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J. David Palmer
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October 31, 2018

Ms. Mary Loos
Arkansas Public Service Commission
P. O. Box 400
1000 Center Street
Little Rock, AR 72203

Re: APSC Docket No. 07-016-U
Entergy Arkansas, Inc. 2018 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, Inc. ("EAI") submits its 2018 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 or Jeff McGee at (501) 377-3976.

Sincerely,

/s/ J. David Palmer

DP
Attachments

c: All Parties of Record

Entergy Arkansas, Inc.
2018 Integrated Resource Plan

Entergy

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ABBREVIATIONS & DEFINITIONS	
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
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals
CEO	Chief Executive Officer
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CT	Simple Cycle Combustion Turbine
DLC	Direct Load Control
DR	Demand Response
DSM	Demand-Side Management
EAI	Entergy Arkansas, Inc.
EE	Energy Efficiency
EGU	Electric Generating Unit
EIA	Energy Information Administration
ELG	Effluent Limitation Guideline Rule
EPA	Environmental Protection Agency
FIP	Federal Implementation Plan
GW, GWh	Gigawatt, Gigawatt Hour
HVAC	Heating, Ventilation and Air Conditioning
ICF	ICF International, Inc.
IRP	Integrated Resource Plan
ISES	Independence Steam Electric Station
kW, kWh	Kilowatt, Kilowatt Hour
LMR	Load Modifying Resource
MISO	Midcontinent Independent System Operator
MLG	Modified Load Growth
MTEP	MISO Transmission Expansion Plan
MW, MWh	Megawatt, Megawatt Hour
NAAQS	National Ambient Air Quality Standard
NERC	North American Electric Reliability Corporation
NO_x	Oxides of Nitrogen
OISR	Optional Interruptible Service Rider
POV	Point of View
PPA	Power Purchase Agreement
PV	Solar Photovoltaic
RICE	Reciprocating Internal Combustion Engine
RPOC	Resource Planning and Operations Committee
RTO	Regional Transmission Organization
SAE	Statistically Adjusted End-Use
SIP	State Implementation Plan
SERC	Southeastern Electric Reliability Council
SO_2	Sulfur Dioxide
SSRP	Strategic Supply Resource Plan
TOU	Time-of-Use
WB	White Bluff Steam Electric Station
UPC	Usage Per Customer
UPP	Union Power Plant
WIIN Act	Water Infrastructure Improvements for the Nation Act

EXECUTIVE SUMMARY

For more than a century, Entergy Arkansas, Inc.'s ("EAI" or the "Company") has provided safe, reliable, and affordable electricity to its customers in Arkansas. EAI continues to serve its diverse, growing customer base by proactively planning for future resource needs by the most reliable and economic means possible.

This document describes EAI's long-term Integrated Resource Plan ("IRP") for the study period 2020-2039 and is intended to provide Arkansas Public Service Commission ("APSC" or the "Commission") and stakeholders insight into the Company's long-term planning process for meeting future demand and energy needs. Similar fundamental uncertainties remain when compared to EAI's most recent IRP, which was filed with the Commission on October 31, 2015. These uncertainties include advances in renewable technologies and their associated costs, future natural gas prices, economics of existing generation, and prospective changes in environmental regulations. Based on subsequent analysis, EAI's total generating capacity is forecasted to be short of its peak customer demand plus reserve margin target in 2025, coinciding with the assumed deactivation of the Company's Lake Catherine resource, or potentially sooner given uncertainty around near-term resource assumptions. This 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 2018 IRP utilized a futures-based approach by which three future worlds were constructed in order to reasonably bookend a broad range of future uncertainties. These futures were supplemented with sensitivity cases, which provide insight as to how each future's portfolio of resources reacts to possible changes in key input assumptions. An economically optimal portfolio of both supply-side and demand-side resources was developed for each of the three futures and sensitivity cases. A summary of the modeled portfolios is shown in the table below.

2018 IRP Results	Future A	Future B	Future C
Total Incremental Installed Capacity:	6,660 MW	4,984 MW	7,128 MW
Natural Gas Capacity Additions:	68.4%	94.0%	67.5%
Renewable Capacity Additions:	31.6%	6.0%	32.5%

Based on the results of the IRP analysis, it is reasonable to conclude that EAI's future supply-side resource additions will likely consist of a mix of both natural gas-fired and renewable energy resources. The total amount, timing, and technology mix of new supply-side capacity additions are each uncertain. Based on this uncertainty, EAI has not established any specific targets for traditional or renewable generation additions as part of this IRP analysis.

