh in 2021 and 285 GWh in 2022 as a result of these programs.
6. **Coal Environmental Compliance:** EAL has continued to monitor changes in environmental law and regulations at the state and federal level and evaluates options for environmental compliance for the EAL coal units. Detailed updates with respect to the Regional Haze Rule, Cross-State Air Pollution Rule, Coal Combustion Residuals Rule, Effluent Limitation Guideline Rule, and Potential Greenhouse Gas Regulation are outlined in Chapter 4 of this report.
7. **Stakeholder Engagement Process:** As in prior IRP cycles, stakeholder engagement has been an important part of the development of this IRP. As noted, EAL has taken steps to enhance the stakeholder engagement process and address some of the concerns and feedback raised in the 2018 IRP's Stakeholder Report. Additional detail on the stakeholder engagement process is included in Chapter 7 of this report.

As part of the 2021 IRP process, EAL also addressed feedback and recommendations received in the 2018 IRP's Stakeholder Report, including: enhancing stakeholder communications and IRP document postings, clearly communicating IRP timelines, accommodating specific modeling/portfolio requests, and accommodating some specific feedback regarding the IRP's data inputs.

Chapter 3

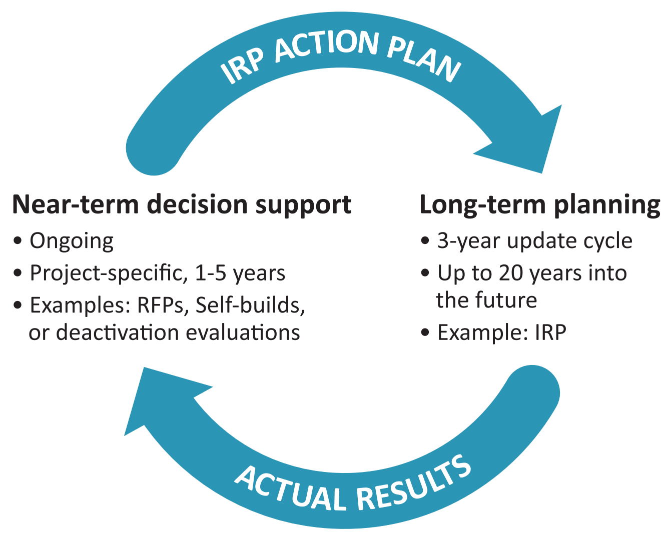
Integrated Resource Planning Process

Summary

- EAL's IRP strategy ensures that the Company is taking the necessary steps today to continue to enhance reliability, affordability, and environmental stewardship 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, as well as 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 typically are presented to the Commission for approval.

The considerations detailed in this report are focused on efficiently meeting all our customers' ever-changing supply needs. EAL's IRP strategy ensures EAL is taking the necessary steps today to continue to enhance reliability, affordability, and environmental stewardship for its customers. This approach also provides the flexibility EAL requires to respond and adapt to a constantly shifting utility landscape. In response to customer demand and a business environment that is exponentially focused on sustainability and renewable energy goals, EAL filed for approval of its proposed Green Promise Tariff in Docket No. 21-054-TF in July 2021. This voluntary product offering seeks to provide participating customers direct access to renewable energy and to support economic development in Arkansas.



The twenty-year study period for the 2021 IRP outlines the current energy landscape as well as the challenges and opportunities that lie ahead. A twenty-year study period was chosen for this IRP in order for EAL to evaluate long-term trends under a broad range of possible future outcomes. As in EAL's previous IRPs, the 2021 IRP is guided by EAL's Resource Planning Objectives, which focus on affordability, reliability, and environmental stewardship. This IRP looks at both 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.

Existing Resources

EAL's customer base has grown to over 722,000 residential, commercial, industrial, and governmental customers located in 63 of Arkansas' 75 counties, covering over 40,880 square miles. The Company currently controls, through ownership or through Power Purchase Agreements ("PPA"), a diverse array of generating resources totaling approximately 5,466 MW of installed capacity to serve these native load customers as of 2020. The Company's nuclear power resources include 1,712 MW from the two-unit Arkansas Nuclear One ("ANO") plant located near Russellville and 303 MW from the Grand Gulf Nuclear Station ("Grand Gulf") near Port Gibson, Mississippi, under a long-term PPA. EAL also utilizes 1,028 MW from coal-fired generation at White Bluff Steam Electric Station ("WB") and Independence Steam Electric Station ("ISES") located near Redfield and Newark. 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, and several municipal electric utilities. EAL also relies on 2,106 MW of natural gas-fired generation that includes 600 MW from the Hot Spring Plant, 486 MW from the Ouachita Plant, and 498 MW from Power Block 2 of Union Power Station, which are modern combined cycle gas turbines ("CCGT"). The Company's generation fleet is rounded out with 81 MW of solar from the Stuttgart Solar facility and 100 MW of solar from the Chicot Solar facility, as well as 73 MW of hydro-electric capacity along the Ouachita River Valley. Chart 2 below shows the percentage, by fuel type, of energy sources serving EAL's native load in 2020.

Sources of Energy Serving EAL's Native Load in 2020

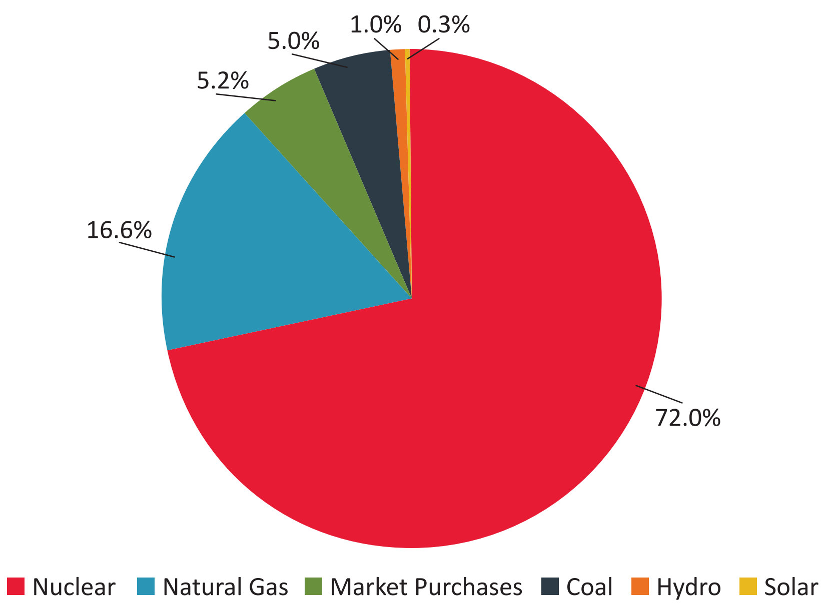


Chart 2: Fuel Mix

A new addition to EAL's portfolio since the 2018 IRP and a result of EAL's 2016 Request for Proposal,[2] EAL executed a long-term PPA for a 100 MW solar photovoltaic ("PV") resource located near Lake Village, Arkansas named Chicot Solar.[3] The Commission issued Order No. 4 in Docket No. 17-041-U on June 18, 2018, approving the PPA. The resource achieved commercial operation in October 2020 with EAL's PPA commencing on November 1, 2020.

Additional information about EAL's existing resources is available in Appendix B.

2 Information on EAL Requests for Proposals can be found at http://www.entergy-arkansas.com/rfp/energy_capacity.aspx.

3 Docket No. 17-041-U.

In addition to these generating resources, EAL's portfolio also includes resources that provide capacity value through reductions in customer load. For the 2020/2021 Planning Year, these Load Modifying Resources ("LMRs") contributed nearly 273 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 for the Company. These programs have reduced the Company's load behind the customer meter by an incremental 146 MW since 2018 and an aggregate 400 MW since programs were introduced in 2014. Under the 2020-2022 EE Program Plan, the 2020 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. Gross program savings increased from 267,395 MWh for the 2019 Program Year to 320,609 MWh for the 2020 Program year. To further supplement its successful EE programs, in 2020 EAL also began offering a Low-Income Program in accordance with Act 1102 guidelines. Evaluated savings and overall goal achievement for the 2020 Program Year are shown in further detail in Table 1.

Table 1: EE Program Metrics

Evaluated Savings and Goal Achievement	
Evaluation Metrics	**2020**
EAL Gross Savings (ex ante)	320,609 MWh
As adjusted by Tetra Tech for Realization Rate (ex post)	327,167 MWh
As adjusted for Net-To-Gross ("NTG") ratios	294,313 MWh
EAL MWh Target adjusted for SD	221,740 MWh
% of Target Achievement Based on Evaluated Energy Savings	133%

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 a number of 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 the best options for replacement capacity over the planning horizon. Based on the current design life assumptions incorporated into the IRP, a number of EAL's existing generating units are anticipated to deactivate over the IRP planning horizon (2023-2042). During this planning period, the total reduction in EAL's generating capacity from the assumed unit deactivations grows to approximately 4,800 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 IRP reflects a 30-year useful life for its fleet of CCGT generators in three of the four futures based on a generic assumption for that type of generation technology. Because it is reasonable to assume EAL's CCGT generators may continue to cost-effectively generate energy well beyond the 30-year assumption, the impact of extending those generators to the end of the planning horizon is considered in one of the four futures, as discussed in more detail below. Additionally, for EAL's nuclear fleet, the IRP reflects deactivation at the expiration of the current operating licenses in 2034 for ANO Unit 1 and 2038 for ANO Unit 2 in three of the four futures. Entergy's Nuclear group has not yet begun its license extension review process for these two units, and some degree of risk exists that an operating license extension will not be granted under the Nuclear Regulatory Commission's ("NRC") Subsequent License Renewal ("SLR") process for units requesting extended operations from 60 years to 80 years. This planning assumption results in decreased base load and load following capacity over the planning horizon as these units reach the expected end of their useful lives. These assumptions are discussed in greater detail in Chapter 5 of this report.

It is important to recognize that assumptions related to these uncertainties about operating lives of existing generating units do not reflect actual decisions regarding the future investment in resources or the actual dates that generating units will be removed from service. As planned deactivation dates near, a significant equipment failure occurs, or operating performance diminishes, 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, 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 requirements of legislation, regulation, and relative economics. 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

Since 2018, EAL has sought regulatory approval for additional renewable generation. As part of EAL's 2017 Request for Proposals for Build-Own-Transfer Solar Photovoltaic Resources, EAL sought up to 200 MW of solar generation to add to its resource portfolio. Out of this competitive solicitation, EAL selected a planned 100 MW solar photovoltaic resource with a 10 MW/30 MWh battery energy storage system ("BESS") to be located in White County, Arkansas, to be called Searcy Solar.[4] On April 23, 2020, the Commission issued Order No. 7 in Docket No. 19-019-U approving the resource. The 2021 IRP assumes that Searcy Solar achieves commercial operation prior to the end of 2021.

Additionally, in its 2019 Request for Proposals for Solar Photovoltaic Resources, EAL sought up to 200 MW of solar generation to add to its resource portfolio. Out of this competitive solicitation, EAL selected two resources: Walnut Bend Solar, a 100 MW solar resource, approved in Order No. 8 in Docket No. 20-052-U and West Memphis Solar, a 180 MW solar resource, approved in Order No. 8 in Docket No. 20-067-U. The 2021 IRP assumes that commercial operation for Walnut Bend Solar and West Memphis Solar are achieved in 2022 and 2023, respectively.

In August 2021, EAL filed an application in APSC Docket No. 20-049-U seeking approval for Power Through, a turnkey backup generation product offering that would include up to 75 MW of natural gas-fired distributed energy resources ("DER") to be deployed across the Company's service territory. Power Through would offer energy resiliency as a service for commercial and industrial customers via 100 kW - 10 MW generators. These generators will serve the dual functions of 1) meeting a portion of EAL's capacity and energy needs by delivering power to the grid when favorable market conditions exist, and 2) meeting the backup power needs of host customers during outages.

Under the assumption that the planned resources described above proceed as planned, the 2021 IRP reflects a total of approximately 5,803 MW of resources in EAL's portfolio by 2023 on an effective capacity basis.[5] The diversity of EAL's currently planned resource portfolio in 2023 is shown in Chart 3 below.

4 Docket No. 19-019-U.

5 Effective capacity is 50% of installed capacity for solar resources, 15.6% for wind resources and 100% for conventional resources. LMRs receive peak hour capability plus reserve margin and transmission losses.

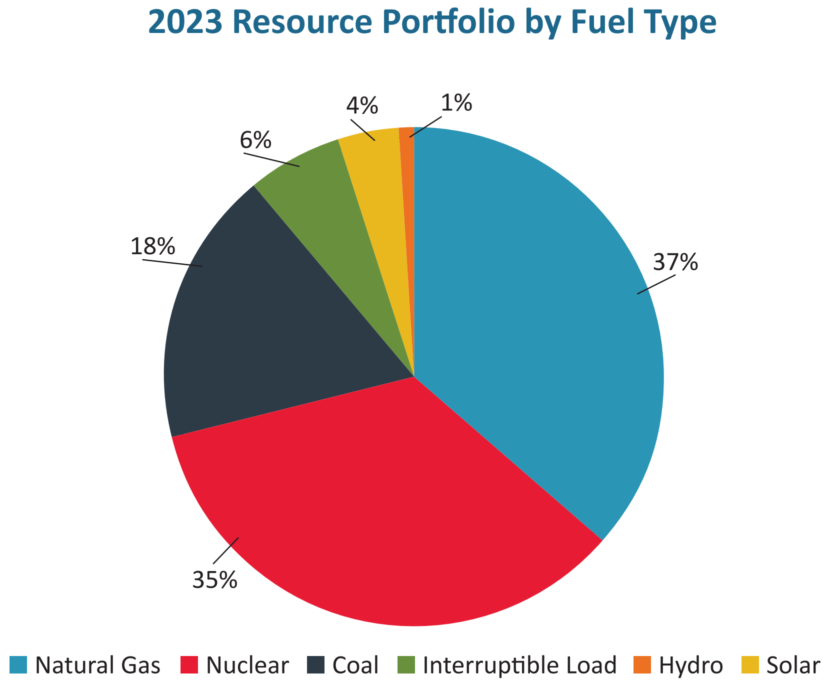


Chart 3: Capacity Mix

Environmental Justice

EAL is mindful that public health impacts and Environmental Justice ("EJ") concerns are important considerations in the daily operation of the Company. 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 the advancement and protection of human rights in all our operations.

EAL strives to minimize any potential adverse effects of our activities on the local communities it serves, including the communities of its low-income customers. EAL considers EJ impacts in its policies and planning 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 environmental and all applicable regulatory requirements and enhancing the communities it serves.

To that end, the following provides several examples of measures that EAL has taken regarding potential public health impacts and EJ considerations. In developing new generation, EAL identifies candidate sites and then conducts an evaluation of 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, and ambient air quality. Many of these factors are similar to the environmental indicators considered by the Environmental Protection Agency ("EPA") EJSCREEN tool. 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 EPA EJSCREEN environmental and justice mapping tool to evaluate the proposed Searcy Solar and Walnut Bend Solar projects to evaluate potential EJ issues that may warrant additional consideration and to inform our 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.

Project	Minority Population			Low Income Population			Demographic Index		
	1-Mile	10-Mile	State Average	1-Mile	10-Mile	State Average	1-Mile	10-Mile	State Average
Searcy Solar	37%	14%	27%	58%	43%	41%	48%	30%	34%
Walnut Bend	38%	44%		40%	46%		45%	39%	

Table 2: EPA EJSCREEN Results

The EPA EJSCREEN results indicate that the project sites are within an area with a demographic index of 30% and 39% for a 10-mile radius, which are slightly below and above the state demographic index average of 34%. For a 1-mile radius, the project sites are within an area with a demographic index of 48% and 45% which are both above the state average but not significantly so. These two solar sites will generate emissions-free renewable power and are not expected to disproportionately affect minority or low-income populations.

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 Entergy's commitment to achieve net-zero carbon emissions by 2050, to retire all coal-powered capacity by 2030, and to conduct due diligence in its operations, it is apparent that Entergy is striving not only to improve the environment but also to improve the communities it serves by reducing potential public health impacts.

Customer Preferences and Long-term Planning

With advancements in technology and evolving priorities, both within and outside of 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.

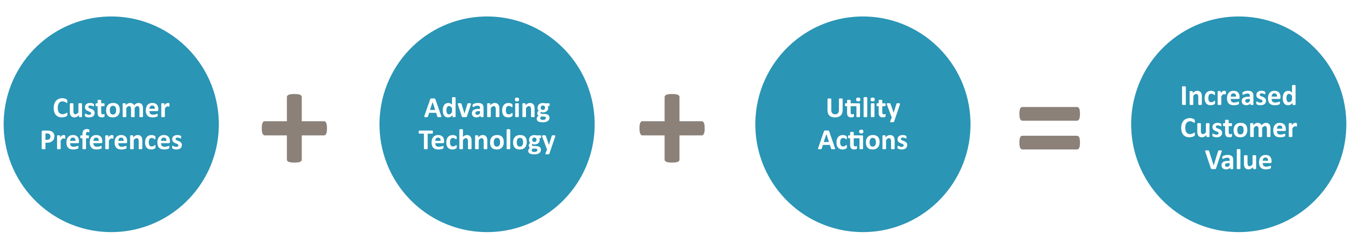


Figure 1: Changes and Opportunities Within the Utility Industry

Customers are also seeking more options in the generation and delivery of energy, including how they interact with, understand, and manage their own energy use, as well as the actual sources from which their energy is derived. As reflected in EAL's AMI proceeding in Docket No. 16-060-U, EAL's deployment of AMI is in response to ever-evolving customer expectations regarding the provision of electric service and technological innovation that is changing the way energy is supplied and distributed. EAL's interest is in actively engaging its customers to obtain a better sense of those expectations and the ways in which EAL can bring offerings to the marketplace to meet those expectations.

Increasingly, our customers are becoming more interested in sourcing their power from cleaner, more sustainable sources of energy, with clear preference for renewable resources like solar. In addition to the Green Promise tariff discussed above, EAL also has one offering under the Solar Energy Purchase Option ("SEPO") tariff to customers seeking solar energy as part of their energy supply. Like similar solar offerings throughout the United States, EAL's SEPO offering provides participating customers the ability to subscribe directly to output from the Stuttgart Solar PPA while avoiding the financial and operational risks associated with building or contracting for their own solar facilities.

In response to evolving customer needs, EAL also has been engaged with two military installations in its service territory to explore opportunities for customer-centric power resiliency projects. U.S. Department of Defense Energy Policy[6] directs the Secretary of Defense to "ensure the readiness of the armed forces for their military missions by pursuing energy security and energy resilience." Based on this mandate, these military installations require uninterrupted power to support critical national defense and humanitarian missions. The various branches of the U.S. Armed Forces have responded by forming internal administrative offices that support their respective strategic energy and resiliency initiatives, which includes partnering with local utilities wherever possible. Like many of EAL's customers, the U.S. Department of Defense also has renewable and sustainability goals, such as its 25% renewable energy mandate by 2025. With these priorities in mind EAL has been working with its military customers in an effort to provide power resiliency paired with renewable resources. While these projects are in the early stages of development, several project precedents exist throughout the United States, including the Hawaiian Electric Company's partnership with the U.S. Army on the Schofield Barracks Generating Station project and the recently approved partnership between the Public Service Company of Oklahoma and the U.S. Army at Fort Sill.

EAL is focused on achieving a better understanding of these evolving customer preferences, and the IRP is one set of input information EAL can leverage to help accomplish that goal. That understanding will allow EAL to:

- Develop a comprehensive outlook on the future utility environment so EAL can more effectively anticipate and plan for the future energy needs of our customers and region.
- Incorporate new, smart technologies and advanced analytics to better assess where expanding resource alternatives can be leveraged, and plan for improvements and enhancements to the electrical grid.
- Continue to seek cost-effective renewable resource additions to EAL's portfolio to support and expand offerings of renewable energy to interested customers.

Advancing Technology - Technological advancements provide the energy industry 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 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.

6 10 U.S.C. § 2911

The deployment of advanced meters and development of smart energy grids, for example, are enabling the entire utility industry to better understand the new and changing ways in which customers are using energy. This allows energy companies to make more informed decisions and provide tailored customer solutions through enhancements to electric infrastructure and the adoption of new products and services.

Increased Customer Value - By combining an understanding of what customers want with sound and comprehensive planning, EAL can deliver the type of service 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 our 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 effort of modernizing its supply portfolio.

Innovation

EAL strives to solve critical customer frictions for residential, commercial, and industrial customers by building new products and services. Every customer is an integral part of EAL's success. EAL collaborates with its customers, partners, and colleagues to build a more robust, sustainable power network for today and future generations.

For example, with the growing opportunity and challenges that will come with electrification of transportation in the coming years, EAL expects its customers to increasingly electrify as more vehicle models become available and their prices reach parity with, or become less expensive, than internal combustion engine alternatives. Specific to the commercial space, EAL also sees a growing number of organizations exploring electric vehicle alternatives in order to help them reach their internal sustainability goals. EAL's forecasting processes include assumptions around increased energy usage tied to electrification, which is discussed in greater detail in Chapter 4.

EAL looks to enable opportunities in this space and expects to remain customer centric with its approach. Accordingly, EAL will be exploring solutions in the future relating to fleet electrification, public charging, and workplace and residential charging. In parallel, EAL is committed to having the resources and infrastructure in place to support these initiatives.

Another example of EAL's efforts includes being one of the founding members of The Electric Highway Coalition. The collective group of utilities announced a plan in March 2021 to enable electric vehicle drivers seamless travel across major regions of the country through a network of direct current fast chargers for electric vehicles. The companies are each taking steps to provide EV charging solutions within their respective service territories. Since the March announcement, the coalition already has doubled in size with commitments from other utility partners.

MISO Resource Adequacy & Planning Reserve Requirements

MISO RA Requirements - As a load serving entity ("LSE") within the Midcontinent Independent System Operator, Inc. ("MISO") since 2013, EAL is responsible for planning and maintaining a resource portfolio to reliably meet its customers' power needs. To this end, EAL must maintain 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 procure sufficient short-term capacity, through the procurement of zonal resource credits ("ZRCs") equal to their Planning Reserve Margin Requirement ("PRMR"), in order 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 peak load coincident with MISO's forecasted peak load, plus a planning reserve margin established by MISO annually for the MISO footprint.

Under MISO's Resource Adequacy process, the MISO-wide planning reserve margin is determined annually by November 1st prior to the upcoming planning year (June - May). Additionally, through MISO's annual Resource Adequacy process, MISO determines the amount of physical capacity needed within a particular region or Local Resource Zone ("LRZ") based on load requirements, capability of existing generation, and import capability of the LRZ. Those capacity requirements are referred to as the Local Clearing Requirement ("LCR") for the LRZ for 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.

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, apply 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 as a result 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 due to potentially insufficient in-zone generation to meet the LRZ 8 Local Clearing Requirement.

MISO market constructs, rules, and methodologies continue to evolve, including items that impact Resource Adequacy requirements and capacity accreditation. Currently, MISO is conducting a stakeholder process to design and implement a seasonal resource adequacy construct. EAL is participating in this process, and if needed, will adapt future resource planning efforts to align with changes implemented by MISO. Additionally, as capacity accreditation for renewable resources, such as solar, is updated by MISO and approved by the Federal Energy Regulatory Commission ("FERC"), EAL will align with these updates as needed. With anticipated increases in renewable penetration, EAL assumed that the capacity value contribution of solar will evolve.

As an LSE within MISO, EAL is responsible for planning and maintaining a resource portfolio to reliably meet its customers' power needs. Therefore, EAL plans beyond the immediate year requirements outlined by MISO's Resource Adequacy process. However, as discussed below, EAL's long-term reserve margin target will be informed by MISO's Resource Adequacy construct going forward.

Long-Term Planning Reserve Margin Targets - Although the MISO Resource Adequacy process establishes minimum requirements that must be met in the short-term and are reviewed regularly as part of the resource planning process, it does not provide an appropriate basis for determining EAL's long-term resource needs. Moreover, relying on the short-term market for ZRCs to meet customers' long-term power needs could unnecessarily expose customers to cost and reliability risk. EAL employs a more stable approach for long-term planning to meet its long-term planning objectives. EAL's current planning reserve margin reflects a long-term point of view that is intended, in part, to provide a buffer, or margin, above peak load to maintain reliable service during unplanned events such as higher than expected peak loads and unplanned outages of units committed to supply energy into the MISO market.

EAL's long term planning construct is informed by a recently performed Loss of Load Expectation analysis which draws upon EAL's experience particiapting in MISO. The result of that analysis was a decision to change from the prior 12% reserve margin based on installed capacity ratings and forecasted non-coincident peak to a 12.69% reserve margin based on unforced capacity ratings and forecasted peak coincident to MISO. The changes in the planning reserve margin are intended to maintain the 1-day-in-10-year level of reliability over the long-term planning horizon while taking into account long-term uncertainty related to load forecast, weather impacts, and available supply.

EAL's current long-term planning construct is an annual construct and uses EAL's summer peak load coincident with MISO. In the event that MISO moves from its current annual Planning Resource Auction ("PRA") construct to a seasonal construct, EAL will evaluate what changes, if any, are needed to the long-term planning construct.

Resource Needs

A number of factors are considered and evaluated in order to understand and determine EAL's resource needs:

Long-Term Capacity Requirements - EAL is projected to need new generating capacity over the course of the 20-year IRP period in order to reliably serve customers. Taking deactivation assumptions and load growth into account, the long-term deficit is expected to exceed 770 MW by 2028. This need may grow to over 4,600 MW by the end of the planning horizon. Chart 4 below shows EAL's portfolio of existing resources, including both generating units and demand-side capacity, and planned resources, as described above, compared to EAL's peak load-plus-reserve-margin target. An assumption for future energy savings due to continued and expanded EE programs is included in the peak load. The deficit expands over time as expected loads increase and older generating units reach an assumed end of useful life.

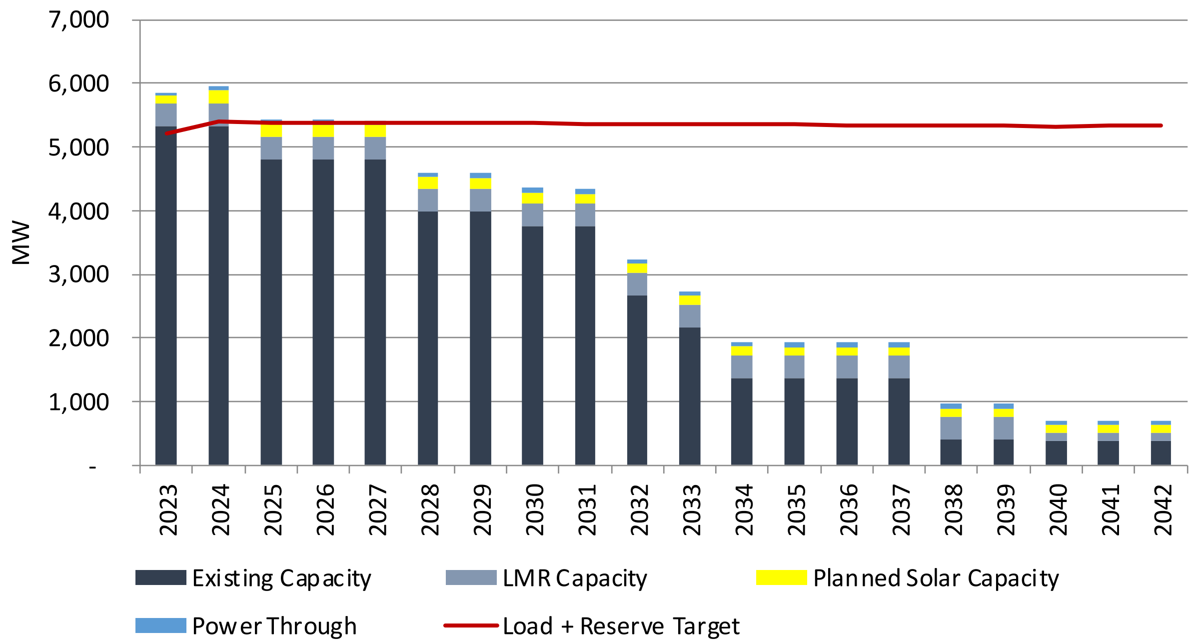


Chart 4: EAL Capacity Position

Energy Requirements - In addition to 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 2032 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 both capacity and energy requirements over the long-term planning horizon. As resources deactivate and capacity requirements increase, EAL will look to balance energy producing and peaking generation to meet customer requirements effectively and efficiently.

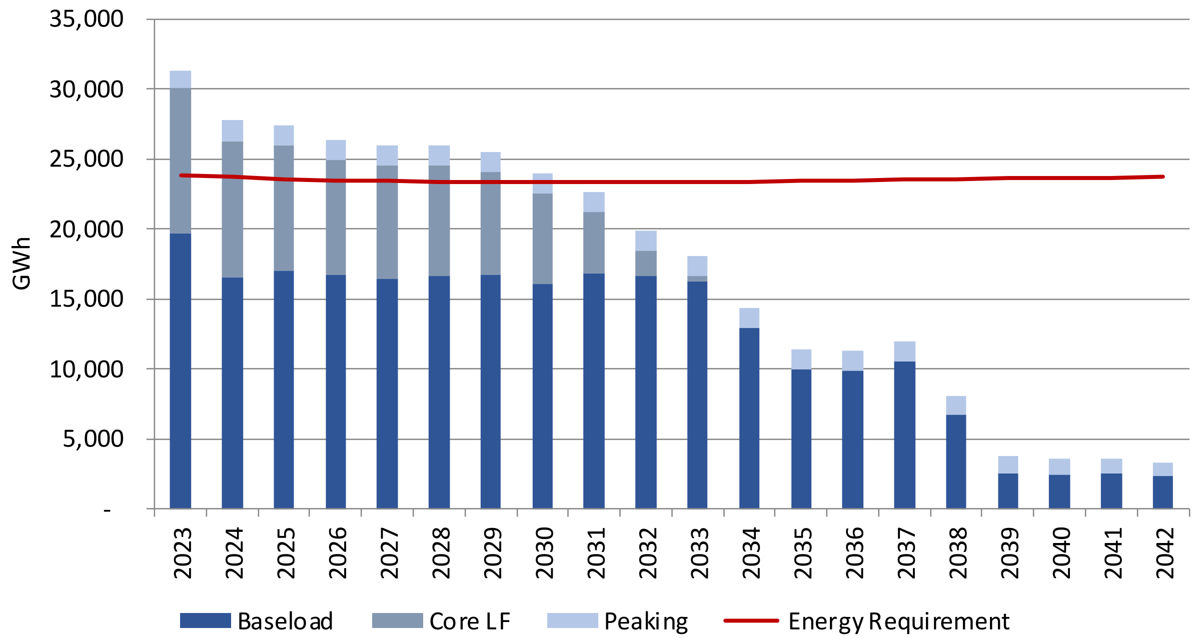


Chart 5: EAL Energy Requirements

Customer Usage - Of course, both 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 may be affected as customers gain additional resources to manage consumption, such as those that will be enhanced by AMI or those affected by increased accessibility to rooftop solar or battery storage technology.

EAL's long-term planning process and the evaluation outlined in this IRP helps 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 close proximity to customer load with flexible attributes to help provide sufficient capacity during peak demand periods as well as adequate reserves. Given the primary objective of risk mitigation, these practices ensure that EAL is able to continue providing safe and reliable service at a just and reasonable cost for its customers.

Supply Role Needs - As discussed previously in the existing resource section, EAL's CCGT generation fleet provides customers base load and load-following energy supply, and the IRP reflects the current 30-year generic useful life assumption (with the exception of Future 2, which includes a 40-year useful life) for our existing CCGTs based on the technological design life of the facilities. These deactivation assumptions result in a significant decrease in base load and load following capacity within the planning horizon. As noted previously, EAL is continually assessing these units in order to refine the useful life assumptions based on historical operations and current conditions of the facilities.

EAL's current generating fleet also includes its Lake Catherine 4 gas unit that continues to provide a large amount of installed capacity and serves to meet reliability needs over seasonal peaks. However, the assumed deactivation of Lake Catherine 4 early in the IRP planning horizon will reduce EAL's peaking and load-following resource capability.

Locational Considerations - The location of resources can have a significant impact on the electric grid. Resources, both supply-side and demand-side, can have an impact on the pattern of power flowing on the transmission system and on the voltage at the substations in the vicinity of the resource. The addition of 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 which can provide voltage regulation. This effect on the eletric grid is particuarly 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 a LRZ allows a resource to contribute to the local clearing requirement of a LRZ in the MISO PRA.

Flexibility Considerations - The portfolio design analytics explore the value of renewable energy projects, energy storage, peaking, and CCGT capacity. Based on these analyses, the long-term planning horizon will likely include additions of both renewable and energy storage technologies to EAL's portfolio. As intermittent additions increase and EAL's legacy fleet deactivates, 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 continues to be 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 continually 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 ("SERC") and our local planning criteria, and (2) is designed to efficiently deliver energy to end-use customers 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 65,800 miles of high voltage transmission and 198,933 megawatts of power generating resources 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 22 cycle. Participation in the MISO MTEP process is the method by which 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 provide benefits to EAL customers are thoroughly examined. This combination of Bottom-Up and Top-Down planning helps ensure all issues are addressed in an effective and efficient manner.

EAL's transmission strategy is centered upon 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 as well as our 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 any 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 which are 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) to verify that the proposed solutions solve the reliability need, and 3) to provide stakeholders the opportunity to propose alternatives. Additionally, MISO performs other studies each year 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 22. The EAL projects that were approved for inclusion in Appendix A of MISO's MTEP 20 cycle are provided in Appendix C - Table I. Also, submitted Target Appendix A projects for MTEP 21 are in Appendix C - Table II, and projects for Target Appendix A of MTEP 22 are in Appendix C -Table III These future transmission projects and other transmission plans developed during the next three years will be important inputs to consideration of future resource needs.

Integration of Transmission and Resource 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 an LSE, 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, distribution investment will enable the interconnection of DERs and impact the reliability of the system. Additionally, driven by customer specific sustainability 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 is crucial to ensure that EAL's planning objectives of affordable cost, high reliability, and environmental stewardship are met.

Distribution Planning & Grid Modernization - Through its distribution planning process, EAL's efforts will continue to maintain and improve the reliability of our distribution lines and our 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 the reduction in costs from extending the life of distribution assets and minimizing maintenance costs with respect to 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 not only critical for day-to-day utility reliability needs but also to support the greater deployment of advanced meters and related infrastructure, DERs, and other technologies. EAL's objective is to achieve a modernized distribution system over time that also 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 reliability of the system. Additionally, driven by customer specific sustainability 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 is crucial to ensure that EAL's planning objectives of affordable cost, high reliability, and sustainability are met.

Sustainability Goals

Entergy has been an industry leader in voluntary climate action for two decades. Building on its longtime legacy of environmental stewardship, 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 reliability, affordability, and sustainability.

In 2001, Entergy was the first U.S. utility to voluntarily limit its carbon dioxide emissions. After beating this target by more than twenty percent, Entergy renewed and strengthened this commitment twice. Today, Entergy is outperforming by eight percent its current commitment to maintain carbon emissions from Entergy-owned facilities and controllable power purchases through 2020 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.

2001	2006	2011	2019	2020
First U.S. utility to voluntarily set goals to stabilize greenhouse gas emissions	Intensified commitment with a goal to reduce CO_2 emissions to 20% below year-2000 levels through 2010	Extended CO_2 reduction commitment through 2020	Introduced new goal to reduce CO_2 emission rate to 50% below year-2000 levels by 2030	Committed to achieve net-zero emissions by 2050

Entergy is taking action now toward a carbon-free future and expects 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, continuing to engage with partners and gain experience on enhancing natural systems like forests and wetlands that absorb carbon, and 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 2020 Integrated Report**.*[7]

7 *https://integratedreport.entergy.com/*

Chapter 4

Model Inputs and Assumptions

Summary

- EAL's reference forecast projects nearly flat growth in electricity consumption, with total energy growth of 0.1% annually and peak demand to growth of about 0.1% over the forecast horizon.
- EAL's technology assessment and fuel price forecasts have been expanded and updated.
- A third-party consultant was engaged to conduct an independent forecast of the achievable potential of DR program types and DER technologies on the Company's system. The resulting forecast was used to provide hourly inputs for the IRP's modeling process.

Resource Planning Considerations

Guided by its Resource Planning Objectives, EAL's resource planning process seeks to maintain a portfolio of resources that reliably meets customer power needs at a just and reasonable supply cost while minimizing risk exposure. The landscape within the electric utility industry is changing, and this IRP offers early insight for opportunities to respond to this evolving environment.

EAL recognizes the way customers consume energy and the type of energy they prefer is changing, so the way the Company plans for, produces, and delivers the power on which customers rely must continue to evolve as well. EAL strives to have a planning process that provides for the flexibility needed to better respond to this constantly evolving environment.

Load Forecasting Methodology

Each year, EAL develops a forecast that is used for financial and resource planning. That forecast is often used as the Base Case or Reference Case for scenario analysis such as the IRP process. The Reference Case is developed sequentially starting with a forecast of monthly billed sales, which is then converted to a calendar month view, which is then converted into hourly loads across each month. Scenario forecasts are then developed in a similar manner starting with monthly energy and then converting those levels to hourly loads. EAL developed three scenario forecasts in addition to the Reference Case forecast for the 2021 IRP. These are discussed in further detail below.

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

- Increases in EE, brought about by:
  - Technological changes – lighting, heating, ventilation, and air conditioning ("HVAC"), appliance efficiency.
  - Structural changes – changes in building codes or state/national requirements.
  - Other conservation measures – changes in personal behavior.
- Increased adoption of Electric Vehicles (EVs) in place of vehicles using internal combustion engines.
- Other electrification opportunities brought about by reductions in natural gas usage in favor of electric end-use equipment.
- Levels of economic activity and growth, including expansion or contraction with large industrial load as well as changes in population affecting residential and commercial classes.
- Potential adoption of behind-the-meter self-generation technologies (e.g., rooftop solar).
- Changes in temperature and weather patterns over time.

Such factors may affect the levels of electricity consumption over the term of a study period as well as the hourly patterns of consumption across individual days. Annual peak loads could be higher or lower, and daily peaks could shift to later hours in the day. Uncertainties in these load levels and patterns may affect both the amount and type of resources required to efficiently meet customer needs in the future.

Reference Case Energy Forecast - The Reference Case forecast was developed in 2020 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 December 2019, as well as future estimates for normal weather and EE. In addition, the forecast includes estimates for changes in customer counts, future growth in large industrial usage, and estimates of future consumption growth from 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 data 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 the Metrix ND® forecasting software, which is licensed from Itron. This software is used to develop statistical relationships between historical consumption levels and explanatory variables such as weather, economic factors, and/or month-of-year, and those relationships are applied going forward to estimates of normal weather, economic factors, and/or month-of-year to develop the forecast. Explanatory variables are included in each class-level forecast model if the statistical significance is greater than 95%.

Residential Forecasts - Long-term residential forecast projects a slight increase in electricity consumption with 0.1%/yr. CAGR over the planning period. This forecasted increase is largely due to increasing average Use Per Customer (“UPC”) offset slightly by flat growth in residential customer counts.

Population projections come from IHS Markit[8] county level data for EAL’s service territory. Overall, average annual kWh consumption per household is expected to grow slightly by 0.1%/yr..

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

Residential UPC per day =

Heating Degree Days * Heating efficiency index * Heating coefficient +

Cooling Degree Days * Cooling efficiency index * Cooling coefficient +

other use coefficient * other use efficiency index

The residential forecasts use variables for individual months rather than using 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 normal weather levels in the future.

Trended Normal Weather - 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 versus current (2020/2021) levels. 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 2000-2019, which are used in the Reference Case forecast. 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. The 20-year trended normal temperatures are built from hourly temperatures and are allocated to each calendar month. By 2042, the effect of the trended normal temperature assumption increases summer (July - September) residential and commercial energy consumption by 125 GWh (3.2%) and decreases winter (January, February, December) energy consumption by 55 GWh (-1.7%).

8 IHS Markit Ltd. - www.ihsmarkit.com

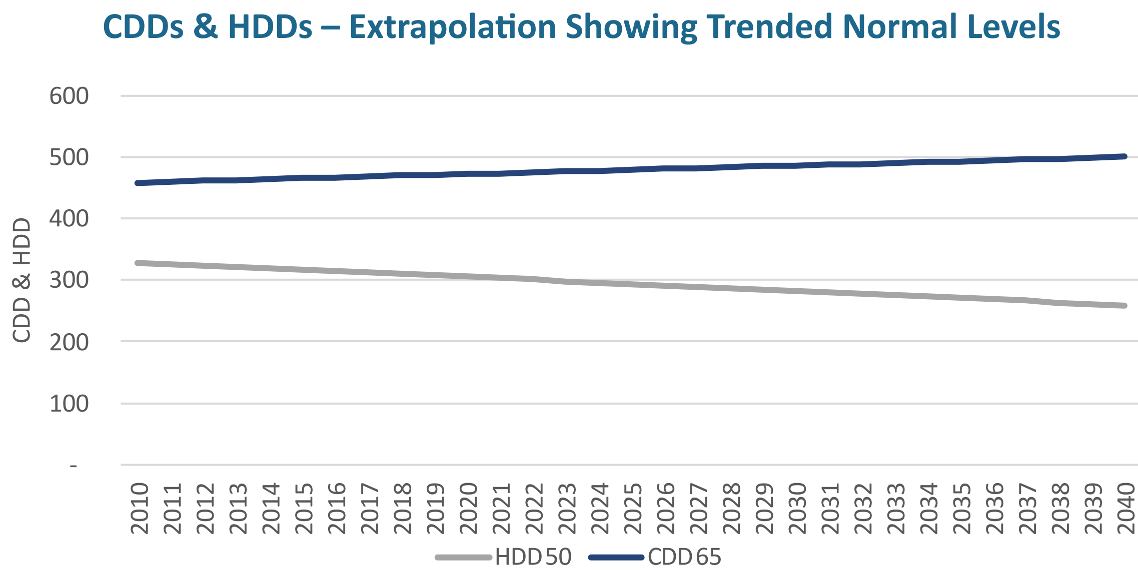


Chart 6: CDDs and HDDs – Extrapolation of 20 Year Rolling

Residential Forecast - Offsetting the declines in residential customer counts are expectations for average residential UPC growth. Based on expected future growth in average residential UPC in EAL's service territory, EAL is expected to have positive average residential UPC growth starting in the early-2030s, slightly tapering off during the mid-2030s and then finishing the forecast period with some further growth. For the period overall, the forecast is for relatively flat residential UPC growth of 0.1%/yr. for 2023-2042. The combined effect of higher UPC and a slight decrease of customer count leads to a net forecasted CAGR in residential energy of 0.08%/yr. The sales forecast includes a net 1.5% decrement to the residential sales, phased-in between 2020 and early 2022. The phase-in for these effects was based on the latest AMI deployment schedule available at the time of the forecast development plus a time allowance for the AMI-related customer information programs to show an effect.

Table 3: YoY Growth Residential			
Year	**Energy**	**Customers**	**UPC**
2024	-0.3%	0.0%	-0.3%
2027	-0.1%	0.1%	-0.2%
2030	0.0%	0.0%	0.0%
2033	0.2%	0.0%	0.2%
2036	0.5%	-0.1%	0.5%
2039	0.4%	-0.1%	0.5%
2042	0.3%	-0.1%	0.4%
2023-2042 CAGR	**0.1%**	**0.0%**	**0.1%**

See Table 3 showing the year-over-year changes and CAGRs in residential energy, customer counts, and UPC.

Commercial Forecast - Commercial use of electricity is forecasted to increase slightly for 2023-2042 with a CAGR of 0.3%/yr. This increase is driven by forecasted UPC increases of 0.4%/year offset by flat customer count growth.

The commercial sales forecast is developed using a similar methodology to the residential forecast with the exception that commercial sales are forecasted in total rather than by UPC 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 HVAC and refrigeration, as well as Company-sponsored Demand Side Management ("DSM") programs discussed further below. The commercial forecast also includes the same type of AMI-related decrement phased-in from 2020-22 and then at the full 1.5% for the remainder of the study period.

Table 4: YoY Growth Commercial

Year	Energy	Customers	UPC
2024	-0.1%	-0.3%	0.2%
2027	-0.1%	-0.1%	0.0%
2030	0.3%	-0.1%	0.4%
2033	0.4%	0.0%	0.4%
2036	0.5%	0.0%	0.5%
2039	0.8%	0.1%	0.7%
2042	0.8%	-0.1%	0.9%
2023-2042 CAGR	**0.3%**	**-0.1%**	**0.4%**

Commercial Sales$_m$=

Heating Degree Days * Heating efficiency index * Heating coefficient$_m$ +

Cooling Degree Days * Cooling efficiency index * Cooling coefficient$_m$ +

other use coefficient * other use efficiency index$_m$

See Table 4 for estimated year-over-year changes and CAGRs for commercial sales, commercial customer counts, and UCP.

Governmental Forecast - Governmental energy usage is forecasted to be relatively flat with only a slight decrease for 2023-2042 with a CAGR of -0.01%/yr. This is largely due to a slight decrease in customer counts, offset by a modest increase in UPC.

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

Large Industrial Growth - The 2023-2042 CAGR for EAL's large industrial sales is 0.20%/yr. Due to their size, 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 customers are also risk-adjusted based on the customer's progress towards achieving commercial operation.

Table 5 shows the forecasted year-over-year growth in sales attributable to large industrial customers.

Table 5: YoY Large Ind Growth

Year	Energy
2024	-0.1%
2027	0.2%
2030	0.3%
2033	0.3%
2036	0.3%
2039	0.3%
2042	0.3%
2023-2042 CAGR	**0.20%**

Energy Consumption by Class - EAL's energy consumption comes mostly from the industrial and residential customer classes who account for 38% and 36%, respectfully, of the forecasted sales for 2023. Commercial customers consume 25% of the energy with governmental customers consuming the remaining 1%.

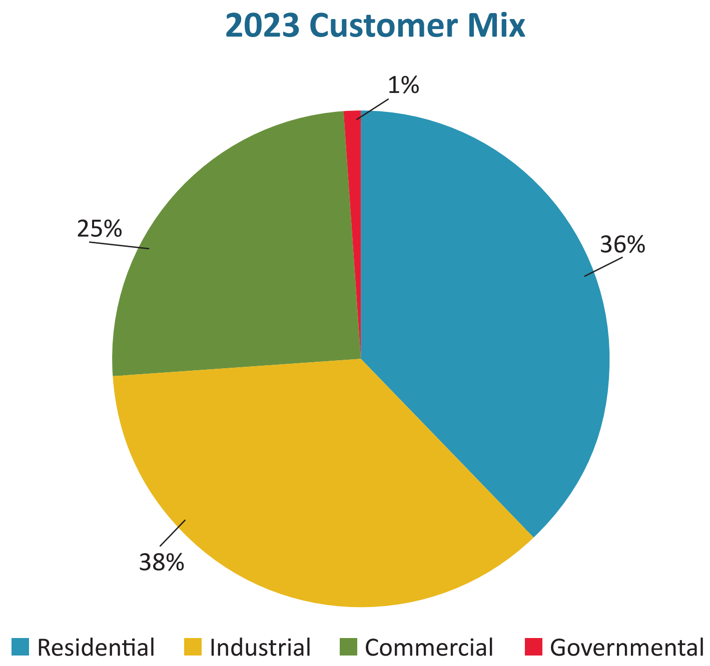


Chart 7: 2023 Energy Class Mix

This consumption mix by class is expected to remain largely unchanged throughout the study period, apart from some slight increases in the commercial sector. See Chart 8 below for the projected 2042 energy mix by customer class.