The IRP's future resource portfolios are developed consistent with the Commission's Resource Planning Guidelines but do not represent planning decisions by EAI. Rather, the Company's specific long-term resource planning actions (e.g., capacity additions) are typically 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 for implementing those options. They are merely planning assumptions, with the actual costs to be determined at a later time, likely through a market solicitation. In addition, while the IRP seeks to address EAI's capacity needs, this approach should not be read to foreclose a future resource that may provide significant energy value to EAI's customers, and it is not EAI's intent to do so.

While no specific approvals are sought for this IRP pursuant to the Commission's Resource Planning Guidelines, the Action Plan outlined in Section IV of the IRP reflects EAI's present expectations regarding the planning actions that can be expected over the next several years based on the relevant information available at that time.

The 2018 IRP Action Plan consists of seven action items, which are summarized below:

1. Complete Build-Own-Transfer of Solar PV Capacity	As a result of EAI's 2017 Request for Proposals for Build-Own-Transfer Solar Resources, EAI has made selections and is currently working toward acquiring additional solar PV generation by 2021.
2. Supply-side Resource Additions	EAI will monitor its load and capability position and take steps to add supply side resources for both traditional and/or renewable resources as warranted. A competitive solicitation may be issued in 2019 for long-term resources.
3. Potential 2025 Capacity Need	EAI will complete an evaluation of the availability of Lake Catherine Unit 4 past the assumed deactivation date of 2025. In combination with Action Item 2 above, EAI will update the load and capability position in order to monitor the capacity need in 2025.
4. Demand-side Resource Opportunities	EAI will seek and evaluate cost-effectiveness and feasibility for potential projects/programs to gain energy efficiencies in addition to its existing Arkansas Energy Efficiency Program Portfolio.
5. Continue participation in EE	EAI 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 State law.
6. Coal Environmental Compliance	EAI will continue to monitor changes in environmental law and regulations at the state and federal level and evaluate options for environmental compliance for the EAI coal units.
7. Stakeholder Engagement Process	Stakeholder engagement has been an important part of the development of this IRP. An immediate priority will be for EAI to closely review the stakeholder report and take steps to address concerns and suggestions.

I. Integrated Resource Plan Background and Context

1. Introduction

This document describes EAI's long-term IRP for the period 2020 – 2039. This is the fifth IRP filed by EAI since the APSC adopted its Resource Planning Guidelines in Order No. 6 in Docket No. 06-028-R. Similar to prior IRPs, the 2018 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 EAI's 2015 IRP filed with the Commission on October 31, 2015 (*e.g.,* uncertainties associated with potential environmental regulation and advances in renewable resource technology) still 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 EAI intends to continue to research and monitor.

EAI's process for preparing this IRP considered potential future scenarios in which various resource plans could be evaluated. As with EAI's 2015 IRP, this IRP was (i) developed by EAI's Resource Planning and Operations Staff, (ii) reviewed by EAI's Resource Planning and Operations Committee ("RPOC"), and (iii) approved by EAI's current President and Chief Executive Officer ("CEO"), Laura R. Landreaux.

As indicated above, this IRP does not provide a fixed path for future EAI resource planning. Rather, EAI's specific long-term resource planning actions (e.g., capacity additions) typically are subject to review and approval by the Commission. While no specific approvals are sought for this IRP pursuant to the Commission's Resource Planning Guidelines, the Action Plan contained within this IRP reflects EAI's current expectations regarding the planning actions it will take over the next several years.

2. Resource Planning Objectives

EAI 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 EAI's former President and CEO Hugh McDonald on May 16, 2012. During the next planning cycle, EAI intends to review and update, if necessary, its planning objectives, which will remain focused on four key areas: cost, risk, reliability, and sustainability. EAI's resource planning objectives are shown in Appendix A.

3. Regulatory Context for EAI'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. EAI met that obligation by filing the Strategic Supply Resource Plan ("SSRP") that was in place at that time. EAI's next resource plan was filed in 2009, and included the results and report of a stakeholder input process conducted for EAI's 2009 IRP, as well as more comprehensive considerations of demand-side management and load control options. For EAI's 2012 IRP, EAI modified its stakeholder process, reviewing actual study results with stakeholders rather than only reviewing high-level study assumptions and plans, as EAI did for its 2009 IRP. In addition, EAI addressed numerous questions from stakeholders, presented at open meetings or in writing to EAI, with written responses provided for all such questions.

For the 2015 IRP, EAI'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 EAI participation and input. EAI takes this opportunity to note the extensive work by the Stakeholder Group on this IRP, which is reflected in the Stakeholder Comments that were attached to the 2015 IRP. 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 this IRP, EAI's Stakeholder Engagement Process began in May 2018 with distribution of a detailed slide presentation describing proposed assumptions, inputs and modeling framework. The materials, while still preliminary, were posted to EAI's IRP website[2]. Additional meeting materials, which included preliminary modeling results from all three Futures, were provided to stakeholders in advance of the in-person stakeholder meeting hosted by EAI in June 2018. The meeting was well-attended with representation from many stakeholder groups. The agenda included an update on the status of EAI's planning activities since 2015, assumptions and modeling framework for the 2018 IRP, as well as preliminary modeling results and a discussion of challenges and observations. In response, during June and July 2018 over 100 detailed questions were submitted to EAI by stakeholders, to which EAI responded via follow-up postings to the IRP website. Most of the questions received were responded to within a week of receipt. In August 2018, EAI hosted a conference call with the Stakeholder Committee to have a technical discussion of the Committee's feedback regarding EAI's IRP

[1] *See* Order No. 6 in APSC Docket 06-028-R
[2] http://www.entergy-arkansas.com/integrated_resource_planning

modeling. Finalized portfolio optimization modeling results for all Futures and Sensitivities were posted to EAI's IRP website on October 4th, 2018.

4. The 2015 IRP Action Plan

The 2015 EAI IRP Action Plan contained six action items, some of which are still in process. The current status of each action item is described below:

1. Coal Unit Environmental Compliance – EAI has resolved its regional haze compliance requirements for its White Bluff Steam Electric Station ("WB") by committing to burn low sulfur coal and to cease burning coal at WB by 2028. EAI continues to work with the Arkansas Department of Environmental Quality ("ADEQ") and other interested parties regarding long-term environmental compliance issues at the Independence Steam Electric Station ("ISES"). EAI will continue to monitor changes in environmental law and regulations at the state and federal level and evaluate options for environmental compliance for the EAI coal units.

2. Clean Power Plan – EAI is continuing to monitor changes in environmental law at the state and federal level. Since the Clean Power Plan was published in the Federal Register in October 2015, there have been various legal challenges. Recently, the Environmental Protection Agency ("EPA") has proposed to repeal the Clean Power Plan and published the proposed Affordable Clean Energy (ACE) Rule, which is intended to replace the Clean Power Plan. See *infra* Section III of this IRP for a detailed discussion of environmental regulation/compliance issues.

3. Complete Acquisition of Power Block 2 from Union Power Plant ("UPP") – EAI completed its acquisition of Power Block 2 from the UPP in March 2016, adding over 500 MW to EAI's generation fleet.

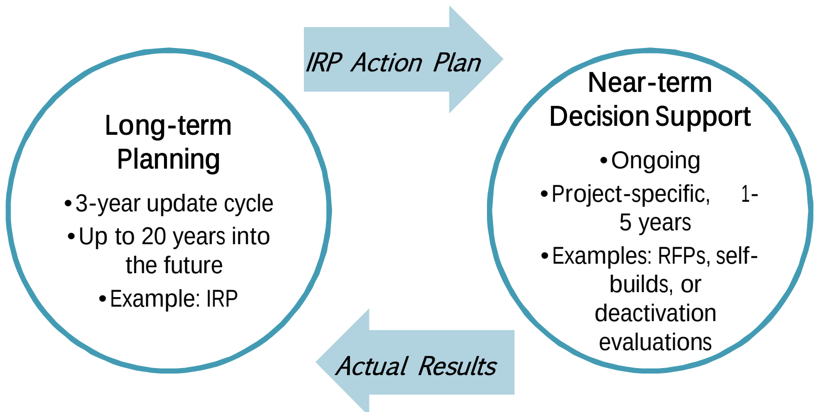
4. Continue Participation in Energy Efficiency – Since 2015, EAI has added approximately 125 MW of peak period savings as a result of expanded DSM and EE programs. A detailed discussion of EAI's participation in DSM and EE is provided *infra* in Section III.