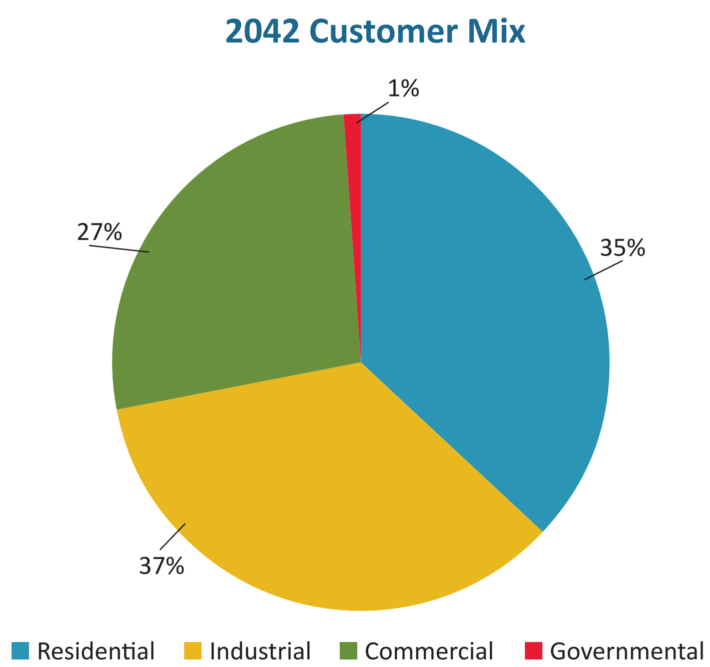


Chart 8: 2042 Energy Class Mix

Demand Side Management - EAL has had company-sponsored DSM programs since 2008, such as ones targeted for lighting, appliances, and HVAC efficiency.

DSM programs from one year have effects that carry forward into future years. For example, a program to encourage customers to switch from using incandescent lighting to LED lighting in one year will result in lower electricity consumption for years to come. As such, to develop an estimate of the DSM effects on the forecast, EAL starts with the historical (by year) DSM levels and develops an estimate of the cumulative effects of each year's programs on future years.

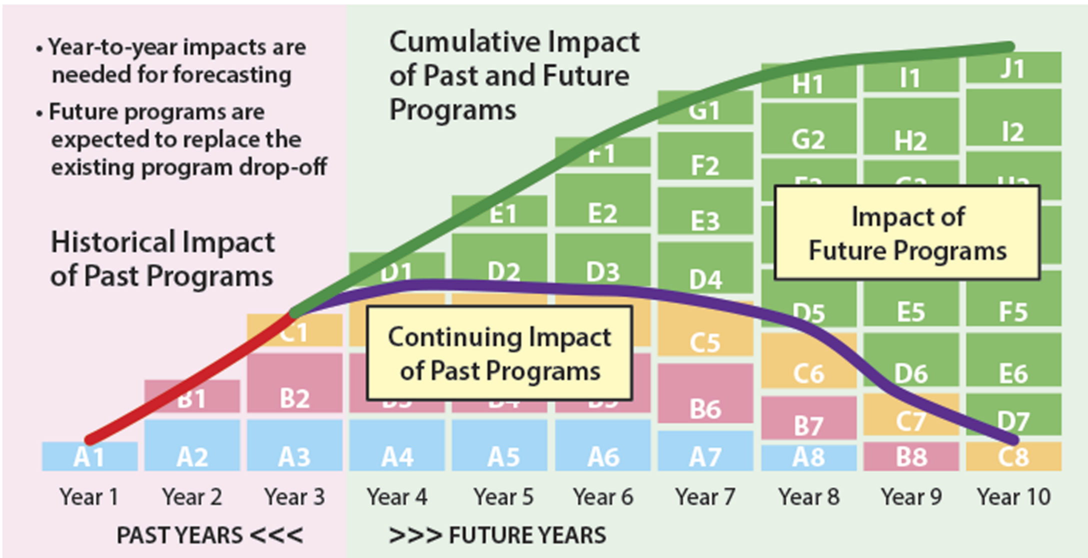


Figure 2: Chronological DSM Impacts

An add-back method was employed to develop the load forecast. See Figure 3 below. The add-back method takes the estimated cumulative historical volume of DSM savings in kWh and adds those amounts back to monthly billed-sales to develop a forecast as if there had never been DSM programs. From that forecast, the expected future levels of DSM are subtracted from the No-DSM forecast to arrive at the net forecast levels. This method was used for the Residential, Commercial and Small Industrial forecasts.

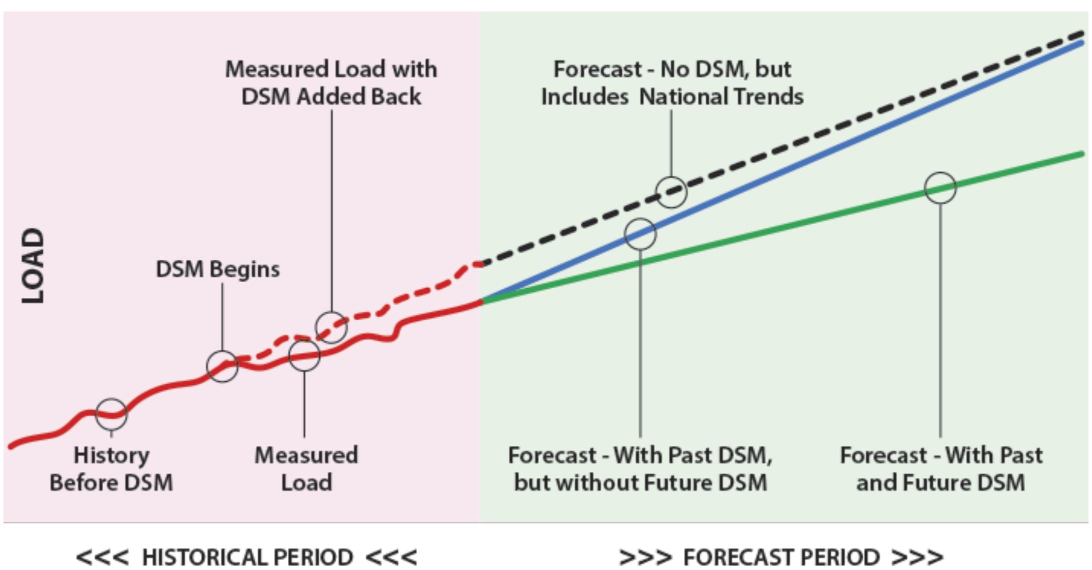


Figure 3: Add-Back Method

Using this methodology, new programs in future years are expected to reduce nearly 1.58% of the total annual sales for EAL by 2022 in the Reference Case forecast. Table 6 below shows EAL's expected incremental savings from pre-approved programs. After 2022, it is assumed these incremental savings remain consistent with the latest data provided (2022 levels).

Table 6: Annual MWh Savings[9] (Incremental Assumptions)

	2020	2021	2022
Home Energy Solutions	27,429	27,136	27,136
Energy Solutions for Multifamily Homes	11,892	14,010	14,010
Energy Solutions for Manufactured Homes	5,403	5,403	5,403
Low-Income Solutions	6,740	7,863	7,863
Point of Purchase Solutions	56,884	65,094	66,846
Large Commercial & Industrial Solutions	129,805	118,078	114,387
Small Business Solutions	17,991	15,663	13,871
Public Institutions Solutions	20,965	21,987	24,661
Agricultural Energy Solutions	6,897	6,398	5,998
Smart Direct Load Control	1,551	4,133	4,973

Chart 9 below shows the estimated levels of annual energy savings included in the Reference Case forecast as a result of EAL's historically implemented DSM programs as well as savings from future DSM programs based on the incremental levels laid out in Table 6 above. DSM levels are expected to increase gradually through early 2030s, and then level off by mid-2030s and beyond.

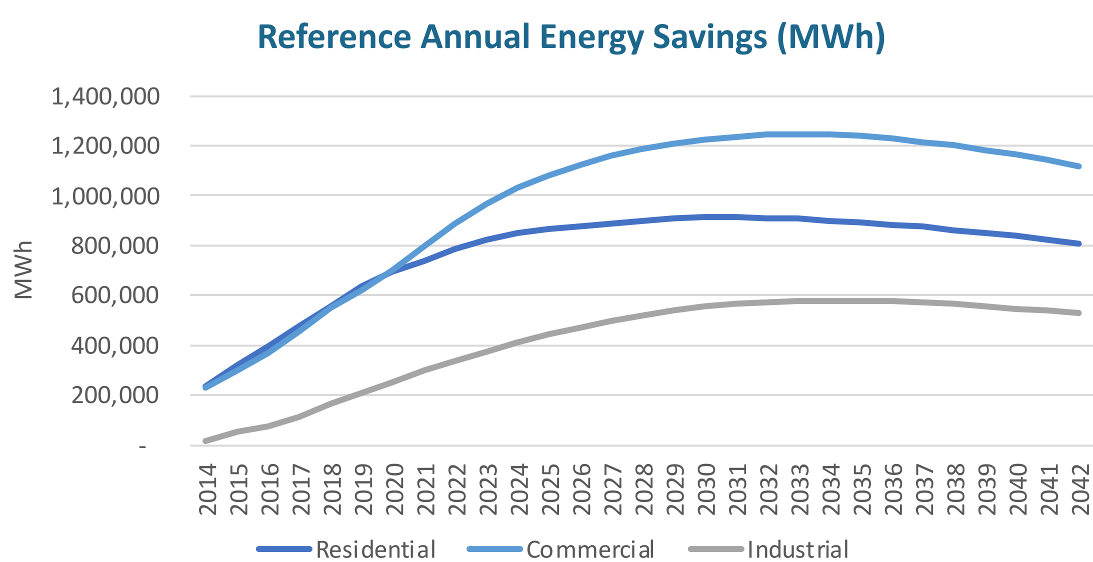


Chart 9: EAL Annual Energy Savings

Electrification and Conversions - The Reference Case forecast includes an assumption for sales growth as a result of programs sponsored by EAL to encourage electrification. The programs include electric forklifts, electric billboards, electricity-consuming services at truck stops, and agricultural irrigation pumps. Based on estimates from May 2020, these projects are expected to add nearly 440 GWh to commercial sales by 2042.

9 *Docket No. 07-085-TF*

Hourly Load Forecast

Methodology - The load forecast is the result of combining 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 customers, and EE. The monthly volumes are also used to develop the peak forecasts, which 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.

Reference Case Peak Comparison to Previous IRP - Since EAL's 2018 IRP cycle there have been decreases in the peak load forecast levels. This decrease is largely due to decreases in estimated levels of customer counts for residential and commercial customer classes and decreases in average UPC.

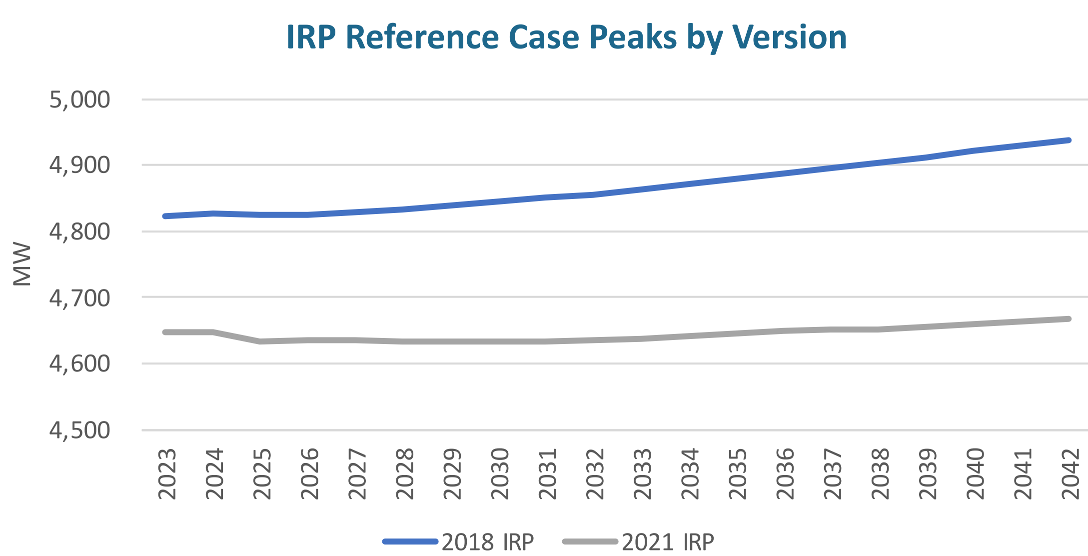


Chart 10: EAL IRP Reference Case Peaks by Version

IRP Scenarios - In previous IRP iterations, EAL would create "High" and "Low" sensitivity forecasts by adjusting the Reference Case forecasts up or down by a certain percentage to reflect a range of load possibilities. For this IRP iteration, a different approach was used in the development of the sensitivity forecasts for each Future by discerning the likely levers present based on the characteristics of each Future. Future 1 is the Reference Case forecast described above. See Table 7 below for a list of the levers and load effect in each Future scenario. Additional information for each Future used within the IRP analytics is described in Chapter 5.

Table 7: Load Levers by Future

	Item	Future 2: Current Environment Persists; Gas Centric	Future 3: Decentralized Focus; DSM and Renewables	Future 4: Economic and Renewables Growth
Traits	Policy Traits	Renewables are not encouraged; No incentives for BTM solar	Significant increase in BTM solar + battery; Increased EV adoption	Higher EV and non-EV electrification; Utility-scale solar favored over BTM solar
	Other Traits	Lower Res/Com growth; Flatter industrial growth	Healthy economic conditions; Res/Com/Ind growth	Higher economic growth and technology adoption
Results	Peaks Energy	Lower: Slower growth in customer counts offsets declines in DSM; Industrial growth softens	Higher: Increased EV adoption partially offset by increases in BTM solar	Higher: High EV adoption and building electrification, higher growth in Res/Com/Ind offset increased BTM solar
	Load Shapes	Same as Reference	Intra-day shifts due to higher EV and higher BTM solar	Higher with intra-day shifts due to higher EV and higher BTM solar
Inputs	BTM Solar	ICF Low	ICF High + Batteries	ICF High + Batteries
	Electric Vehicles (EVs)	Same as Reference (2075)	Higher (2055)	Higher (2040)
	Building Electrification	Same as Reference	Same as Reference	Higher
	DSM	Same as Reference	Same as Reference	Same as Reference
	Res. & Com. Growth	Lower	Reference	Higher
	Refinery Utilization from EVs	Same as Reference	Lower (opposite of EVs)	Lower (opposite of EVs)
	Industrial Growth	Lower	Same as Reference	Higher

In **Future 2**, environmental regulations are not heavily set, which then causes lower incentives for customers to invest in behind-the-meter solar and EE measures. The increases in energy usage from a lack of incentives for these energy saving programs is slightly offset by lower residential and commercial customer count growth. From the Reference Case, EAL does not have a significant amount of new industrial load that is included in the forecast and, as such, the lower industrial growth does not have a significant effect on this scenario for EAL's load forecast.

In **Future 3**, there are high incentives for energy saving measures such as behind-the-meter solar coupled with batteries. Offsetting these energy saving measures is an attempt to curb carbon emissions in other industries with high adoption of EVs whereby an assumed 100% of new vehicle sales are electric by 2055. Due to this increase in EV adoption, there is an inverse reaction from the refinery industry, decreasing their demand.

In **Future 4**, there are similar renewable incentives as in Future 3, although a large focus on solar energy is directed towards utility scale solar. Offsetting these energy saving measures is an attempt to curb carbon emissions in other industries by even higher adoption of electric vehicles whereby an assumed 100% of vehicle sales are electric by 2040. In addition, there is a high level of building electrification and industrial growth due to economic growth and new technology adoption.

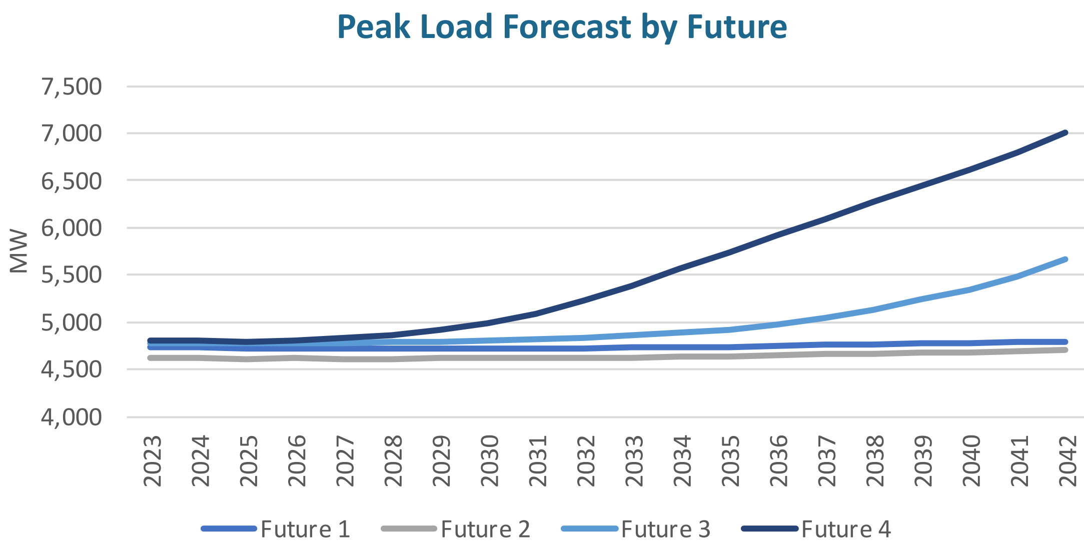


Chart 11: EAL IRP Peak Load Forecast by Future

Behind-the-meter Solar Generation - For all of the Futures scenarios, ICF produced behind-the-meter solar or solar plus battery impact estimates including a Reference Case level for Future 1, a Low Case level for Future 2, and a High Case level that was used for Future 3 and Future 4. Discussion of the methodology and assumptions for those can be found in Appendix G which contains the report produced by ICF.

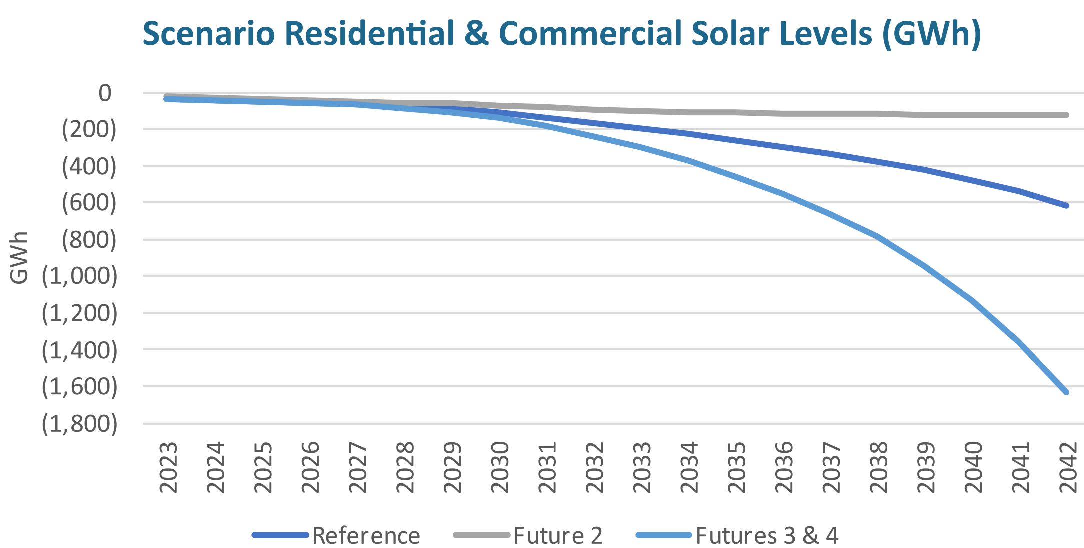


Chart 12: Residential & Commercial Solar Levels

Electric Vehicles - The Reference Case forecast includes an assumed level of additional energy consumption resulting from the adoption of EVs as well as growth in the numbers of total on-road vehicles over time as overall population is expected to continue to increase. The adoption over time is gradual based on an S-curve that assumes 99% of all light-duty vehicle sales will be EVs by 2075. The effects for EAL are based on the estimated proportional numbers of vehicles in each jurisdiction within Entergy's footprint.

Overall, the additional GWh volumes from the EV forecast in the Reference Case are minimal in the near term with growth to the residential and commercial consumption volume estimated to start increasing more in the mid-2030s. These levels were used for the EV forecast inputs for Future 1 and Future 2.

Futures 3 and 4 used more aggressive forecasts in which 100% of new vehicle sales are expected to be EVs by 2055 and 2040, respectively. These forecasts consider EV adoption for both light-duty vehicles and medium to heavy-duty vehicles as well as expected population growth and vehicle per capita increases. EV market share growth in new vehicle sales is based on an S-curve. Overall, the additional GWh volumes for the 2055 and 2040 EV forecasts are accelerating higher in the near-term compared to the Reference Case estimate and are adding 30% and 80% to EAL's sales totals by 2041, respectively.

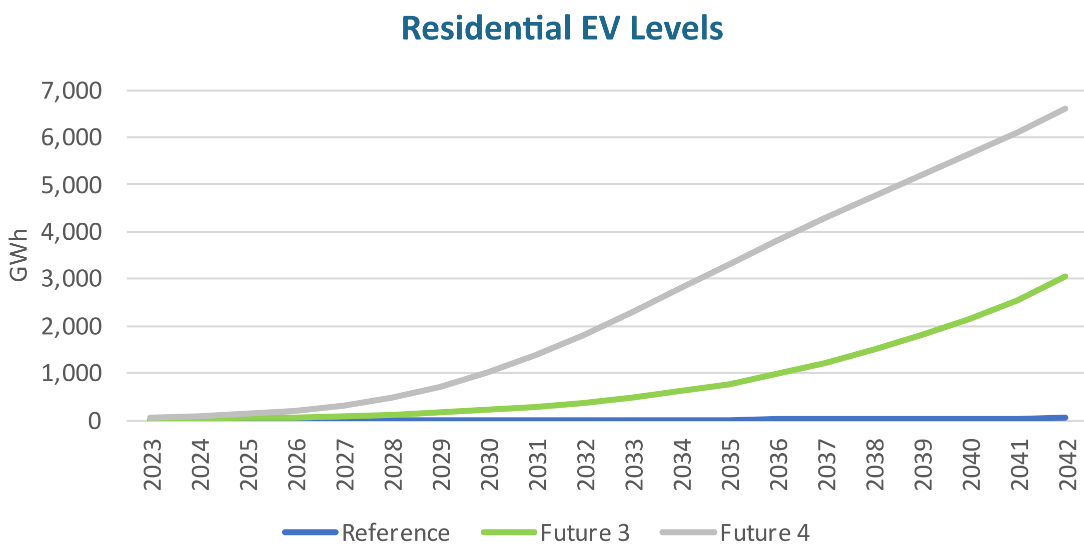


Chart 13: Residential EV Levels

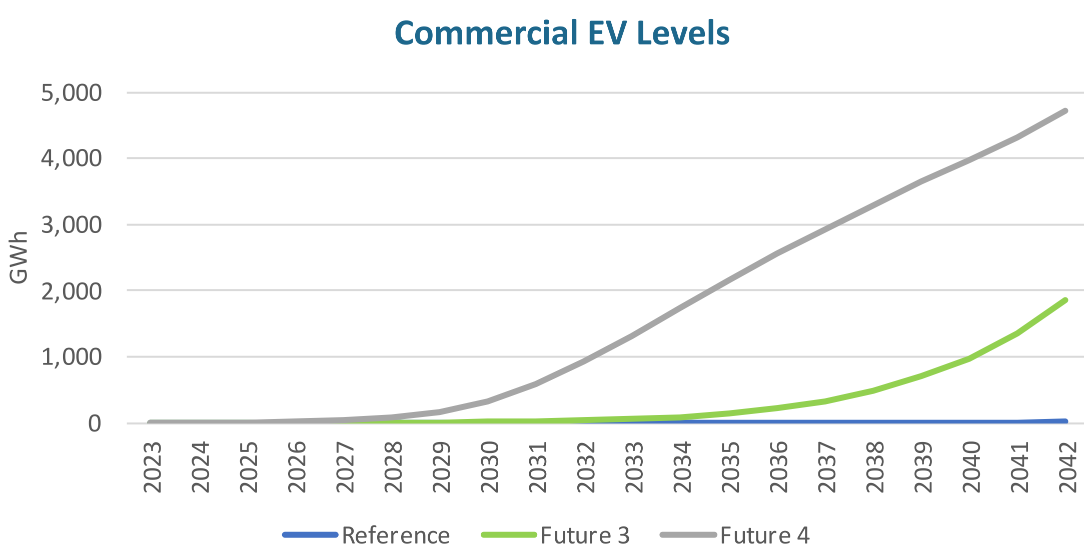


Chart 14: Commercial EV Levels

DSM and EE Measures - For details regarding DSM methodology, refer to the DSM section above. Due to EAL's already high levels of DSM/EE in the Reference case, EAL's levels for Futures 2, 3 and 4 were the same as the Reference Case levels. However, other load serving entities with lower levels of DSM/EE that were also modeled as part of this IRP had their assumed levels increased for Futures 3 and 4.

These savings represent energy savings from both existing (or previously implemented) programs that continue to provide MWh savings going forward as well as newly implemented savings going forward with the reference case savings providing ~2% sales savings by 2042.

Industrial Growth - Regarding industrial growth, Futures 2 and 4 have different levels of growth than the Reference Case and Future 3. Future 2 has lower industrial expectations due to the ongoing expansion of a current project being put on hold. Future 4, with higher expected industrial growth, includes additional industrial projects from the Economic Development pipeline.

Capacity Resource Options

Generation Technology Assessment - As part of its long-standing environmental stewardship and as the operator of one of the cleanest generation fleets in the nation, the commitment by Entergy to reduce utility emissions by 50% below 2000 levels and achieve net-zero emissions by 2050 requires a continued transformation of its generation portfolio. The IRP process evaluates available generation alternatives to meet customer energy needs in accordance with planning objectives, including the existing generation fleet, DSM, and supply-side resources. As part of this process, the Generation 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 reliability, affordability, and environmental stewardship.

Screening Approach and Technology Selection - In this IRP, EAL implemented a screening approach (see Figure 4) to evaluate the cost-effectiveness and feasibility of deployment of potential resources. This approach includes quantitative and qualitative criteria, including a technical and economic screening, leading to a final selection of supply-side resources to be included in capacity expansion models.

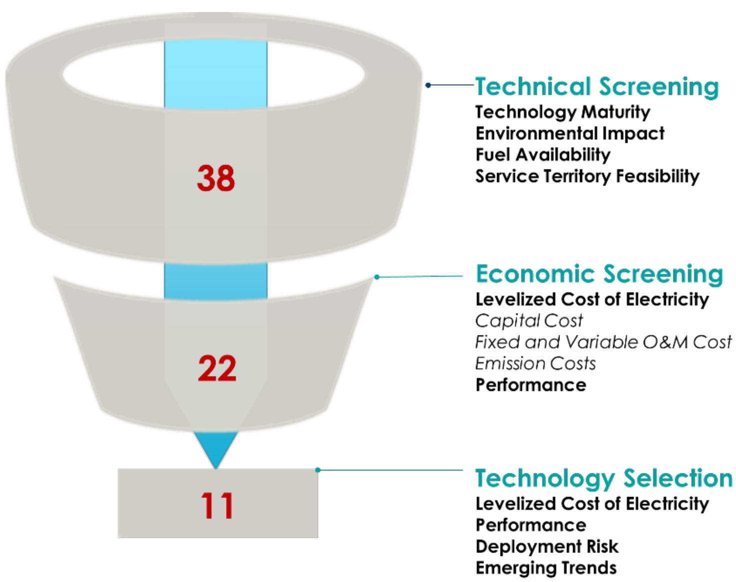
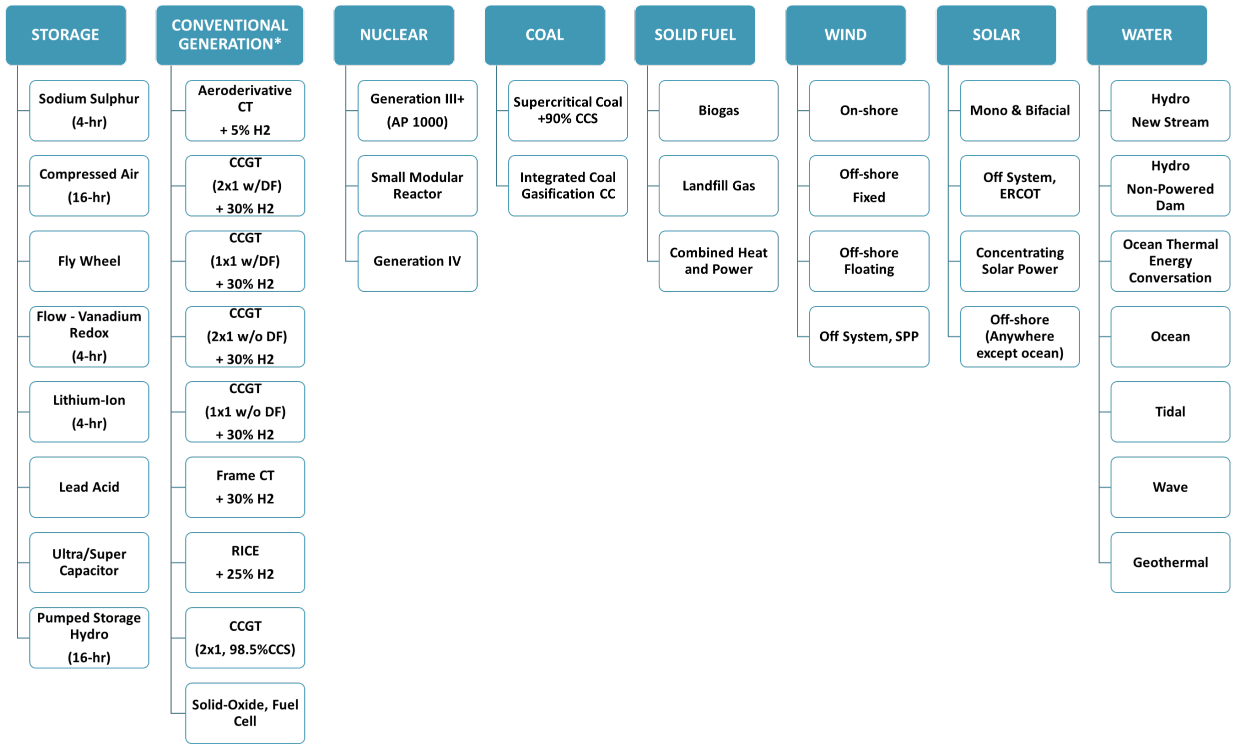


Figure 4: Screening Approach and Technology Selection Process

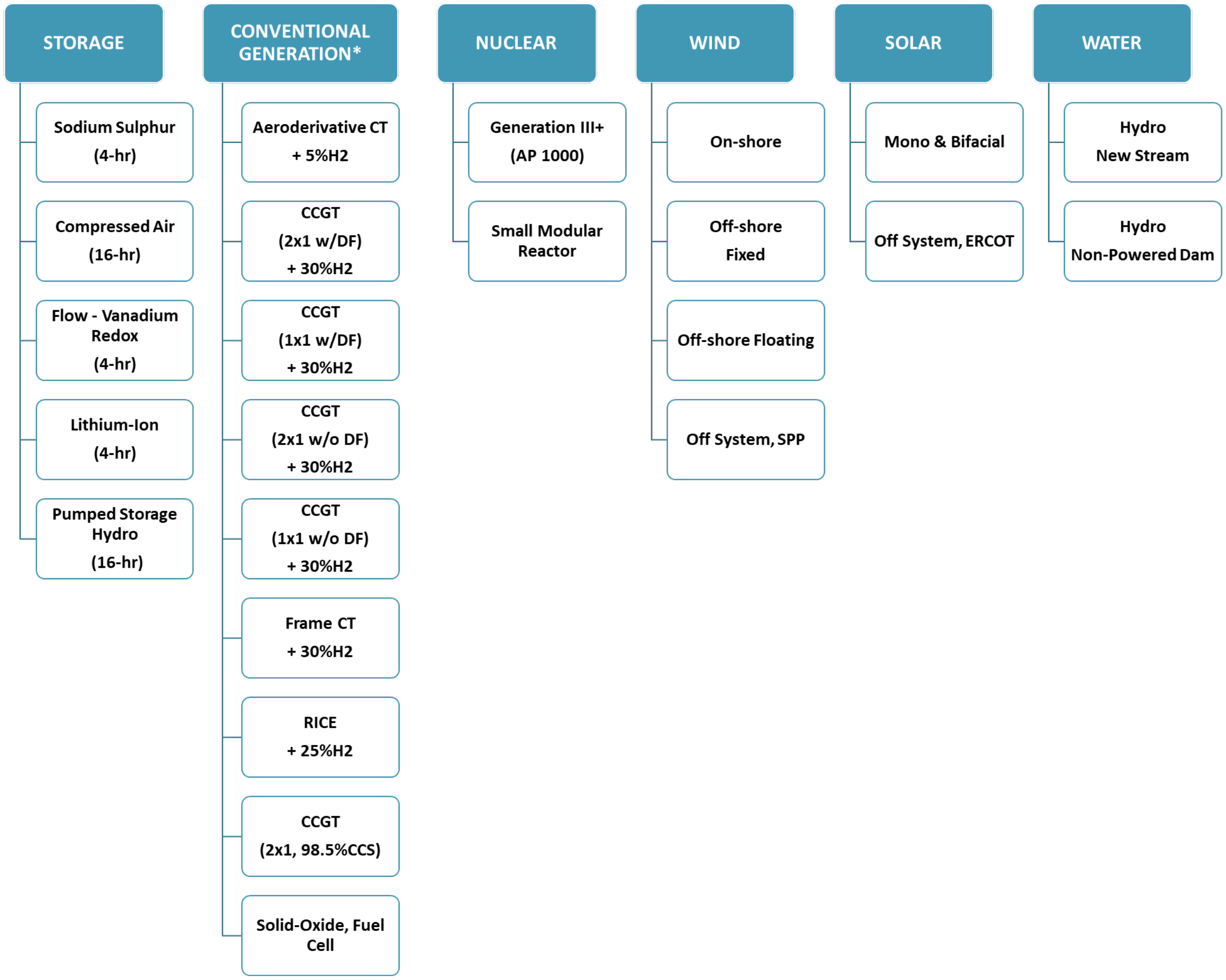
In the Technical Screening, we evaluated approximately 40 generation alternatives (see Figure 5) relative to technology maturity, environmental impact, fuel availability, and service territory feasibility.



*Any large-scale future gas resources will be hydrogen capable.

Figure 5: Potential Supply-Side Resource Alternatives (Technical Screening)

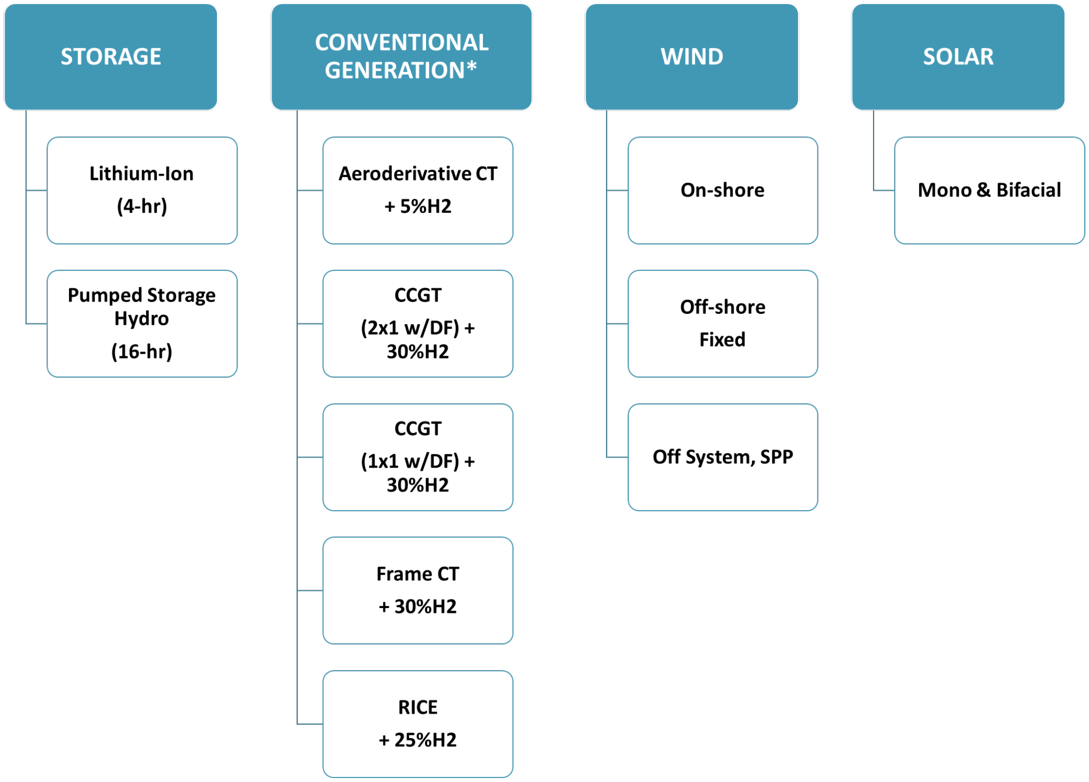
From the technical screening, 22 potential supply-side resources were selected for the economic screening. The economic screening process evaluated Levelized Cost of Electricity ("LCOE") metrics and key performance parameters and included renewable, energy storage, and hydrogen-capable conventional generation, as well as consideration for off-system wind and solar.



*Any large-scale future gas resources will be hydrogen capable.

Figure 6: Potential Supply-Side Resources Selected for Economic Screening

Following the economic screening, generation alternatives are narrowed down for inclusion in the capacity expansion models. The technologies selected are those deemed to be most feasible to serve EAL's generation needs based on comparative LCOE and performance parameters, deployment risks (cost / schedule certainty), and emerging commercial, technical, and policy trends. Notwithstanding the technologies specifically discussed in this IRP and included in the capacity expansion models, EAL continually evaluates existing, new, and emerging technologies to inform deployment decisions and a balanced generation portfolio that optimizes our planning objectives. Figure 7 lists the technologies selected for inclusion in the capacity expansion models.



*Any large-scale future gas resources will be hydrogen capable.

Figure 7: Supply-Side Resources Selected for Capacity Expansion Models

In the sections that follow, the selected technologies are discussed in more detail as well as the key emerging supply trends and implications that will shape the future of EAL's resource portfolio.

Conventional Generation w/Hydrogen Capability - Natural gas-powered generation technologies are a competitive supply-side resource alternative due to current relatively lower natural gas prices in EAL's service territory 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.

The long-term suitability of natural gas-powered generation technologies to meet planning objectives is largely dependent on natural gas prices and technology improvements, specifically, development of hydrogen co-firing capabilities (30% and eventually 100%) in support of EAL's sustainability objectives. EAL continues to track the development of hydrogen fueled power generation technologies as developers continue to make advancements. To successfully deploy these technologies, necessary advancements that need to be made, include, but are not limited to, combustor systems, Oxides of Nitrogen ("NOx") emissions reduction technologies, building hydrogen production and delivery infrastructure.

Table 8 below summarizes the natural gas-powered w/hydrogen capability generation alternatives resource assumptions, followed by a comparison of relative benefits of each alternative along with a description of each technology.

Table 8: Conventional generation with Hydrogen capable-powered resource assumptions[10]

Technology	Net Max Summer Capacity [MW-ac]	Installed Capital Cost [2021$/KW]	Fixed O&M [2021$/KW]	Variable O&M [20219/MWh]	Full HHV Summer Heat Rate[11] [Btu/kWh]
CT M501JAC + 30%H2	380	$935	$6.53	$14.45	9,192
1x1 CCGT M501JAC w/o Duct Firing + 30%H2	557	$1,237	$18.07	$3.40	6,271
2x1 CCGT M501JAC w/o Duct Firing + 30%H2	1,114	$1,077	$11.84	$3.41	6,271
Aero-CT LMS100PA + 5%H2	102	$1,735	$6.34	$3.14	9,397
RICE 7x Wartsila 18V50SG + 25%H2	129	$1,673	$22.89	$7.90	8,464

Combined Cycle Gas Turbines with 30% Hydrogen Firing Capability - CCGT plants included in the analysis are comprised of either one or two frame CTs and a steam turbine plant to recover the thermal energy from the CTs. This recovery of thermal energy provides an efficient heat rate and moderate flexibility. Driven by economies of scale and low gas prices, CCGT fleet operators have remained competitive with solar and wind in terms of $/MWh. CCGTs are suitable to efficiently serve as baseload and load-following with flexibility that is expected to continue to gradually improve. Hydrogen capability of CCGT plants is expected to be dependent on the technology development of hydrogen fired CTs. Depending on the relative hydrogen co-firing volume, system modifications would be required in the CT and steam system portions of the plant. In addition to CT modifications described below, potential modifications for a future hydrogen fueled CCGT plant could include, but is not limited to, modifications to the heat recovery steam generator system and post-combustion NOx control systems.

Combustion Turbine (Frame) with 30% Hydrogen Firing Capability - Combustion Turbines ("CT") have historically functioned as the technology of choice to support peaking application due to low gas prices and technological improvement. Renewable energy resources (e.g., solar), however, have continued to become more competitive for peaking applications. While renewable energy resources are expected to continue playing a larger part in peaking applications and a balanced generation portfolio, CTs can play a role in the integration of renewable energy by offering quick-start (~30 minutes) backup power when renewable sources cannot meet peak demands.

Many frame CT OEMs have experience with developing CTs capable of burning hydrogen at various blends. Current CT model hydrogen co-firing potentials are dependent upon their combustor designs, among other systems. 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. In addition to combustor modifications to achieve higher hydrogen firing rates other system modifications may need to be considered. These include fuel management systems, CT enclosure modifications, and control system updates.

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10 Natural gas-powered resources shown are hydrogen capable. Assumptions do not include costs associated with firing hydrogen.

11 Heat Rate in Full HHV Summer Condition. CCGT w/ Duct Firing heat rate is reflective of the base capacity without duct firing.

12 Source: EPRI, Technology Insights Brief: Hydrogen-Capable Gas Turbines for Deep Decarbonization, Palo Alto, CA:2019. 3002017544. https://www.epri.com/research/products/000000003002017544

Aeroderivative Combustion Turbine with 5% Hydrogen Firing Capability - AERO CTs have gained market share in applications for peak and intermittent power. The inherent flexibility of these technologies is a product of application from the aviation to the power industry. Traditionally, AERO CTs provide higher relative flexibility than (frame) CTs due to their hot start time (10 minute), minimum up/down time (5/5 minute), and ramp rate (102 MW/minute).

As is the case for Frame CTs, OEMs are continuing to develop AERO CT 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 5% with ongoing development of advanced combustor systems to enable higher blending rates, up to 100%.[13]

Reciprocating Internal Combustion Engine with 25% Hydrogen Firing Capability - As renewable penetration increases, RICE units will likely see increased deployment across North America to support the integration of renewable generation. RICE units can meet increased demand for reliability, dispatchable power can be placed online rapidly, and started/stopped frequently in response to changing load conditions. RICE units can ramp up to a full load in less than 5 minutes and operate at about 33% of nominal rating without compromising heat rate. On the other hand, CTs generally ramp at a slightly slower rate (10 – 15 minutes) and while they can turn down to approximately 40% of their rated output, heat rate is compromised. However, deployment of these resources may be slow due to actual forced outage rate being higher when compared to the expected forced outage rate. As experienced is gained within the domestic power markets, these are expected to improve.

Current RICE OEMs have claimed that existing models are able to accompany blends of hydrogen up to 25%. As is the case for CT and AERO CT OEMs, RICE technology developers are working on technology advancements and identifying necessary plant modifications which would be required to increase the hydrogen blend capability above 25%.[14] RICE OEMs are also working to develop models compatible with other potential low-carbon fuels such as ammonia, which is anticipated to be the renewable fuel of choice versus pure hydrogen.

Renewable and Energy Storage Systems - Over the past decade, driven by technology improvements resulting in lower costs and improved performance, renewable and energy storage technologies have been increasingly deployed around the world, particularly utility-scale solar, on-shore wind, and BESS. Renewable energy resources add fuel diversity to gas-centric resource portfolios that were once supported by coal generation.

When paired, renewable energy projects and energy storage technologies have zero net emissions and fuel costs and provide increased diversity to the 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 (e.g., on-peak production versus off-peak production).

Table 9 below summarizes the renewable and energy storage resource assumptions used in this IRP followed by a discussion on each technology.

13 Source: GE, Gas Power, Gas Turbines: Hydrogen Capability and Experience, A presentation to the DOE Hydrogen and Fuel Cell Technology, 9 March 2020, https://www.hydrogen.energy.gov/pdfs/06-Goldmeer-Hydrogen%20Gas%20Turbines.pdf

14 https://www.wartsila.com/docs/default-source/power-plants-documents/pps-catalogue.pdf

Table 9: Renewable and Energy Storage Resource Assumptions[15]

Technology [16]	Net Max Summer Capacity [MW-ac]	Installed Capital Cost [2021$/KW]	Fixed O&M [2021$/KW-yr.]	Capacity Factor [%]	Useful Life [yr.]	Factor [% in yr 2021]
Utility-scale Solar [17] (single axis tracking)	100	$1,160	$10.31 (U.S. Generic)	25.5% (MISO South)	30	25.5% (MISO South)
Onshore Wind	200	$1,476	$37.59 (U.S. Generic)	36.8% (MISO South)	25	36.8% (MISO South)
Offshore Wind	600	$4,323	$88.71 (GOM)	37.1% (GOM)	25	37.1% (GOM)
BESS [18] (Li-ion, 4hr)	50MW/ 200MWh	$1,260*/$1,435** (U.S. Generic)	$13.17 (U.S. Generic)	N/A	20	N/A
Pumped Storage Hydro (16-hr)	500MW / 8,000MWh	$2,799	$16.87 (U.S. Generic)	N/A	50	N/A

*without augmentation **with augmentation

Solar - Solar energy resources continue to rapidly increase. The US Energy Information Administration ("EIA") expects 15.4 GW of grid connected solar to be added in 2021, an increase of 3.4 GW relative to 2020 additions. From 2014 to 2020, utility-scale solar capital costs declined by more than 50% resulting primarily from declines in global PV module prices and economies of scale from larger project capacities. Beyond 2030, project costs are expected to continue to decline, albeit at a slower pace than in the prior decade as the industry continues to mature. In addition to technology cost declines realized as the industry matures, new module designs and configurations continue to be developed to improve efficiency and reduce overall costs. Over the next 30 years, costs are expected to decrease for both solar and wind, and renewable resources are expected to become a larger share of the generation portfolio mix. However, because solar energy production is variable in nature, grid flexibility and quick start backup 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.

Onshore Wind - Onshore wind continues to be and expected to remain one of the fastest growing resources in the US. Onshore wind capital costs continue to decline. Between 2014 to 2020, onshore wind capital cost decreased by approximately 18%, resulting primarily from turbine cost reductions and economies of scale from larger turbines and higher capacity projects. Larger wind turbine blade diameters have rapidly entered the market, and in 2010 there were no projects which utilized blades 115 meters or larger.[19] However, in 2020, 91% of the installed wind turbines were 115 meters in diameter or larger. With the wind industry being more mature and established versus the solar industry, any cost improvements are expected to be incremental as developers improve efficiency and as larger turbine model market penetration increases. As is the case for solar energy, because wind energy is also variable in nature, this requires considerations to be combined with other resources.

15 Source: IHS 12.2019 (Solar & Wind): All rights reserved. The use of this content was authorized in advance. Any further use or redistribution of this content is strictly prohibited without prior written permission by IHS Markit. IHS 01.2020 (BESS): All rights reserved. The use of this content was authorized in advance. Any further use or redistribution of this content is strictly prohibited without prior written permission by IHS Markit.

16 Solar, wind, and BESS fixed O&M excludes property tax and insurance. Solar includes inverter replacement in year 16.

17 Solar capacity value is representative of year 1. Further explanation of solar capacity value as evaluated in the 2021 EAL IRP is summarized in the "Portfolio Design Analytics" section.

18 BESS round-trip efficiency is assumed as 86%. BESS installed capital cost includes module replacement in year 11. BESS capacity credit is representative of year 1. Modeling assumes 2% annual degradation, returning to full output in year 11 due to module replacements.

19 Source: Lawrence Berkley National Lab, https://emp.lbl.gov/wind-technologies-market-report/

Offshore Wind - Offshore wind continues to be a developing industry within the US with most of the activity occurring off the US East Coast. Internationally, offshore wind industries are considered mature given widespread deployment Europe. In 2016, the 30 MW Block Island Wind Farm off the coast of Rhode Island became the first US commercial offshore wind farm. There are several US offshore wind projects in various stages of development. The Bureau of Ocean Energy Management has proposed to identify potential wind energy areas and hold the first federal lease auction in the Gulf of Mexico in 2022. Offshore wind technologies are comprised of both fixed and floating foundations. The conditions in the Gulf of Mexico are expected to be able to utilize fixed foundation turbines, which are relatively more mature than floating foundations and are suitable for deployment in areas of shallower depth. As the US offshore wind market continues to mature and additional projects achieve commercialization, additional technology cost and performance improvements are expected. As is the case for onshore wind technology development, OEMs are continuing to develop larger and more efficient systems which result in cost reductions due to economies of scale. Offshore turbine capacity has increased significantly in recent years with OEMs offering larger diameter systems in the range of 14 MW per turbine. Assuming the US offshore wind industry evolves like solar and onshore wind industries, offshore wind could potentially become a significant contributor to the energy system.

Battery Energy Storage Systems - From 2015 to 2020, utility-scale BESS capital cost declined by 180% with battery modules contributing to two-thirds of the decline (ATB NREL). As illustrated in Figure 8, forecasts suggest costs will fall by another 78% by 2030, partially attributable to a decline in battery prices. Current use cases of battery technology are applied to discharge times that are four-hour or less to provide peak shaving capabilities. When efficiently integrated into the electric grid, BESS has 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 shift some solar energy production to late afternoon hours, mitigating the ramping requirement created by the decline in solar energy production.

In addition to the above, BESS have the potential to offer stacked values 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. The spread (i.e., cost difference) between the time periods creates 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, qualify for MISO's capacity market. As the industry learns more and further deploys this technology, safety considerations and practices are becoming clearer, including fire prevention. Disposal or recycling of Li-ion batteries are classified as hazardous waste and requires further research, whereas over 90% of materials can be recaptured with nothing landfilled for solar PV.

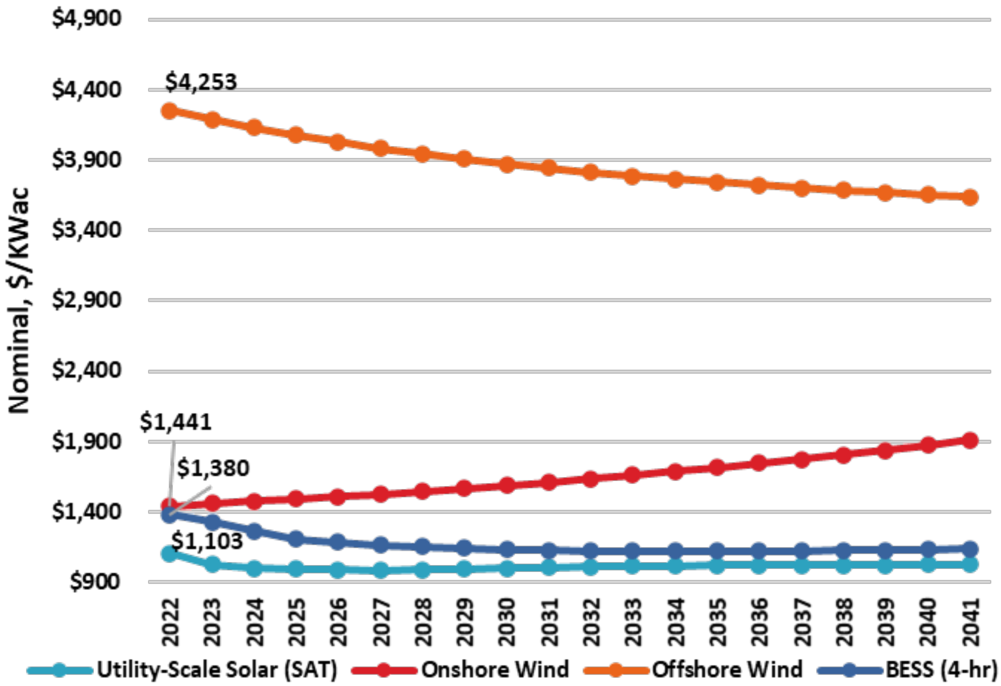

Figure 8[20]: Renewable and Energy Storage Installed Capital Costs[21]

Pumped Storage Hydroelectric - Pumped storage hydroelectric remains the largest source of grid connected energy storage in the US and can provide large-scale, long duration energy storage. In 2019, the US had approximately 22.9 GW of pumped storage hydroelectric capacity.[22] 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 which turns a generator to convert the energy into electricity. 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.

Summary of Emerging Supply Trends and Implications - Advancement in generation technologies provides new opportunities to meet customer needs reliably and affordably, 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 have emerged as viable economic alternatives and are expected to continue to improve through the planning horizon. 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.

20 Utility-scale solar shown in single-axis tracking. Utility-scale solar size: 100MW, on-shore wind size: 200MW, 4-hr BESS size: 20MW. Utility-scale solar life: 30-year, on-shore wind life: 30-year, 4-hr BESS life: 20-year

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22 Source: EIA, https://www.eia.gov/todayinenergy/detail.php?id=41833

Looking ahead, EAL will endeavor to maximize clean energy options while balancing reliability, affordability, and environmental stewardship. Efforts will include renewable energy as well as modern resources with optionality to be powered with hydrogen and/or retrofitted with carbon capture and sequestration technology.

Potential DSM Resource Assessment

As part of the development of the 2021 IRP, EAL engaged a third-party consultant, ICF International, Inc., ("ICF") to conduct an independent forecast of the achievable potential of DR program types and DER technologies on the utility's system. DR programs and DER technologies were selected for analysis based on their relevance to utility planning practices nationwide and their specific relevance to EAL's customers and planning processes.

The resulting ICF forecast is being utilized by EAL to provide hourly inputs for its IRP modeling process over the period 2023 through 2042. ICF produced forecasts for three scenarios: high levels of program or technology adoption, reference levels of adoption, and low levels of adoption.

The starting point of ICF's forecasts for EAL was the selection of relevant DR programs and DER technologies. Among DR, ICF analyzed event-based program types, separated for residential, commercial, industrial, and agricultural customers, as well as one existing rate-based DR program. For DER, PV and battery storage technologies were separated by residential and C&I adoption.

For each selected DR program and DER technology, ICF produced hourly EAL net load forecasts covering 20 years for each of three scenarios: low adoption, reference (expected) adoption, and high adoption. The reference scenario reflects ICF's judgment as to the level of adoption that is most likely to occur given EAL and external market information available at the time of the study.

As described in detail later in this IRP, these incremental DR portfolios were included in Aurora's Capacity Expansion Tool for economic selection along with supply-side resource options. Each portfolio included an assumed start date, program measure life, hourly demand profile, and annual program costs.

Environmental

Another key driver to changes in future resource needs is the various environmental regulations that have the potential to affect 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 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 are not known fully at this time.

Regional Haze Rule – The current Regional Haze Program was established as part of the 1990 amendments to the Clean Air Act. This program is designed to protect visibility at certain federally designated Class I areas and to return visibility conditions at 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 to 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. Many states, including Arkansas, continue to prepare their second planning period SIP for submittal to the EPA. On July 8, 2021, the EPA issued a memorandum to provide states with additional information and feedback to consider for supporting their SIP development. In that same memorandum, EPA recognizes that while some states have already submitted final SIPs, others are at different stages of the SIP development process. While Arkansas continues to evaluate and consider the EPA's recent memorandum along with feedback received from other various stakeholders, it is anticipated the state will be submitting a final SIP to the EPA either late in 2021 or early in 2022.

Ultimately, two separate SIPs stemmed from the regional haze first planning period which affect EAL, a Phase I SIP which addressed NOx emissions from electric generating units ("EGUs") and a Phase II SIP which primarily addressed Sulphur Dioxide ("SO2") emissions.

The Phase I SIP was finalized by the Arkansas Department of Environmental Quality ("ADEQ") in October 2017 and approved by the EPA on February 12, 2018. This SIP replaced source-specific Federal Implementation Plan ("FIP") NOx limits for White Bluff, Independence, and Lake Catherine with an obligation to meet the Regional Haze program obligations for NOx via compliance with the Cross-State Air Pollution Rule ("CSAPR") ozone-season NOx cap-and-trade program.

The Arkansas Phase II SIP was finalized by ADEQ in August 2018 and approved by the EPA on September 27, 2019. This SIP replaced source-specific FIP SO2 emission limitations for White Bluff and Independence with a requirement that each unit at these plants achieve SO2 emission reductions via combustion of low-sulfur coal. In addition, the SIP requires that White Bluff cease to burn coal by December 31, 2028.

It currently is anticipated that the regional haze second planning period SIP will be disseminated for public notice and comment later in 2021. Based on the EPA's guidance on regional haze state SIPs for the second planning period, which was issued in August 2019, White Bluff is excluded from further analysis in the second planning period due to the federally enforceable cease-to-use coal date of December 31, 2028. Like White Bluff, Independence has a federally enforceable cease-to-use coal date of December 31, 2030 and Unit 4 of Lake Catherine must cease operation by December 31, 2027 as approved in the Settlement Agreement between EAL, the Sierra Club, and the National Parks Conservation Association that was entered by the U.S. District Court of the Eastern District of Arkansas on March 11, 2021. The limited remaining useful life of each of these units will be taken into consideration by the state in the second planning period SIP development.

Cross-State Air Pollution Rule (CSAPR) – The EPA finalized the CSAPR in 2011 under the "good neighbor" provision of the Clean Air Act 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 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 which programs their respective state is required to 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 which revised 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 the revised CSAPR update rule, which was published in the Federal Register on April 30, 2021. This rule establishes a new CSAPR Group 3 which is comprised of 12 of the 21 CSAPR Group 2 states. Arkansas remains 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. While the reduction in the size of the Group 2 emission allowance market may impact allowance pricing, any changes are not expected to result in a significant impact for EAL's generating assets in Arkansas.

Coal Combustion Residuals Rule – EAL operates Coal Combustion Residuals ("CCR") units at both 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 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 ("WIIN Act") was signed into law, which authorizes 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 provisions of the CCR rule that relate 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. Both the White Bluff and Independence facilities have ceased using their unlined ponds and have initiated clean closure. EAL believes that on-site disposal options will continue to be available at its facilities, to the extent needed for CCR that cannot be transferred for beneficial reuse.

The CCR rule allows states to seek approval from EPA for state CCR permit programs. Arkansas has not submitted a CCR permit program proposal to the EPA to date.

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 which 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 the requirements for bottom ash transport water.

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 establish an ELG zero-discharge compliance date of December 30, 2023 for bottom ash transport water.

On October 13, 2020, EPA issued a further revision to the final rule which would allow for limited discharges of bottom ash transport purge water under certain defined circumstances.

The new bottom ash handling systems placed into service at White Bluff and Independence in 2020 are designed to achieve zero discharge of bottom ash transport water and operation of these systems is expected to ensure compliance with the applicable ELG requirements.

316(b) Cooling Water Intake Rule – Section 316(b) of the Clean Water Act requires the EPA to issue regulations on the design and operation of water intake structures to minimize adverse impacts on aquatic organisms. On August 15, 2014, the EPA issued the final 316(b) Rule for existing electric generating facilities that use one or more cooling water intake structures to withdraw water from waters of the US and have a cumulative design intake flow of greater than 2 million gallons per day ("MGD"). This rule applies to the White Bluff, Independence, Lake Catherine, and Hot Spring Plants because each operates a raw water intake structure. The rule requires the implementation of the Best Technology Available ("BTA") to minimize adverse impacts which must be approved by the permitting authority (ADEQ). 316(b) applicable requirements including the approved BTA for each plant have been addressed in the current NPDES permits issued by ADEQ.

Potential GHG Regulation – EAL's Point of View ("POV") is that national carbon regulation for the power generation sector will occur; however, the timing, design, and outcome of any carbon control program are highly uncertain. The EPA issued the final Clean Power Plan ("CPP") on October 23, 2015. The final plan targeted emissions from electric generators utilizing three building blocks (coal plant heat rate improvements, an increase in dispatch of NGCC units, and an increase in zero and low-emitting generation) to establish state-by-state emission rate limits, expressed in terms of lbs. CO_2/MWh.

On February 9, 2016, the US Supreme Court issued a stay of the CPP. On March 28, 2017, President Trump signed an executive order directing the EPA administrator to review the CPP. Formal review of the CPP was announced by the EPA on April 4, 2017, and a proposal to repeal the CPP was published by the EPA on October 10, 2017. On

August 31, 2018, the EPA published the proposed Affordable Clean Energy ("ACE") Rule, which was intended to replace the CPP.

The final repeal of the CPP and publication of the final ACE rule occurred in parallel on July 8, 2019. The ACE rule required subject coal-powered generating facilities, including Independence and White Bluff, to conduct an evaluation of the technical and economic feasibility of potential Heat Rate Improvement (HRI) projects which could potentially be implemented to reduce the CO_2 emission intensity of the electric generating units. EAL performed this analysis for Independence and White Bluff, and it was submitted to the ADEQ for its review on April 17, 2020.

The ACE rule was subsequently vacated and remanded to the EPA by a decision of the DC Circuit Court issued on January 19, 2021. In response to this court decision, the EPA issued a memorandum on February 12, 2021 which indicated that the EPA did not expect states to take any further action to implement the ACE rule.

At this time, EAL expects that the current administration will likely propose some form of nation-wide greenhouse gas regulation for emissions from existing electric generating units, but the exact timing or substance of any such proposal remains to be determined.

CO_2 Price Forecasts – EAL's CO_2 point of view is based on the following four cases:

1. A "$0/ton CO_2 price" Low Case represents either no program or a program that requires only "inside-the-fence" measures at generating facilities, such as efficiency improvements, that do not result in a tradable CO_2 price but may require some capital expenditures.
2. A "CPP with Delay" Mid Case reflects a 6-year delay in the implementation of the Clean Power Plan, consistent with the March 2017 Executive Order and subsequent agency actions.
3. A "National Cap and Trade" High Case that assumes a program that begins in 2028 and targets an approximately 80 percent reduction from 2005 sector emissions by 2050.
4. A "CO_2 Price" High Tax Case that assumes a national carbon tax based on the Climate Leadership Council's Carbon Dividend proposal.

After deriving projections of CO_2 allowance prices for each of these four cases, the following probability weightings were applied to each to arrive at the EAL's point of view assumption:

Table 10: CO_2 Probability Weightings

Probability	2020	2022	2025	2026	2028	2030	2035	2040	2050
No CO_2 Case	100%	95%	95%	80%	62%	45%	43%	30%	15%
Mid Case	0%	5%	5%	20%	35%	50%	40%	40%	40%
High Case	0%	0%	0%	0%	0%	0%	2.5%	15%	30%

The low case assumes no CO_2 price, the reference case assumes the EAL's point of view CO_2 price, and the high case assumes the CO_2 Price High Tax case as shown below:

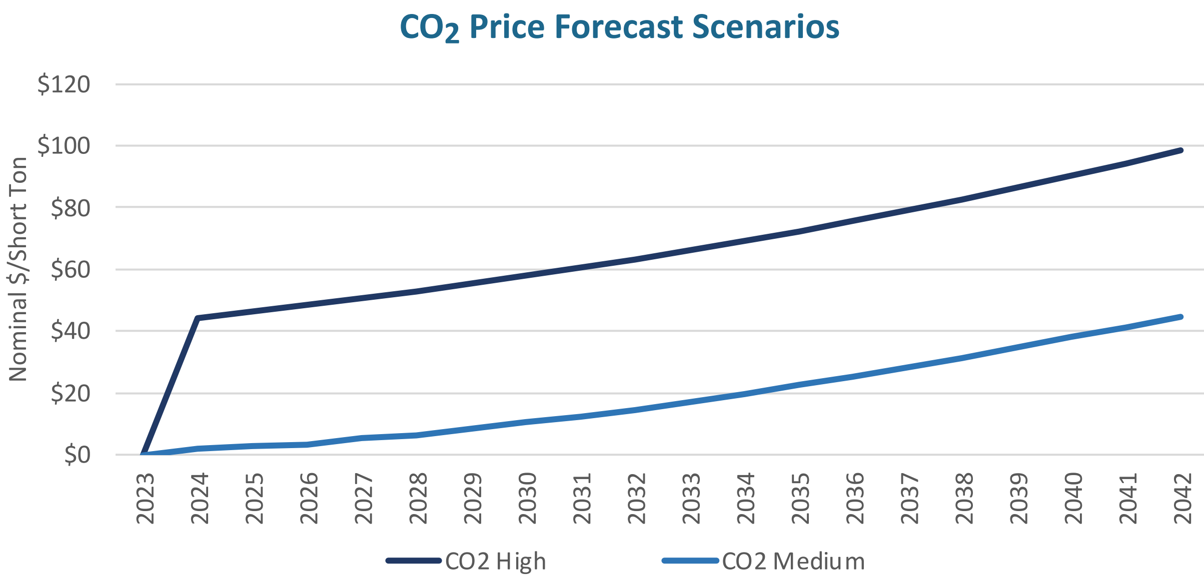


Chart 15: CO_2 Price Forecast Scenarios

Fuel Price Forecasts

Natural Gas Price Forecasts - Three natural gas price forecasts were used in the development of the 2021 IRP. The near-term portion (year one) of the natural gas price forecast is based on NYMEX Henry Hub forward prices, which are market future prices as of December 2020. 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 point of view regarding future natural gas prices utilizes a consensus across several independent, third-party consultant forecasts. Gas markets are influenced by a number of complex forces; consequently, long-term natural gas prices are highly uncertain and become increasingly uncertain as the time horizon increases. Therefore, EAL presents and uses three alternatives for natural gas prices to address this uncertainty. In levelized 2023 dollars per MMBtu throughout the IRP period, the reference case natural gas price forecast is $3.64, the low case is $2.39, and the high case is $4.97.

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

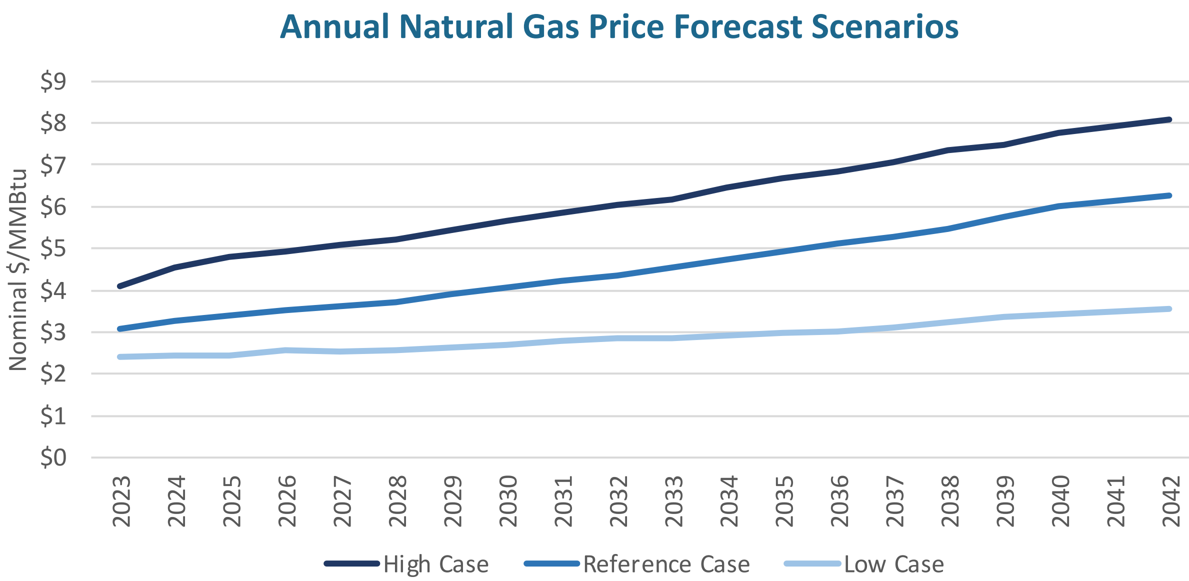


Chart 16: Natural Gas Price Forecast

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, as well as 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 2023 dollars per MMBtu throughout the IRP period, the delivered coal price is $2.56 in the reference gas case, $2.37 in the low gas case, and $2.60 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.

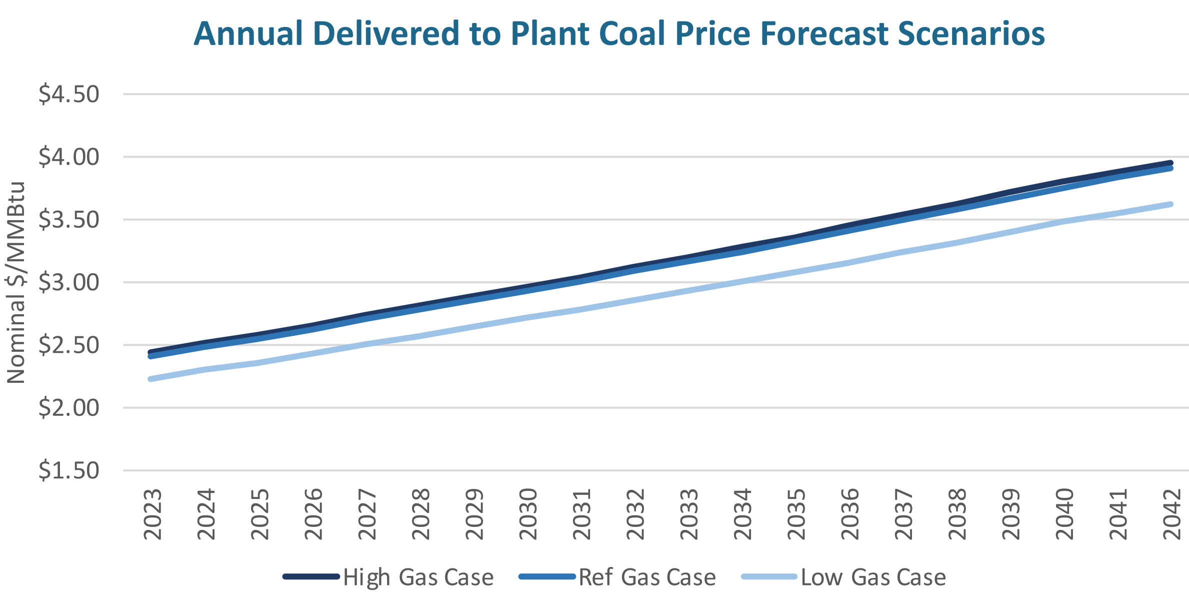


Chart 17: Coal Price Forecast

Chapter 5

Modeling Framework

Summary

- As with the 2018 IRP, a futures-based approach was employed for the 2021 IRP. Four futures were modeled to bookend a broad range of uncertainties.
- Four sensitivity cases that assume earlier than scheduled cease-to-use coal dates at White Bluff and Independence were modeled per Stakeholder requests.
- Renewable capacity accreditation was aligned with MISO MTEP methodology.

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. This is done because long-term outcomes are uncertain for many input assumptions. Futures are described as different combinations of assumptions that could plausibly coexist together resulting in a range of market outcomes. The 2021 IRP considers the following four Futures:

Table 11: IRP Futures Assumptions

	Future 1	Future 2	Future 3	Future 4
Peak / Energy Load Growth	Reference	Reference	Low	High
Natural Gas Prices	Reference	Low	Low	High
DR/EE/DER Additions	Medium	Low	High	Medium
Market Coal Retirements	Reference (60 years)	Reference (60 years)	Accelerated (55 years)	Accelerated (50 years)
Market Legacy Gas Fleet Retirements	Reference (60 years)	Reference (60 years)	Accelerated (55 years)	Accelerated (50 years)
Magnitude of Coal & Legacy Gas Deactivations	23% by 2030 69% by 2040	23% by 2030 69% by 2040	49% by 2030 84% by 2040	67% by 2030 89% by 2040
CO_2 Tax Assumption	Reference	None	Reference	High
EAL Existing CCGTs	Reference (30 years)	Extend (through 2043)	Reference (30 years)	Reference (30 years)
EAL Nuclear Capacity Availability	Reference	Reference	Extended (past 2043)	Reference

Future 1: Progression Towards Resource Mix - Future 1 is defined by reference load growth and gas prices, DSM additions, and CO2 reductions targets. Peak load and energy growth are dampened by moderate DER and DSM penetration. Coal economics continue to face pressure from low natural gas prices and renewable and natural gas technologies play balanced roles in replacing retiring capacity.

Future 2: Current Environment Persists - Future 2 is defined by reference load growth, low gas prices, low DSM additions, and no CO2 reduction target. The slower deployment of DERs and DSM contribute to recover in peak load and energy projections. Continued political support for domestic gas production leads to sustained low gas prices. Additionally, a low mandate on carbon reductions allows natural gas-powered generation to comprise the majority of capacity additions, complemented by some renewable energy projects.

Future 3: Decentralized Focus - Future 3 is defined by low load growth and gas prices, and high DSM additions. Social trends and corporate initiatives shift, demanding high penetration of DERs, DSM, and EE. Non-EAL coal plants are driven to retire earlier than anticipated resulting from moderate carbon mandates. Additionally, the increased levels of EE, renewable resources, and DERs coupled with a lower level of demand growth lessen the need for natural gas-powered generation as compared to the reference case. However, there is still a considerable need for natural gas-powered capacity to replace coal generation retirements.

Future 4: Economic Growth with Emphasis on Renewable Energy - Future 4 is defined by high load growth, high natural gas prices, and high CO2 tax assumption. Peak load and energy projections recover due to economic growth. Political and economic pressure on coal and legacy gas plants accelerates retirements. Renewable energy resources will largely fill the load growth needs due to the slow expansion of natural gas pipeline infrastructure, economics, and state pressure for fuel diversity.

Sensitivities - As EAL continues to transform its generation portfolio to be cleaner and more sustainable, EAL expects that the recent trend continues with a focus on renewable resources due to customer interest, environmental benefits, improving cost-effectivess and numerous benefits that renewable resources can provide. To that end, EAL has developed portfolio sensitivities that assume White Bluff and Independence generating units cease to use coal earlier than EAL's current planning assumption. These senstivity portfolios are evaluated under Future 1 to estimate total relevant supply costs for each portfolio. The resulting capacity deficits in each sensitivity are replaced with a mix of solar, wind and BESS capacity. The four sensitivites that will be run under Future 1 are:

Table 12: Sensitivity Portfolios

	Sensitivity Portfolio 1: White Bluff Cease to Use Coal	Sensitivity Portfolio 2: White Bluff Cease to Use Coal	Sensitivity Portfolio 3: Independence Cease to Use Coal	Sensitivity Portfolio 4: Base Deactivation
White Bluff Unit 1	2026	2026	2028	2028
White Bluff Unit 2	2023	2026	2028	2028
Independence Unit 1	2030	2030	2025	2030

As discussed in detail in the previous sections, environmental regulations are an important factor to consider in resource planning. The U.S. District Court for the Eastern District of Arkansas approved a Settlement Agreement between EAL, Sierra Club and the National Parks Conservation Association in March 2021 in which EAL agreed to cease using coal at White Bluff and Independence by the end of 2028 and 2030, respectively, and to deactivate Lake Catherine 4 by the end of 2027.

With consideration of the limited remaining useful life of White Bluff and Independence, it is highly improbable that any further emission controls will be required. For the 2021 IRP, no further emissions controls were assumed because EAL included the commitment to cease to use coal by December 31, 2028, for White Bluff and December 31, 2030, for Independence, by assuming the units deactivate before or on that date as shown in Table 12.

Renewables Capacity Credit - The solar capacity credit assumption used in the IRP aligns with the solar assumption detailed in the 2021 MISO Futures Report. Under this assumption, all solar units have a 50% capacity credit at the beginning of the study period and then decreases by 2% starting in year 2026, until the capacity credit reaches a minimum of 30%.

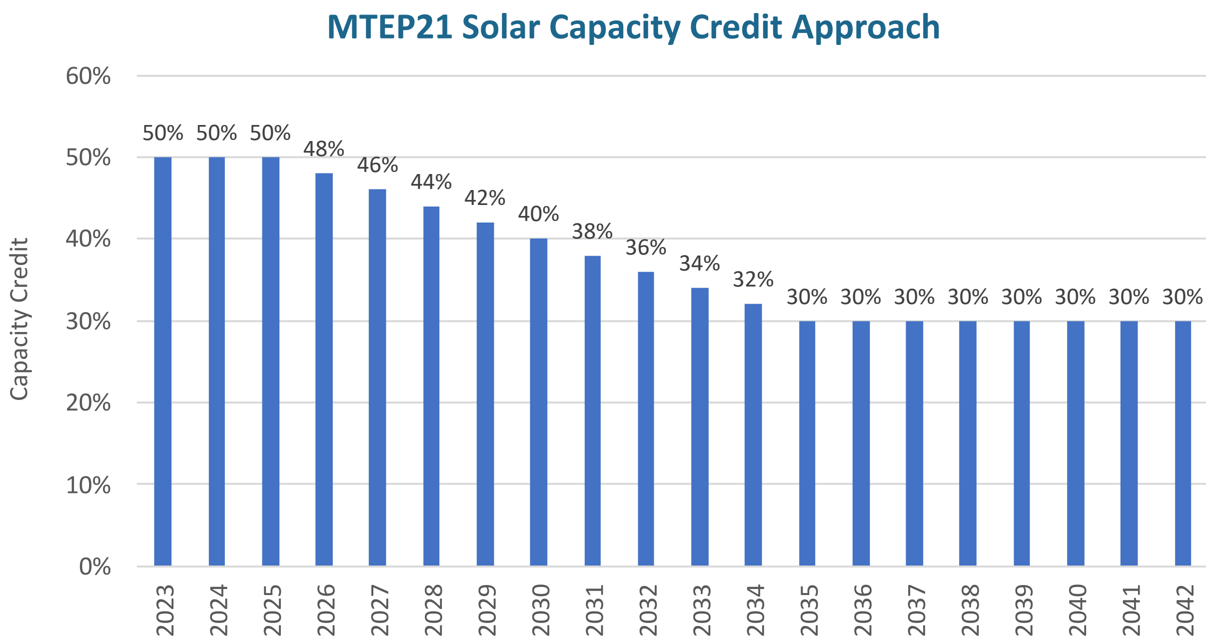


Chart 18: MTEP21 Solar Capacity Credit Approach

The 16.6% wind capacity credit assumption used in the IRP is sourced from MISO's 2020/2021 PY Wind & Solar Capacity Credit Report. The MISO system-wide wind capacity credit is calculated using a probabilistic approach to find the Effective Load Carrying Capability ("ELCC") value for all wind resources in the MISO footprint.

Market Modeling

The development of the 2021 IRP relied on the Aurora[23] Energy Market Model to develop optimized portfolios and generate market prices ("LMPs") for the MISO energy market and for 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, available DSM program alternatives, 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.

The first step within the market modeling process is to utilize Aurora to perform capacity expansion to develop a projection of the future market supply based on the specific characteristics of each future. Once the market supply resources are determined for each future, energy market simulations are performed, which results in hourly energy prices for each of the four futures. This projection encompasses the power market for the entire MISO footprint (excluding EAL). MISO (excluding EAL) projected power prices are extracted from the energy market simulations to assess potential portfolio strategies for EAL within each future. Charts 19 – 26 below show the projected market supply for each of the four futures. Chart 27 represents projected annual MISO (excluding EAL) power prices for each future.

23 The Aurora model is the primary production cost tool used to perform MISO energy market modeling and long-term variable supply cost planning for EAL. Aurora supports a variety of resource planning activities and is well suited for scenario modeling and risk assessment modeling through hourly simulation of the MISO market. It is widely used by a range of organizations, including large investor-owned utilities, small publicly owned utilities, regulators, planning authorities, independent power producers and developers, research institutions, and electric industry consultants.