5. Supply-side Resource Additions – In addition to the completed acquisition of Power Block 2 from Union Power Plant in item 3 above, EAI also has added two long-term Power Purchase Agreements ("PPAs") to its portfolio since the 2015 IRP. A detailed discussion of these solar PPAs is provided *infra* in Section II.

6. Stakeholder Engagement Process – EAI implemented changes in the IRP project schedule as well as the modeling based on feedback received through the Stakeholder Engagement Process in the 2015 IRP, as well as EAI's experiences and observations. A detailed discussion of this process is provided in Section V.

II. EAI Resource Planning

The IRP plays an important role in the planning of EAI's future resource portfolio by providing a comprehensive look at long-term themes and tendencies in designing and leveraging a diverse, balanced, and forward-thinking portfolio of resources to EAI 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.



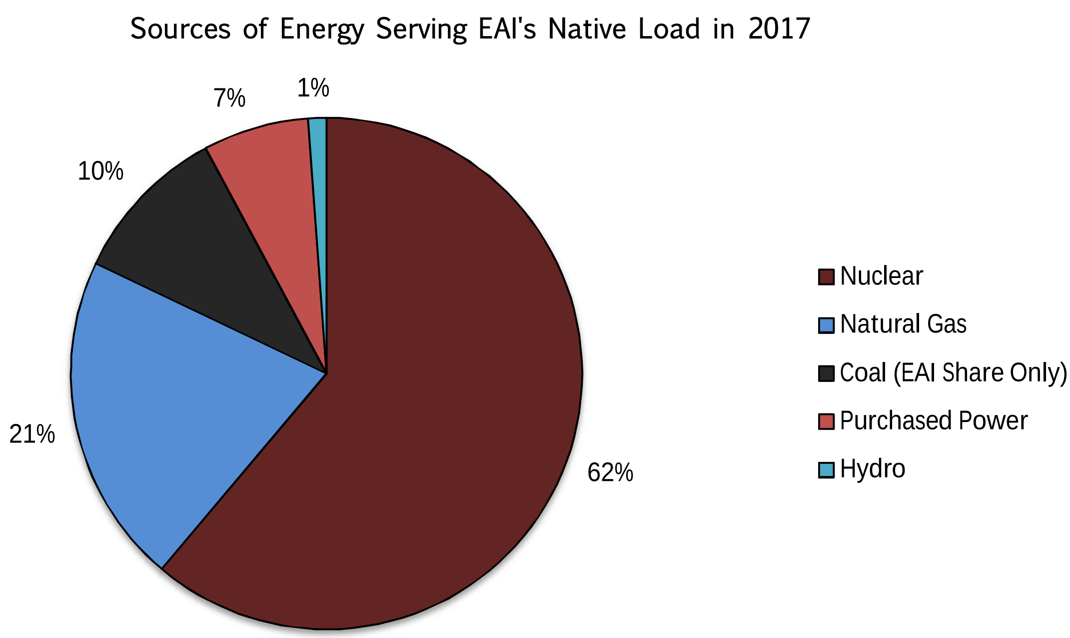
The considerations detailed in the following pages are focused on efficiently meeting all of our customers' ever-changing supply needs. EAI's IRP strategy ensures we are taking the necessary steps today to continue to enhance reliability and affordability while mitigating risks that could impact either of these factors for our customers as much as possible. This approach also provides the flexibility EAI requires to respond and adapt to a constantly shifting utility landscape.

The study period for the 2018 IRP is 2020 through 2039 and 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 EAI to evaluate long-term trends under a broad range of possible future outcomes. As in EAI's previous IRPs, the 2018 IRP is guided by EAI's Resource Planning Objectives, which focus on four key areas: cost, risk, reliability and sustainability. The full details of the Resource Planning Objectives are available in Appendix A.

1. Existing Resources

EAI's customer base has grown to over 709,000 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 PPAs, a diverse array of generating resources totaling approximately 5,365 MW to serve these native load customers. The Company's nuclear power resources include 1,722 MW from the two-unit Arkansas Nuclear One ("ANO") plant located near Russellville and 308 MW from the Grand Gulf Nuclear Station ("Grand Gulf") near Port Gibson, Mississippi, under a long-term PPA. EAI also utilizes 1,024 MW from coal-fired generation at WB and ISES located near Redfield and Newark. EAI shares ownership of WB with the Arkansas Electric Cooperative Corporation ("AECC") and several municipal electric utilities and shares ownership of ISES with Entergy Mississippi, Inc., AECC, Entergy Power Inc., an Entergy affiliate, and several municipal electric utilities. The Company's generation fleet is rounded out with 92 MW of hydro-electric capacity along the Ouachita River Valley and 2,139 MW of natural gas-fired generation that includes 606 MW from the Hot Spring Plant, 505 MW from the Ouachita Plant and 501 MW from Power Block 2 of UPP, which are modern combined cycle gas turbines ("CCGT"). Figure 1 below shows the percentage, by fuel type, of energy sources serving EAI's native load in 2017.