Future 1 Annual MISO Market Non-EAL Installed Capacity

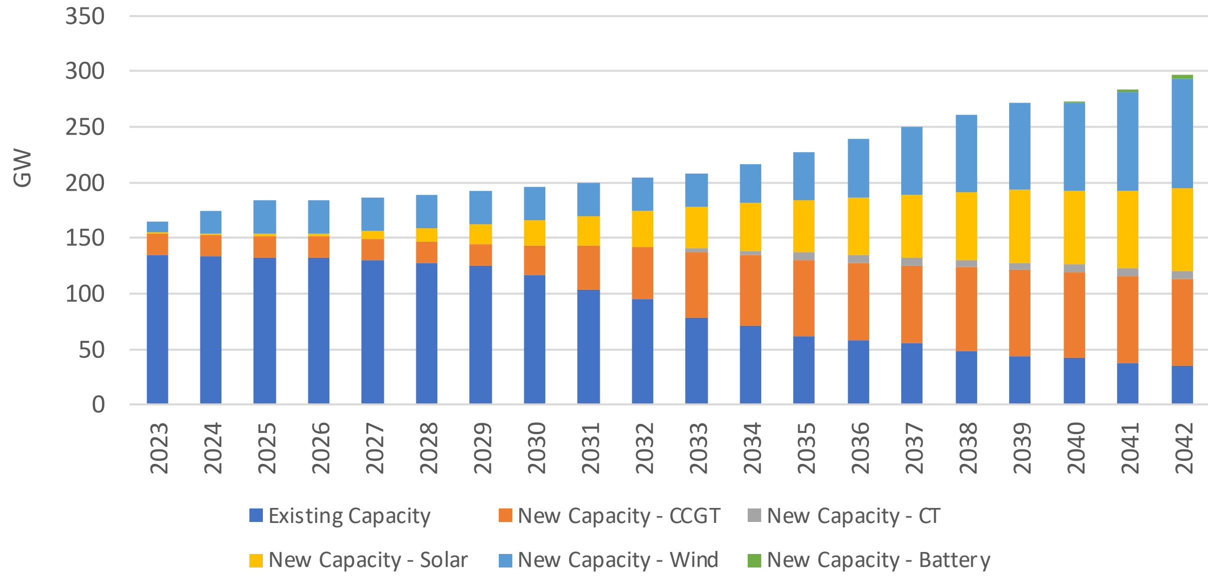


Chart 19: Future 1 Projected Future Market Installed Capacity

Future 1 Annual MISO Market Non-EAL Effective Capacity

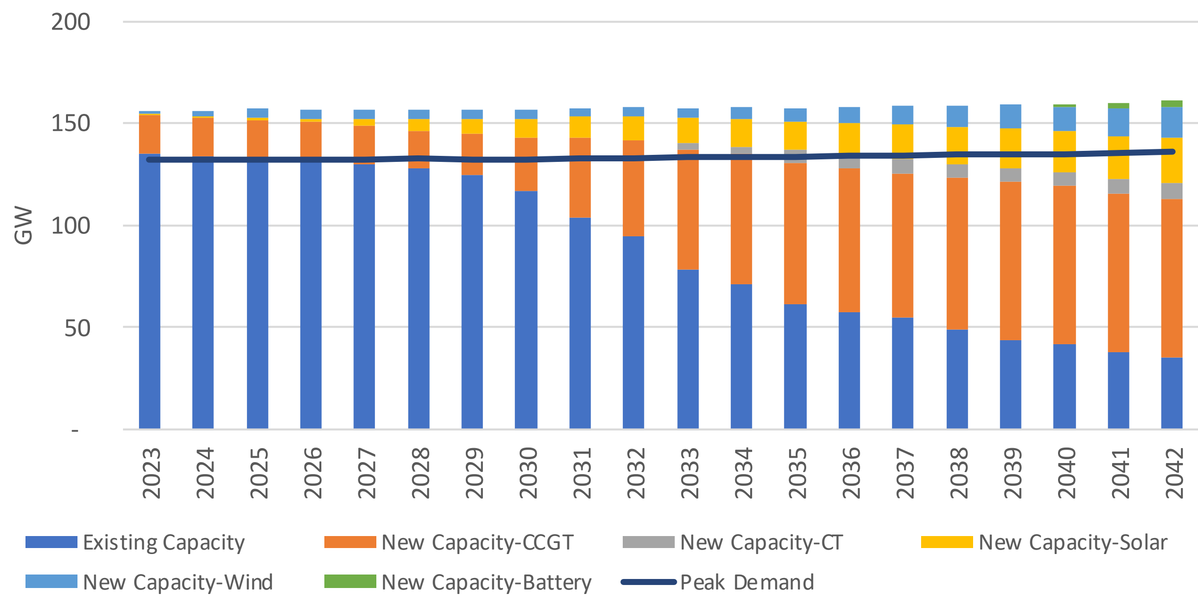


Chart 20: Future 1 Projected Future Market Effective Capacity

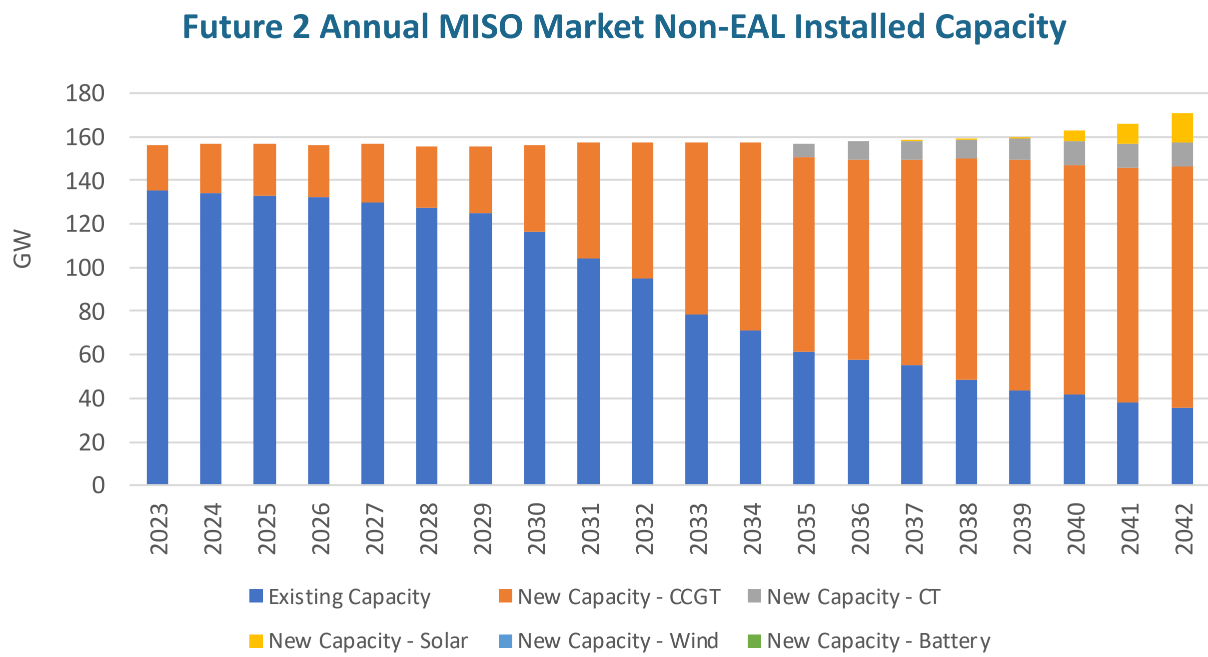


Chart 21: Future 2 Projected Future Market Installed Capacity

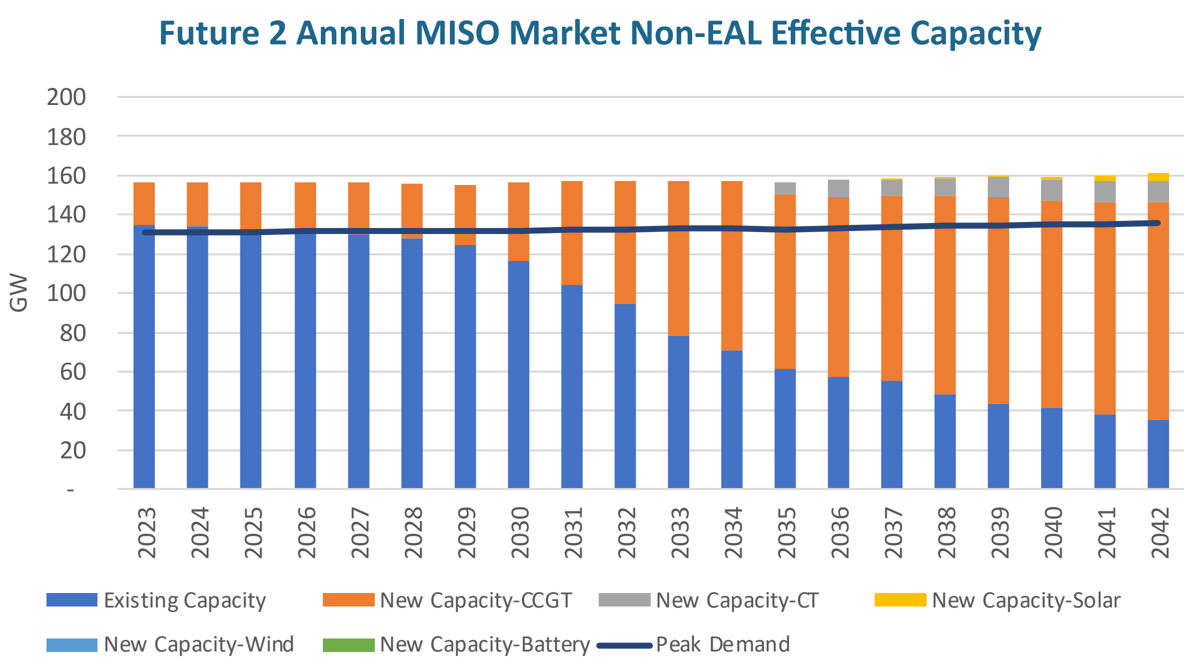


Chart 22: Future 2 Projected Future Market Effective Capacity

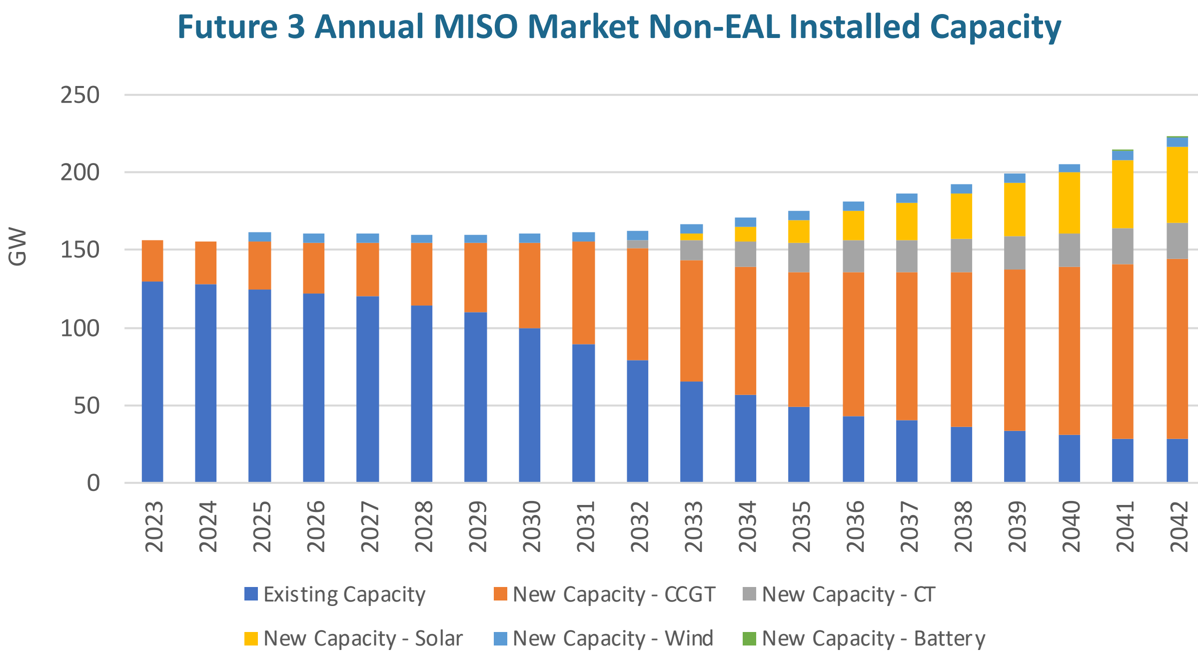


Chart 23: Future 3 Projected Future Market Installed Capacity

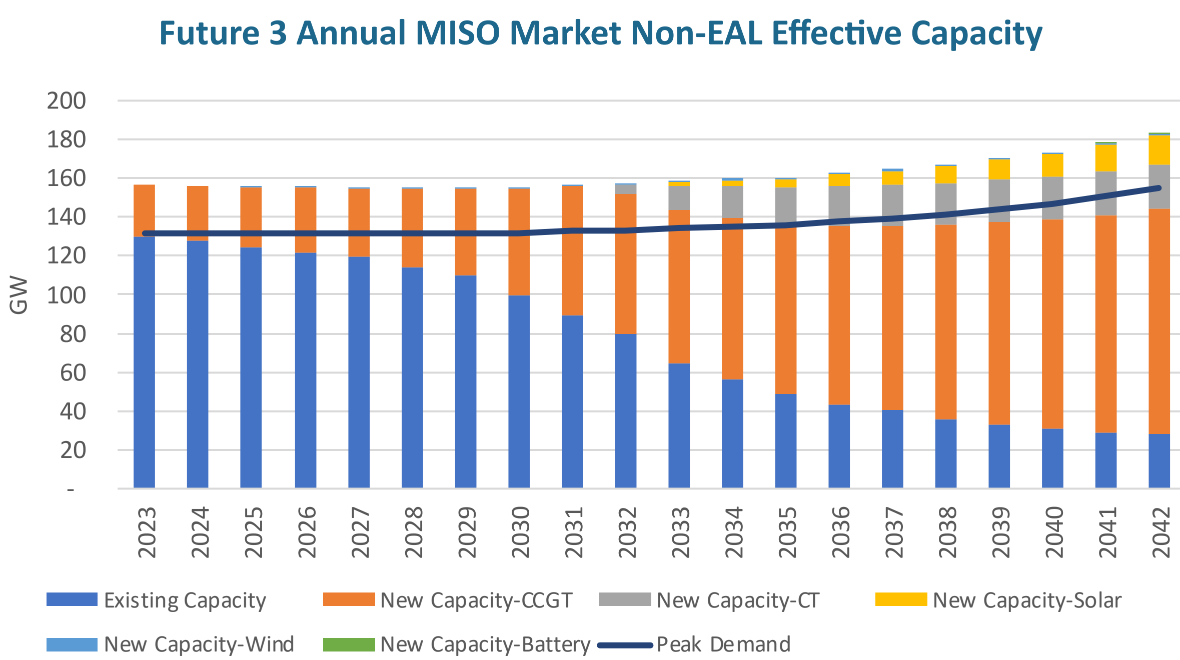


Chart 24: Future 3 Projected Future Market Effective Capacity

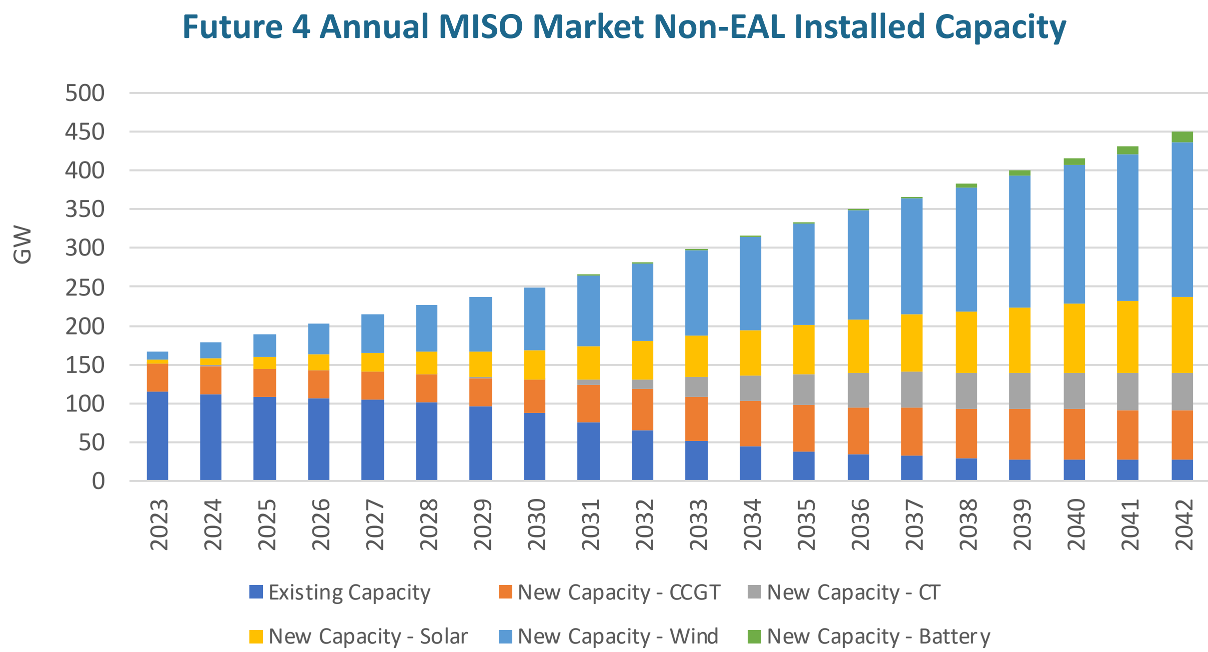


Chart 25: Future 4 Projected Future Market Installed Capacity

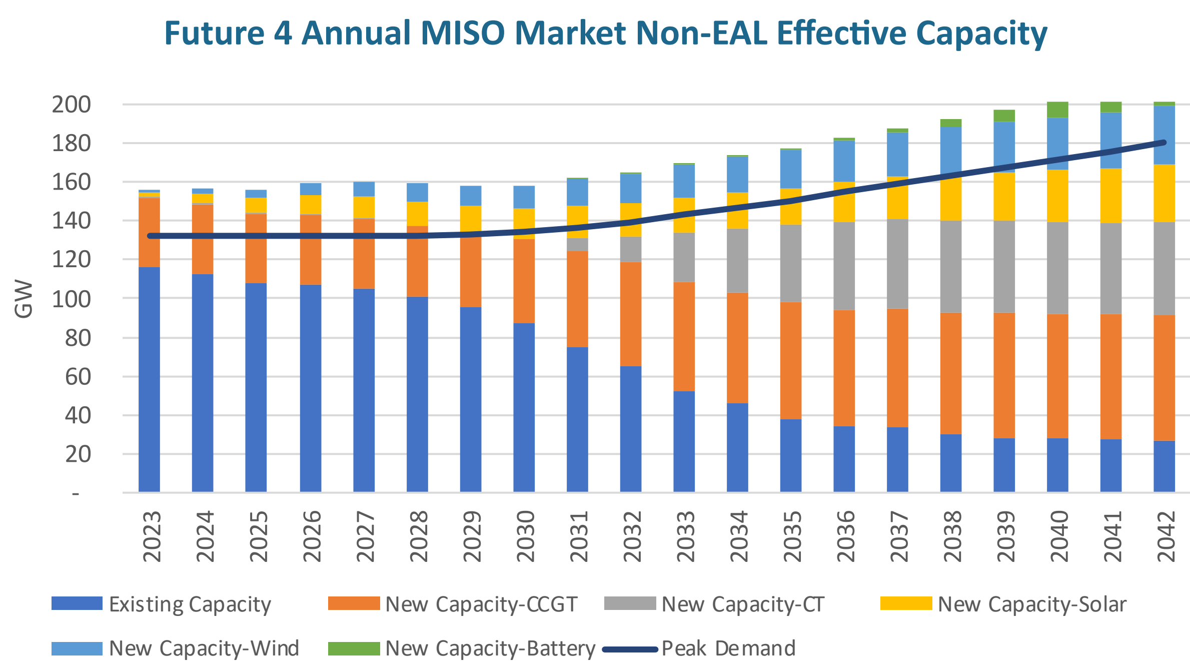


Chart 26: Future 4 Projected Future Market Effective Capacity

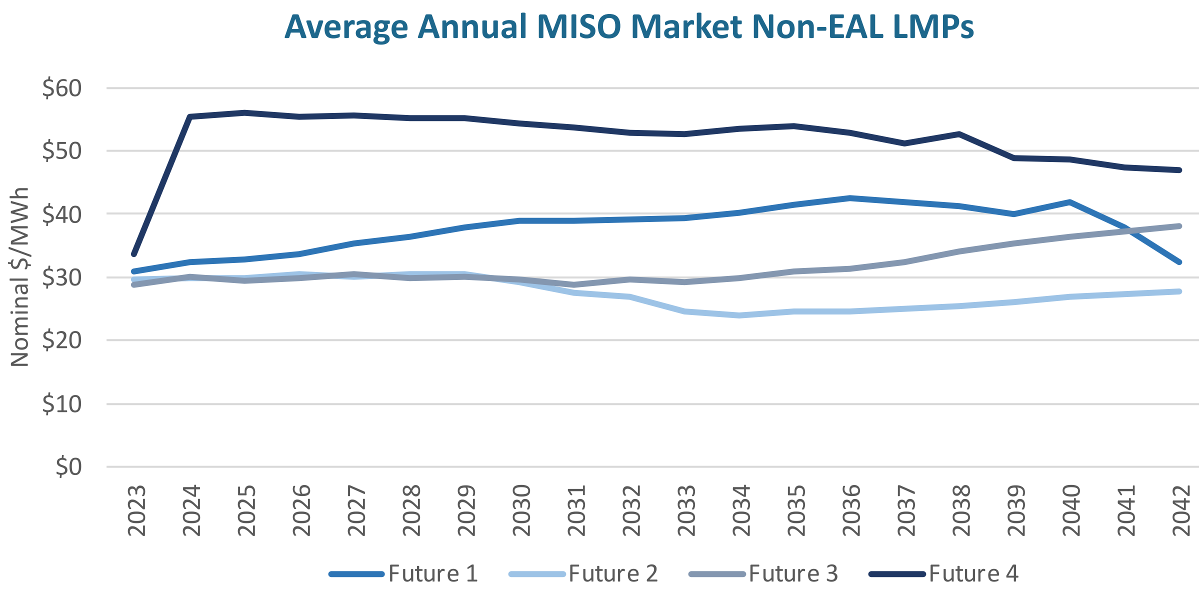


Chart 27: Average Annual MISO Non-EAL LMP

EAL Portfolio Optimization

Following the market modeling process, which results in LMPs for the non-EAL MISO region, the Aurora long-term capacity expansion logic was used to identify economic type, amount, and timing of demand-side resources and supply-side resources needed to meet EAL's future capacity needs. The result of this process is a portfolio of demand-side resources and supply-side resources that produces the lowest total supply cost to meet the identified need within the constraints defined in each of the four futures (the "optimized portfolio").

DSM Modeling - DSM Potential Programs were evaluated as resource alternatives in the Aurora capacity expansion optimization in order to identify the most economic programs to be included in EAL's portfolio.

Potential DR programs were developed and evaluated by ICF based on the characteristics and attributes described in Chapter 4. Each DR program was modeled in Aurora based on annual program costs, hourly demand reduction profiles, program start date, and assumed program life and evaluated to identify the DSM programs that are economic (i.e., have a positive net benefit). The following DR potential programs were modeled, totaling 6 potential alternatives available to begin in 2023:

1. Residential - Direct Load Control - Water
2. Residential - Direct Load Control - Central AC
3. Residential Smart Thermostat
4. Commercial - Direct Load Control - Water
5. Industrial - Agricultural Irrigation Load
6. Industrial - Interruptible / Curtailable

Aurora considers the cost and revenue of energy and capacity in the context of the MISO market for each DSM alternative. Due to the nature of the forecasted DR programs that gain adoption by customers over time, each program was designed to start in 2023 and continue through the end of the technical life of the technology, if applicable, or through the end of planning horizon. Because EAL is not projected to have a need for incremental capacity in 2023, the selection of the DR programs in the model was based strictly on economics, and not capacity position. The capacity credit of selected DR programs is counted toward meeting EAL's capacity needs through reduction of peak load.

Table 13: DR Programs Selected by Aurora by Future

Future	Selected Programs
Future 1	Agricultural Irrigation Load Smart Thermostat (Residental)
Future 2	Agricultural Irrigation Load Smart Thermostat (Residental) Interruptible (Industrial)
Future 3	Agricultural Irrigation Load
Future 4	Agricultural Irrigation Load

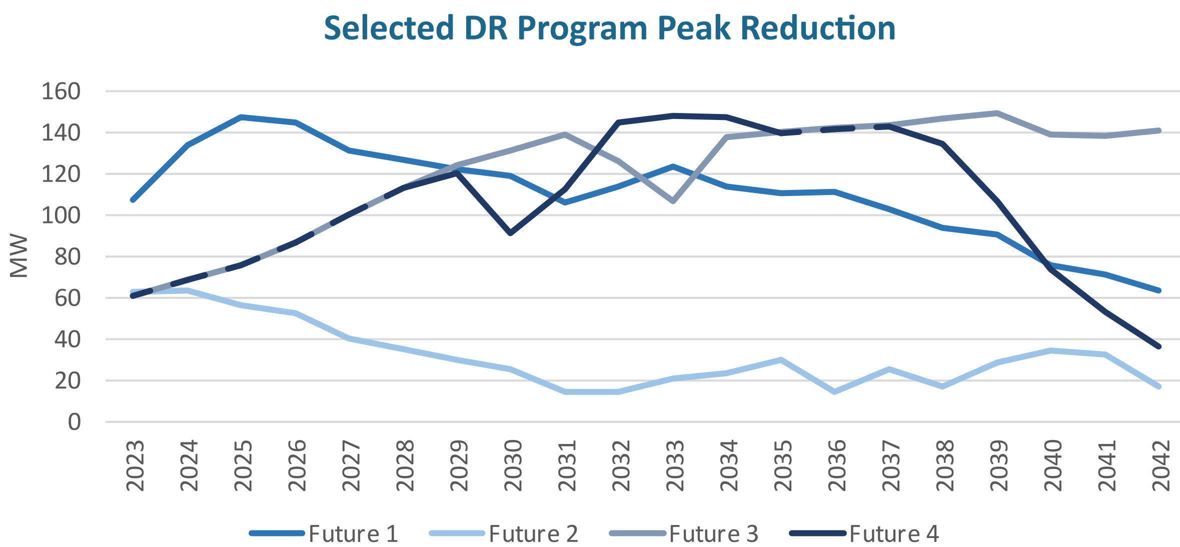


Chart 28: Selected DR Programs

Results - Capacity Expansion & Total Relevant Supply Cost Metric

The following charts show the timing of resource additions and existing capacity throughout the EAL IRP evaluation period of 2023-2042. For each optimized portfolio, the load requirement is reflective of the future for which the portfolio is optimized (e.g., Portfolio 1 is optimized in Future 1), and includes the assumed effects of incremental DSM on the peak load requirement.

In addition to the optimized portfolios, four additional portfolios were developed as sensitivities to assess the accelerated cease-to-use coal date of White Bluff 1 & 2 from 2028 to 2023 and/or 2026 and Independence 1 from 2030 to 2026 and to assess the impact of building renewables in place of gas resources in the Reference Future. For the accelerated cease-to-use coal sensitivities, the Future 1 optimized portfolio was adjusted in the near-term, as needed to balance the load and supply in the years that were forced out of balance by the changes in deactivation assumptions. Additionally, the 2029 CCGT and BESS that were selected in the Future 1 portfolio were removed and replaced with renewable resources for the sensitivities. All four sensitivity portfolios fill the remaining capacity needs from 2030 through 2043 consistent with Portfolio 1, resulting from the Aurora capacity expansion process, but with different timing and amounts.

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 relevant supply cost. The results of the analysis are summarized below.

Future 1

Future 1 is defined by reference load growth and gas prices, DSM additions, and CO2 reduction targets. The capacity under the reference assumptions is optimized to include a diverse mix of baseload energy producing resources, renewable energy projects, energy storage, and DSM.

In Future 1, 4.1 GW of installed capacity additions are sourced from solar and wind resources and another 2.4 GW are sourced from solar resources with BESS. The Future 1 optimized portfolio also includes 700 MW of additional BESS capacity which could be paired with a renewable resource or utilized as standalone resources, and about 1.7 GWs are sourced from combined cycle and combustion turbine resources. As shown above, two DR programs that represent potentially cost-effective DR opportunities were selected for this portfolio as well. These resources address EAL's energy needs as well as account for the future deactivation of energy producing units. The total relevant supply cost for the Future 1 portfolio is $6,452 million on a net present value basis (2021 dollars). More detail on the total relevant supply cost estimate for each future can be found in Appendix F.

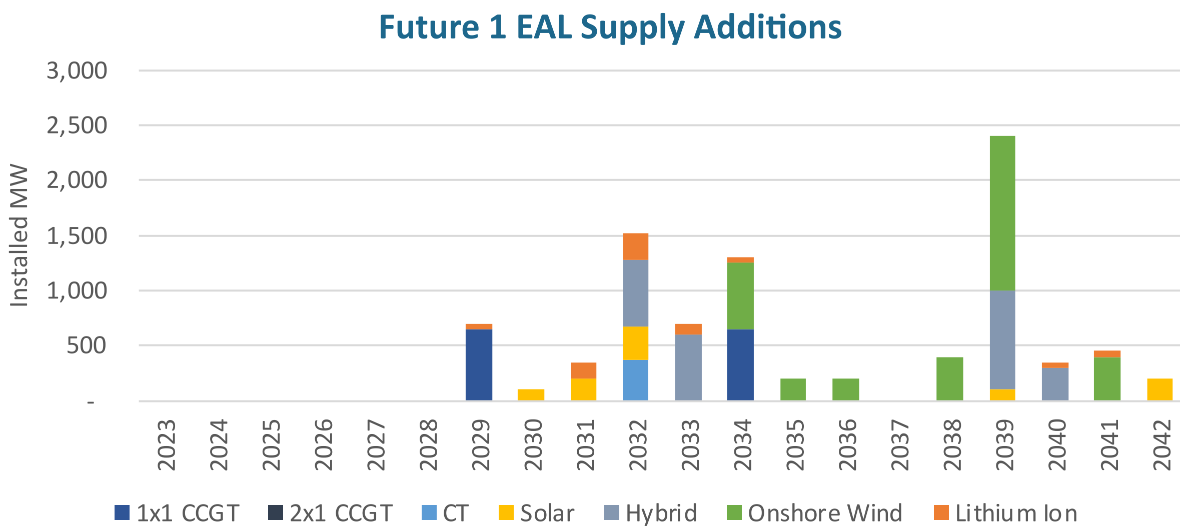


Chart 29: Annual Capacity Expansion Additions Future 1

Future 1 EAL Portfolio

Technology[24]	F1 Installed MW (UCAP)	F1 Effective MW (UCAP)
2x1 CCGT	-	-
1x1 CCGT	1,300	1,300
CT	372	372
Single Axis Solar	900	270
Solar + Battery	2,400	1,440
Lithium-Ion Battery	700	700
On-shore Wind	3,200	531
Total Supply Side Additions	8,872	4,613
DR (average)[25]	110	110

Table 14: Capacity Expansion Portfolio Future 1

24 Reciprocating Internal Combustion Engine, Aeroderivative CT, Offshore Wind, Off-system Wind, and Pumped Storage were included as resource alternatives for EAL but were not selected by the Aurora model in any Future during the optimization process.

25 DR capacity is represented in Table 14 as an average over the 2023-2042 time period.

Future 1 Sensitivity Portfolio 1 - Future 1 Sensitivity Portfolio 1 is defined by the earlier dates for ceasing to use coal at White Bluff 1 and 2 in 2026 and 2023, respectively. The resulting supply additions are illustrated in the chart below:

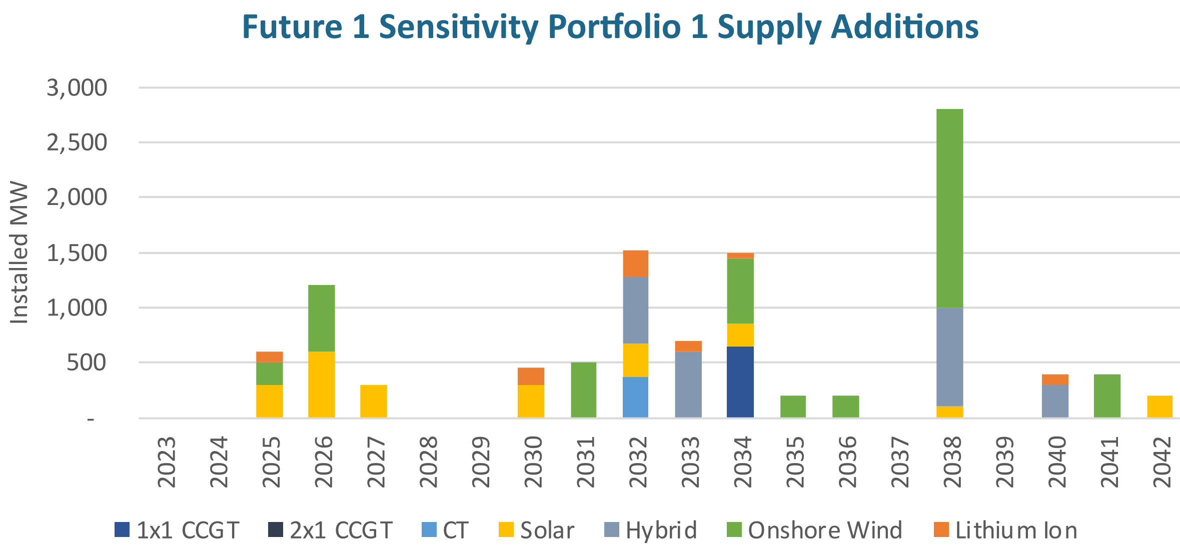


Chart 30: Annual Capacity Additions Future 1 Sensitivity Portfolio 1

Future 1 Sensitivity Portfolio 1

Technology[18]	F1 Installed MW (UCAP)	F1 Effective MW (UCAP)
2x1 CCGT	-	-
1x1 CCGT	650	650
CT	372	372
Single Axis Solar	2,300	690
Solar + Battery	2,400	1,440
Lithium-Ion Battery	750	750
On-shore Wind	4,500	747
Total Supply Side Additions	10,972	4,649
DR (average)[19]	110	110

Table 15: Capacity Expansion Portfolio Future 1 Sensitivity Portfolio 1

Future 1 Sensitivity Portfolio 2 - Future 1 Sensitivity Portfolio 2 is defined by the early cease-to-use coal date of White Bluff 1 and 2 in 2026. The resulting supply additions are illustrated in the chart below:

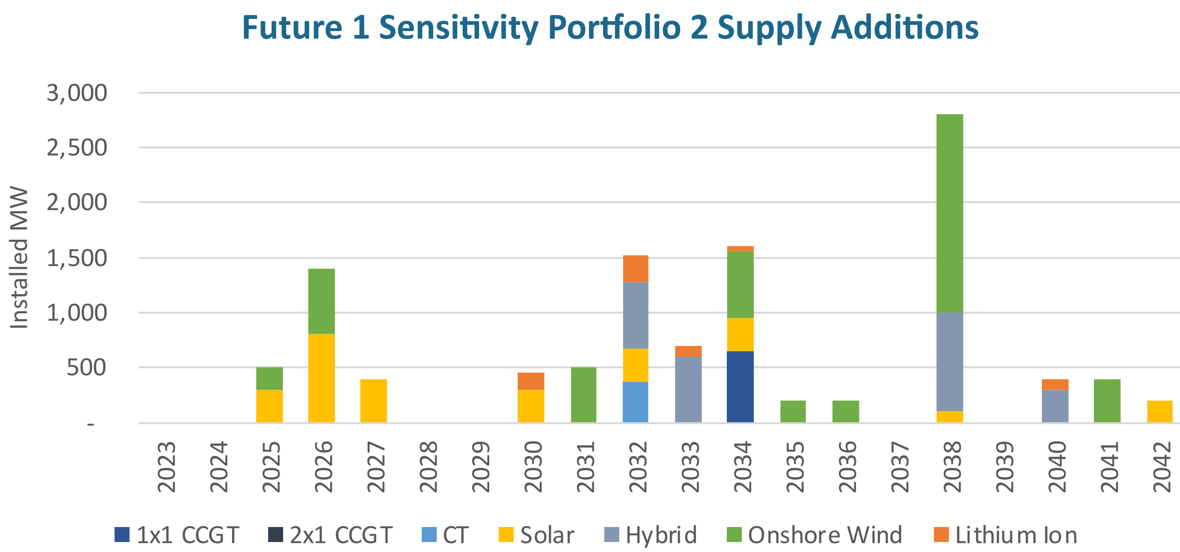


Chart 31: Annual Capacity Additions Future 1 Sensitivity Portfolio 2

Future 1 Sensitivity Portfolio 2

Technology[18]	F1 Installed MW (UCAP)	F1 Effective MW (UCAP)
2x1 CCGT	-	-
1x1 CCGT	650	650
CT	372	372
Single Axis Solar	2,700	810
Solar + Battery	2,400	1,440
Lithium-Ion Battery	650	650
On-shore Wind	4,500	747
Total Supply Side Additions	11,272	4,669
DR (average)[19]	110	110

Table 16: Capacity Expansion Portfolio Future 1 Sensitivity Portfolio 2

Future 1 Sensitivity Portfolio 3 - Future 1 Sensitivity Portfolio 3 is defined by the early cease-to-use coal date of Independence 1 in 2026. The resulting supply additions are illustrated in the chart below:

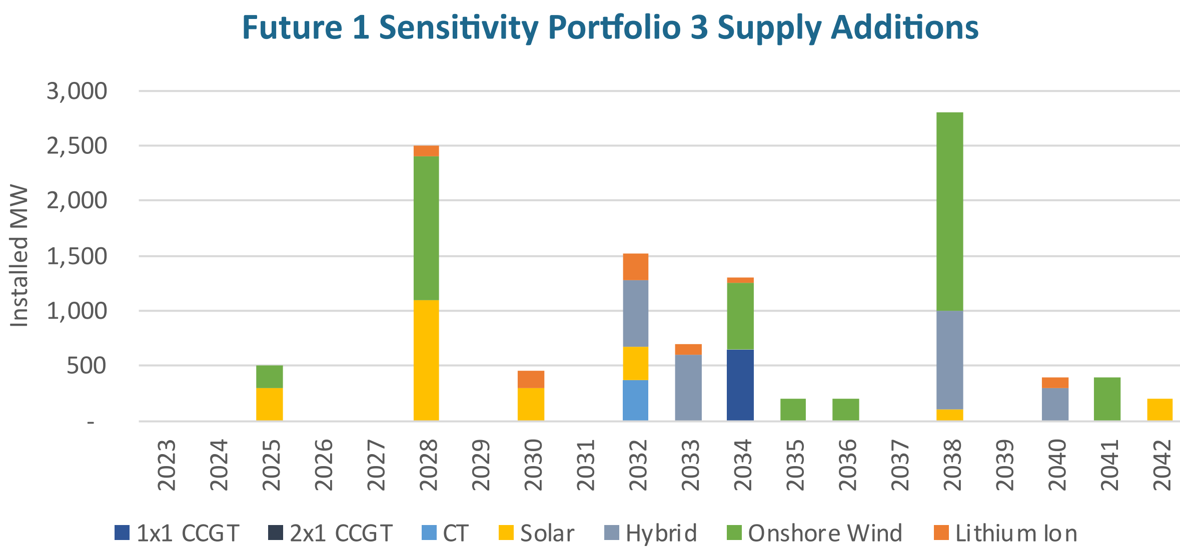


Chart 32: Annual Capacity Additions Future 1 Sensitivity Portfolio 3

Future 1 Sensitivity Portfolio 3

Technology[18]	F1 Installed MW (UCAP)	F1 Effective MW (UCAP)
2x1 CCGT	-	-
1x1 CCGT	650	650
CT	372	372
Single Axis Solar	2,300	690
Solar + Battery	2,400	1,440
Lithium-Ion Battery	750	750
On-shore Wind	4700	780
Total Supply Side Additions	11,172	4,682
DR (average)[19]	110	110

Table 17: Capacity Expansion Portfolio Future 1 Sensitivity Portfolio 3

Future 1 Sensitivity Portfolio 4 - Future 1 Sensitivity Portfolio 4 removes the 2028 EAL 1x1 and the 2029 EAL battery without adjusting the cease-to-use coal dates of White Bluff 1 and 2 and Independence 1 in Future 1. The resulting supply additions are illustrated in the chart below:

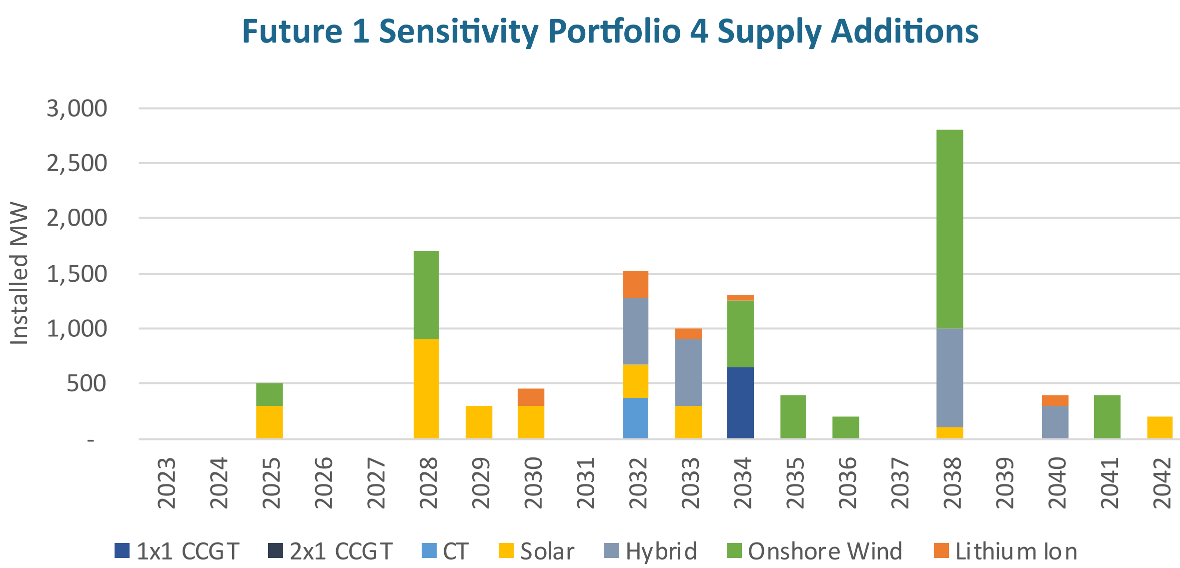


Chart 33: Annual Capacity Additions Future 1 Sensitivity Portfolio 4

Future 1 Sensitivity Portfolio 4

Technology[18]	F1 Installed MW (UCAP)	F1 Effective MW (UCAP)
2x1 CCGT	-	-
1x1 CCGT	650	650
CT	372	372
Single Axis Solar	2,700	810
Solar + Battery	2,400	1,440
Lithium-Ion Battery	550	550
On-shore Wind	4400	730
Total Supply Side Additions	11,072	4,452
DR (average)[19]	110	110

Table 18: Capacity Expansion Portfolio Future 1 Sensitivity Portfolio 4

Future 2

Future 2 is defined by reference load growth, low gas prices, low DSM additions, and no CO2 price. Because Future 2 assumes low gas prices and no CO2 price throughout the planning horizon, an environment which would be favorable for the economics of gas-powered resources, it also includes an assumption that the expected life of the existing EAL CCGTs is extended through the end of the planning horizon. As a result, less incremental capacity is required in Future 2 compared to Future 1.

In Future 2, 600 MW of installed capacity additions are sourced from solar resources and another 750 MW are sourced from solar resources with BESS. The Future 2 portfolio also includes 650 MW of additional BESS capacity and an additional 1.7 GW are sourced from combined cycle or combustion turbine resources. As shown above, three cost-effective DR programs were selected for this portfolio as well. Future 2 produces an environment where EAL would be predominantly reliant on baseload resources, including combined cycle resources, due to the low gas and CO2 prices, lack of push for DSM and renewable energy and the extension of the useful life of EAL's currently existing CCGTs. The total relevant supply cost for the Future 2 portfolio is $4,175 million on a net present value basis (2021 dollars).

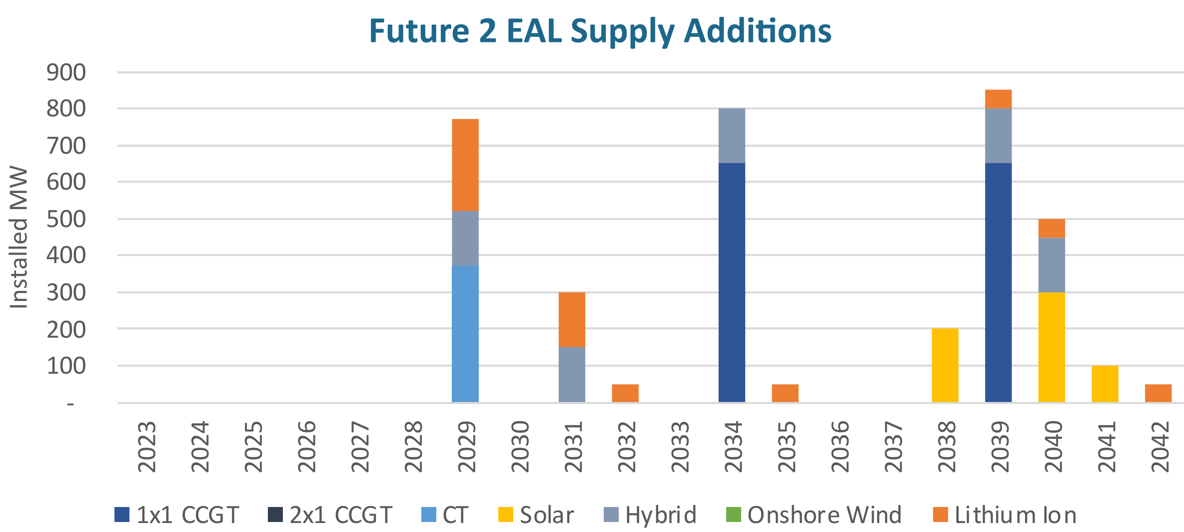


Chart 34: Annual Capacity Expansion Additions Future 2

Future 2 EAL Optimized Portfolio

Technology [26]	F2 Installed MW (UCAP)	F2 Effective MW (UCAP)
2x1 CCGT	-	-
1x1 CCGT	1,300	1,300
CT	372	372
Single Axis Solar	600	180
Solar + Battery	750	450
Lithium-Ion Battery	650	650
On-shore Wind	-	-
Total Supply Side Additions	3,672	2,952
DR (average) [27]	32	32

Table 19: Capacity Expansion Portfolio Future 2

26 *Reciprocating Internal Combustion Engine, Aeroderivative CT, Offshore Wind, Off-system Wind, and Pumped Storage were included as resource alternatives for EAL but were not selected by the Aurora model in any Future during the optimization process.*

27 *DR capacity is represented in Table 18 as an average over the 2023-2042 time period.*

Future 3

Future 3 is defined by low load growth and gas prices, and high DSM additions and includes the assumption that the licenses for EAL's nuclear resources would extend out past the study horizon. The optimized capacity selected to best fit this environment includes a greater supply of baseload energy resources, with renewable energy, energy storage, and DSM resources providing a substantial amount of capacity.

In Future 3, 1.7 GW of installed capacity additions are sourced from solar resources and another 900 MW are sourced from solar resources with BESS. The Future 3 optimized portfolio also includes 1.1 GW of additional BESS capacity which could also be paired with a solar resource or utilized as standalone resources. Also, an additional 1.7 GW are sourced from combined cycle or combustion turbine resources. As shown above, the Agricultural Irrigation Load DR program was cost effective and selected for this portfolio as well. This is a result of the low gas prices and reference CO2 prices, which make the combined cycle and solar technologies favorable in this Future. The total relevant supply cost for the Future 3 portfolio is $5,232 million on a net present value basis (2021 dollars).

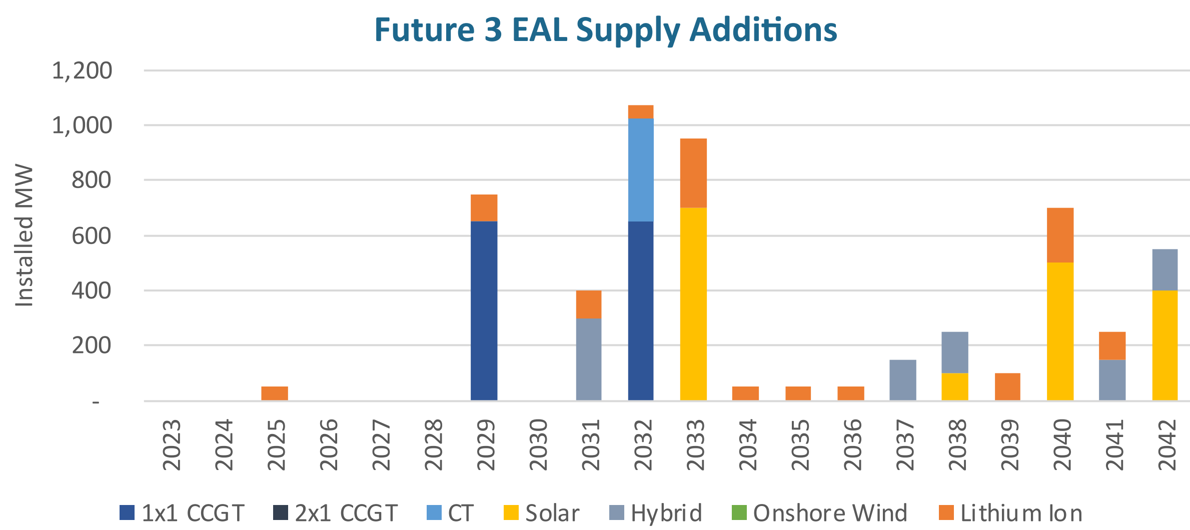


Chart 35: Annual Capacity Expansion Additions Future 3

Future 3 EAL Optimized Portfolio

Technology [28]	F3 Installed MW (UCAP)	F3 Effective MW (UCAP)
2x1 CCGT	-	-
1x1 CCGT	1,300	1,300
CT	372	372
Single Axis Solar	1,700	510
Solar + Battery	900	540
Lithium-Ion Battery	1,100	1,100
On-shore Wind	-	-
Total Supply Side Additions	5,372	3,822
DR (average) [29]	120	120

Table 20: Capacity Expansion Portfolio Future 3

28 Reciprocating Internal Combustion Engine, Aeroderivative CT, Offshore Wind, Off-system Wind, and Pumped Storage were included as resource alternatives for EAL but were not selected by the Aurora model in any Future during the optimization process.

29 DR capacity is represented in Table 20 as an average over the 2023-2042 time period.

Future 4

Future 4 is defined by high load growth, high natural gas prices, and high CO2 price assumption and includes an assumption that the licenses for EAL's nuclear resources would extend out past the study horizon. The optimized capacity selected to fulfill the supply need in this future primarily consists of renewable energy.

In Future 4, 5.8 GW of installed capacity additions are sourced from solar resources, another 150 MW are sourced from solar resources with BESS, as well as 4 GW of wind resources. The Future 4 portfolio also includes 2.4 GW of additional BESS capacity, which could be paired with a renewable resource or utilized as standalone resources. Also, an additional 650 MW are sourced from CCGTs. As shown above, similar to Future 3, the Agricultural Irrigation Load DR program was cost effective and selected for this portfolio as well. The highest amount of renewable capacity is added in Future 4 due to the high CO2 price assumption, paired with high natural gas prices, which makes renewable energy a more economic option than natural gas. The total relevant supply cost for the Future 4 portfolio is $7,565 million on a net present value basis (2021 dollars).

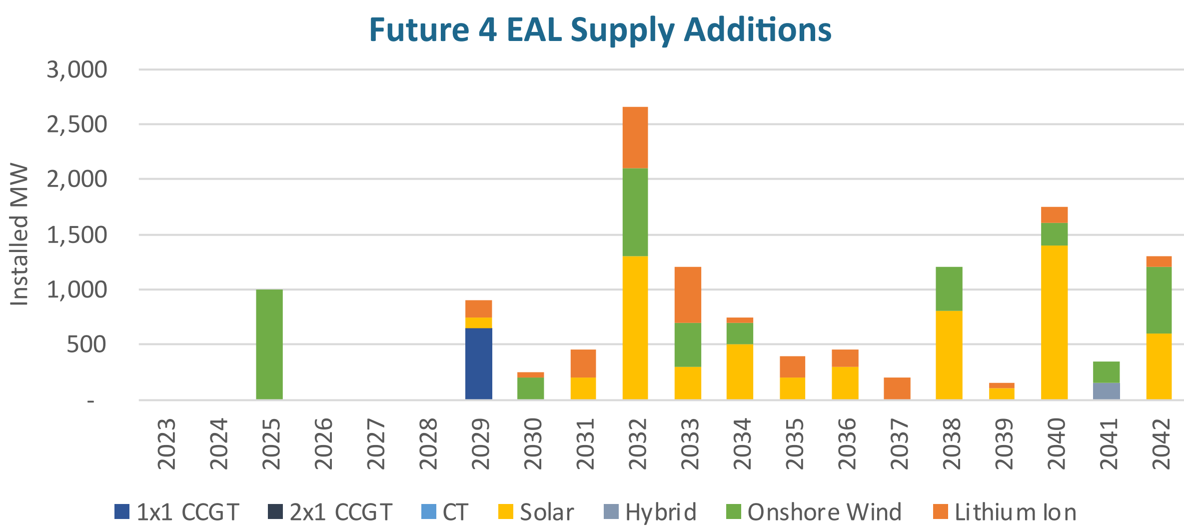


Chart 36: Annual Capacity Expansion Additions Future 4

Future 4 EAL Optimized Portfolio

Technology [30]	F4 Installed MW (UCAP)	F4 Effective MW (UCAP)
2x1 CCGT	-	-
1x1 CCGT	650	650
CT	-	-
Single Axis Solar	5,800	1,740
Solar + Battery	150	90
Lithium-Ion Battery	2,400	2,400
On-shore Wind	4,000	664
Total Supply Side Additions	13,000	5,544
DR (average) [31]	105	105

Table 21: Capacity Expansion Portfolio Future 4

30 Reciprocating Internal Combustion Engine, Aeroderivative CT, Offshore Wind, Off-system Wind, and Pumped Storage were included as resource alternatives for EAL but were not selected by the Aurora model in any Future during the optimization process.

31 DR capacity is represented in Table 21 as an average over the 2023-2042 time period.

In addition to the total relevant supply cost components detailed in Appendix F, the sensitivity portfolios include the following cost component:

Coal Unit Avoided Costs – The return of and on capital expenditures and O&M spend that may be avoided by early cessation of burning coal at Independence and/or White Bluff earlier than the reference case. These costs are based on preliminary planning estimates that exclude other key costs and risks associated with operating the coal units through their current assumed operating life and otherwise may be avoided in the early cessation of burning coal scenario.

Future 1 Optimized Portfolio TRSC Results Compared to Sensitivity Portfolios

	Cost [$MM, 2021$ NPV]	Variance to Future 1 Portfolio [$MM, 2021$ NPV]
Future 1 Portfolio	$6,452	$--
Sensitivity Portfolio 1	$6,457	$5
Sensitivity Portfolio 2	$6,363	($89)
Sensitivity Portfolio 3	$6,387	($65)
Sensitivity Portfolio 4	$6,291	($161)

Table 22: Future 1 Optimized Portfolio TRSC Versus Sensitivity Portfolios

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. The following factors are intended to give EAL an indication of the qualitative risk characteristics that may contribute to future portfolio decisions and are considered as part of selecting the preferred portfolio:

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 that is 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.

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.

Modernization of Fleet – Understanding technology based useful life assumptions coupled with the average age of generating resources helps to inform an assessment of potential risks associated with maintaining and operating a portfolio of assets.

Executability - Assessing the executability of a portfolio allows EAL to evaluate the relative risks associated with the procurement of 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, RFP process and negotiations, construction, etc.

Optionality - Optionality considers the adaptability of a portfolio which enables EAL to adjust to various market conditions, such as 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.

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

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.

Chapter 6

Action Plan

Summary

- Increasing the amount of renewables capacity in EAL's portfolio is supported under a broad range of future conditions.
- The next driver for a large capacity deficit will be the timing of ceasing-to-use-coal at the White Bluff and Independence plants. Incremental additions of renewables starting in 2025 appear to be a cost-effective approach to addressing that need.
- Potential may exist for incremental cost-effective demand response in EAL's portfolio.

Findings & Conclusions

As discussed above, the Aurora capacity expansion process resulted in four distinct resource portfolios, each of which is economically optimal for the combinations of assumptions for the respective future. Four additional resource portfolios were evaluated as sensitivities to Future 1. Comparison across the futures provides insight on the supply additions that are robust under a wide range of uncertain future outcomes over the 20-year planning horizon, whereas comparisons between the sensitivities is better for assessing the effects of specific, near-term assumptions.

Findings across Futures - When reviewing the results of the four resource portfolios across the futures, the many varying inputs across the futures must be taken into consideration. The portfolios that are 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 23 below summarizes key results for each future.

2023-42 Modeling Results (MW)	Future 1	Future 2	Future 3	Future 4
Total Incremental Installed Capacity:	8,872	3,672	5,372	13,000
Natural Gas Capacity Additions:	1,672	1,672	1,672	650
Renewable Capacity Additions:	6,500	1,350	2,600	9,950
DSM Capacity Additions:	110	32	120	105

Table 23: Modeling Results Summary

Renewable Resources are Even More Cost-effective than the Prior IRP - Renewables account for the majority of incremental supply additions across three of the futures, and across all four futures assuming all future BESS is paired with renewable resources. In comparison to the 2018 IRP, incremental gas-powered capacity additions have decreased significantly, amidst a continued period of low natural gas prices. Table 24 below shows the proportion that renewable additions make of the future portfolios. These percentages ranged from 6% to 33% in the 2018 IRP. By contrast, dispatchable gas-powered and BESS resource additions are primarily made to provide flexible capacity to allow integration of solar and wind resource additions, though the amount and timing varies across futures because of different market conditions and amount of renewable resources added.

This result supports that adding renewables to EAL's portfolio is a cost-effective approach across a broad range of future assumptions.

Future	Renewable[32] resource capacity additions as percent of total incremental supply additions
Future 1	81%
Future 2	53%
Future 3	68%
Future 4	95%

Table 24: Renewable Capacity Additions (%)

DSM is Cost-effective in all Futures - At least one DSM program is selected by Aurora to be cost-effective in each of the four futures, however, the amount selected varies from a low level in Future 2 with an average of 32 MW of capacity contribution to a higher level in the other three futures with 105-120 MW of capacity contribution. This result indicates that opportunity may exist for EAL to explore growth of existing or potentially new, cost-effective demand response investments as part of its future portfolio of resources, even in if low gas prices continue for an extended period of time, as in Future 2. In addition to being an alternative to supply side generation, DR resources may also address unique customer preferences, as well as locational reliability needs. All potential benefits of DR should be considered in development of actual, executable programs.

Timing of first addition - The year in which the first incremental resource addition is needed to meet the reserve margin target is 2029 for Futures 1 and 2, and in 2025 for Futures 3 and 4. As discussed in detail above, all four futures assume cessation to use coal at White Bluff in 2028 and Independence 1 in 2030. Futures 1 and 2 assume lower load growth than Future 4. Therefore, a 2025 supply need may result should higher load growth occur or the timing of cease-to-use coal at White Bluff and Independence 1 occurs earlier than assumed or both. Given the uncertainty around both of these drivers, a plan to begin methodically adding generation between 2025 and 2029 is needed.

Findings across Sensitivities - While the futures provide a strategic view of EAL's potential future portfolio, the four sensitivities can be used to focus on smaller changes in the near-term portion of the planning horizon. In addition to the four portfolios summarized in Table 23, Future 1 was supplemented with four sensitivity cases, which provide insight around the effect of potential changes at the time that EAL anticipates it will cease to use coal in its portfolio. The four sensitivity portfolios cover a range of cease-to-use-coal dates for White Bluff and Independence and replace the coal capacity with renewable resources.

The spread in TRSC across all four sensitivity portfolios, compared to Future 1 Portfolio is less than +/- 1%, which indicates very little potential cost effects for alternative cease-to-use-coal dates for White Bluff and Independence. This result does not set forth a clear delineation around earlier cease-to-use-coal dates than those assumed in Future 1 Portfolio and Sensitivity Portfolio 4, which are 2028 for White Bluff and 2030 for Independence.

Sensitivity Portfolio 4 indicates a small potential cost savings relative to Future 1 Portfolio, about 2.5% on a TRSC basis. In addition to being a lowest cost portfolio based on the reference case future, this result is consistent with the findings across the futures discussed above, including the "no regrets" strategy of adding renewables to the EAL portfolio. The near-term addition of renewables enhances the adaptability of EAL's portfolio to changes, such as rapidly evolving customer demand. It also increases fuel supply diversity, lowers environmental cost risk, and responds to customers' preferences for renewable energy.

The IRP provides a high-level analysis which necessarily employs many varying assumptions over a long period of time. More detailed evaluations of White Bluff and Independence, including coordination with the co-owners of both plants, may be appropriate.

32 Renewable resources include solar, solar with storage, wind and BESS technologies

2023-42 Sensitivity Modeling Results	Future 1	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4
White Bluff 1 CTUC Date:	2028	2026	2026	2028	2028
White Bluff 2 CTUC Date:	2028	2023	2026	2028	2028
Independence 1 CTUC Date:	2030	2030	2030	2026	2030
Incremental Generation Capacity 2025-2028:	2028 1x1 CCGT 2029 BESS	2025 Solar, Wind & BESS 2026 Solar & Wind 2027 Solar	2025 Solar & Wind 2026 Solar & Wind 2027 Solar	2025 Solar & Wind 2028 Solar, Wind & BESS	2025 Solar & Wind 2028 Solar & Wind 2029 Solar
Total Relevant Supply Cost:	$6,452	$6,457	$6,363	$6,387	$6,291

Table 25: Sensitivity Portfolio Results Summary

2021 IRP Preferred Resource Plan

Based on the modeling, analysis and findings discussed above, the 2021 IRP supports the conclusion that EAL's future supply-side resources will be focused primarily on renewable energy resources with additions beginning in 2025. Based on the work conducted as part of the 2021 IRP analysis, it is also reasonable to conclude that demand-side resources will continue to be a component of the capacity portfolio. In the near term, renewable resource additions will be made based on specific project proposals. Over the long-term, the amount of total capacity that will be needed and exactly when that capacity will be needed are uncertain.

EAL's preferred resource plan maintains the planning assumptions for existing units and begins adding renewable resources starting in 2025 consistent with Sensitivity Portfolio 4 though the exact amount of each type of renewable resource will be based on a market solicitation and may vary from the amounts in Sensitivity Portfolio 4.

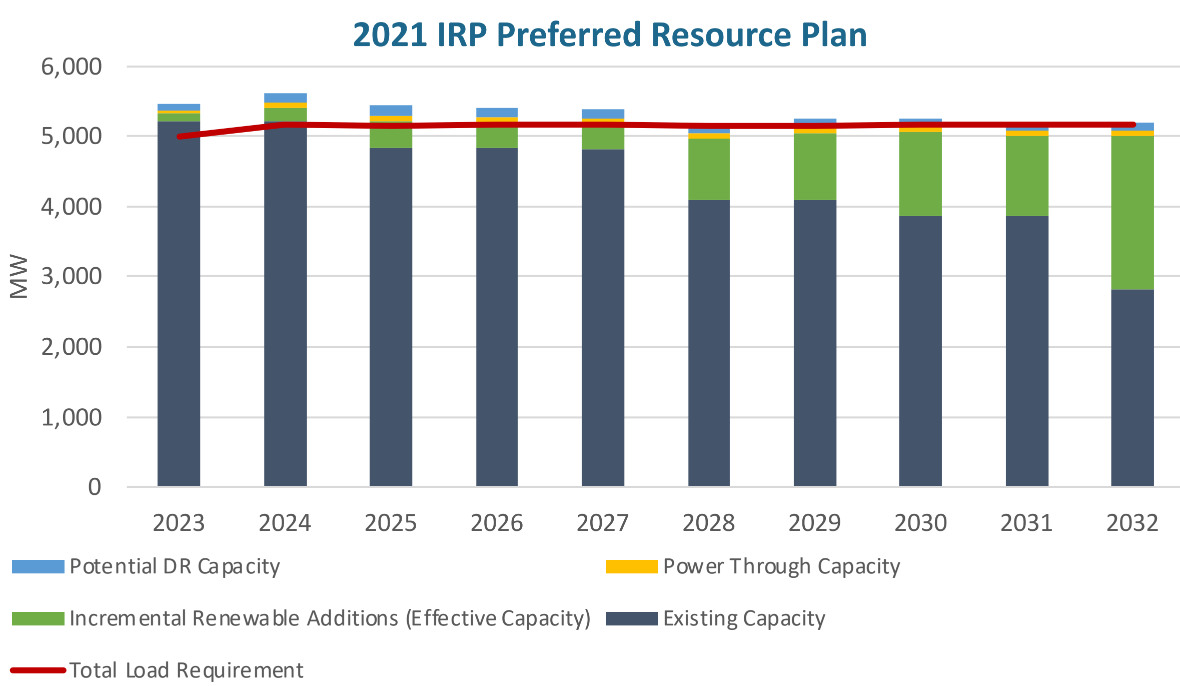


Chart 37: 2021 IRP Preferred Resource Plan2021 IRP Action Plan

2021 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 planning process is subdivided into work streams, each with its own process and timeline.

2021 IRP Action Plan

1. Complete the Acquisitions of Searcy, Walnut Bend, and West Memphis Solar Build-Own-transfer Resources	EAL will complete the acquisitions of the Searcy, Walnut Bend and West Memphis facilities from 2021 through 2023 as construction is completed for each facility.
2. Complete the 2021 Renewables RFP	In August 2021, EAL issued its 2021 Renewables RFP and is expected to be completed in early 2022. The RFP is seeking to procure up to 500 MW of solar and/or wind resources with PPA deliveries starting and/or acquisitions starting in the 2024-25 timeframe.
3. Effectuate the Deactivation of Lake Catherine 4 in 2025	In preparation for the assumed deactivation of Lake Catherine Unit 4 in 2025, EAL will initiate the processes necessary to reliably support the end of commercial operation.
4. Identify Demand-side Management Opportunities	EAL is researching DR devices for compatibility with AMI communications to expand the Company's DR offerings. Evaluation of potential offerings is planned to take place in 2022.
5. 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 the updated targets adopted in EAL's 2020-2022 EE Program Plan as filed in Docket No. 07-085-TF.
6. Pursue Power Resiliency	EAL will develop and implement customer-centric power resiliency solutions. Power Through represents EAL's initial power resiliency offering. Upon APSC approval, EAL will offer Power Through to its customers starting in 2022.
7. Implement Sustainable Solutions	Develop and implement customer-centric sustainability solutions. Green Promise is a green tariff designed to assist residential (including low-income) and nonresidential customers in the achievement of their sustainability objectives. Following APSC approval, EAL will offer Green Promise to its customers. Also, in conjunction with Action Plan Item #2, additional customer-centric sustainability solutions will be considered once additional renewable resources are selected.
8. Evaluate Stakeholder Engagement	Stakeholder engagement has been an important part of the development of this IRP. An immediate priority will be for EAL to closely review the stakeholder report, which can be found in Appendix H of this report and continue taking steps to address concerns in the Company's IRP process.

Chapter 7

Stakeholder Engagement

Summary

- Based on feedback received from stakeholders, EAL has worked to enhance the Stakeholder engagement process for this IRP.
- Due to the COVID-19 pandemic, all Stakeholder meetings were hosted virtually.
- EAL hosted four stakeholder meetings, conducted multiple rounds of Q&A, responded to stakeholder letters, and accommodated multiple stakeholder requests.

Pursuant to the APSC Resource Planning Guidelines, one component of the development of the IRP is to engage with stakeholders in EAL's long-term planning process. As defined in the Resource Planning Guidelines, 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 has worked diligently with stakeholders to address feedback provided in the 2018 IRP's Stakeholder Report as well as feedback received during the 2021 IRP's planning cycle.

The stakeholder engagement process began in June 2020 with a public Preliminary Information Posting to EAL's IRP website.[33] Due to the ongoing COVID-19 pandemic, the Stakeholder Kickoff Meeting was held virtually in August 2020 and included a broad amount of information regarding EAL's planning processes and objectives, including preliminary assumptions and inputs for the IRP's modeling. Following this meeting, in September 2020 EAL posted a Q&A document that responded to questions received both during and after the Stakeholder Kickoff Meeting.

Following these stakeholder engagements, in late September and early October 2020, EAL received letters from four Stakeholder Committee members: Arkansas Advanced Energy Association ("AAEA"), Audubon Arkansas, Sierra Club, and the Southern Renewable Energy Association ("SREA"). These letters submitted multiple requests for EAL's consideration and primarily focused on three key areas: modeling and portfolio requests, conducting an All-Source RFP to inform the IRP process, and environmental and public health considerations. EAL provided formal written responses to these requests in December 2020. Some of the feedback received from various parties was addressed through EAL including portfolio scenarios that assume cease-to-use-coal dates that are earlier than EAL's current planning assumption for its White Bluff and Independence generating units. The IRP also includes an assessment of the impacts of those earlier dates on total supply costs compared to alternative portfolios, as well as the viability of earlier cease-to-use coal timeframes. Additionally, per stakeholder request, the IRP now includes a discussion of measures that EAL has taken regarding potential public health impacts and EJ considerations in Chapter 4.

EAL provided stakeholders with its IRP Data Posting in January 2021, which was subsequently updated in February 2021 to address feedback from stakeholders. EAL hosted a virtual meeting to review and discuss the Data Posting materials in early March 2021. EAL again hosted a virtual meeting in early May 2021 to 1) present stakeholders with updates to the original Data Posting, and 2) provide stakeholders a Supplementary Data Posting, which included additional details around the IRP's timeline, a scope matrix of EAL's proposed futures, updates to its Technology Assessment, and updates regarding the ICF DR and DER Potential Study. EAL responded to Q&A received during this meeting via public posting in late-May 2021.

33 https://www.entergy-arkansas.com/integrated_resource_planning/

In late-May 2021, EAL received an additional letter from the referenced Stakeholder Committee members submitting comments regarding a broad range of IRP assumptions, including costs and risks for various technology types, modeling input assumptions, solar plus battery alternatives, MISO MTEP assumptions, and additional Q&A. EAL provided formal written responses to these comments in mid-June 2021.

In August 2021, EAL received a letter from the APSC General Staff outlining recommendations regarding the Company's integrated resource planning process. These recommendations centered on four key areas: the value of a 'Preferred Resource Plan' and justification for deviations from this plan, alignment of IRP assumptions with resource procurement experience, near-term and long-term customer rate impacts, and the integration of ownership structure with the IRP's resource assumptions. EAL provided a formal written response to these recommendations in September 2021, and based on General Staff feedback, more clearly identified its Preferred Resource Plan within the IRP.

Finalized IRP portfolio optimization results were posted publicly on the IRP website in September 2021. EAL hosted a virtual meeting to review these results with stakeholders in mid-September to allow sufficient time for the Stakeholder Committee to complete their 2021 IRP Stakeholder Report.

Abbreviations & Definitions

AAEA	Arkansas Advanced Energy Association
ACE	Affordable Clean Energy
ADEQ	Arkansas Department of Environmental Quality
AECC	Arkansas Electric Cooperative Corporation
AILC	Agricultural Irrigation Load Control
AMI	Advanced Metering Infrastructure
ANO	Arkansas Nuclear One
APSC	Arkansas Public Service Commission
BESS	Battery Energy Storage System
BOT	Build-Own-Transfer
BTA	Best Technology Available
CAVR	Clean Air Visibility Rule
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals
CDD	Cooling Degree Days
CEO	Chief Executive Officer
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CT	Simple Cycle Combustion Turbine
CTUC	Cease-to-Use Coal
DER	Distributed Energy Resource
DLC	Direct Load Control
DR	Demand Response
DSM	Demand-Side Management
EAL	Entergy Arkansas, LLC
EE	Energy Efficiency
EGU	Electric Generating Unit
EIA	Energy Information Administration
EJ	Environmental Justice
ELCC	Effective Load Carrying Capability
ELG	Effluent Limitation Guideline Rule
Entergy	Entergy Corporation
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FIP	Federal Implementation Plan
Grand Gulf	Grand Gulf Nuclear Station
GW, GWh	Gigawatt, Gigawatt Hour
HDD	Heating Degree Days
HVAC	Heating, Ventilation and Air Conditioning
ICF	ICF International, Inc.
IRP	Integrated Resource Plan
ISES	Independence Steam Electric Station
kW, kWh	Kilowatt, Kilowatt Hour
LCOE	Levelized Cost of Electricity
LCR	Local Clearing Requirement
LMP	Locational Marginal Price
LMR	Load Modifying Resource
LRZ	Local Resource Zone
LSE	Load Serving Entity
MGD	Million Gallons per Day
MISO	Midcontinent Independent System Operator
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
NRC	Nuclear Regulatory Commission
NTG	Net-to-Gross
POV	Point of View
PPA	Power Purchase Agreement
PRA	Planning Resource Auction
PRMR	Planning Reserve Margin Requirement
PV	Solar Photovoltaic
RICE	Reciprocating Internal Combustion Engine
RPOC	Resource Planning and Operations Committee
RTO	Regional Transmission Organization
SIP	State Implementation Plan
SEPO	Solar Energy Purchase Option
SERC	Southeastern Electric Reliability Council
SLR	Subsequent License Renewal
SO2	Sulfur Dioxide
SREA	Southern Renewable Energy Association
SSRP	Strategic Supply Resource Plan
TEP	Tax Equity Partnership
WB	White Bluff Steam Electric Station
UPC	Use Per Customer
WIIN Act	Water Infrastructure Improvements for the Nation Act
ZRCs	Zonal Resource Credits

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 Chief Executive Officer. 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 provide 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	831	100%	786	1974
Arkansas Nuclear One Unit 2	979	100%	926	1980
Carpenter Unit 1	31	100%	31	1932
Carpenter Unit 2	31	100%	31	1932
Hot Spring	600	100%	600	2002
Independence Unit 1	826	31.5%	224	1983
Lake Catherine Unit 4	522	100%	522	1970
Ouachita Unit 1	242	100%	242	2002
Ouachita Unit 2	244	100%	244	2002
Remmel Units 1, 2 & 3	12	100%	12	1925
Union 2	498	100%	498	2003
White Bluff Unit 1	815	57.0%	400	1980
White Bluff Unit 2	823	57.0%	404	1981

Purchased Generation	Total Installed Capacity (MW)	Retail Capacity (MW)	Commercial Operations Date
Blakely	86	86	1956
DeGray	77	77	1972
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)
Demand Response	86
Interruptible Load	77

Notes:

- Estimates above are 2021 reductions.
- EAL's Demand Response includes Residential Direct Load Control and Agricultural Irrigation Load Control programs.
- Demand Response and Interruptible capacity is grossed up to account for reserve margin and line loss value in the Load & Capability analysis.

Appendix C - MISO MTEP Submissions

Table I: EAL Projects Approved in Appendix A of MTEP20

Project Driver	Project Name	Current Projected ISD
Generator Interconnection	Searcy Price 161kV: Expand 161kV Station (J893)	Complete
Generator Interconnection	Kuhn Road 161kV: Expand substation (J934)	6/1/2022
Generator ERIS & NRIS	Rebuild Kuhn Road - Ebony 161 kV Line (J934)	6/1/2022
Generator Interconnection	Marston 161kV: Cut In Switching Station (J944)	10/1/2022
Generator Interconnection	Bob White 161 kV: Cut in SS (J1007)	11/1/2022
Transmission Reliability	Hot Springs 115 kV: SPOF	12/1/2022
Transmission Reliability	Pleasant Hill 500 kV: Add 2 Reactors	12/31/2022
Generator Interconnection	Locust Creek 161kV: Construct Station (J919)	2/1/2023
Generator Interconnection	Ritchie Plant 230 kV: Expand substation (J834)	2/15/2023
Generator Interconnection	Falls 161 kV: New Cut In (J1125)	3/1/2023
Generator Interconnection	Driver 230 kV: POI at Substation (J1155)	3/1/2023
Generator Interconnection	Flat Fork 230kV: Cut In Switching Station (J907)	6/1/2023
Enhanced Transmission Reliability	Danville 161 kV: Install Capacitor	6/1/2023
Load Growth	Screeton 115 kV: Construct New Substation	6/1/2024
Load Growth	Hot Springs Plemmons 115 kV: New Substation	6/1/2024
Generator Interconnection	Heth 500 kV: New Substation (J1060)	10/1/2024

Table II: EAL Projects Submitted as Target Appendix A in MTEP21

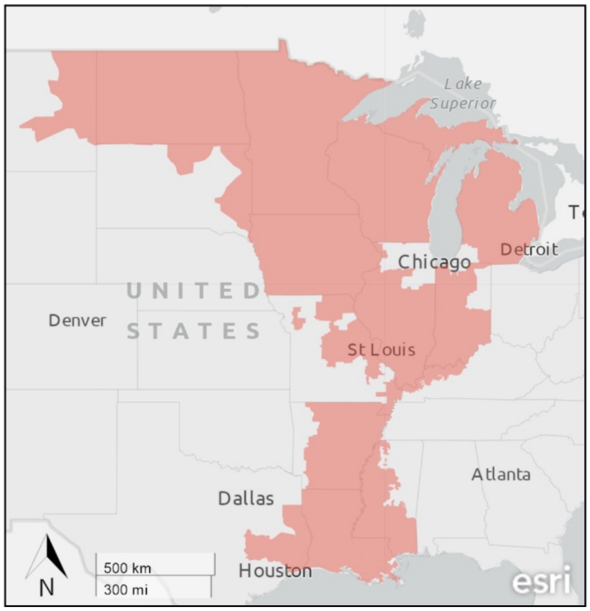
Project Driver	Project Name	Current Projected ISD
Asset Management	2021 EAL Asset Renewal Program	12/31/2021
Load Growth	Moreland 161 kV: Rebuild Substation	12/31/2022
Asset Management	2022 EAL Asset Renewal Program	12/31/2022
Generator Interconnection	Happy 115kV Switching Station (J1373)	3/15/2023
Load Growth	Cave City 161 kV: Add 2nd Transformer	6/1/2023

Table III: EAL Projects Submitted as Target Appendix A in MTEP22

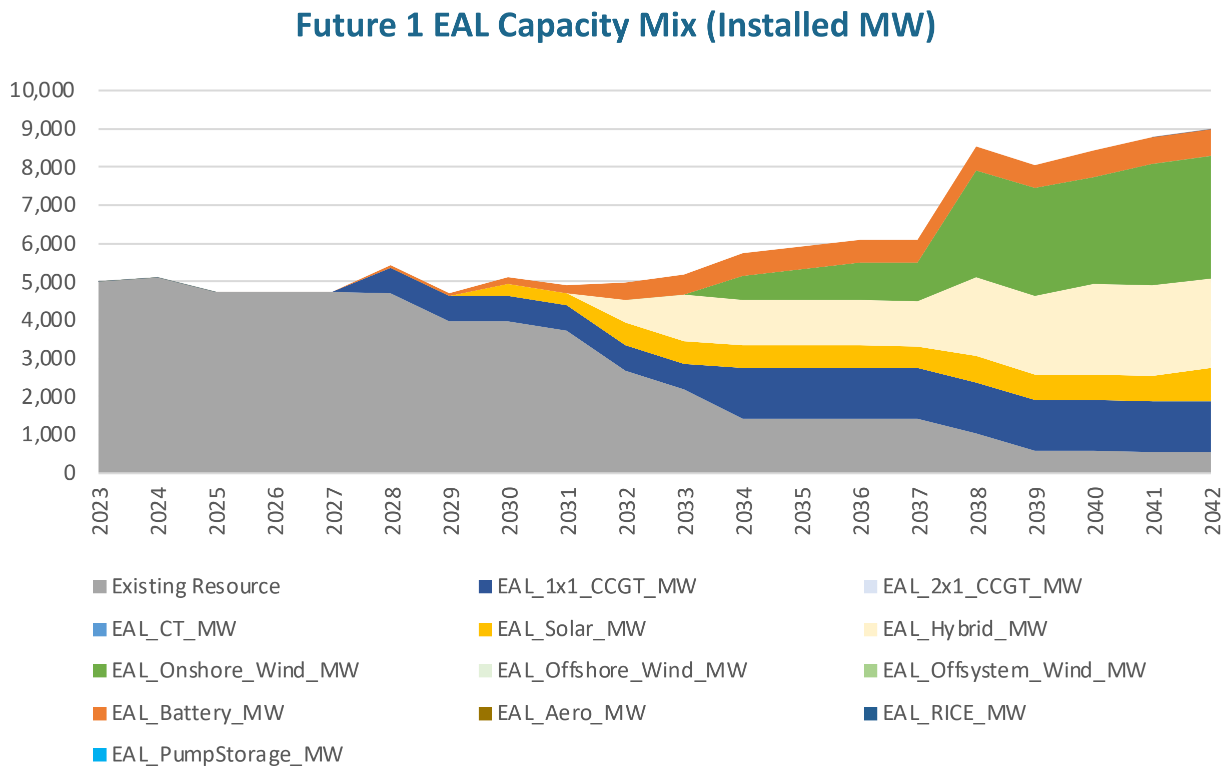
Project Driver	Project Name	Current Projected ISD
Enhanced Transmission Reliability	Junction City 115 kV: Upgrade CTs	12/1/2023
Asset Management	2023 EAL Asset Renewal Program	12/31/2023

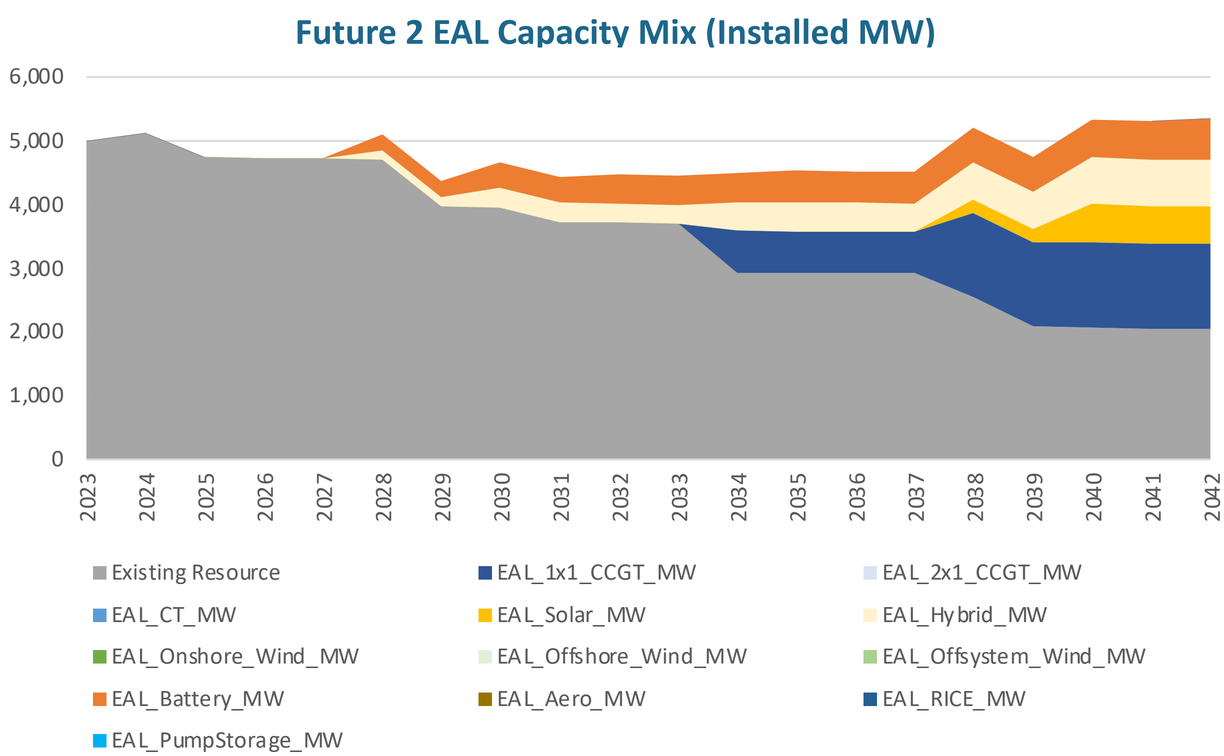
Appendix D – Scope of AURORA Market Model

The shaded areas shown on the map are modeled in AURORA. These areas include MISO-South, the 1st tier markets adjacent to MISO-South (SPP, TVA, AECI and SOCO), and the remainder of the MISO (MISO-Central and MISO-North).

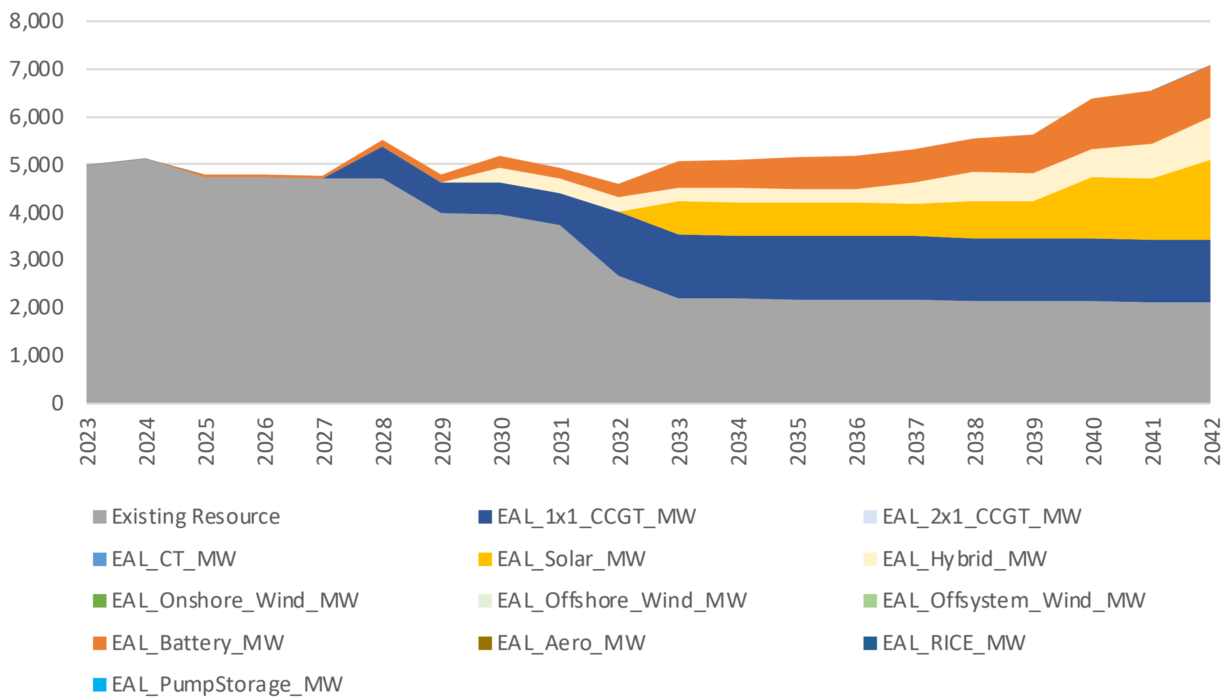


Appendix E – Portfolio Capacity Mix Charts

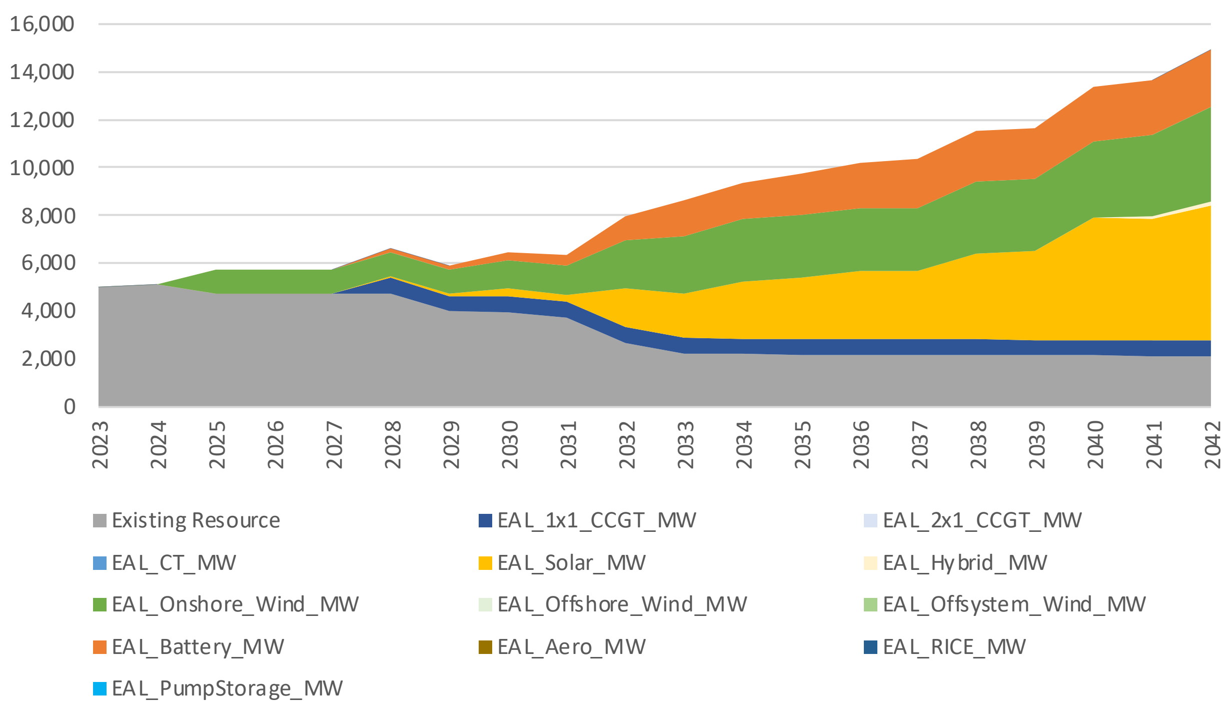




Future 3 EAL Capacity Mix (Installed MW)



Future 4 EAL Capacity Mix (Installed MW)



Appendix F – TRSC Analysis Results

Total Relevant Supply Cost Analysis Results

The Total Relevant Supply Cost (TRSC) for each portfolio was calculated for the future for which it was developed. The total relevant supply cost is calculated using:

Variable Supply Cost - The variable output from the Aurora model for each portfolio in each of the futures, which includes fuel costs, variable O&M costs, emission costs, startup costs, energy revenue, make-whole payments, and uplift charges.

Levelized Real Non-Fuel Fixed Costs - Return of and on capital investment, fixed O&M, and property tax for the incremental resource additions in each portfolio, calculated on a levelized real basis.

DSM Costs - Costs associated with DSM programs less capacity value associated with the program.

Capacity Purchases/(Sales) - The capacity surplus (or deficit) in each portfolio multiplied by the assumed capacity value.

Future 1 Optimized Portfolio Total Relevant Supply Cost Results

	Cost [$MM, 2021$ NPV]
Variable Supply Cost	$3,351
Resource Additions Fixed Costs	$3,242
DSM Net Fixed Costs	($57)
Capacity Purchases / (Benefit)	($85)
Total Relevant Supply Cost	$6,452

Table F-1: Future 1 Optimized Portfolio TRSC

Future 2 Optimized Portfolio Total Relevant Supply Cost Results

	Cost [$MM, 2021$ NPV]
Variable Supply Cost	$2,975
Resource Additions Fixed Costs	$1,334
DSM Net Fixed Costs	($33)
Capacity Purchases / (Benefit)	($101)
Total Relevant Supply Cost	$4,175

Table F-2: Future 2 Optimized Portfolio TRSC

Future 3 Optimized Portfolio Total Relevant Supply Cost Results

	Cost [$MM, 2021$ NPV]
Variable Supply Cost	$3,280
Resource Additions Fixed Costs	$2,017
DSM Net Fixed Costs	($4)
Capacity Purchases / (Benefit)	($62)
Total Relevant Supply Cost	$5,232

Table F-3: Future 3 Optimized Portfolio TRSC

Future 4 Optimized Portfolio Total Relevant Supply Cost Results

	Cost [$MM, 2021$ NPV]
Variable Supply Cost	$2,578
Resource Additions Fixed Costs	$5,129
DSM Net Fixed Costs	($36)
Capacity Purchases / (Benefit)	($106)
Total Relevant Supply Cost	$7,565

Table F-4: Future 4 Optimized Portfolio TRSC

Table F-5 below summarizes the total relevant supply cost results for the optimized portfolio in future 1, relative to sensitivity portfolios 1-4.

Future 1 Optimized Portfolio TRSC Results Compared to Sensitivity Portfolios

	Cost [$MM, 2021$ NPV]	Variance to Future 1 Portfolio [$MM, 2021$ NPV]
Future 1 Portfolio	$6,452	$--
Sensitivity Portfolio 1	$6,457	$5
Sensitivity Portfolio 2	$6,363	($89)
Sensitivity Portfolio 3	$6,387	($65)
Sensitivity Portfolio 4	$6,291	($161)

Table F-5: Future 1 Optimized Portfolio TRSC Versus Sensitivity Portfolios

Appendix G – ICF DR & DER Achievable Potential Study

[Attachment]

Entergy Arkansas: Demand Response and Distributed Energy Resources Achievable Potential Study

Final Report

October 05, 2021

Submitted to:
Entergy Arkansas, LLC

Submitted by:
ICF Resources, LLC
9300 Lee Highway
Fairfax, Virginia 22031

TABLE OF CONTENTS

1 EXECUTIVE SUMMARY

Entergy Arkansas, LLC (EAL) engaged consulting firm ICF Resources, LLC (ICF) to conduct an independent, forecast of the achievable potential of selected demand response (DR) program types and distributed energy resources (DER) technologies on the utility's system. DR programs and DER technologies were selected for analysis based on their relevance to utility planning practices nationwide and their specific relevance to EAL's customers and planning processes.

The resulting ICF forecast is being utilized by EAL to provide hourly inputs for its integrated resource planning (IRP) process over the period 2023 through 2042. ICF produced forecasts for three scenarios: high levels of program or technology adoption, reference levels of adoption, and low levels of adoption. Doing so both allows the forecasts to be aligned with EAL's futures planning scenarios and recognizes the inherent uncertainty in forecasting over a 20-year horizon.

Key methodologies and outcomes from ICF's analysis are summarized below for both DR and DER technologies.

1.1 Demand Response

ICF took a systematic approach, as discussed in the following sections, to assess the potential for a variety of DR programs and technologies, and ultimately provided forecasts for those technologies which proved cost-effective and for the existing programs irrespective of their cost-effectiveness. These technologies included:

- Direct Load Control (DLC):
    - Water Heaters and Pool Pumps (*within 'DLC – Water End Uses' program*)
    - Central Air Conditioners (*Existing Residential DLC program*)
- Smart Thermostats (*Existing Smart DLC program*)
- Interruptible Load (*Existing program associated with Rider OIS*)
- Agricultural Irrigation Load Control (Existing AILC program)

Technologies that were evaluated but did not pass cost-effectiveness test, i.e., a Total Resource Cost (TRC) benefit-cost ratio test in any of the scenarios modeled, and thus were not included in the forecasts, included:

- Direct Load Control:
    - Battery Storage
    - Electric Vehicle Smart Charger
    - Room Air Conditioner
- Thermal Storage

Scenarios modeled were reference, low, and high cases with the participation rate as the primary variable differing across scenarios. These scenarios were subsequently mapped to Futures 1-4 used by EAL in its long-range planning. All the programs in all the scenarios are modeled to start in 2023.

Key findings on potential dispatch of DR from the study analysis are:

- Future 1 shows a DR potential of 20% of peak demand in 2042, and the range of variation within Futures 1-4 is from 16% to 26% under varying participation assumptions.

- Industrial potential, which is the dominant fraction, is 55% of the achievable DR potential, residential potential is 43%, and commercial potential is 2%.
    - In 2042, at a program level, DLC - Water end-uses program constitutes 25% of the savings while smart thermostats constitute 75% of the achievable potential for the residential sector. Direct load control - water end-uses program, which contributes 100% of the achievable potential in commercial sector. In the industrial sector, agricultural

irrigation load control program accounts for 32% while interruptible program accounts for 68% of achievable potential.
- Sector level portfolios have benefit-cost ratios greater than 1 for TRC and Program Administrator Cost (PAC). The programs included in achievable potential are (a) the ones that have a TRC benefit-cost ratio of 1 in at least one of the scenarios, (b) existing programs, irrespective of their TRC.

1.2 Distributed Energy Resources

Forecasts were prepared for five DER technologies: residential solar photovoltaic (PV); commercial and industrial (C&I) PV; residential battery storage paired with PV; C&I battery storage paired with PV; and standalone C&I battery storage. The C&I technology forecasts were divided into separate commercial and industrial estimates.

ICF used a combination of project-level economics and individual DER market acceptance curves drawn from experience in other U.S. markets to produce top-down, EAL systemwide forecasts for each technology through a five-step analytic process.

Key findings from the DER forecasts are:

- All five technologies have moderate levels of adoption in the first 10 years of the forecast period due to challenging economics (investment payback periods typically greater than seven years and up to 15 years or more).

- Due to consistently improving economics from the combination of expected declines in PV system capital costs and rising retail electricity prices, PV adoption increases sharply in the second decade of the forecast period. By 2042, ICF estimates that 635 alternating current megawatts (MW_{AC}) of residential PV capacity, 251 MW_{AC} of commercial PV capacity, and 72 MW_{AC} of industrial PV capacity will be installed cumulatively by EAL customers in its *high scenario*.
    - Those volumes of installed capacity translate into the equivalent of about 1,140,000 megawatt-hours (MWh) of residential PV output, 450,000 MWh of commercial PV output, and 125,000 MWh of industrial PV output annually at EAL's central station plant level by 2042 in the *high scenario*.

- However, there are very large differences in outcomes across scenarios, with *reference (medium) scenario* cumulative installed capacity by 2042 at less than half of high scenario levels (259, 84, and 24 MW_{AC} for residential, commercial, and industrial PV, respectively). *Low scenario* outcomes are at levels of 10% or less of the levels of the high scenario by 2042. These outcomes reflect differing assumptions across scenarios about how fast PV capital and operating costs will decline in the future and how much C&I capacity will be installed in 2021 and 2022 before the forecast period begins.

- Residential PV is forecasted to reach higher levels of deployment by 2042 than C&I PV largely because residential PV capital costs are estimated to decline at a greater rate than C&I capital costs and to reach near-parity on a per-kilowatt (kW) basis as the PV industry continues to mature. This is also consistent with national PV deployment patterns to date: 62% of behind-the-meter PV capacity is residential, while 30% is commercial and 8% industrial.[1]

- Though there is no known deployment of battery storage systems at present by EAL customers, the combination of significant decreases in storage system capital costs (declines of more than

[1] Energy Information Administration, U.S. Department of Energy (DOE), *Short-Term Energy Outlook*, December 2020, Table 8b: U.S. Renewable Electricity Generation and Capacity, https://www.eia.gov/outlooks/steo/tables/pdf/8btab.pdf. Data are from individual PV systems below 1 MW_{AC} in capacity.

30% in real dollars in the next 20 years), increases in retail electricity prices, and the relatively large peak demand components of some EAL C&I rate schedules, is expected to result in greater levels of deployment by the end of the forecast period. In the *high scenario*, 171 MW_{AC} of C&I battery power is estimated to be installed by 2042 for standalone battery systems and another 79 MW_{AC} for C&I battery power paired with PV.

- On an aggregate annual energy (MWh) basis, battery storage technologies are expected to have low impacts on the EAL system. For example, the total forecasted impact is only an increase of 2,700 MWh in utility annual net load by 2042 in the *reference scenario* for residential battery storage systems paired with PV. C&I battery storage systems are forecasted with even smaller impacts. These low annual impacts are not only because battery systems tend to be used infrequently (to their full potential less than 5% of hours during a year), but also because their aggregate annual impacts on the grid are only the difference between their charging and discharging cycles. Since battery systems are net consumers of utility power, they increase EAL loads on an annual basis, unlike PV systems that decrease net utility loads.
    - In any given hour, however, battery systems can increase or decrease net loads on the EAL grid, depending on the aggregate battery charging and discharging behavior of customers during that hour. For example, residential battery systems (paired with PV) can increase EAL net loads in a single hour by up to 13 MWh in the *reference scenario* and 71 MWh in the *high scenario* in 2042.

- Benefit-cost ratios and related metrics were not calculated for DER technologies because EAL has not yet contemplated DER-specific programs during the forecast period.

2 INTRODUCTION

2.1 Purposes and Uses of Forecasts

The starting point of ICF's forecasts for EAL was the selection of relevant DR programs and DER technologies. Among DR, we analyzed event-based program types, separated for residential, commercial, industrial, and agricultural customers, as well as one existing rate-based DR program. For DER, PV and battery storage technologies were separated by residential and C&I adoption.

For each selected DR program and DER technology, ICF produced hourly EAL net load forecasts covering 20 years for each of three scenarios: low adoption, reference (medium) adoption, and high adoption. The reference scenario reflects ICF's judgment as to the level of adoption that is most likely to occur given EAL and external market information available at the time of the study.

ICF's residential, commercial, and industrial DER forecasted hourly load impacts for the 2023 through 2042 period were added to EAL's forecasted customer class consumption loads for that period as the baseline for ICF's DR analysis.

The results of ICF's analysis for all scenarios can both inform EAL's planning and be utilized as direct inputs into the utility's IRP. Though ICF's analysis is intended for the utility's internal planning purposes, EAL can publish this report at its discretion as regulatory or business circumstances warrant.

2.2 Organization of the Report

The balance of the report contains explanations of the data inputs and analytic methodologies used, forecast results from applying those inputs and methodologies, and key findings. The DR programs are described first, followed by DER technologies. For DR and DER, the descriptions are divided into these main sections:

- Overview
- Program (DR) or Technology (DER) Types and Definition
- Data Collection
- Program (DR) or Technology (DER) Modeling

The modeling section also contains DR and DER achievable potential results and key findings, as well as benefit/cost analysis for EAL DR programs.

The report concludes with brief descriptions of the hourly inputs and other information that ICF provided to EAL for its IRP process.

3 APPROACH FOR DEMAND RESPOSE (DR)

3.1 Overview

Demand response (DR) provides an opportunity for utilities to include customers in playing a significant role in the operation of the electric grid by reducing or shifting their electricity usage during peak periods in response to financial incentives. These financial incentives vary by program and can take the form of enrollment incentive for participating in a program, annual incentive for responding to events, or incentives for committing a certain portion of the flexible load for demand response.

A high-level process flow of ICF's bottom-up approach for DR potential evaluation, which includes calculation of program participation, savings impacts, and costs for various DR programs, is shown in **Figure 1**. Details of the process are discussed in Section 3.4.3.

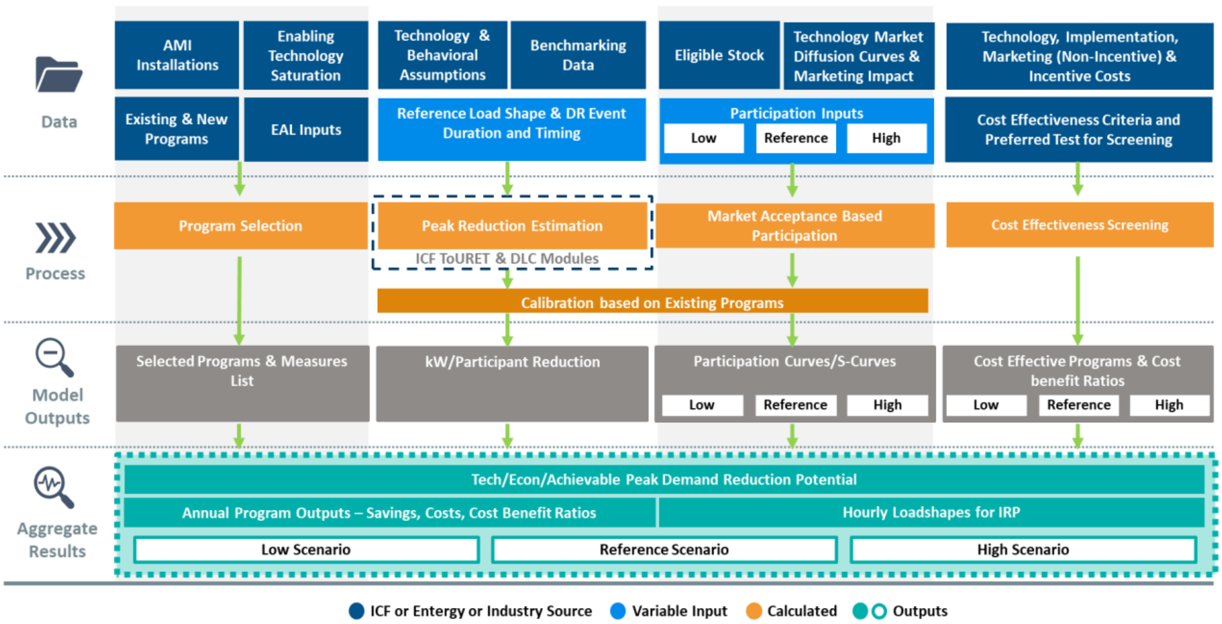


Figure 1: Summary of ICF's Approach to DR Achievable Potential Modeling

3.2 DR Program Types and Definition

Table 1 shows the list of programs and measures ICF selected, in consultation with EAL, to assess in this potential study. All the programs included are event-based programs that rely on events called by the utility to invoke a response either from the customer or directly controlled by the utility to reduce demand. All programs included except Interruptible Rates, are dispatchable and controlled by the utility. Dispatchable program provide greater control to the utility to reduce the peak demand at the time of system need, as compared to other types of DR programs that rely on price responsiveness and behavioral uncertainty.

*Table 1: List of Programs and Measures**

Sector	Program	Measure	Existing/New Program
Residential	Direct Load Control	EV Smart Chargers	New
Residential	Direct Load Control	Room AC	New
Residential	**Direct Load Control**	**Water Heaters; Pool Pumps**	**New**
Residential	**Smart Thermostat**	**Smart Thermostat**	**Existing****
Residential	Direct Load Control	Battery Storage	New
Residential	**Direct Load Control**	**Central AC**	**Existing**
Commercial	Direct Load Control	Room AC	New
Commercial	**Direct Load Control**	**Water Heaters; Pool Pumps**	**New**
Industrial	**Interruptible**	**Interruptible**	**Existing*****
Industrial	**Agricultural Irrigation Load Control**	**Agricultural Irrigation Load Control**	**Existing**

* bold font indicates programs that have cleared TRC test in at least one of the future scenarios, or is an existing program
** Program spans both residential and commercial, but is predominantly residential for existing participants
*** Program spans both industrial and commercial, but is predominantly industrial for existing participants

A brief description of the programs, that cleared the cost-effectiveness test in at least one of the future scenarios, is provided below.

- **Direct Load Control (DLC)**
  Direct load control is a program wherein the utility sends a signal to the customer end use device to either completely turn off the device or reduce the power usage of the device. Customers are given the option to override the event when they choose to, and event notifications can be setup via electronic/mobile communication.

  - ***Water Heaters and Pool Pumps***

  The DLC switch, in the case of these measures, is assumed to disconnect the heating or filtration process. There are additional options available such as pre-heating of water, and optimization of the daily schedules along with remote ability to control or override events similar to smart thermostats.

  - ***Central AC (Existing Residential DLC Program)***

  The DLC switch, in the case of these measures, is assumed to cycle the compressor for the central air conditioning system.

- **Smart Thermostats (Existing Smart DLC Program)**
  Smart thermostat program for residential HVAC systems operates through a remotely controllable programmable or smart thermostat. During the event, the utility sends a signal to the thermostat which in turn increases the setpoint by a few degrees. Additionally, there is a 2-hour pre-cooling to ensure maximum comfort for the participants. Thermostats return to the original setpoint after the event. Customers are given the option to override the event when they choose to. Event notifications can be setup via electronic/mobile communication (email or phone) or via display on the thermostat for supporting devices.