FIGURE 1: FUEL MIX



In addition to these generating resources, EAI's portfolio also includes resources that provide capacity value through reducing customer load. These load modifying resources ("LMRs") contributed nearly 230 MW combined of capacity including value associated with reduced line losses and reserves. EAI also manages a portfolio of energy efficiency ("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 125 MW since 2015 and an aggregate 348MW since programs were introduced in 2008.

A new addition to EAI's portfolio since the 2015 IRP and a result of EAI's 2014 Request for Proposals[3], EAI has executed a long-term PPA for an 81 MW solar photovoltaic resource located near Stuttgart, Arkansas named Stuttgart Solar.[4] The Commission issued Order No. 5 in Docket No. 15-014-U on September 24, 2015, approving the PPA. The resource achieved commercial operations ahead of schedule in December 2017. EAI's PPA began with the start of the 2018/19 MISO Planning Year, which was June 1, 2018.

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

2. Planned Resources

Since 2015 EAI has sought regulatory approval for additional renewable generation. As a result of EAI's 2016 Request for Proposals for Renewable Generation Resources, EAI has executed a long-term PPA for a planned 100 MW solar photovoltaic resource to be located near Lake Village, Arkansas, to be called Chicot Solar[5]. The Commission issued Order No. 4 in Docket No. 17-041-U on June 18, 2018, approving the PPA. The 2018 IRP assumes the resource achieves commercial operations and the PPA begins by 2020.

Additionally, in its 2017 Request for Proposals for Build-Own-Transfer Solar Photovoltaic Resources EAI sought up to 200 MW of solar generation to add to its resource portfolio. EAI has not yet brought this future resource before the Commission to seek approval; however, EAI expects to initiate those proceedings in the near future. These acquisitions would provide low-cost, emissions-free capacity and energy to EAI's portfolio. The 2018 IRP assumes Commission approval is received and commercial operation is achieved by 2021.

Under the assumption that the planned resources described above proceed as planned, the 2018 IRP reflects a total of approximately 5,859 MW of resources in EAI's portfolio

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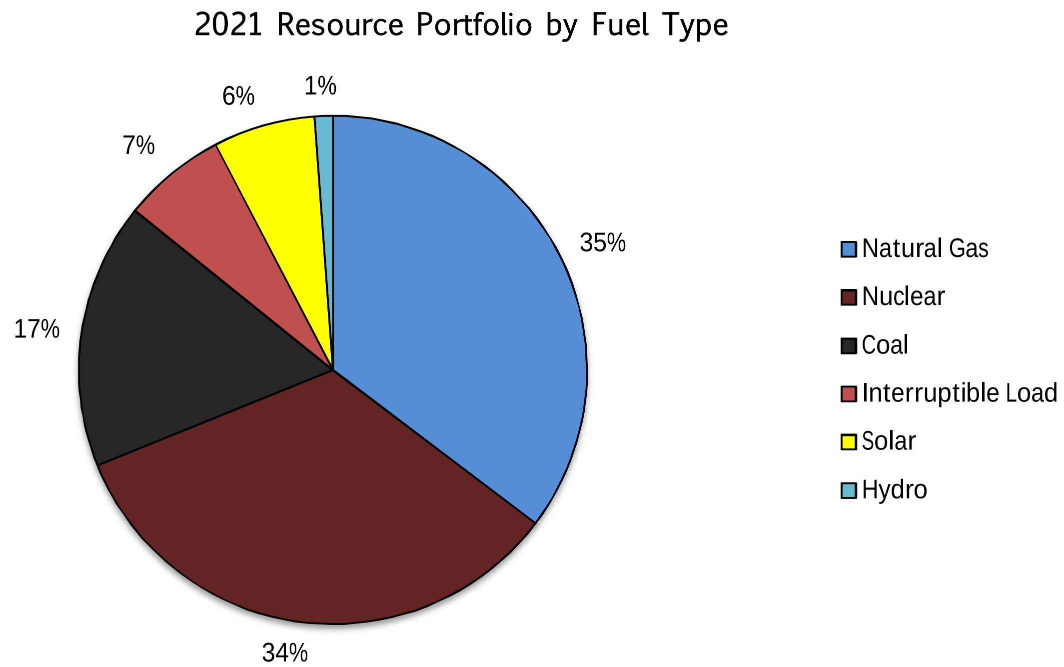
[3] Information on EAI Requests for Proposals can be found at: http://www.entergy-arkansas.com/rfp/energy_capacity.aspx.
[4] Docket No. 15-014-U
[5] Docket No. 17-041-U.