  For this potential study, this program is assumed to be delivered via two options - direct install and BYOT, however, results are reported at program level. While the utility pays for all costs for direct install, it pays an incentive for enrollment into the program in the case of bring your own thermostat. As for the program implementation, the event calls for commercial programs were modeled as 4-hour events aligning with other programs, while the residential programs were assumed to call a 6-hour event split into three overlapping 4-hour blocks with 33.33% of participating customers in each block. This avoids the possibility of creating a new peak due to snapback.

- **Interruptible Load (Existing Program)**
  Interruptible load is a program for C&I customers that involves customers identifying load that constitutes the flexible component for the customer and can be eliminated or curtailed during peak events. This is an existing program associated with the rider Optional Interruptible Service Rider.
- **Agricultural Irrigation Load Control (Existing Program)**
  This is an existing program wherein EAL installs the hardware required for controlling the irrigation in Summer for a maximum of four hours per event, with the events restricted to weekdays. The wells are powered off during the event. The events are called between noon and 9:00 pm, with a limit of 15 events per summer, and a notification is provided to the farmers up to a couple of hours prior to the event.

3.3 Data Collection

This section details the data that was used in developing the potential for the DR programs modeled for EAL.

3.3.1 EAL-Provided Data

The following utility data was provided by EAL:

- Annual and hourly system energy usage forecasts, by customer class
- Annual avoided cost forecasts - energy and capacity
- Annual customer count forecasts, by customer class
- Annual retail rate escalation
- Transmission and distribution losses by customer class
- Reserve margin
- Discount rates
- Program tracking data from 2017-2022 for existing programs covering details-
  - Annual MWh savings
  - Annual MW savings
  - Incentive costs
  - Non-incentive costs
  - Participant count
- Non-incentive costs breakdown for existing programs–
  - Implementing contractor
  - Incentives & direct Install
  - Planning & design
  - Evaluation, Measurement & Verification (EM&V)
  - Administrative costs

3.3.2 External Program and Measure Data

ICF estimated the residential technical feasibility of the programs selected using the Residential Appliance Saturation Study (RASS) data provided by EAL. However, a similar survey for commercial sector was not available and the technical feasibility data was estimated using:

- U.S. Department of Energy Commercial Buildings Energy Consumption Survey (CBECS, 2016)

For the electric vehicle charging direct load control program, program development inputs also use the following sources:

- U.S. Department of Energy Residential Energy Consumption Survey (RECS, 2015)

- U.S. Department of Transportation – Federal Highway Administration
- InsideEVs - All-Electric Car Energy Consumption Compared (EPA, 2019)
- Entergy Mississippi forecast for electric vehicle (EV) load used as reference to develop Entergy Arkansas forecast for EV load

3.3.3 Development of EAL-Specific Inputs for the Selected Programs

EAL specific inputs for the selected DR programs use various sources as references:

- Potential studies conducted across the country for various utilities
- Form EIA_861 from the U.S. Energy Information Administration
- Program data from ESource
- ICF program implementation data and experience

The two primary inputs that are needed to model and estimate the long-term potential are:

- **Impact Estimation**
  DR programs use kilowatt (kW) per participant reduction or a percentage of customer peak reduction, to determine the peak reduction potential of a program. The estimates developed and used in this potential study for the various programs selected are provided in Appendix 6.1. These have been calibrated to EAL historic program tracking data for the existing programs, and they are obtained from research of other programs, pilots and potential studies coupled with inputs from ICF implementation teams, for the new programs. (**Table 21**)

- **Participation Modeling**
  Participation for DR is modeled using Bass diffusion curve, which results in a cumulative participation across years. The ramping parameters for the curve are determined based on ICF program implementation experience and potential study modeling data, while the maximum market share (i.e., the steady state participation achieved towards the end of the study period) is determined from the sources specified above in this section. The maximum market shares used for various scenarios in this potential study are shown in Appendix 6.1 as well.

  For existing programs, the participation curve was calibrated to the historic program tracking participation data provided by EAL. While all programs are expected to continue recruiting participants, the Residential DLC program; i.e., switch-based Central AC DLC program, is expected to ramp down. ICF modeled the participation decline in this program, in accordance with the declining trend seen in program tracking received from EAL, resulting in the program having zero participation after 2030. The in-built assumption is that these participants are moved into the thermostat-based program eventually. (**Table 21**)

3.4 Program Modeling

3.4.1 Elements of Analysis

The assumptions with respect to the elements of the analysis and the reporting methodology that were made in the study are listed in this section:

- **Peak months and events**: Peak summer months were June through September. A maximum of 10 4-hour events are called during the highest average 4-hour load during summer months for any program, with exception of residential smart thermostat[2].
- **Baseline peak**: The peak month was assumed to be July. The event four-hour blocks in July, are used to determine the baseline peak load and the reported savings.

[2] Smart thermostat program, with high participation, runs into issues of creating a new peak due to pre-cooling or snapback. This warranted the events for smart thermostat program to be called over a 5-hour period instead of the standard 4-hour period, as in the case of other programs

- **Economic screening**: All programs were screened for cost-effectiveness with a primary cost-effectiveness test of TRC test. Programs were included in the achievable potential if it passed the TRC test.
- **Mode of program delivery**: It was assumed that all programs were opt-in.
- **Level of savings used in the analysis**: Savings reported for DR are all at central station generator.
- **Program applicability to sub-sectors**:
  - For the residential programs, all programs were assumed to be applicable to all sub-sectors and building types.
  - For the commercial programs, smart thermostat and room AC programs are applicable to the small and medium commercial customers. Thermal Storage and DLC – Water End Uses programs are assumed to be applicable to all sub-sectors and building types within the commercial and government sector.
  - For the industrial sector, the interruptible program is applicable to all large industrial customers.

  Note that the smart thermostat program for commercial is merged into residential program

- **Program hierarchy**: The program hierarchy shown in **Figure 2** was assumed for eligible stock accounting, wherein if a customer can't participate in two programs simultaneously (such as thermal storage and smart thermostat), the eligible stock for the second program in the hierarchy assumes that the participants in the first program are excluded.

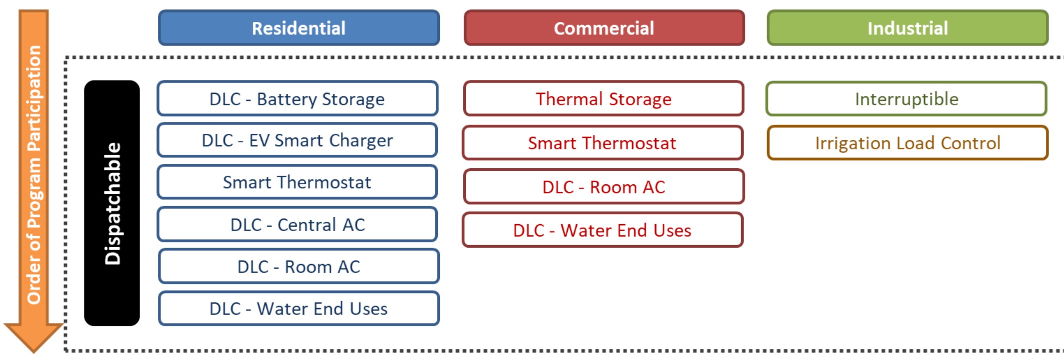


Figure 2: Program Hierarchy Assumption

- **Non-Incentive Costs for Programs**: Non-incentive costs for programs that are applicable to multiple sectors are assumed to have a split of costs between the sectors. For example, the DLC – Water End Uses program is assumed to be primarily residential, which takes up the bulk of the fixed costs, and the commercial programs are assumed to leverage the existing residential setup for program administration and implementation.
- **Levelized Cost ($/kW)**: The levelized cost is the net present value of the cost of unit demand reduction over its lifetime. The costs include all of the incentive and non-incentive costs from the PAC test.

3.4.2 Scenario Definition and Development

ICF modeled three scenarios for this potential study, and the primary differentiating input between the three scenarios is the participation achieved. The varying participation also results in the savings and the costs to be different for the three scenarios, thus representing a range for the achievable potential from DR programs. Sample participation curves showing different levels of maximum market share being achieved over the study period is shown in **Figure 3**.

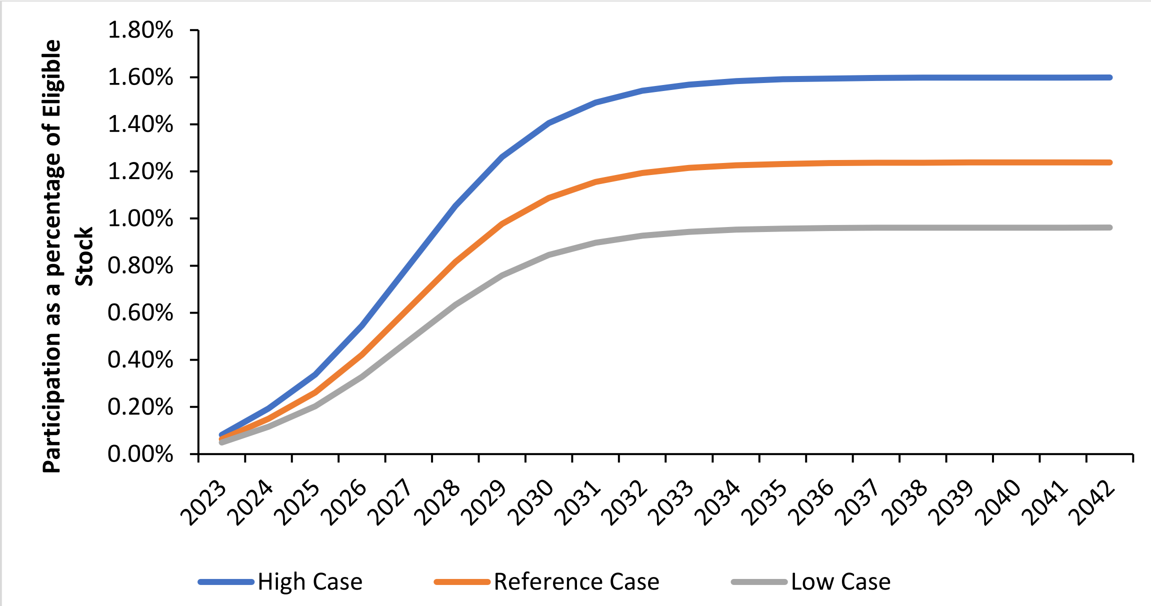


Figure 3: Sample Participation Curves by Case

- **Reference Case**
  This case represents the realistic level of participation and cost-effective savings that could be achieved by utility programs.
- **Low and High Cases**
  The low and high cases represent a conservative and aggressive level of potential achievement, when compared to the reference level. These were modeled by changing the maximum market share of the participation curves, and setting them to 0.75 times and 1.5 times, respectively. Note that this also changes the adoption across the entire study period, since the rate of adoption varies across years to achieve the different levels of maximum market share set for each scenario.

ICF's scenarios, developed primarily using EAL's Future 1 hourly load forecast, can also be associated with the four futures scenarios that EAL uses in its long-range planning, though the linkages between ICF's scenarios and EAL's futures are not exact:

- ICF's reference scenario for DER can be associated with EAL's Future 1.
- ICF's low scenario with EAL's Future 2.
- ICF's high scenario with EAL's Future 3 and Future 4, with changes to some program(s) that would otherwise cause new peaks to be formed.

For the low and high scenarios, the events during which the DR resources are expected to be dispatched were adjusted to reflect the peaks determined by the hourly forecast of the corresponding Futures. For Future 4, the change to programs includes mapping the results to the Industrial Interruptible program reference case results. This mapping ensures that there are no new peaks for Future 4 too.

3.4.3 Potential Assessment Approach

This potential study involved a two-stage process as described in Section 3.1. Each of Stages 1 and 2 involved a four-step process: program selection, peak reduction estimation by program, application of market acceptance-based participation, and then cost-effectiveness screening to result in the achievable potential **(Figure 4).**

Figure 4: Potential Assessment Process Flow

- **Program Selection**
  Program selection is a critical task in determining the potential of demand side management (DSM) resources. There are a myriad of demand response pilots and implementations underway in the United States, but it is important to determine which ones are applicable to the service territory of EAL taking into consideration the eligible technological stock, the load profile characteristics, feasibility of implementation of programs as well as utility and/or stakeholder preference for programs. The programs selected for this study, after discussion with EAL, are listed in **Table 1**.

- **Peak Reduction Estimation**
  ICF uses a bottom-up approach to estimate the demand savings from DR programs and their measures, as applicable. The savings of measures are then aggregated into programs, and the program savings rolled up into the complete DR portfolio savings. For the event-based programs, ICF uses a load control module, a high-level schematic of which is shown in **Figure 5**.

- **Market Acceptance based Participation**
  This step involves estimating eligible stock, technology market diffusion curves and marketing impacts. Program participation is estimated once the size of the eligible stock is determined for each program. The maximum achievable participation levels for programs were determined from research and applied to the program using the Bass diffusion curves discussed in Section 3.3.3. For existing programs, the participation curve was calibrated to the historic program tracking participation data provided by EAL.

- **Cost Effectiveness Screening**
  ICF estimated the implementation and technology costs classified into incentive and non-incentive costs. The overarching assumption was 1 full time equivalent each for the administrative component of the costs and program development, with additional marketing, implementation and incentive costs layered in. To come up with these costs, ICF leveraged the database of costs it has built over time from various program implementations and resources such as filings and potential studies for new programs; and program tracking data provided by EAL for existing programs. The costs for programs that are common to the residential and commercial sectors, are assumed to be split with the residential program starting up first and taking the bulk of the information technology infrastructure setup. The benefits on the other hand, were estimated using the avoided capacity and energy costs provided by EAL. The capacity benefits were calculated for the MWs coincident with MISO peak; i.e., HE 15 – HE 18 for the month of July – the average hourly DR dispatch during this time was estimated for each program for this calculation.

  Once the programs were modeled and the corresponding costs determined, the following cost effectiveness ratios were also estimated for the study - TRC, PAC, Ratepayer Impact Measure (RIM), and levelized costs ($/kW). The benefits and costs were evaluated over 20 years.

After estimating the achievable potential for all screened programs, the hourly load shapes were built. Except for thermal storage and interruptible programs - all other programs assume 100% snapback pre- or post- the DR event, and the load shapes consequently are energy neutral.

Figure 5: ICF Direct Load Control Module

3.4.4 Program Screening and Benefit/Cost Analysis

As mentioned in the previous section, the TRC, PAC and RIM benefit-cost ratios were calculated for the programs and portfolios. The program screening however was done using the TRC test. All programs that have a TRC > 1 at least for one of the scenarios, and existing programs (irrespective of their TRC), were included in the final achievable potential for all scenarios.

Table 2: TRC Screened Cost-Effective Programs (and Existing Programs)

Sector	Program	Measure	Existing or New Program
Residential	Direct Load Control	Pool Pumps	New
Residential	Direct Load Control	Water Heaters	New
Residential	Smart Thermostat	Smart Thermostat	Existing – Smart DLC
Residential	Direct Load Control	Central ACs	Existing – Residential DLC
Commercial	Direct Load Control	Pool Pumps	New
Commercial	Direct Load Control	Water Heaters	New
Industrial	Interruptible	Interruptible	Existing
Industrial	Agriculture Irrigation Load Control	Agriculture Irrigation Load Control	Existing

The list of programs that cleared the TRC test for EAL are listed in the **Table 2**. Room AC program for residential and commercial sectors, EV smart chargers program for residential and thermal storage program for commercial did not clear the TRC test.

3.5 Achievable Potential Results

The achievable potential results shown in this section are the DR dispatched annually – calculated as the average reduction from the events in the peak months i.e., July. The MISO coincident peak reduction from the DR programs, used for cost-benefit calculation, is shown in Appendix 6.2.

In Future 1, DR programs have the potential to reduce load at the time of the forecasted summer peak demand by 20% by the year 2042 for Future 1, which amounts to 533.2 MW. **Figure 6** shows the trend of savings across the study period for all Futures.

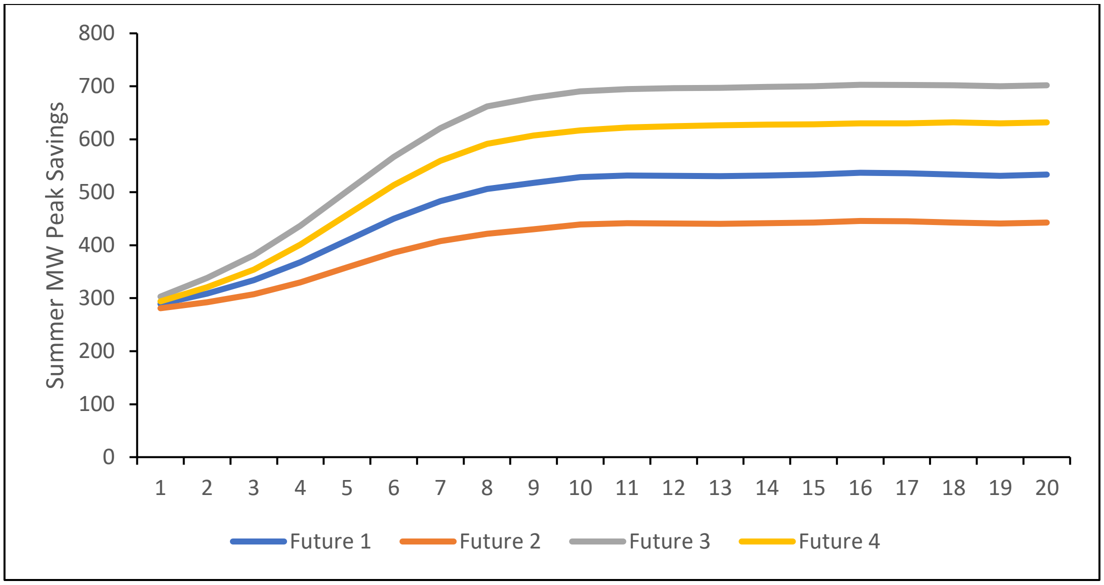


Figure 6: Savings Across the Study Period, by Future

Figure 7 shows the absolute MW savings by scenario wherein it shows that 533.2 MW of peak demand can be reduced in Future 1.

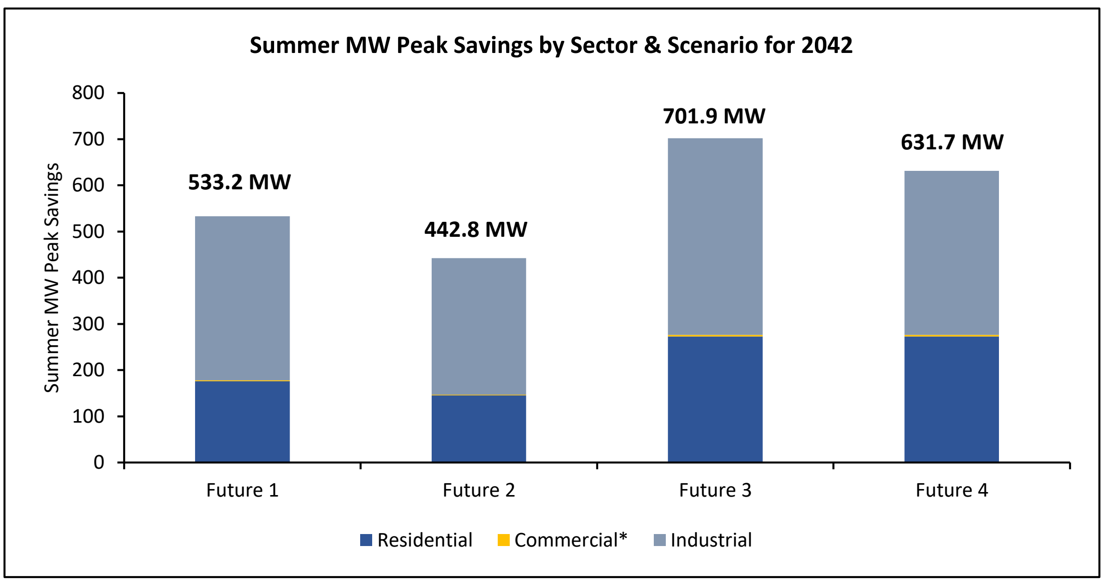
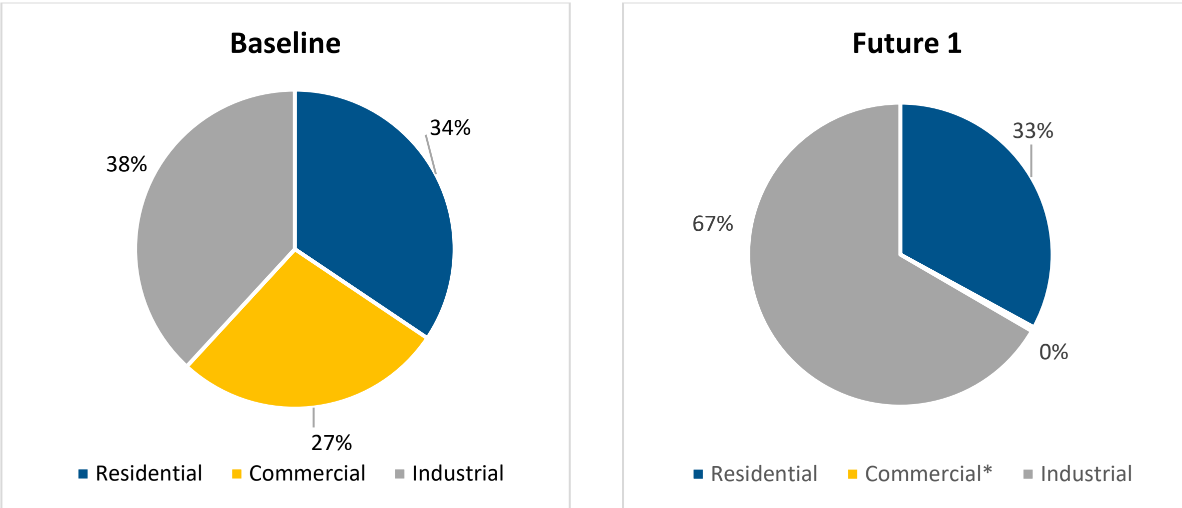


Figure 7: Summer MW Peak Savings Split by Sector & Future Scenario for 2042

Figure 8 shows the baseline split of the peak load for 2042, with the residential contribution being 38% of the peak load, and 27% contribution from the commercial sector in baseline. The savings pie chart in **Figure 8** maintains the high savings proportion from the industrial sector at 66.6%.



*Commercial savings contribution is 0.4% in Future 1

Figure 8: Baseline and Savings Split by Sector & Scenario for 2042

Figure 9 shows the nominal costs that will be incurred for running the programs in Future 1 in each year. The nominal costs are expected to rise until 2028 and then drop till 2032 around when the participation rates for all programs start to saturate. The replacement costs of enabling devices and re-participation costs (including marketing) for existing customers whose enabling devices expire, results in the curve for the second half mimicking the first half of the study period, albeit higher due to incentives for the larger participant base. The share of costs is the highest for the residential sector, due to the higher share of participant count as well as the number of programs.

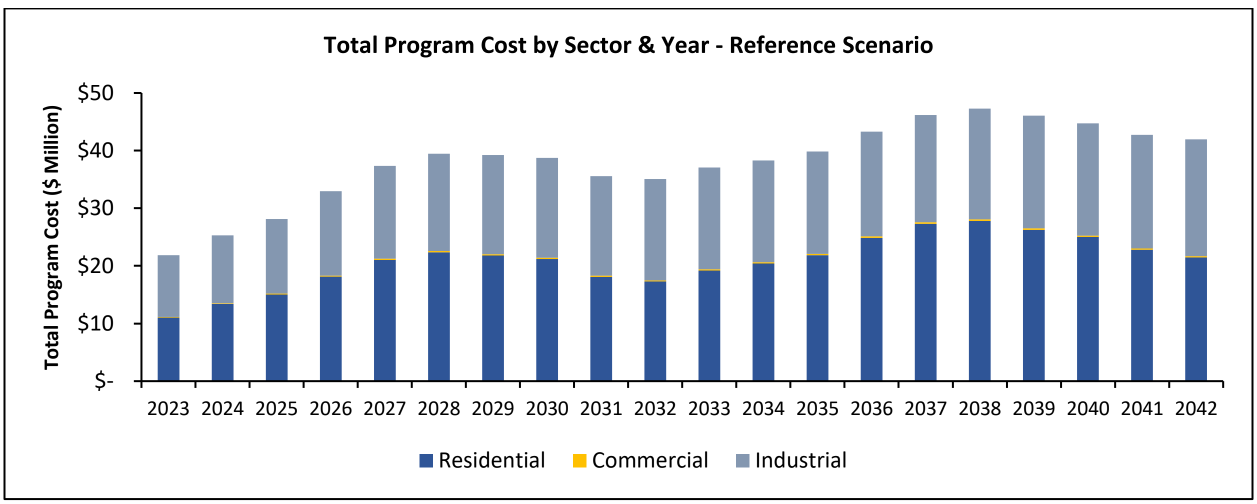


Figure 9: Annual Program Costs Split by Sector for Future 1 Scenario

3.5.1 Residential Results

Figure 10 and **Table 3** show the residential savings potential in the year 2042, by program for all the three scenarios. DLC Central AC results show up as zero for 2042, since the program participants are assumed to move to a thermostat-based program eventually. As noted earlier, the DLC Central AC program phases out by 2031.

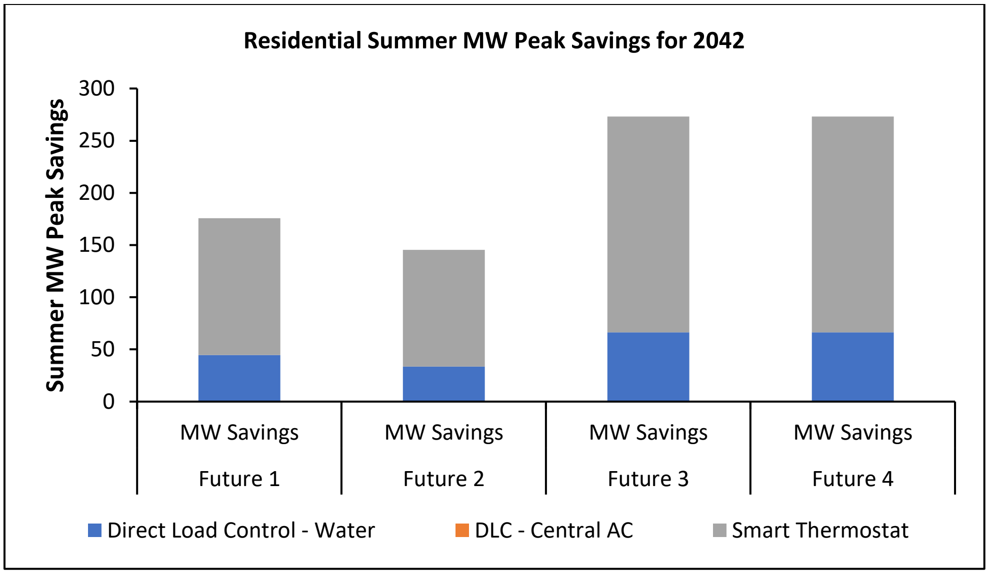


Figure 10: Residential Summer MW Peak Savings for 2042, by Program for four Scenarios

Table 3: Residential Summer MW Peak Savings & Share for 2042, by Program and Scenario

Program	Future 1		Future 2		Future 3		Future 4	
	MW Savings	Savings Share (%)	MW Savings	Savings Share (%)	MW Savings	Savings Share (%)	MW Savings	Savings Share (%)
Direct Load Control – Water End Uses	44.5	25%	33.5	23%	66.5	24%	66.5	24%
DLC - Central AC	0.0	0%	0.0	0%	0.0	0%	0.0	0%
Smart Thermostat	131.2	75%	112.0	77%	206.5	76%	206.5	76%
Total	**175.7**	**100%**	**145.5**	**100%**	**273.0**	**100%**	**273.0**	**100%**

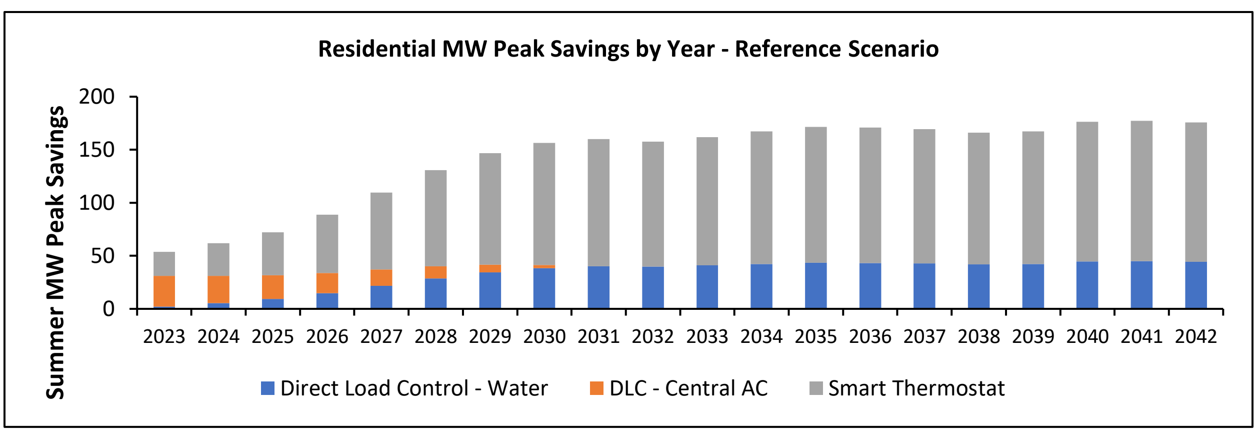


Figure 11: Achievable Future 1 Scenario Summer MW Peak Savings for Residential 2023-2042

Smart thermostats contribute to the bulk of the savings at 75% of the total for Future 1 scenario. **Figure 11** shows the trend of savings by program for Future 1 scenario for the 20 years of the potential study.

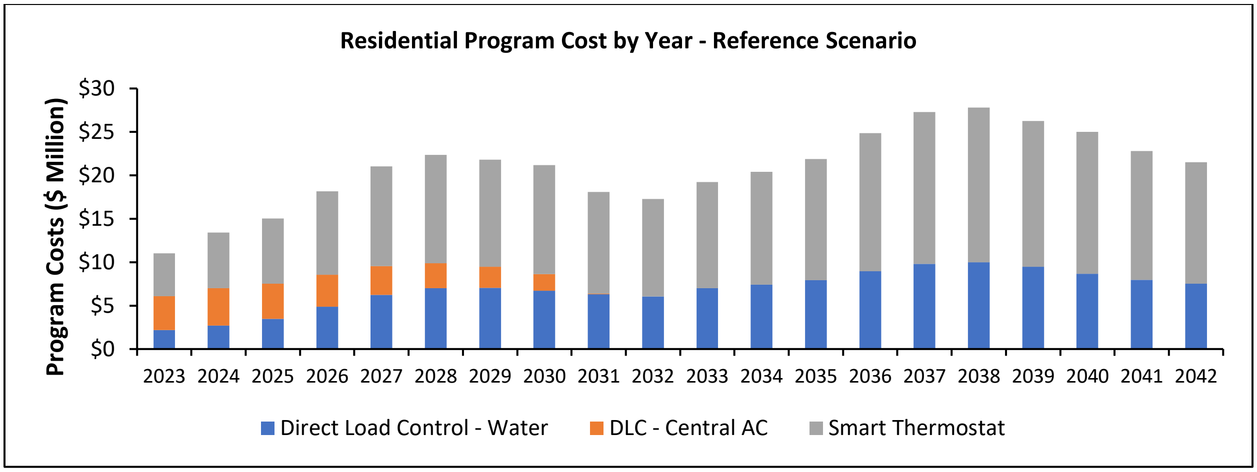


Figure 12: Achievable Future 1 Scenario Nominal Cost Savings for Residential 2023-2042

Figure 12 shows the nominal costs by year for the residential sector, which, as expected, follows the same pattern as the nominal cost graph for the overall portfolio. **Table 4** shows the cost-effectiveness results for the residential programs. Smart Thermostat program has TRC of 1.07 followed by DLC – Water End Uses TRC at 0.74[3]. The overall portfolio clears TRC at 1.00.

Table 4: Residential Achievable Future 1 Scenario Cost Effectiveness Ratios

Scenario	Program	TRC	PAC	RIM	Levelized Cost ($/kW)
Reference	Direct Load Control – Water End Uses	0.74	0.30	0.30	$ 244.36
Reference	DLC - Central AC	0.42	0.32	0.32	$ 233.26
Reference	Smart Thermostat	1.07	0.78	0.58	$ 117.95
Reference	**Total**	**1.00**	**0.50**	**0.40**	**$ 149.47**

3.5.2 Commercial Results

Table 5 and **Figure 13** summarize the commercial sector savings potential in the year 2042 for the cost-effective programs, by scenario. Direct Load Control – Water End uses contributes to 100% savings.

Table 5: Commercial Summer MW Peak Savings & Share for 2042, by Program and Scenario

Program	Future 1		Future 2		Future 3		Future 4	
	MW Savings	Savings Share (%)	MW Savings	Savings Share (%)	MW Savings	Savings Share (%)	MW Savings	Savings Share (%)
Direct Load Control – Water End Uses	1.8	100%	2.3	100%	3.5	100%	3.5	100%
Total	1.8	100%	2.3	100%	3.5	100%	3.5	100%

[3] Note that the programs included in achievable potential are (a) the ones that have a TRC benefit-cost ratio of 1 in at least one of the scenarios, (b) existing programs irrespective of their TRC.

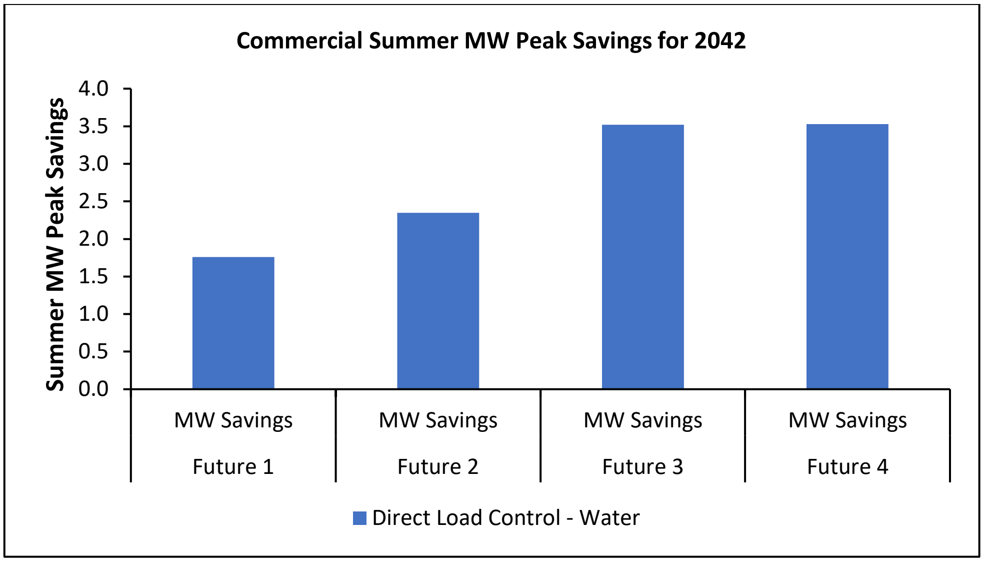


Figure 13: Commercial Summer MW Peak Savings for 2042, by Program and Scenario

Figure 14 shows the trend of savings by program for the Future 1 case scenario for the 20 years of the potential study.

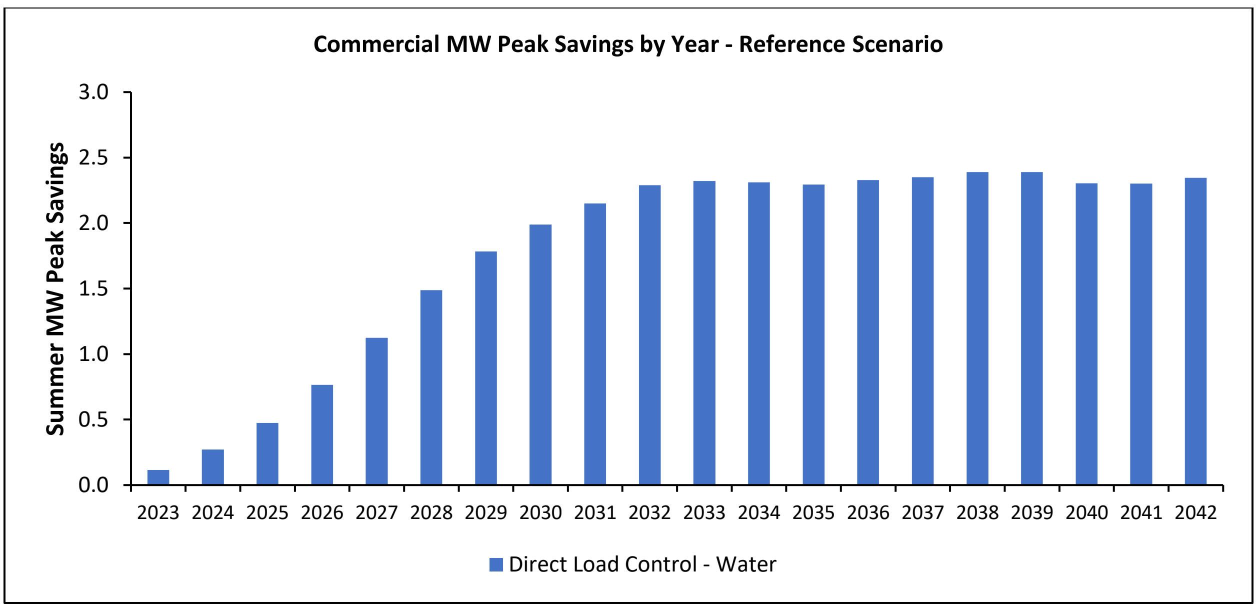


Figure 14: Achievable Future 1 Scenario Summer MW Peak Savings for Commercial 2023-2042

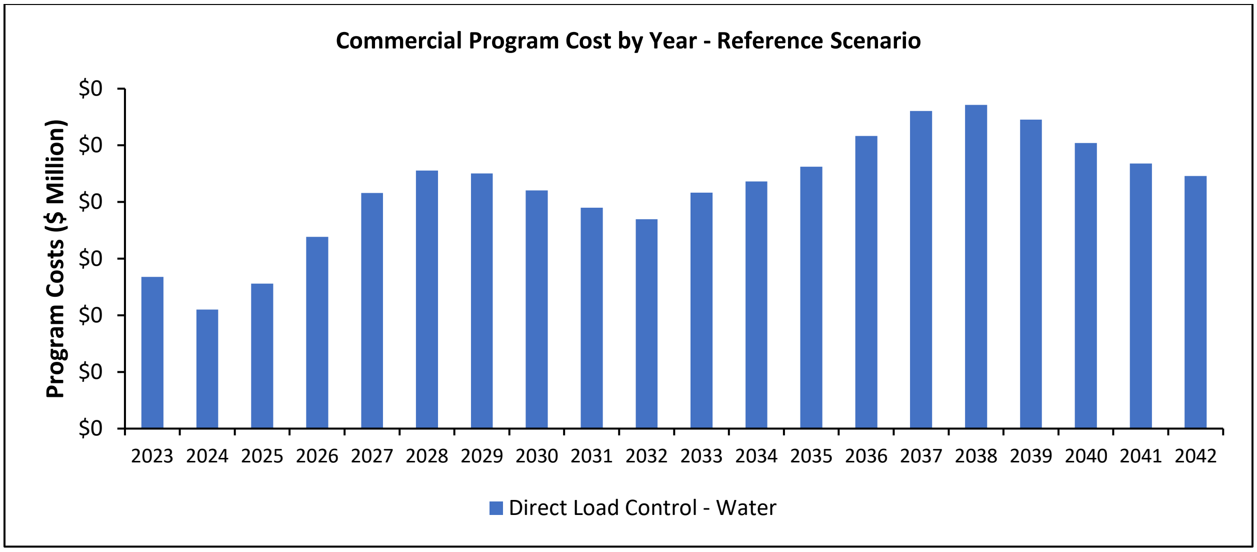


Figure 15: Achievable Future 1 Scenario Nominal Cost Savings for Commercial 2023-2042

Figure 15 shows the nominal costs by year for the commercial sector.

Table 6: Commercial Achievable Future 1 Scenario Cost Effectiveness Ratios

Scenario	Program	TRC	PAC	RIM	Levelized Cost ($/kW)
Reference	Direct Load Control – Water End Uses	1.05	0.55	0.18	$139.81

Table 6 shows the cost-effectiveness results for commercial program. The Direct Load Control – Water End Uses has a TRC of 1.05 and PAC of 0.55.

3.5.3 Industrial Results

Table 7 and **Figure 16** summarize the savings potential in the year 2042 for the two programs in the industrial sector including agricultural irrigation load control, by scenario. **Figure 17** shows the trend of savings for Future 1 for the 20 years of the potential study.

Table 7: Industrial Summer MW Peak Savings & Share for 2042, by Program and Scenario

Program	Future 1		Future 2		Future 3		Future 4	
	MW Savings	Savings Share (%)	MW Savings	Savings Share (%)	MW Savings	Savings Share (%)	MW Savings	Savings Share (%)
Agricultural Irrigation Load	113.2	38%	128.4	36%	128.4	30%	126.3	36%
Interruptible	182.4	62%	226.8	64%	297.1	70%	226.8	64%
Total	**295.6**	**100%**	**355.2**	**100%**	**425.5**	**100%**	**353.0**	**100%**

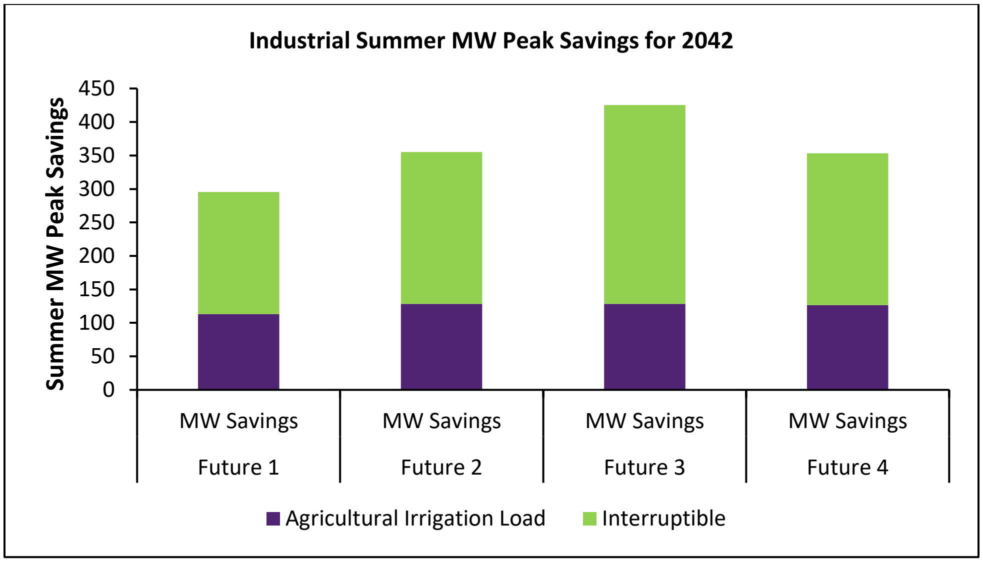


Figure 16: Industrial Summer MW Peak Savings for 2042

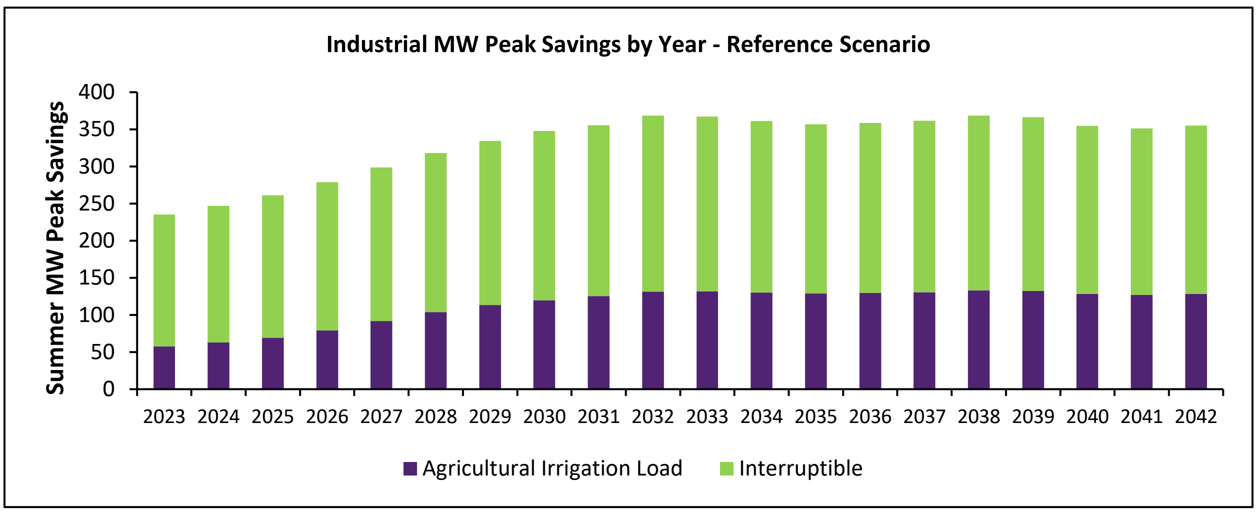


Figure 17: Achievable Future 1 Scenario Summer MW Peak Savings for Industrial 2023-2042

Table 8: Industrial Achievable Future 1 Cost Effectiveness Ratios

Scenario	Sector	Program	TRC	PAC	RIM	Levelized Cost ($/kW)
Reference	Industrial	Agricultural Irrigation Load	2.6	2.1	0.3	$36.1
Reference	Industrial	Interruptible[4]	0.6	0.6	0.1	$129.3
Reference	**Industrial**	**Total**	**1.2**	**1.1**	**0.1**	**$69.2**

[4] Note that industrial program is included in the achievable potential, even if TRC < 1, since it is an existing program.

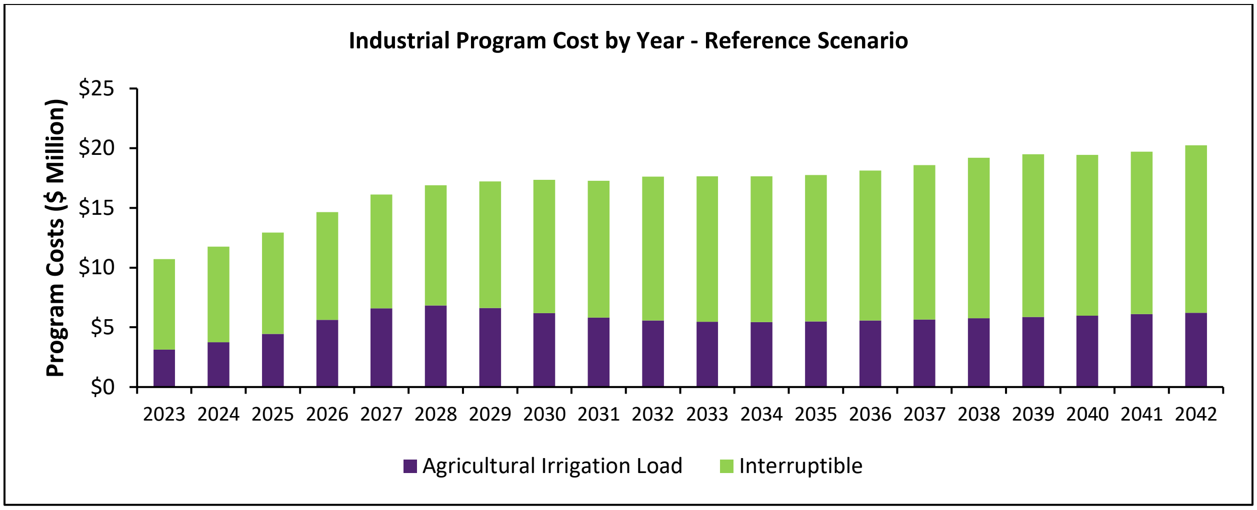


Figure 18: Achievable Future 1 Scenario Nominal Cost Savings for Industrial 2023-2042

Table 8 shows the cost-effectiveness results, with the Agricultural Irrigation Load Control program having a benefit-cost ratio greater than 1 for both TRC and PAC. **Figure 18** shows the nominal costs by year for the industrial programs.

3.6 Key Findings

Future 1 shows a DR potential of 20% of peak demand in 2042, and the range of variation within Futures 1-4 is from 16% to 26% under varying participation assumptions. Industrial potential, which is the dominant fraction of the total DR potential, is 55% of total load, residential potential is 43%, and the commercial potential is 2%.

In 2042, at a program level, DLC - Water end-uses program constitutes 25% of the savings while smart thermostats constitute 75% of the achievable potential for the residential sector. Direct load control - water end uses program contributes to 100% of the achievable potential in the commercial sector. In the industrial sector, agricultural irrigation load control program accounts for 32% while interruptible program accounts for 68% of achievable potential. Absent Arkansas Public Service Commission-approved tariff changes, the existing Rider OIS tariff, that is the basis of this result, will no longer qualify as a Demand Response resource in MISO starting in 2022.

Sector level portfolios have benefit-cost ratios greater than 1 for TRC and PAC.

4 APPROACH FOR DISTRIBUTED ENERGY RESOURCES (DER)

4.1 Overview

ICF's approach to DER modeling relies on the same type of project-level economics used in our forecasting of DR. ICF applied these project economics via a top-down (service territory-wide) correlation between project economics and DER adoption in other U.S. markets. Doing so creates analytic efficiencies while allowing strong comparability of results between EAL and other utility markets.

ICF's analysis followed the five-step process described below and pictured in **Figure 19**:

1. Establish baseline conditions and customer project-level economics for each DER technology in EAL territory. This included:

   a. Collecting relevant DER cost, performance, and adoption data from EAL, national sources, and other state and utility markets.

   b. Drafting input assumptions for low, reference, and high scenarios, reviewing assumptions with EAL, and mutually agreeing on assumptions to be used.

   c. Populating assumptions into 25-year pro-forma (cash flow) models of project-level DER economics from the customer perspective.

   d. Calculating the investment payback period from the pro-forma models for the 240 combinations of customer type and DER technology, scenario, and forecast year listed below.[5]

      i. Residential PV; C&I PV; C&I combined PV and battery storage; and standalone C&I battery storage[6] (4 customer/technology combinations).

      ii. High, reference, and low scenarios (3 scenarios)

      iii. Annual forecasts for 2023 through 2042 (20 years).

2. Utilize the historical adoption experience of other U.S. markets with customer PV and battery storage systems to inform market acceptance curves. ICF linked these curves to the forecasted investment payback periods for DER technologies in EAL territory and secular growth trends to estimate adoption (i.e., the achievable potential) of the technologies by EAL customers.
3. Produce annual achievable potential forecasts of customer DER installed capacity and net electricity generation in EAL territory for the 2023 through 2042 period.
4. Separate the annual C&I forecasts into commercial and industrial customer results.
5. Convert the annual generation forecasts into EAL net hourly load impacts, including gross charge and discharge data for battery storage, through the use of well-grounded data on DER technology use patterns.

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[5] ICF used an "attachment rate" model (with high, reference, and low scenario rates) based on precedents in other U.S. markets in lieu of calculating investment payback periods for the fifth DER customer technology, residential PV combined with battery storage. This is because there is not an economically-viable use case for this technology in EAL's territory given the utility's most commonly used residential rate structure. ICF observes residential customers adopting battery storage when they install PV systems even in markets without present economic uses, whether to offer back-up power, in expectation of future electricity rate changes, or for other reasons.

[6] Standalone residential battery storage was not included as a DER technology in ICF's analysis because there is not economic use case for this technology in EAL territory.

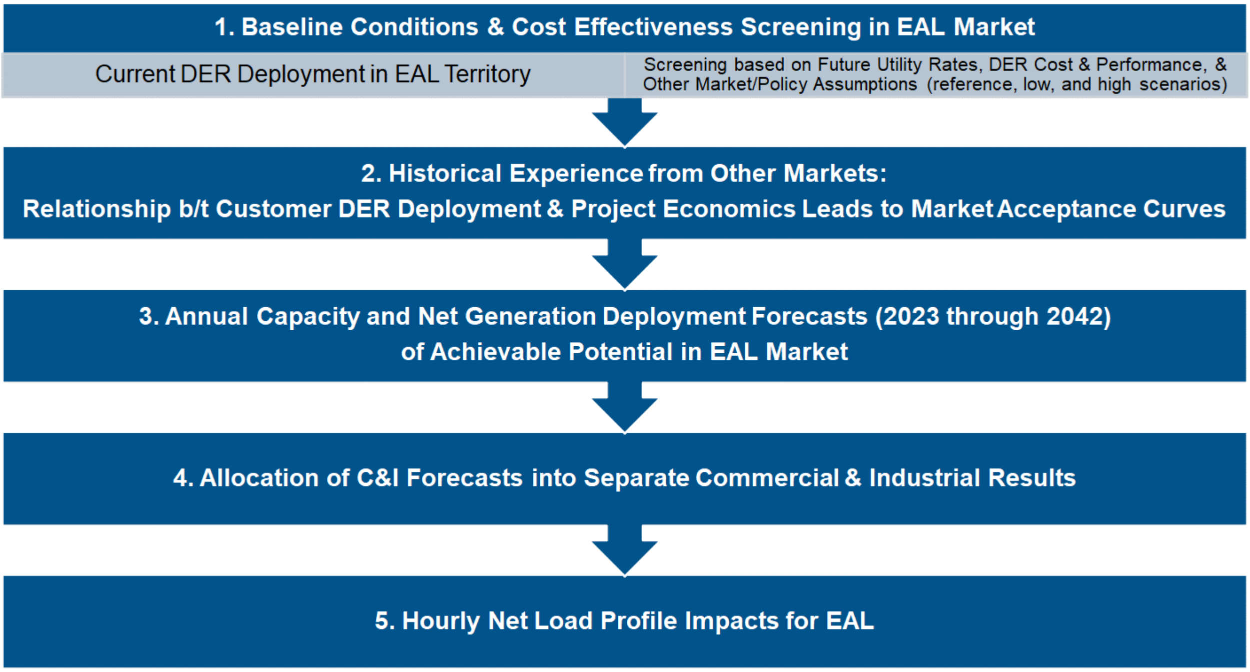

Figure 19: Summary of ICF's Approach to DER Achievable Potential Modeling

4.2 DER Technology Types and Definition

ICF analyzed five combinations of customer type and DER technologies (hereafter abbreviated as "DER technologies"), as shown in **Table 9**. We used a prototype size for each technology and customer type to assess annual, project-level economic returns and to produce net load shapes of forecasted EAL customer adoption of the technology.

System sizes for PV technologies are listed in direct current (DC), while battery storage technology sizes are listed in alternating current (AC) measures of power (kW) and energy (kilowatt-hour, or kWh). The former denotes the maximum amount of power that can flow into or out of the battery system at any one time subject to technical limitations (its instantaneous capacity), while the latter describes the amount of energy that can be stored in total in the battery system.[7] The ratio of energy (kWh) to power (kW) in a battery storage system is called its "duration" and is expressed in hours.

[7] For more information on battery metrics, see National Renewable Energy Laboratory (NREL), *Batteries 101 Series: How to Talk About Batteries and Power-To-Energy Ratios*, 2016, at: https://www.nrel.gov/state-local-tribal/blog/posts/batteries-101-series-how-to-talk-about-batteries-and-power-to-energy-ratios.html.

Table 9: List of DER Technologies Analyzed

Sector	Technology	Prototype Individual Project Size
Residential	PV	7 kW_{DC}
C&I	PV	70 kW_{DC}
Residential	PV + Battery Storage	PV: 7 kW_{DC} Battery: 6 kW_{AC}/14 kWh
C&I	PV + Battery Storage	PV: 70 kW_{DC} Battery: 50 kW_{AC}/150 kWh
C&I	Standalone Battery Storage	Battery: 50 kW_{AC}/150 kWh

The prototype size for residential PV reflects the average national system size, as does the size of the residential battery storage system, as further described in Section 4.3.3 below. The prototype C&I PV system size is based on deployments to date in EAL territory and is somewhat higher than the national median size.

The size of the C&I battery storage system paired with PV was selected to have AC power modestly below the PV system's AC-equivalent capacity and a three-hour battery duration, as is common among C&I battery storage systems. The size of the standalone C&I battery system was established at the same level. In both instances, the power and energy sizing maximizes economic use for batteries under EAL's C&I rate schedules with monthly peak demand charges, such as the utility's Large General Service (LGS) schedule.

4.3 Data Collection

ICF relied on a mix of public data from credible government and electricity industry sources and confidential data provided directly by EAL in response to ICF requests. The categories of data used in our analysis are described in the two sections below and, then, the use of that data to create specific input assumptions tailored for this analysis is described in Section 4.3.3.

4.3.1 EAL-Provided Data

EAL provided the following types of data that were used in the DER forecasts, as well as additional information that was requested by ICF but not directly used in our forecasts.

- Capacity of interconnected customer PV systems.[8]
- Guidance on the portion of solar electricity that is typically consumed on-site by EAL customers versus exported to the utility.
- Guidance on any current and planned utility DER programs.
- Aggregate hourly consumption load shapes by customer class.
- Customer counts by class and tariff rate.

[8] No interconnected customer (behind-the-meter) battery storage systems for residential or C&I customers were included in the EAL data.

- Forecasted future retail electricity prices by customer class.
- General price inflation estimates through 2042.
- Transmission and distribution (T&D) loss factors by customer class.
- Weighted-average cost of capital (WACC).

The non-PV specific information provided by EAL was also used in the DR forecasts.

In addition to data sent by EAL, ICF collected information on EAL customer residential and C&I electricity rates and its Net-Metering and Solar Energy Purchase Option requirements from the utility's published tariffs.

4.3.2 External Technology and Market Data

ICF collected data on PV and battery storage technology capital costs, operations and maintenance (O&M) costs, and performance factors from a combination of U.S. Department (DOE) and DOE-sponsored laboratory sources, as well as state public utility commission-funded, grid operator-funded, and DER industry reports. Data were distinguished between residential and C&I systems and sized in relation to the prototype systems used for this EAL analysis.

In addition to technology cost and performance data, ICF collected and evaluated detailed data on annual adoption patterns for net metered PV and battery storage systems across all states from DOE and DER industry sources to inform the market acceptance curves used in these forecasts.

4.3.3 Development of EAL-Specific Inputs for the Selected Technologies

Key assumptions for the project-level DER pro-forma models are listed in **Table 10**. The assumptions apply equally to the high, reference, and low scenarios, unless otherwise noted. Distinctions between assumptions for residential and C&I systems are noted where relevant.

Assumptions were reviewed with EAL and reflect mutual agreement between EAL and ICF that the values are appropriate for the purposes, and within the limitations, of this analysis. Decimal digits have been rounded in some cases.

Table 10: Key Input Assumptions for DER Technologies Analyzed

Input	Value	Source
Individual System PV Capacity	7 kW_{DC} (residential) 70 kW_{DC} (C&I)	Residential: Rounded up from median value of 6.4 kW_{DC} from Lawrence Berkeley National Laboratory (LBNL), *Tracking the Sun*, 2019, p. 10, https://emp.lbl.gov/sites/default/files/tracking_the_sun_2019_report.pdf.[9] C&I: Approximate average (mean) capacity of interconnected PV systems in EAL territory for C&I customers.
Individual Residential Battery Storage Size	6 kW_{AC} (power) 14 kWh (energy)	Power is the national average (mean) of residential systems deployed as of 2018 in

[9] Historically, the average (mean) size of residential PV systems in EAL territory has been approximately 9 kW_{DC}. However, as third-party financing of customer PV systems has recently become available in Arkansas opening up more financing choices for customers, ICF expects that average system sizes will move towards national norms.

Input	Value	Source
		DOE, *Annual Electric Power Industry Report, Form EIA-861 Detailed Data Files*, 2020, https://www.eia.gov/electricity/data/eia861/. Power is also equivalent to the approximate AC power capacity of the individual PV system utilized in this analysis.[10] Energy is from three example states comprising 84% of the national market in the public edition of Smart Electric Power Alliance, *2019 Utility Energy Storage Market Snapshot*, 2019, p. 9, https://sepapower.org/resource/2019-utility-energy-storage-market-snapshot/.
Individual C&I Battery Storage Size	50 kW_{AC} 150 kWh	Established battery power modestly below the PV power of the prototype individual C&I system used in this forecast on an AC basis and used a 3-hour duration for energy based on industry experience for C&I systems and tailoring to EAL demand-based rate structures.
Behind-the-Meter (BTM) Inverter Loading Ratio (DC to AC capacity ratio)	1.135	Average of the median values for central/string inverters from LBNL, *Tracking the Sun*, 2019, p. 13 for residential and “small non-residential” systems. The “small non-residential” value was used because it corresponds to the system size analyzed in this report for C&I systems. The resulting inverter loading ratio was used in this analysis to convert DC capacity factors for individual PV systems into EAL systemwide residential and C&I PV electricity production forecasts.
Annual PV Capacity Factors$_{DC}$ (in year 1 of operation)	16.87%	EAL’s technology assessment contains a PV capacity factor of 22.1% on an AC basis for utility-scale fixed-tilt systems. The AC value was converted to a DC capacity factor of 16.87%. The AC to DC conversion was based on the median inverter loading ratio of 1.31 for utility-scale fixed-tilt systems in LBNL’s *Utility-Scale Solar Data Update: 2020 Edition*, 2020, p. 16, https://emp.lbl.gov/sites/default/files/2020_utility-scale_solar_data_update.pdf. That DC capacity factor calculated for EAL utility-

[10] The AC capacity of the prototype residential PV system is 6.17 kW_{AC}. That is calculated by dividing the 7 kW_{DC} system capacity by the assumed inverter loading ratio of 1.135.

Input	Value	Source
		scale systems was used in this analysis for residential and C&I systems to maintain consistency between PV systems of different sizes in EAL territory.[11]
Annual PV System Performance Degradation (after year 1 of operation)	0.5%	Median value from NREL, *Solar Technical Assistance Team (STAT) FAQs Part 2: Lifetime of PV Panels*, 2018. https://www.nrel.gov/state-local-tribal/blog/posts/stat-faqs-part2-lifetime-of-pv-panels.html.
Annual Battery Storage System Performance Degradation (after year 1 of operation)	1%	BTM lithium-ion battery storage values from California Public Utilities Commission (CPUC), *Proposed Inputs & Assumptions: 2019-2020 Integrated Resource Planning*, 2019, p. 18, https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/Prelim_Results_Proposed_Inputs_and_Assumptions_2019-2020_10-4-19.pdf.
Portion of PV Annual Output Exported Back to Utility	30.00% (residential) 9.86% (C&I)	Residential: EAL input based on initial analysis of data from its customers with PV systems. C&I: Hourly calculation based on ICF's PV production modeling, EAL's 2023 commercial customer load profile, and an ICF assumption on the capacity sizing of C&I PV systems vis-à-vis load.
Consumption Load Shapes (applied to all years of analysis)	Hourly, systemwide residential and commercial load shapes for 2023[12]	EAL.
PV System Capital Cost	Annual residential and commercial values from NREL, *2020 Annual Technology Baseline*, https://atb.nrel.gov/. Commercial values were used for both commercial and industrial PV systems. Used NREL's advanced, moderate, and conservative cases for the high, reference, and low scenarios, respectively, in this forecast.[13]	

[11] National Renewable Energy Laboratory (NREL) PV Watts® (https://pvwatts.nrel.gov/) electricity output profiles as of November 2020 for fixed roof mount systems, averaged from the locations of Little Rock, Jonesboro, and Pine Bluff, Arkansas, were used to convert this annual capacity factor into hourly PV outputs.
[12] The 2023 consumption load shapes provided by EAL were applied to all DER forecast years.
[13] ICF converted NREL's costs in 2018 dollars to nominal dollars by using the U.S. Bureau of Labor Statistics (BLS) Consumer Price Index for All Urban Consumers of 2.29% from December 2018 to December 2019 (https://www.bls.gov/cpi/tables/supplemental-files/historical-cpi-u-201912.pdf) and, then, EAL's inflation rate forecasts were applied to all subsequent years. C&I system costs were adjusted upward based on size-specific capital cost data in LBNL, *Tracking the Sun*, to reflect the 70 kW_{DC} representative system size in this forecast. That adjustment was warranted

Input	Value	Source
C&I Battery Storage System Capital Cost in 2023[14,15]	BTM lithium-ion battery storage values	CPUC, *Proposed Inputs & Assumptions: 2019-2020 Integrated Resource Planning*, 2019, p. 61. Low (meaning "low cost"), mid, and high values from the CPUC source correspond to the high, reference, and low scenarios, respectively, in the EAL analysis.[16]
C&I Battery Storage System Capital Costs after 2023	Annual percentage decline rates from the NREL source at right were applied to the 2023 values listed above	NREL, *2020 Annual Technology Baseline*. Used NREL's advanced, moderate, and conservative case decline rates for the high, reference, and low scenarios, respectively, in this forecast.[17]
Federal Investment Tax Credit (ITC)	0% (C&I standalone battery storage) 22% in 2023 and 0% in 2024 and thereafter (residential PV) 22% in 2023 and 10% in 2024 and thereafter (C&I PV) 16.5% in 2023 and 7.5% in 2024 and thereafter (C&I battery storage when paired with PV)[18]	Internal Revenue Service and U.S. Congress, *Consolidated Appropriations Act, 2021*.
Federal Accelerated Depreciation	Not applied (residential)	Internal Revenue Service.

because NREL *Annual Technology Baseline* cost projections are for a 300 kW_{DC} system. These adjusted C&I system capital costs were capped at no more than residential capital costs on a per-kW basis.

[14] Because ICF's analysis of residential battery storage paired with PV was accomplished via attachment rates, instead of cash flows, residential battery system cost assumptions were not required.

[15] Because there are typically capital cost savings when battery storage systems are installed contemporaneously with PV systems, the capital costs of C&I battery storage were reduced by 8% when paired with PV compared to standalone battery storage systems. These cost savings are from efficiencies in shared hardware, construction labor, and other activities per NREL, *2018 U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark*, 2018, p. iv, https://www.nrel.gov/docs/fy19osti/71714.pdf. Though that NREL report pertained to utility-scale systems, ICF has found in its experience that cost efficiencies can be present on smaller systems.

[16] CPUC costs assumed for 2022 were adjusted to be 2023 costs by applying the NREL *Annual Technology Baseline* decline rate and the EAL-provided general inflation rate for the year.

[17] ICF converted NREL's decline rates to nominal dollars with EAL-provided general inflation rates.

[18] For the analysis, it was assumed that these battery storage systems were charged 75% of the time from PV and, thereby, eligible for 75% of the PV ITC level for the high scenario. For the low and reference scenarios, no ITC was applied to these C&I battery storage system costs because it was assumed that less than 75% of their charging was from PV power.

Input	Value	Source
	200% Declining Balance Schedule with half-year convention (C&I)[19]	
Annual PV Fixed O&M Cost in first project year ($/kW$_{DC}$)	Annual residential and commercial values from NREL, *2020 Annual Technology Baseline*. Commercial values were used for both commercial and industrial PV systems. Used NREL's advanced, moderate, and conservative cases for the high, reference, and low scenarios, respectively, in this forecast.[20]	
Annual C&I Battery Storage Fixed O&M and Warranty Costs	1.5% of capital cost for first three years of system operation, then 2.5% per year thereafter	Lithium-ion battery storage system values from Electric Power Research Institute (EPRI), *Energy Storage Technology and Cost Assessment: Executive Summary*, 2018, p. 15, https://www.epri.com/research/products/3002013958. Warranty cost component starts after three years.
Annual Escalation in PV Fixed O&M Costs (after first project year) **and Battery Storage Fixed O&M Costs** (after fourth project year)[21]	2.0%	EAL-provided general inflation rate for 2022 and beyond.
PV Inverter Replacement Cost (in year 15 of system operation)	8% of original capital cost	ICF report for ISO New England, *Economic Drivers of PV*, 2015, p. 21, https://www.iso-ne.com/static-assets/documents/2015/02/icf_economic_drivers_of_pv_report_for_iso_ne_2_27_15.pdf.
C&I Battery Pack Replacement Cost (in year 10 of system operation)	$200/kWh	Low end of range for lithium-ion technologies from EPRI, *Energy Storage Technology and Cost Assessment: Executive Summary*, 2018, p. 15.[22]
Battery Storage Roundtrip Efficiency (RTE)[23]	86%	Lithium-ion battery storage system value from DOE, *Energy Storage Technology and Cost Characterization Report*, 2019, p. viii, https://www.energy.gov/sites/prod/files/2019/07/f65/Storage%20Cost%20and%20Performance%20Characterization%20Report_Final.pdf.

[19] For C&I PV systems, the 5-year depreciation schedule was used, while the 7-year schedule was used for C&I battery storage systems. See Internal Revenue Service, *Publication 946: How To Depreciate Property*, 2020, Table A-1, p. 70, https://www.irs.gov/pub/irs-pdf/p946.pdf.
[20] ICF converted NREL's costs in 2018 dollars to nominal dollars with BLS inflation data for 2019 and EAL-provided general inflation rates for 2020 and afterwards.
[21] Due to the structure of the EPRI battery storage O&M assumption on the prior row of this table, the escalation for price inflation is not applied until the fifth project year.
[22] ICF also capped this value at no more than 25% of pre-ITC battery system capital costs for all forecast years.
[23] RTE measures the percentage of power injected into a battery storage system that is dischargeable over a full cycle of charging and discharging the battery system. One minus RTE reflects roundtrip power losses.

Input	Value	Source
Battery Storage Maximum Depth of Discharge	90%	ICF judgment based on battery storage industry experience and studies on the impact of maximum depth of discharge on system lifetime.
Retail Electricity Prices (applicable to PV power consumed on-site and costs for charging battery storage)	EAL-provided rates for residential and commercial customers. The utility's specific price forecasts extended through 2025, after which EAL's general price inflation rate of 2% for 2022 and beyond was applied.[24]	
Net-Metering Rate in 2023 (applicable to PV power exported to the utility)	Based on EAL-provided rates for residential and commercial customers described immediately above, with further adjustment so that only per-kWh charges and the associated share of taxes are offset by net excess generation (i.e., PV power exported to the utility) consistent with EAL's Net-Metering rate schedule.	
Net-Metering Rate after 2023	Escalated at the same annual rates as EAL-provided retail electricity prices.	
Renewable Energy Certificate (REC) Price	$0	Because there is no special market or tariff provision for RECs from new PV systems in EAL territory, and the value to customers of monetizing voluntary RECs is very low, this was excluded from the analysis.
Federal Corporate Income Tax Rate	21% (applicable to C&I technologies only)	Internal Revenue Service.
State Corporate Income Tax Rate	6.5% (applicable to C&I technologies only)	Tax Foundation, *State Corporate Income Tax Rates and Brackets for 2020*, https://taxfoundation.org/state-corporate-income-tax-rates-brackets-2020/.

4.3.4 Limitations of Analysis

There are many credible approaches to estimating future levels of customer PV and battery storage adoption, each with its own strengths and limitations. In all instances, uncertainties about future technology capital costs and performance, government policies, and utility rate structures (both for system output consumed on-site and exported to the utility grid) are important to note and can lead to substantial differences in outcomes.

Additionally, important limitations particular to this forecast include that it was conducted: (i) at the utility territory level using utility-wide (as opposed to more localized) assumptions, (ii) without customer demographic data; (iii) with annual average electricity rates for PV (as opposed to analyzing the full rate

[24] ICF adjusted the residential rate downward based on a per-kWh equivalent of the monthly fixed customer charge for the General Purpose Residential Service (RS) rate because that charge would not be affected by PV output. Similarly, ICF adjusted the commercial rate downward based on a per-kWh equivalent of the monthly fixed customer charge for the Small General Service (SGS) rate. The commercial rate was applied to the commercial and industrial analysis. For C&I customers, there was an additional downward adjustment to account for the observation that PV output only partially reduces peak demand charges (by approximately 12% in ICF's EAL-specific modeling). The RS and SGS rates were used as the basis for residential and C&I PV analysis because they are used by more than 99% and 93% of EAL's residential and commercial customers, respectively, according to *FERC Form No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report*, 2019/Q4 for EAL, pp. 304-304.4.

structures on hourly or sub-hourly interval bases); and (iv) without distinctions between competing financing/contract structures and the extent of debt financing on DER economics.

4.4 Technology Modeling

This section provides an overview of how the EAL-specific inputs were turned into project-level economic analysis of the DER technologies and, then, forecasts of adoption and energy generation. It also highlights results of the adoption forecasts and key findings from our analysis.

4.4.1 Elements of Analysis

Using a standard DER project cash flow model for a 25-year investment period and the inputs described in Section 4.3.3, ICF calculated the investment payback period on an unlevered basis (without debt) in nominal dollars for potential DER projects becoming operational each year between 2023 and 2042.[25] The cash flows included appropriate replacement of major equipment (PV inverter and battery pack for storage technologies) within the investment period.

In the project-level economic analysis of PV, sources of customer cost savings were distinguished between electricity consumed on-site versus exported to the utility (and thereby compensated at EAL Net-Metering rates). PV cost categories including net capital costs (after federal incentives and depreciation benefits, where applicable), annual O&M costs, major equipment replacement, and income taxes (for C&I customers).

For C&I battery storage, there is an additional layer of potential cost savings from peak demand charge reductions netted against the cost of electricity lost in roundtrip battery use cycles. ICF developed dispatch algorithms based on battery storage technology performance and EAL retail demand-based rate structures to maximize potential savings from battery system operation, within reasonable technology use constraints. These algorithms then established the number, scale, and timing of peak shaving events annually. Battery storage capital costs, O&M costs, major equipment replacement, and income taxes were applied in the same manner as in the PV project economic analysis.

The project-level economic outcomes for residential PV, C&I PV, and C&I battery storage technologies were converted to forecasted systemwide AC capacity additions using a two-part formula with components accounting for:

- Cumulative growth patterns of DER capacity over time, and
- The accelerating effect of shorter investment payback periods on growth.

For PV technologies, ICF calibrated that formula based on DOE data on the annual growth of net metered residential and C&I PV systems, distinguished at the state level. The calibration ensured that forecasted PV growth rates for EAL would not be below reasonable lower bounds nor above reasonable upper bounds of observed U.S. customer PV growth rates and that the effect of improving economics on PV adoption would be consistently represented.[26]

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[25] As noted earlier, ICF applied an attachment rate methodology, instead of cash flow analysis, to estimate residential battery storage that will be adopted in EAL's service territory.
[26] ICF also applied a modest downward adjustment in forecasted PV capacity installed by customers to account for 200 MW of additional solar capacity sought by EAL in its 2019 Request for Proposals, which may be used by EAL for additional solar offerings to customers. ICF made that adjustment (applicable to 10% of the new solar capacity in total and evenly spread between 2023 and 2029 and between residential and C&I customers) because a small percentage of customers participating in the solar offering may have chosen to install Net-Metering PV systems if the offering was not available. For reference, EAL customers are not eligible for the existing Solar Energy Purchase Option tariff if they are already taking service under the utility's Net-Metering tariff.

For residential battery storage, attachment rates were used that denoted the percentage of new PV capacity installed in a year that would be paired with battery systems. The attachment rates applied in each scenario are described below.

- Low: Beginning at 3.75% in 2023, with ratable annual growth of approximately 0.59% until reaching a 5% attachment rate in 2026 and, then, remaining at that level.[27]

- Reference: ratable annual growth of approximately 1.18%, beginning at 7.5% in 2023 and terminating at a 30% attachment rate in 2042.[28]

- High: ratable annual growth of approximately 2.36%, beginning at 15% in 2023 and terminating at a 60% attachment rate in 2042.[29]

Annual generation for each DER technology was obtained by multiplying the installed capacity, accounting for capacity degradation for battery storage, for each forecast year by a DER technology-specific capacity factor.

Annual generation was then converted into hourly load impacts through the use of:

- For PV: NREL PV Watts® output profiles for residential and C&I systems from the Arkansas locations listed in Section 4.3.3.

- For residential battery storage: charge and discharge patterns from a fleet of residential battery storage systems on non time-of-use rates.[30]

- For C&I battery storage systems: ICF's project-level dispatch algorithm applied to EAL's 2023 reference scenario commercial customer load profile, while also incorporating PV output profiles when battery storage is paired with PV.

4.4.2 Scenario Definition and Development

ICF produced high, reference, and low scenario results for each of the five DER technologies (i.e., residential PV, C&I PV, residential PV paired with battery storage, C&I PV paired with battery storage, and standalone C&I battery storage). The reference scenario reflects ICF's best estimate of future outcomes based on available information, the high scenario is associated with more favorable DER

[27] Among six states reviewed in an LBNL report, the attachment rates varied from 1% to 5% (LBNL, *Tracking the Sun*, 2019, p. 16). The low scenario in this report reflects an environment where battery storage penetration does not exceed those levels and starts at one-half of assumed reference scenario levels. That starting level is consistent with 2018 national average data from LBNL, *Distributed Solar 2020 Data Update*, 2020, p. 12, https://emp.lbl.gov/publications/distributed-solar-2020-data-update.

[28] This terminal value attachment rate for the reference scenario was established at one-half the high scenario rate.

[29] This terminal value attachment rate reflects a highly-developed battery storage market. For example, this value approximates the attachment rate among distributed PV permit applications in Hawaii in 2018 where system economics and utility regulations incentivize high levels of battery storage attachment to PV systems (LBNL, *Tracking the Sun*, 2019, p. 16). The starting value in the high scenario is based on recent attachment rates in mainland U.S. markets with attractive PV economics (see, for example, Sunnova Energy International, *Q3 2020 Earnings Prepared Remarks*, 2020, p. 3, https://s23.q4cdn.com/546214306/files/doc_financials/2020/q3/Q3-2020-Sunnova-Prepared-Remarks-FINAL.pdf).

[30] Data were based on CPUC, *2018 SGIP Advanced Energy Storage Impact Evaluation*, 2020, pp. 4-34 and 4-35, https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Demand_Side_Management/Customer_Gen_and_Storage/SGIP%20Advanced%20Energy%20Storage%20Impact%20Evaluation.pdf. Data were adjusted to reflect the 86% roundtrip efficiency assumption in this analysis. They also reflect the observation that, in a fleet of residential battery storage systems across a utility service territory, one can expect that customers will be charging and discharging their systems at various times due to various use cases and the timing of their household electricity consumption and PV production.

market trends, and the low scenario with less favorable DER trends. ICF views outcomes below the low scenario and above the high scenario to be unlikely.

ICF's scenarios can also be associated with the four futures scenarios that EAL uses in its long-range planning, though the linkages between ICF's scenarios and EAL's futures are not exact:

- ICF's reference scenario for DER can be associated with EAL's Future 1.
- ICF's low scenario with EAL's Future 2.
- ICF's high scenario with EAL's Future 3 and Future 4.

For example, the high scenarios have lower system capital costs (for PV and battery storage technologies) and lower fixed O&M costs (for PV technologies) than the reference scenarios, reflecting rapid DER industry growth and economies of scale. The opposite trend occurs in the low scenarios, with system costs declining at lower rates than in the reference scenario due to continuing low natural gas prices and other factors less conducive to DER market development. Specific differences in inputs between scenarios are listed in Section 4.3.3 above.

4.4.3 Potential Assessment Approach

ICF's analysis of DER is top-down and does not proceed through bottom-up, iterative technical potential and economic potential stages at the individual customer site level before arriving at achievable potential. Instead, ICF uses project-level economic analysis, combined with the relationship between project economics and DER adoption in other U.S. markets, to arrive at its DER achievable potential forecasts for EAL. Doing so allowed ICF to efficiently produce results grounded in DER market experience and to avoid creating technical and economic potential outputs that would not be used in the utility's IRP process.

4.4.4 Program Screening and Benefit/Cost Analysis

EAL informed ICF that it, like several other utilities, has no specific incentive programs now directed at customer PV or battery storage technologies and currently has no plans to introduce such programs. Therefore, ICF did not conduct program benefit/cost analysis of DER technologies.

However, ICF did calculate the net energy production for each DER technology on an hourly basis. Annual summaries of that energy production are provided in the next sub-section of the report.

4.4.5 Achievable Potential Results

This section presents results for customer installed capacity and annual energy production for each DER technology studied. These results arise from the economic, market acceptance curve, and attachment rate analysis conducted by ICF.

For PV, estimated investment payback periods varied in the *reference scenarios* from approximately seven to 13 years across customer types and forecast years, with forecasted technology adoption accelerating when payback periods decline below 10 years.[31] Payback periods decline over time as the combination of declining estimated capital and O&M costs and increasing retail electricity rates improve project economics.[32]

For standalone C&I battery storage, payback periods in the *reference scenario* ranged from more than 17 years at the start of the forecast period to less than 9 years at the end, with the improvements due to estimated capital cost declines combined with increases in retail electricity prices. C&I battery storage

[31] Forecasted investment payback periods never decline below 10 years in the low scenario for residential or C&I PV.
[32] As noted in Section 4.1 above, project-level economics were not calculated for residential battery storage, and an attachment rate methodology was used due to the lack of economic use cases for this technology in EAL territory.

systems paired with PV had slightly better estimated economics, with payback periods in the reference scenario being about two to three years shorter than standalone systems. The economic improvement is due to modest capital cost efficiencies from combining the PV and battery technologies, the ability to access the ITC, and greater ability to shave peak demand due to PV system operation.

These project-level economics of DER technologies were converted into annual EAL systemwide forecasts of DER capacity using the market acceptance curves and attachment rates described in Sections 4.4.1 through 4.4.3. The forecasts of installed DER capacity (at the customer meter) are in **Table 11** and **Table 12** for PV technologies. **Table 12** breaks out the C&I PV capacity from the prior table into separate commercial and industrial components.

Capacity forecasts are in **Table 13**, **Table 14,** and **Table 15** for battery storage technologies. These results are shown for commercial and industrial systems combined in the latter two tables. In ICF's forecasts, 78% of C&I battery storage capacity is assigned to commercial customers, with the remaining 22% assigned to industrial customers.[33] The battery storage tables show results for both battery power (MW) and battery energy (MWh), with totals rounded to the nearest MW and MWh.[34,35,36,37]

Table 11: Forecasted Cumulative Installed Capacity of Residential and C&I PV Systems at Meter (MW_{AC})

Forecast Year	Residential PV: Low Scenario	Residential PV: Reference Scenario	Residential PV: High Scenario	C&I PV: Low Scenario	C&I PV: Reference Scenario	C&I PV: High Scenario
2023	15	15	15	13	18	18
2024	18	18	18	13	20	20
2025	20	20	20	14	21	21
2026	23	23	23	15	23	23
2027	27	27	27	15	24	26
2028	30	30	33	15	26	29
2029	33	36	41	16	28	34
2030	38	44	54	17	32	41

[33] This reflects the relative share of commercial and industrial PV capacity interconnected in EAL territory from January 2019 through September 2020. Because ICF's modeling accounts for the deployment of whole, rather than partial, battery storage systems of the prototype project sizes listed in Section 4.2, the commercial to industrial capacity ratios in these tables can differ modestly from a strict 78:22 ratio.
[34] Estimated residential battery storage capacity in the high scenario is much higher than in the reference scenario due to the combined effects of (i) greater PV capacity forecasted in the high scenario and (ii) higher attachment rates of battery storage to PV in the high scenario.
[35] For C&I battery storage technologies (in standalone configurations and when paired with PV), high scenario outcomes are much greater than reference scenario outcomes. That is primarily because the high scenario assumes faster decreases in battery storage capital costs, leading to better economics (faster investment payback) and increased technology adoption. In addition, many more PV systems are estimated in the high scenario, increasing the population of systems to which battery storage can be paired.
[36] The battery storage low scenario assumes the slowest pace of capital cost decrease. The result is that project economics never decline to payback periods sufficient to drive adoption of C&I battery storage in the low scenario.
[37] Due to rounding, there are entries of zero for battery power in these tables in the same year as above-zero values for battery energy. That is because the battery power is less than 0.5 MW in the year, but battery energy (at an assumed 2.33-hour duration for residential battery systems and an assumed three-hour duration for C&I battery systems, or three times as high as battery power) is above 0.5 MWh in the year.

Forecast Year	Residential PV: Low Scenario	Residential PV: Reference Scenario	Residential PV: High Scenario	C&I PV: Low Scenario	C&I PV: Reference Scenario	C&I PV: High Scenario
2031	43	54	69	19	37	51
2032	47	66	89	20	42	61
2033	51	78	112	21	47	74
2034	54	92	140	22	52	89
2035	56	106	172	23	58	105
2036	57	121	208	24	64	124
2037	58	137	249	24	70	146
2038	59	154	298	24	76	170
2039	60	175	359	24	82	198
2040	61	199	433	25	90	233
2041	62	226	523	25	98	273
2042	63	259	635	25	108	322

Of the residential PV capacity in **Table 11**, 7.0 MW_{AC} for all scenarios was existing (already interconnected with EAL) as of September 2020. Another 5.8 MW_{AC} of residential PV capacity is assumed to be interconnected between October 2020 and December 2022 in all scenarios. That projection is based on 2020 deployment trends continuing through the end of the year, and 2021-2022 annual deployments being at the average of 2019 and 2020 levels.

Of the combined C&I PV capacity in **Table 11**, 6.9 MW_{AC} for all scenarios was existing as of September 2020, with 4.7 MW_{AC} of that deployed by commercial customers and 2.2 MW_{AC} by industrial customers. Between that time and December 2022, ICF assumed that an additional 4.0 MW_{AC} of commercial PV and 1.1 MW_{AC} of industrial PV capacity will be interconnected in the low scenario and twice those levels of new capacity in the reference and high scenarios. The C&I low scenario calculation used the same method as described in the prior paragraph for the residential PV calculation. The C&I reference and high scenario projections for October 2020 through December 2022 were set at double the low scenario levels due to partial data on EAL's C&I interconnection queue indicating recent growth.[38]

[38] There are substantial uncertainties involved in forecasting what share of C&I capacity in an interconnection queue will ultimately be deployed and when systems that do not drop out of the queue will reach their in-service dates. For that reason, ICF relied primarily on historical PV deployment rates in EAL territory for its capacity forecasts over the October 2020 through December 2022 period.

Table 12: Forecasted Cumulative Installed Capacity: Breakout of Commercial and Industrial PV Systems at Meter (MW_{AC})

Forecast Year	Commercial PV: Low Scenario	Commercial PV: Reference Scenario	Commercial PV: High Scenario	Industrial PV: Low Scenario	Industrial PV: Reference Scenario	Industrial PV: High Scenario
2023	9	13	13	3	5	5
2024	10	15	15	4	5	5
2025	10	16	16	4	5	5
2026	11	17	17	4	6	6
2027	11	18	19	4	6	6
2028	11	20	22	4	6	7
2029	12	21	26	4	7	8
2030	13	25	32	4	8	10
2031	14	28	39	5	9	12
2032	15	32	47	5	10	14
2033	16	36	57	5	11	17
2034	17	40	68	6	12	20
2035	17	45	82	6	13	24
2036	18	49	96	6	15	28
2037	18	54	113	6	16	33
2038	18	58	132	6	17	38
2039	18	64	154	6	19	44
2040	19	69	181	6	20	52
2041	19	76	213	6	22	61
2042	19	84	251	6	24	72

Table 13: Forecasted Cumulative Installed Capacity of Residential Battery Storage Systems Paired with PV at Meter (in MW_{AC} for Battery Power and MWh for Battery Energy)

Forecast Year	Battery Power: Low Scenario	Battery Power: Reference Scenario	Battery Power: High Scenario	Battery Energy: Low Scenario	Battery Energy: Reference Scenario	Battery Energy: High Scenario
2023	0	0	0	0	0	1
2024	0	0	1	0	1	2
2025	0	1	1	1	1	3
2026	0	1	2	1	2	4
2027	1	1	3	1	3	7
2028	1	2	4	2	4	10
2029	1	3	7	2	6	15
2030	1	4	11	3	9	25
2031	1	6	16	3	13	37
2032	2	8	23	4	18	53
2033	2	10	31	4	23	73
2034	2	13	42	5	30	99
2035	2	16	56	5	37	130
2036	2	19	72	5	45	168
2037	2	23	91	5	53	213
2038	2	27	116	5	63	270
2039	2	32	147	5	75	342
2040	2	39	186	5	90	435
2041	2	46	237	6	108	554
2042	2	56	302	6	131	705

There were no existing, interconnected residential or C&I battery storage systems in EAL territory as of September 2020. No new deployments of customer battery storage were assumed in this analysis for the October 2020 through December 2022 period. Therefore, all customer battery storage results in ICF's analysis are assumed to occur within the 2023-2042 forecast period.

Table 14: Forecasted Cumulative Installed Capacity of C&I Battery Storage Systems Paired with PV at Meter (in MW_{AC} for Battery Power and MWh for Battery Energy)

Forecast Year	Battery Power: Low Scenario	Battery Power: Reference Scenario	Battery Power: High Scenario	Battery Energy: Low Scenario	Battery Energy: Reference Scenario	Battery Energy: High Scenario
2023	0	0	0	0	0	0
2024	0	0	0	0	0	1
2025	0	0	0	0	0	1
2026	0	0	1	0	0	2
2027	0	0	1	0	0	3
2028	0	0	2	0	0	5
2029	0	0	2	0	0	7
2030	0	0	4	0	1	12
2031	0	1	6	0	2	18
2032	0	1	9	0	3	26
2033	0	1	12	0	4	35
2034	0	2	16	0	5	47
2035	0	2	20	0	7	60
2036	0	3	25	0	8	75
2037	0	3	31	0	10	92
2038	0	4	37	0	11	111
2039	0	4	45	0	13	134
2040	0	5	54	0	16	162
2041	0	6	65	0	18	196
2042	0	7	79	0	21	237

Table 15: Forecasted Cumulative Installed Capacity of Standalone C&I Battery Storage Systems at Meter (in MW_{AC} for Battery Power and MWh for Battery Energy)

Forecast Year	Battery Power: Low Scenario	Battery Power: Reference Scenario	Battery Power: High Scenario	Battery Energy: Low Scenario	Battery Energy: Reference Scenario	Battery Energy: High Scenario
2023	0	0	1	0	0	3
2024	0	0	3	0	0	9
2025	0	0	6	0	0	18
2026	0	0	10	0	0	30
2027	0	0	15	0	0	46
2028	0	0	22	0	0	65
2029	0	0	29	0	0	88
2030	0	1	38	0	3	115
2031	0	2	48	0	7	145
2032	0	4	59	0	12	176
2033	0	6	69	0	18	207
2034	0	9	80	0	26	239
2035	0	12	90	0	35	271
2036	0	15	101	0	46	304
2037	0	20	113	0	59	338
2038	0	25	124	0	74	372
2039	0	30	135	0	89	406
2040	0	35	147	0	105	441
2041	0	41	159	0	122	477
2042	0	47	171	0	140	514

ICF converted its forecasts of capacity for each DER technology into annual energy generation forecasts by multiplying the installed capacity for each forecast year by the technology capacity factor and further multiplying by 8,760 hours (or 8,784 hours for leap years) and adding customer class-specific T&D loss factors to produce generation (MWh) totals at the central station generation plant level.

For PV, these energy production forecasts do not just denote power exported back to EAL, but all PV power generated by the customer systems. The resulting net energy production forecasts for the low, reference ("ref"), and high scenarios are shown in **Figure 20**, **Figure 21**, and **Figure 22** for residential PV, commercial PV, and industrial PV technologies, respectively. **Table 16** and **Table 17** display the data from these three graphs in tabular form.