by 2021 on an effective capacity basis[6]. The diversity of EAI's currently planned resource portfolio in 2021 is shown in Figure 2 below.

FIGURE 2: CAPACITY MIX



3. 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, EAI will review a number of factors that are assessed to guide and inform the portfolio design strategies and other issues facing EAI'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 EAI'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 in order to plan for and evaluate the best options for replacement capacity over the planning horizon. 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

[6] 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.

assumptions to change over time given the dynamic use and operating characteristics of generating resources.

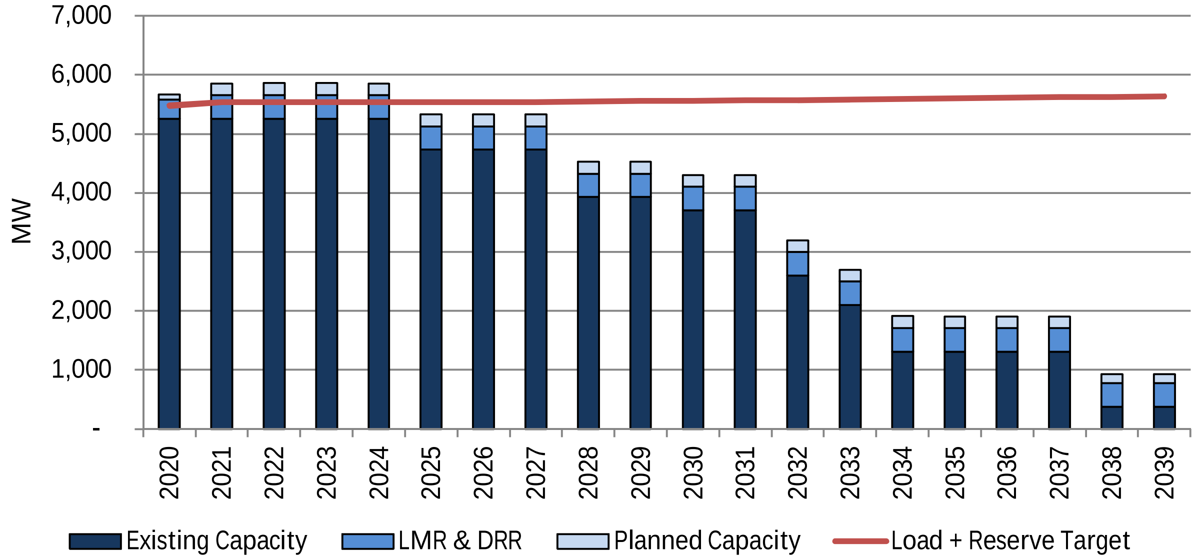
It is important to recognize that assumptions related to these uncertainties about operating lives of existing generating units do not reflect actual decisions regarding the future investment in resources or the actual dates that generating units will be removed from service. Key uncertainties related to environmental compliance, for example, include the requirements of rules still under development, the effective dates for compliance, the outcome of current litigation, congressional activity, and the possibility of extensions of the compliance deadlines. Rather, unit-specific portfolio decisions, e.g. sustainability investments, environmental compliance investment, 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, 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, EAI's resource plans seek to retain the flexibility to respond to changes in circumstances up to the time that a commitment is required to be made.