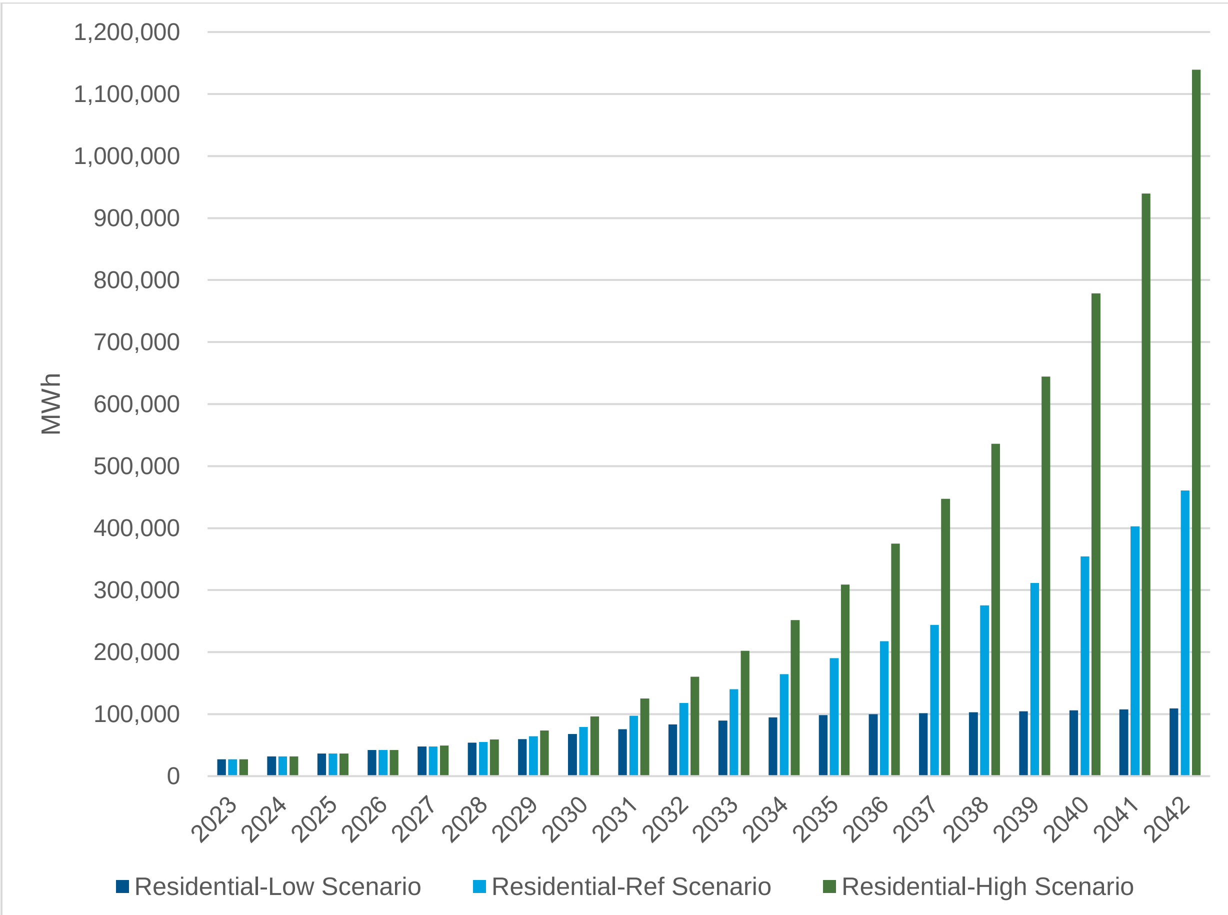

Figure 20: Forecasted Annual Residential PV Production at the Central Station Plant Level (in MWh)

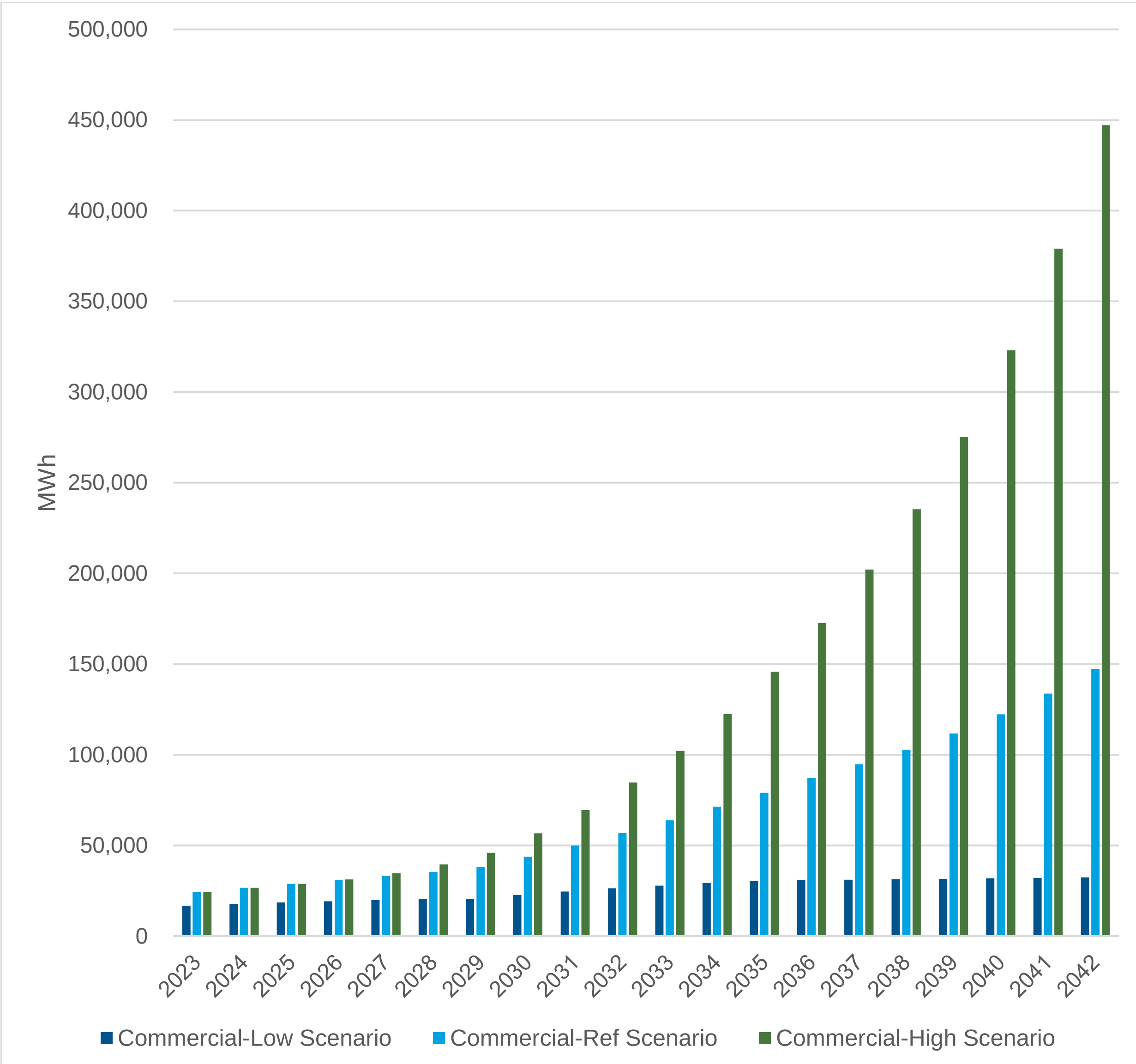

Figure 21: Forecasted Annual Commercial PV Production at the Central Station Plant Level (in MWh)

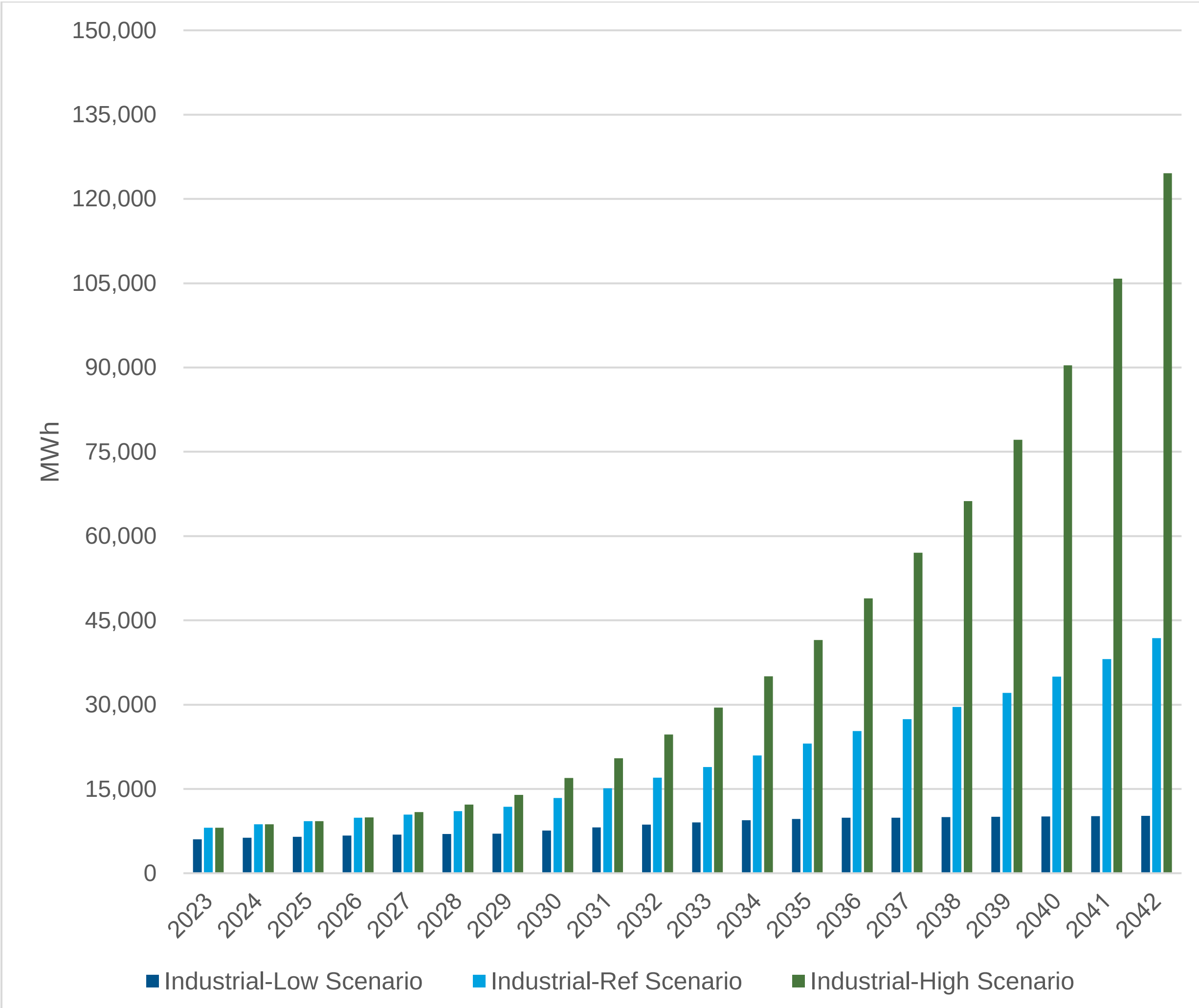

Figure 22: Forecasted Annual Industrial PV Production at the Central Station Plant Level (in MWh)

Table 16: Forecasted Annual Residential PV Production at the Central Station Plant Level (in MWh)

Forecast Year	Residential PV: Low Scenario	Residential PV: Reference Scenario	Residential PV: High Scenario
2023	27,336	27,336	27,336
2024	31,826	31,826	31,826
2025	36,699	36,699	36,699
2026	42,094	42,094	42,094
2027	47,833	47,833	49,139
2028	53,872	54,809	59,315

Forecast Year	Residential PV: Low Scenario	Residential PV: Reference Scenario	Residential PV: High Scenario
2029	59,660	64,094	73,481
2030	67,921	79,559	96,515
2031	75,945	97,409	125,104
2032	83,551	117,879	160,367
2033	89,824	140,067	201,976
2034	94,940	164,447	251,514
2035	98,397	190,321	308,966
2036	100,164	217,559	375,149
2037	101,495	244,012	447,269
2038	103,032	275,216	536,018
2039	104,561	311,469	644,319
2040	106,311	354,445	778,485
2041	107,598	402,964	939,330
2042	109,104	460,623	1,139,160

Table 17: Forecasted Annual Commercial and Industrial PV Production at the Central Station Plant Level (in MWh)

Forecast Year	Commercial PV: Low Scenario	Commercial PV: Reference Scenario	Commercial PV: High Scenario	Industrial PV: Low Scenario	Industrial PV: Reference Scenario	Industrial PV: High Scenario
2023	16,724	24,402	24,402	6,036	8,082	8,082
2024	17,672	26,619	26,619	6,293	8,690	8,690
2025	18,479	28,759	28,759	6,506	9,270	9,270
2026	19,225	30,944	31,203	6,704	9,867	9,938
2027	19,837	33,062	34,657	6,866	10,444	10,884
2028	20,326	35,272	39,497	6,997	11,050	12,216
2029	20,525	38,044	45,875	7,042	11,806	13,966
2030	22,575	43,800	56,686	7,601	13,387	16,943
2031	24,527	50,039	69,500	8,132	15,102	20,472

Forecast Year	Commercial PV: Low Scenario	Commercial PV: Reference Scenario	Commercial PV: High Scenario	Industrial PV: Low Scenario	Industrial PV: Reference Scenario	Industrial PV: High Scenario
2032	26,379	56,853	84,749	8,640	16,978	24,675
2033	27,904	63,831	102,141	9,051	18,894	29,464
2034	29,218	71,278	122,468	9,406	20,943	35,066
2035	30,214	78,993	145,781	9,675	23,065	41,492
2036	30,918	87,068	172,659	9,865	25,289	48,904
2037	31,102	94,833	202,147	9,906	27,423	57,031
2038	31,350	102,729	235,425	9,968	29,595	66,206
2039	31,597	111,730	275,062	10,030	32,072	77,136
2040	31,911	122,265	323,093	10,113	34,975	90,385
2041	32,088	133,745	379,088	10,152	38,134	105,825
2042	32,331	147,190	447,153	10,213	41,837	124,598

For battery storage technologies, charging and discharging from existing systems degrades by 1% annually, and hourly charging and discharging activities are netted to calculate annual net generation impacts. These impacts are negative (i.e., increased utility loads) because battery storage technologies are net consumers of electricity due to their RTE losses.

On an annual basis, the net increases in utility loads from battery storage technologies are very modest. For example, *reference scenario* annual net loads are forecasted to increase by only about 2,700 MWh, 200 MWh, and 1,200 MWh in 2042 from residential battery (paired with PV), C&I battery (paired with PV), and C&I (standalone) battery systems, respectively. In the *high scenario*, the equivalent annual utility net load increases in 2042 are 14,700 MWh, 2,100 MWh, and 4,300 MWh for residential (paired with PV), C&I (paired with PV), and C&I (standalone) battery systems, respectively.[39] The utility load increases are even lower than those levels in earlier forecast years. For example, they are approximately 85% lower in 2032 than in 2042 for residential battery storage in the *reference scenario*.

Table 18 shows the annual net energy production from residential battery storage systems, while **Table 19** and **Table 20** display equivalent data from commercial and industrial battery storage systems paired with PV and in standalone configurations.

[39] These utility load increases from C&I battery storage systems are the sum of totals from commercial battery storage systems and industrial battery storage systems.

Table 18: Forecasted Net Annual Energy Production from Residential Battery Storage Systems at the Central Station Plant Level (in MWh)

Forecast Year	Low Scenario	Reference Scenario	High Scenario
2023	(4)	(8)	(16)
2024	(9)	(19)	(37)
2025	(16)	(32)	(63)
2026	(23)	(48)	(96)
2027	(31)	(67)	(142)
2028	(39)	(92)	(215)
2029	(47)	(128)	(326)
2030	(58)	(194)	(520)
2031	(68)	(274)	(778)
2032	(78)	(373)	(1,117)
2033	(86)	(487)	(1,545)
2034	(93)	(620)	(2,084)
2035	(97)	(768)	(2,743)
2036	(99)	(932)	(3,541)
2037	(101)	(1,101)	(4,460)
2038	(102)	(1,308)	(5,643)
2039	(104)	(1,561)	(7,153)
2040	(106)	(1,872)	(9,103)
2041	(107)	(2,242)	(11,553)
2042	(109)	(2,697)	(14,713)

Table 19: Forecasted Net Annual Energy Production from Commercial Battery Storage Systems at the Central Station Plant Level (in MWh)

Forecast Year	Commercial Battery Storage Paired with PV: Low Scenario	Commercial Battery Storage Paired with PV: Reference Scenario	Commercial Battery Storage Paired with PV: High Scenario	Standalone Commercial Battery Storage: Low Scenario	Standalone Commercial Battery Storage: Reference Scenario	Standalone Commercial Battery Storage: High Scenario
2023	0	0	(3)	0	0	(21)
2024	0	0	(7)	0	0	(61)
2025	0	0	(11)	0	0	(125)
2026	0	0	(16)	0	0	(208)
2027	0	0	(24)	0	0	(313)
2028	0	(1)	(36)	0	0	(442)
2029	0	(3)	(55)	0	0	(595)
2030	0	(8)	(88)	0	(20)	(777)
2031	0	(13)	(131)	0	(47)	(976)
2032	0	(20)	(184)	0	(83)	(1,181)
2033	0	(29)	(251)	0	(125)	(1,388)
2034	0	(40)	(329)	0	(178)	(1,598)
2035	0	(51)	(418)	0	(241)	(1,813)
2036	0	(61)	(522)	0	(314)	(2,032)
2037	0	(73)	(638)	0	(399)	(2,250)
2038	0	(84)	(771)	0	(497)	(2,477)
2039	0	(99)	(930)	0	(600)	(2,707)
2040	0	(115)	(1,125)	0	(710)	(2,944)
2041	0	(133)	(1,358)	0	(822)	(3,176)
2042	0	(154)	(1,639)	0	(941)	(3,413)

Table 20: Forecasted Net Annual Energy Production from Industrial Battery Storage Systems at the Central Station Plant Level (in MWh)

Forecast Year	Industrial Battery Storage Paired with PV: Low Scenario	Industrial Battery Storage Paired with PV: Reference Scenario	Industrial Battery Storage Paired with PV: High Scenario	Standalone Industrial Battery Storage: Low Scenario	Standalone Industrial Battery Storage: Reference Scenario	Standalone Industrial Battery Storage: High Scenario
2023	0	0	0	0	0	(5)
2024	0	0	0	0	0	(15)
2025	0	0	0	0	0	(32)
2026	0	0	0	0	0	(54)
2027	0	0	(1)	0	0	(82)
2028	0	0	(4)	0	0	(116)
2029	0	0	(8)	0	0	(157)
2030	0	0	(17)	0	(5)	(206)
2031	0	(1)	(29)	0	(12)	(261)
2032	0	(3)	(43)	0	(21)	(317)
2033	0	(4)	(61)	0	(32)	(372)
2034	0	(5)	(82)	0	(46)	(429)
2035	0	(8)	(107)	0	(62)	(488)
2036	0	(10)	(135)	0	(82)	(548)
2037	0	(13)	(167)	0	(105)	(608)
2038	0	(16)	(203)	0	(131)	(669)
2039	0	(18)	(247)	0	(158)	(731)
2040	0	(22)	(300)	0	(187)	(795)
2041	0	(26)	(364)	0	(217)	(859)
2042	0	(31)	(441)	0	(248)	(924)

4.5 Key Findings

There are six key findings from the DER forecasts:

1. Residential, commercial, and industrial PV installed capacity is expected to increase to much greater levels in the later forecast years (after 2032) in the reference and high scenarios, largely due to the cumulative effects of PV capital cost declines and higher retail electricity prices.[40]

2. The differences between scenarios for PV and battery storage outcomes demonstrate the importance of capital cost assumptions to forecasted adoption levels. That is because the high scenarios assume much lower future capital costs than the other scenarios.

3. While estimated C&I PV adoption (and energy generation) trails residential PV adoption for EAL, as it does in many U.S. markets, it is still substantial.

4. C&I battery storage is expected to become an attractive investment (with payback periods below 11 years) by 2023 in the *high scenario* and by 2030 (for standalone systems) in the *reference scenario*. The ability of this technology to peak shave demand charges exceeding $11/kW throughout the 20-year forecast period, combined with declining system capital costs throughout that period, lead to these favorable economics.

5. The economics of C&I battery storage is somewhat better (investment payback periods are two to three years less) when the technology is paired with PV than in a standalone configuration. This is because paired PV and battery systems can access the ITC, achieve capital cost efficiencies from shared hardware and installation labor, and are more effective in lowering monthly peak demands.

6. Battery storage systems are not expected to have large aggregate impacts on EAL's net energy loads or capacity.
    - On the energy side, that is because customer battery systems are not expected to be as common as PV systems, they tend to operate infrequently (a small percentage of hours during the year), and battery charges and discharges are netted out in aggregate calculations.
    - On the capacity side, these factors are relevant, as well as the fact that C&I customers are likely to dispatch their batteries to reduce their individual facility peak demand, not in response to systemwide peak demand signals as in some DR programs.
    - In any given hour, the net impact of battery storage on EAL's loads can be positive or negative, depending on the aggregate battery charging and discharging behavior of EAL customers during that hour.

Taken together, these findings imply that customer PV systems are likely to be significant contributors to energy load reductions, especially in the period after 2032. By 2042 residential, commercial, and industrial PV systems combined are forecasted to reduce EAL's annual loads by about 650,000 MWh in the *reference scenario* and 1,700,000 MWh in the *high scenario*. Given their weather-derived energy production patterns that can vary from minute-to-minute, this creates challenges and opportunities on the EAL distribution system as other demand- and supply-side resources, including battery storage, will increasingly be used to accommodate PV production while assuring sufficient system reserves and performance.

[40] The more muted capital cost declines assumed in the low scenario substantially impede forecasted technology adoption. O&M cost declines have smaller effects on system economics and, therefore, technology adoption.

5 IRP INPUTS

5.1 Demand Response

Using the outputs of this study, ICF developed the demand response hourly load shapes for EAL's IRP. We aggregated measure level load shapes to the program level and used these program-level load shapes in the IRP analysis. These load shapes were generated for the high, reference, and low scenarios for all cost-effective programs in each of the sectors - residential, commercial, industrial, and agricultural.

5.2 Distributed Energy Resources

Using the outputs of the analytic approaches described in this report, ICF produced hourly net load inputs that can be used in EAL's IRP process over the 2023 to 2042 forecast period for five DER technologies: residential PV, C&I PV, residential battery storage (systems paired with PV), C&I battery storage (systems paired with PV), and C&I battery storage (standalone systems). These IRP inputs were produced for high, reference, and low scenarios. ICF further separated all C&I hourly IRP inputs into commercial and industrial sectors. For PV technologies, the IRP inputs consist of one net load per hour. For battery storage technologies, both hourly charge and discharge data were provided to offer more granularity. The sum of each hour's battery storage charge (increase in utility load) and discharge (decrease in utility load) is the net load impact.

6 APPENDICES

6.1 Demand Response Data and Assumptions

Table 21: Peak Reduction Assumptions

Sector	Program	Measure	Unit	Savings
Residential	Direct Load Control	EV Smart Chargers	kW/part.	0.2
Residential	Direct Load Control	Pool Pumps	kW/part.	1.5
Residential	Direct Load Control	Room AC	kW/part.	0.3
Residential	Direct Load Control	Water Heaters	kW/part.	0.3
Residential	Smart Thermostat	Smart Thermostat	kW/part.	1.0
Residential	Direct Load Control	Battery Storage	% part. peak	70.4
Residential	Direct Load Control	Central AC	kW/part.	1.63
Commercial	Direct Load Control	Pool Pumps	kW/part.	1.7
Commercial	Direct Load Control	Room AC	kW/part.	0.7
Commercial	Direct Load Control	Water Heaters	kW/part.	0.8
Commercial	Thermal Storage	Thermal Storage	kW/part.	3.7
Industrial	Interruptible	Interruptible	% part. peak	39.1
Industrial	Agricultural Irrigation Load	Agricultural Irrigation Load	kW/part.	26.6

Table 22: Scenario Participation Assumptions

Sector	Program	Measure	Participation		
			Low	Ref	High
Residential	Direct Load Control	EV Smart Chargers	16.88%	22.50%	33.75%
Residential	Direct Load Control	Pool Pumps	14.11%	18.76%	28.04%
Residential	Direct Load Control	Room AC	14.86%	19.75%	29.52%
Residential	Direct Load Control	Water Heaters	17.83%	23.70%	35.42%
Residential	Smart Thermostat	Smart Thermostat	18.61%	24.75%	36.94%
Residential	Direct Load Control	Battery Storage	0.75%	1.00%	1.50%
Commercial	Direct Load Control	Pool Pumps	5.25%	7.00%	10.50%
Commercial	Direct Load Control	Room AC	2.25%	3.00%	4.50%
Commercial	Direct Load Control	Water Heaters	3.75%	5.00%	7.50%
Commercial	Thermal Storage	Thermal Storage	1.13%	1.50%	2.25%
Industrial	Interruptible	Interruptible	25.75%	33.00%	49.50%
Industrial	Agricultural Irrigation Load	Agricultural Irrigation Load	40.00%	50.00%	50.00%

6.2 MISO Coincident Peak Reduction from DR Programs

MISO coincident peaks, i.e., the average of DR dispatch between the hours of HE 15 and HE 18 when DR events are called, are provided in the tables below.

Table 23: Summer MW Savings for Future 1 by Program (Part 1)

FUTURE 1 (2023-32) – MW Savings											
Sector	Program	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Residential	Direct Load Control - Water	1.66	3.94	6.81	10.97	16.10	21.24	25.46	28.34	29.72	29.44
Residential	Direct Load Control - Central AC	21.36	19.15	16.66	14.07	11.36	8.50	5.45	2.23	0.00	0.00
Residential	Smart Thermostat	22.69	30.60	40.42	54.80	72.56	90.41	105.06	115.10	119.80	117.97
Commercial	Direct Load Control - Water	0.09	0.21	0.36	0.59	0.86	1.14	1.37	1.52	1.65	1.75
Industrial	Interruptible	112.08	116.28	121.01	125.72	130.47	135.06	139.47	143.83	145.29	149.14
Industrial	Agricultural Irrigation Load Control	39.62	43.10	47.80	54.60	63.00	71.30	77.93	82.38	86.10	90.38

Table 24: Summer MW Savings for Future 1 by Program (Part 2)

FUTURE 1 (2033-42) – MW Savings											
Sector	Program	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Residential	Direct Load Control - Water	30.32	31.35	30.15	29.69	26.26	23.92	24.13	23.68	23.73	23.74
Residential	Direct Load Control - Central AC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Residential	Smart Thermostat	121.04	125.07	112.39	109.59	82.86	65.49	65.68	55.83	56.08	58.25
Commercial	Direct Load Control - Water	1.77	1.76	1.67	1.68	1.52	1.45	1.45	1.30	1.31	1.35
Industrial	Interruptible	147.71	145.09	129.62	127.42	101.83	89.60	88.78	71.62	71.23	75.17
Industrial	Agricultural Irrigation Load Control	90.58	89.46	81.98	81.02	69.19	64.07	63.76	54.77	54.29	56.33

Table 25: Summer MW Savings for Future 2 by Program (Part 1)

FUTURE 2 (2023-32) – MW Savings

Sector	Program	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Residential	Direct Load Control - Water	1.25	2.97	5.13	8.26	12.11	15.98	19.15	21.33	22.35	22.16
Residential	Direct Load Control - Central AC	21.36	19.16	16.67	14.07	11.37	8.50	5.46	2.23	0.00	0.00
Residential	Smart Thermostat	21.72	28.30	36.45	48.40	63.17	78.02	90.20	98.56	102.43	100.79
Commercial	Direct Load Control - Water	0.07	0.16	0.27	0.44	0.65	0.86	1.03	1.15	1.24	1.31
Industrial	Interruptible	108.55	109.22	110.40	111.57	112.79	113.87	114.81	115.73	116.94	120.00
Industrial	Agricultural Irrigation Load Control	39.07	41.82	45.58	51.01	57.71	64.34	69.62	73.16	76.20	79.84

Table 26: Summer MW Savings for Future 2 by Program (Part 2)

FUTURE 2 (2033-42) – MW Savings

Sector	Program	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Residential	Direct Load Control - Water	22.84	23.62	24.14	24.02	23.79	23.39	23.61	24.81	24.93	24.65
Residential	Direct Load Control - Central AC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Residential	Smart Thermostat	103.37	106.79	109.31	109.02	107.95	105.88	106.69	112.34	113.03	112.01
Commercial	Direct Load Control - Water	1.33	1.33	1.32	1.34	1.35	1.37	1.37	1.33	1.33	1.35
Industrial	Interruptible	118.86	116.76	115.48	116.23	117.12	118.93	118.07	114.65	113.70	115.01
Industrial	Agricultural Irrigation Load Control	79.94	78.91	78.04	78.50	79.22	80.70	80.26	77.73	77.00	77.83

Table 27: Summer MW Savings for Future 3 by Program (Part 1)

FUTURE 3 (2023-32) – MW Savings

Sector	Program	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Residential	Direct Load Control - Water	2.48	5.89	10.18	16.39	24.04	31.72	37.99	42.29	41.29	33.91
Residential	Direct load Control - Central AC	21.35	19.14	16.66	14.06	11.35	8.49	5.45	2.23	0.00	0.00
Residential	Smart Thermostat	26.48	39.62	55.99	79.89	109.37	139.01	163.30	179.97	161.26	97.88
Commercial	Direct Load Control - Water	0.13	0.31	0.54	0.88	1.29	1.71	2.05	2.28	2.32	2.08
Industrial	Interruptible	117.69	127.47	137.79	148.07	158.40	168.49	178.33	188.06	167.50	117.83
Industrial	Agricultural Irrigation Load Control	39.62	43.10	47.80	54.60	63.00	71.30	77.93	82.38	78.35	63.24

Table 28: Summer MW Savings for Future 3 by Program (Part 2)

FUTURE 3 (2033-42) – MW Savings

Sector	Program	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Residential	Direct Load Control - Water	32.52	31.00	31.50	31.17	30.65	30.00	30.17	31.48	31.39	30.78
Residential	Direct Load Control - Central AC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Residential	Smart Thermostat	79.42	59.62	61.04	60.89	60.30	59.14	59.60	62.76	63.15	62.58
Commercial	Direct Load Control - Water	1.96	1.80	1.78	1.81	1.82	1.84	1.83	1.76	1.76	1.79
Industrial	Interruptible	97.03	75.29	74.52	75.10	75.28	75.62	74.33	72.05	71.34	72.01
Industrial	Agricultural Irrigation Load Control	56.56	48.80	48.26	48.56	49.01	49.93	49.65	48.09	47.64	48.15

Table 29: Summer MW Savings for Future 4 by Program (Part 1)

FUTURE 4 (2023-32) – MW Savings

Sector	Program	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Residential	Direct Load Control - Water	2.48	5.89	10.17	16.38	24.01	29.86	27.38	30.41	29.19	28.83
Residential	Direct Load Control - Central AC	21.34	19.14	16.64	14.05	11.34	7.99	3.93	1.60	0.00	0.00
Residential	Smart Thermostat	26.48	39.62	55.99	79.89	109.37	122.55	69.28	76.31	56.94	56.16
Commercial	Direct Load Control - Water	0.13	0.31	0.54	0.88	1.29	1.62	1.51	1.68	1.68	1.77
Industrial	Interruptible	112.01	116.18	120.91	125.51	130.16	121.25	69.67	71.53	57.61	58.43
Industrial	Agricultural Irrigation Load Control	39.62	43.10	47.80	54.60	63.00	65.91	48.42	51.18	46.96	49.30

Table 30: Summer MW Savings for Future 4 by Program (Part 2)

FUTURE 4 (2033-42) – MW Savings

Sector	Program	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Residential	Direct Load Control - Water	29.66	30.59	31.06	30.72	30.22	29.61	29.81	31.12	31.06	30.53
Residential	Direct Load Control - Central AC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Residential	Smart Thermostat	57.67	59.62	61.04	60.89	60.30	59.14	59.60	62.76	63.15	62.58
Commercial	Direct Load Control - Water	1.79	1.77	1.76	1.79	1.80	1.82	1.80	1.74	1.74	1.77
Industrial	Interruptible	57.27	55.83	55.17	55.55	55.64	55.88	54.92	53.28	52.76	53.14
Industrial	Agricultural Irrigation Load Control	49.40	48.80	48.26	48.56	49.01	49.93	49.65	48.09	47.64	48.15

Appendix H – Stakeholder Report

[Attachment]

Stakeholder Committee Report on Entergy Arkansas 2021 Integrated Resources Plan

Alliance for Affordable Energy

Arkansas Advanced Energy Association

National Audubon Society

Natural Environments, Inc. (dba Stellar Sun)

Scenic Hill Solar

Sierra Club

Southern Renewable Energy Association

Union of Concerned Scientists

October 25, 2021

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Stakeholder Committee Report on Entergy Arkansas 2021 Integrated Resources Plan

The stakeholders participating in the 2021 Entergy Arkansas LLC ("EAL" or "Entergy" or the "Company") Integrated Resource Plan ("IRP") thank the Company for providing information and assisting the stakeholders in understanding EAL's planning objectives and modeling for this IRP. We want to thank EAL in particular for providing materials ahead of each scheduled stakeholder meeting and in general EAL has been responsive to stakeholder requests for information. The stakeholders think that EAL should endeavor to continuously improve its resource planning process and therefore have identified the following suggestions and concerns.

I. The Stakeholder Requested Sensitivities Show the Potential for Customer Savings With Earlier Retirement of Coal Units Combined with Construction of Renewable Resources.

Entergy's modeling makes the case for earlier retirement of its coal units than currently planned, and more renewable replacement than natural gas. As background, Entergy's reference case optimized portfolio (Future 1) includes the retirement of White Bluff in 2028 and Independence in 2030. As replacement for these retirements, the Company's capacity reference case expansion modeling selected the addition of a new combined cycle gas unit ("NGCC") and some battery storage in 2029 and solar in 2030.[1] But in its sensitivity portfolios 1 through 4, the Company tested removal of the new NGCC and substituted additional renewable and storage resources. Shown below, these sensitivities mostly provided savings relative to the Company's Future 1 plan: as high as $161 million in savings in Sensitivity 4. Only Sensitivity 1 showed

[1] EAL 2021 IRP Modeling Results, Sept. 2021, slide 12. Available at: https://cdn.entergy-arkansas.com/userfiles/content/IRP/2021/EAL_IRP_Stakeholder_Modeling_Materials.pdf?_ga=2.40748261.694687827.1635099938-224608826.1633713727.

increased cost: just $6 million more in costs over a twenty-year period (less than 0.1% above the costs of Future 1).

Savings by retirement date	White Bluff 1	White Bluff 2	Independence	Savings vs Future 1 ($mil)
Future 1	2028	2028	2030	$0
Sensitivity 1 (solar, wind, battery)	2026	2023	2030	-$6
Sensitivity 2 (solar and wind)	2026	2026	2030	$89
Sensitivity 3 (solar, wind, battery)	2028	2028	2026	$65
Sensitivity 4 (solar and wind)	2028	2028	2030	$161

These sensitivity results show the benefits of earlier retirement of the White Bluff and Independence units, shown in Sensitivities 2 and 3, respectively. We are encouraged by these results which point to earlier retirement at these units as being the optimal choice for ratepayers. Entergy should model these sensitivities (at least Sensitivities 2 and 3) under the other Futures in the IRP as a rigorous way of seeing how they would perform under the Company's gas and carbon price projections. In general, this modeling shows that a clean energy suite of resources could be a cost-effective means for replacing Entergy's coal units.

II. Entergy Has Over-Estimated The Costs of New Solar and Wind Resources.

The Stakeholder Committee has identified five ways in which solar and wind were not adequately evaluated in the IRP, or the cost of solar and wind resources were inflated in this IRP. Entergy should correct its IRP accordingly. Each of these changes should improve the cost effectiveness of a clean energy replacement for the Entergy's coal units.

A. Entergy's reliance on IHSMarkit data is not reasonable.

Entergy's reliance on the IHSMarkit data for renewable energy resources is flawed. The Arkansas Public Service Commission Staff filed a comment to the Entergy Arkansas IRP Team stating, "The differences in the assumptions and the methods of evaluation have led to a divergence between the IRP and the evaluation conducted on RFP bids, which has added avoidable complications to the process of determining whether proposed resource acquisitions are in the public interest. Aligning assumptions and analytical methods could help streamline such review in the future."[2] The IHSMarkit data have not and do not align with competitive solicitations in Arkansas, or elsewhere throughout the southeast. Without accurate, up-to-date market information, modeling results from Entergy will continue to create divergences between the IRP and RFP results.

B. Entergy over-estimates costs of new solar and wind resources by modeling self-build resources only.

By assuming all resources are self-builds, Entergy overstates the cost of renewable energy options. Given Entergy's interest in procuring power purchase agreements ("PPAs"), the IRP should have included PPA options as well. One of the primary goals of the IRP modeling is to optimize resources on a cost-basis; but to do so requires modeling the best information and ownership options available. To preclude the IRP modeling from accessing lower-cost resources means that by definition it will choose more expensive ones because the model cannot select resources that it does not know exist. Unfortunately, Entergy, in its IRP modeling, is assuming that it is the sole owner of all new renewable facilities. Alternatively, PPAs could offer reduced prices and different financing structures that are lower cost than self-build generation resources, which advantages Entergy has recognized in its procurement of the Stuttgart[3] and Chicot[4] projects. For instance, PPAs allow the developer (and by extension the buyer) to benefit from the full Investment

[2] Arkansas PSC General Staff Comments on Integrated Resource Planning, dated Aug. 4, 2021, page 3.

[3] See PSC Docket No. 15-014-U (approving Entergy's Stuttgart Solar PPA).

[4] See PSC Docket No. 17-041-U (approving Entergy's Chicot Solar PPA).

Tax Credit ("ITC") for solar or solar-battery hybrids immediately, whereas regulated utilities must "normalize" the credit over the life of the project, as Entergy is doing this IRP. Entergy has stated that it would consider PPAs at a later date in the procurement stage but that is not enough. The Company must consider these potentially lower-cost options in its model to ensure that it is truly developing a low-cost plan. Therefore, it is critical that Entergy model consider PPAs as well as self-build options.

C. Entergy's assumed solar prices are too high.

The solar prices assumed in this IRP are too high. Entergy Arkansas's Chicot solar facility in Arkansas is a 100 MW solar facility, which is currently selling power to Entergy Arkansas at $28.57/MWh, based on publicly available data from FERC,[5] or nearly 40% lower than assumed by Entergy Arkansas's IRP (at $41.56/MWh).[6] EAL Future 1 - Sensitivity Portfolio 1 adds 1,200 MWs of solar resources between 2025-2027, compared to the AURORA-selected reference case Portfolio 1. Compared to the AURORA generated "optimized" Portfolio 1, Sensitivity Portfolio 1 was estimated to create a $6 million variance; that is, Sensitivity Portfolio 1 was estimated to be $6 million higher cost over a 20-year period. But, those 1,200 MWs of solar resource additions would generate roughly 2.6 million MWhs annually (assuming a 25% capacity factor), and would generate roughly 36 million MWhs in aggregate by 2041. If Entergy had used its current Chicot facility as a base price (at $28/MWh instead of $41/MWh, a $13/MWh difference), its Sensitivity Portfolio 1 would have shown a significant savings over the reference case, not a $6 million cost.

[5] Federal Energy Regulatory Commission. Chicot Solar, LLC, Electronic Quarterly Report. [https://eqrreportviewer.ferc.gov/Summary_Report.aspx?RptType=Product&PeriodYear=2021&PeriodNumber=1&RespondentId=3634037&SellerId=3634037].

[6] Entergy Arkansas, IRP Data Posting, February 2021, slide 40. Available at: https://cdn.entergy-arkansas.com/userfiles/content/IRP/2021/EAL_IRP_Data_Posting_Materials.pdf?_ga=2.5053619.1418551729.1634660516-685984664.1626786667.

The Chicot solar facility prices are not an anomaly. In a new joint proposed Order, the Georgia Public Service Commission staff and Georgia Power Company ("GPC") have announced selection of five individual solar power purchase agreements for a total of 970 MWs of solar projects. Of the five solar projects, four also include some level of energy storage devices, effectively hybrid resources. All five solar PPAs are 30-year contracts. GPC witnesses stated that, "The simple average cost of the Winning PPAs over their thirty-year terms is approximately 3.019 cents per kilowatt hour."[7] GPC's competitive solicitation request for proposals resulted in $30.19/MWh solar PPA's, *including some energy storage components*, saving ratepayers millions of dollars annually. Those contracts will go into effect in 2022/2023.

In Kentucky, Big Rivers Electric Corporation ("BREC") recently signed three power purchase agreements for solar facilities, for a total procurement of 260 MWs of solar.[8] The projects range in price from $27.30/MWh to $29.50/MWh over the 20-year contracts.[9] As a participant in MISO, BREC used MISO's effective load carrying capacity ("ELCC") methodology to determine the capacity value of the solar resources. BREC also used the Plexos resource planning model to evaluate its solar contracts, a model also used by the Southwestern Electric Power Company ("SWEPCO").

[7] Direct Testimony of A. Wilson Mallard and Jeffrey B. Weathers on Behalf of Georgia Power Company's Application for Certification of the 2022/2023 Utility Scale Renewable PPAs, Georgia PSC Docket No. 43814, pages 8-9. Available at: https://psc.ga.gov/search/facts-document/?documentId=185570.

[8] Direct Testimony of Mark Eacret Vice President Energy Services on Behalf of BREC, Kentucky PSC Case No. 2020-00183, page 5. Available at: https://psc.ky.gov/pscecf/2020-00183/roger.hickman@bigrivers.com/04232021101059/Closed/App_Exhibit_4_-_Direct_Testimony_of_Mark_Eacret.pdf.

[9] Id., pages 18, 23.

D. ELCC for solar declines too rapidly, especially in scenarios where the model builds virtually no solar.

The Company is assuming that the effective load carrying capability ("ELCC") of solar declines rapidly over time due to the additions of solar in MISO at-large. But none of Entergy's MISO model runs justify the assumed rapid decline in the ELCC. One of Entergy's futures (Future 2) assumes that no solar is added in MISO until after 2035 and so clearly the ELCC for solar should not be assumed to decline in that Future at all until at least 2035. In Future 3, no new solar is added till 2033, and so the ELCC should not decline at all until at least that year. While Entergy's Future 1 and 4 assume significant solar buildout in the 2030s, even these Futures do not support Entergy's assumed rapid decline in the ELCC for solar. Entergy should adjust its ELCC value assumption to be consistent with its projected solar buildouts.

E. Wind resources in SPP may not have been modeled, and assumed wind prices are too high.

Early in this IRP process, Entergy provided several iterations of technology and economic screens for generation technology types. Entergy included SPP wind at $26.17/MWh and other onshore wind at $39.83/MWh (we presume, MISO South resources). Stakeholders were led to believe that Entergy was providing two separate wind resources into the model, to allow the model to select either SPP or MISO South wind resources. At the final stakeholder meeting, Entergy explained that the model only selected MISO South wind resources, because the SPP wind transmission costs were too high. In its IRP, in contract, SWEPCO has indicated SPP transmission costs to be in the $2-$5/MWh range. Given the SPP transmission prices being less than $13/MWh (the difference in EAL's assumed SPP and MISO prices), the AURORA model should have naturally selected the lower cost resources unless EAL is assuming higher transmission costs. Stakeholders are not sure if Entergy actually modeled SPP wind resources as selectable for Entergy

Arkansas or what transmission assumptions were used. And so more transparency and how SPP wind was modeled is necessary.

In addition, Entergy over-estimates the cost of wind resources. As noted, Entergy stated that only MISO South wind resources were selected in the model, at a cost of $39.83/MWh. LevelTen Energy publishes its quarterly PPA offer prices by ISO report. In the Q2 2021 report, LevelTen found that wind PPAs in SPP were $22.8/MWh and $33.9/MWh in MISO.[10] We therefore believe that there are likely lower cost wind resources available to EAL than those modeled.

III. Entergy Has Under-Estimated The Cost of New Gas Generation.

We are also concerned that the parameters for new gas combined cycle units ("NGCC") in the IRP are unrealistic or not sufficiently specified.

First, the assumed heat rates appear to be unrealistically low, which make these new gas units appear more competitive than gas would likely be in reality. Entergy is assuming a heat rate of either 6,271 btu/kWh or 6,343 btu/kWh.[11] But industry standard sources, like NREL and EIA, assume heat rates of around 6,400 btu/kWh; the midpoint of Lazard's range is 6,525 btu/kWh.[12] If

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[10] LevelTen 2021. LevelTen's Q2 2021 PPA Price Index Shows Rising North American Wind and Solar Prices, While European Prices Continue Relative Stability. Available at: https://www.leveltenenergy.com/post/q2-2021.

[11] Entergy Arkansas, IRP Data Posting, February 2021, slide 46. Available at: https://cdn.entergy-arkansas.com/userfiles/content/IRP/2021/EAL_IRP_Data_Posting_Materials.pdf?_ga=2.5053619.1418551729.1634660516-685984664.1626786667.

[12] Lazard. October 2020. Levelized Cost of Energy Analysis. Version 14.0. Available at: https://www.lazard.com/media/451419/lazards-levelized-cost-of-energy-version-140.pdf. p. 18; U.S. EIA. February 2021. "Cost and Performance Characteristics of New Generating Technologies." Annual Energy Outlook 2021. Available at: https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf; NREL. 2020. "Electricity Annual Technology Baseline (ATB)." Data Download. Available at: https://atb.nrel.gov/electricity/2020/data.php.

Entergy models the current heat rates in its IRP, the model will operate the units above a reasonable level. The Company should consider modeling a more reasonable heat rate, closer to 6,400 or 6,500 btu/kWh to more accurately model these resources in the IRP.

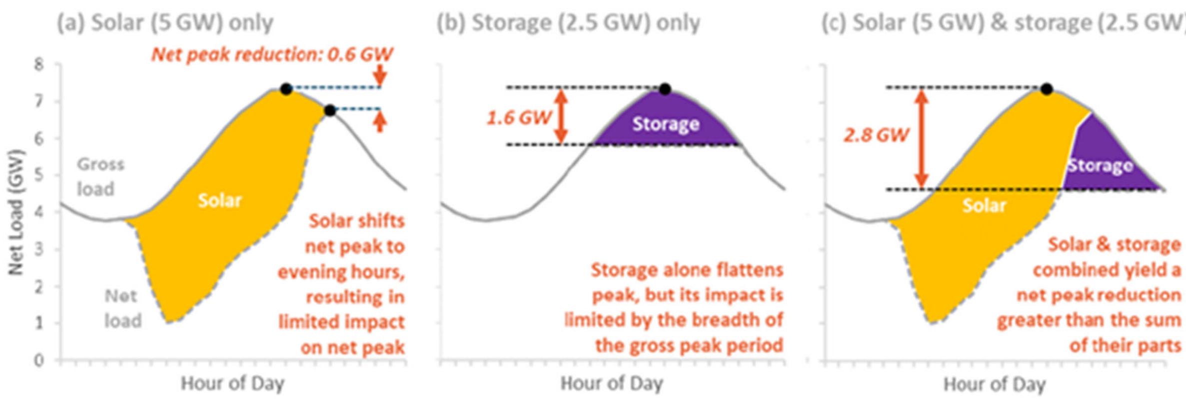
Second, assumptions around hydrogen are not reasonable or supported. Entergy's capital costs for new gas units include conversion to some use of hydrogen but do not appear to account for all of the substantial costs associated with this conversion. Entergy previously provided cost adders for new NGCC conversion of between a 6 and 7% adder for the costs of conversion. But this premium is low compared to other sources that have modeled the change in technology. For instance, Lazard is assuming more than a 20% increase for conversion in levelized costs for a new NGCC.[13] Entergy needs to provide a more detailed estimate of its assumption and ensure that the additional capital costs are in-line with industry expectations. The Company should also assume any other necessary infrastructure and fuel costs associated with hydrogen. We understand that hydrogen technology is in its infancy but that does not provide license to ignore any of the cost categories associated with it.

IV. Entergy Did Not Seriously Consider Solar-Battery Hybrids in Its Portfolios.

Entergy has not modeled solar-battery hybrid resources in the IRP but stated that it would consider them at a later date. This is not sufficient. Solar-battery hybrid resources need to be seriously considered as replacement resources—especially in light of recently extended tax credits and their energy and capacity value. It is no mistake that these hybrid resources are being considered by more utilities. Battery storage resources paired with solar resources receive the same tax credit as the solar resource alone—to the extent that solar power is used to charge the battery. While both solar and battery resources are becoming more attractive on a cost-basis, when paired

[13] Lazard 2020, page 2.

together, they are also mutually beneficial as a capacity resource. For instance, Public Service Company of New Mexico ("PNM") is replacing the retiring San Juan coal plant with solar and battery hybrids, and that company is currently asking for approval to do the same for its share of the Palo Verde nuclear plant. PNM illustrated the value and complementarity of solar and battery storage hybrids in providing capacity below:



Source: Copy of Figure NS-3 from Direct Testimony of Nicolai Schlag, Before the New Mexico Regulation Commission, Case No. 21-04-02-UT, p.11.

Solar-battery hybrid resources should be considered in Entergy's IRP modeling at the outset. Indeed, Entergy is currently building the Searcy solar and battery hybrid project but not including this resource option in its IRP. This is a mistake, as these hybrids are valuable energy and capacity which utilities are increasingly looking towards in lieu of traditional replacement resources.

V. Entergy Should Rely on a Scorecard or Other Objective Metric to Determine Its Preferred Plan.

It is unclear to the stakeholders how Entergy intends to select a preferred portfolio. Cost to customers should be the primary but not the only concern of preferred plan selection. Entergy should also evaluate and score the public health impacts of its portfolios, for example. Regardless of which specific metrics are considered, Entergy should rely on some objective scoring process to rate its various portfolios.

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The Stakeholder Committee appreciates the opportunity to engage with Entergy Arkansas LLC on its IRP process and would welcome further discussion on the issues presented in this report.

Sincerely,

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