4. Resource Needs

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

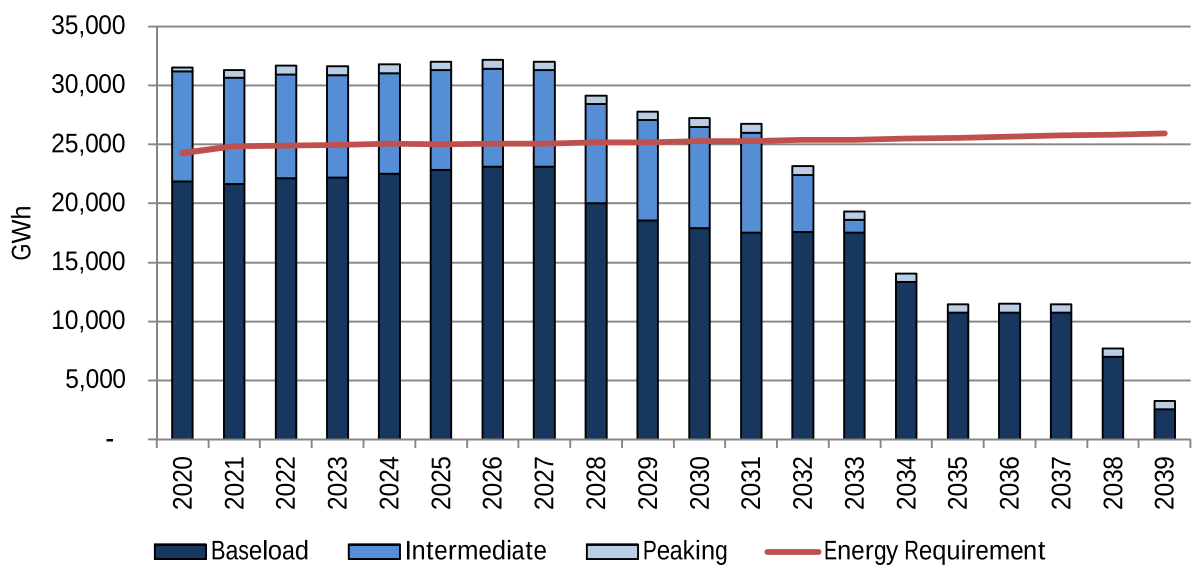
- *Long-Term Capacity Requirements* - EAI is projected to need new generating capacity over the course of the 20-year IRP planning period in order to reliably serve customers. Taking deactivation assumptions into account, short of any new additions to generation beyond the planned resources described earlier, the long-term deficit is expected to exceed 1,000 MW by 2028. This need grows to over 4,700 MW by the end of the planning horizon. Figure 3 below shows EAI's portfolio of existing resources, including both generating units and demand-side capacity, and planned resources, as described above, compared to EAI'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 total capability is short of the peak load plus reserves by as soon as 2025. The deficit expands over time as expected loads increase and older generating units reach an assumed end of useful life.

Figure 3: EAI Capacity Position



- *Energy Requirements* - In addition to capacity requirements, EAI evaluates how its existing and planned resources effectively meet its energy requirements to help inform future portfolio design. As resources deactivate and capacity requirements increase, EAI will look to balance energy producing and peaking generation to effectively and efficiently meet customer requirements.

FIGURE 4: EAI 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 energy efficiency programs, have already directly affected resource needs as discussed further in Section III. 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 Advanced Metering Infrastructure ("AMI") as well as increased accessibility to rooftop solar or battery storage technology

EAI's long-term planning process and the evaluation outlined in this IRP helps inform how EAI will meet its future capacity and energy requirements needed to continue to reliably serve its customers. EAI's planning approach is to use 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, ensuring EAI is able to continue providing safe and reliable service at a just and reasonable cost for our customers, given the primary objective of risk mitigation.

5. Transmission Planning

The Company's transmission planning group ensures that the transmission system: (1) remains compliant with applicable North American Electric Reliability Corporation ("NERC") standards, and related Southeastern Electric Reliability Council ("SERC") and Entergy's local planning criteria, and (2) is designed to efficiently deliver energy to end-use customers at a reasonable cost. Since December 2013, EAI 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 65,000 miles of high voltage transmission and 200,000 megawatts of power generating resources across its footprint. Since joining MISO, EAI 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"). EAI is an active participant in the MISO MTEP development process, which is currently in development of the MTEP 19 cycle. Participation in the MISO MTEP process is the method by which EAI'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 safely and reliably provide service 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, EAI works with MISO, other MISO Transmission Owners, and stakeholders to promote a robust and beneficial transmission system throughout the MISO region. EAI's participation helps ensure that opportunities for system expansion that would provide benefits to EAI 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.

EAI's transmission strategy is centered upon meeting the evolving needs of its customers for safe and reliable energy. Each year the EAI transmission system is thoroughly studied to verify that it will continue to provide EAI customers with reliable and safe service through compliance with all applicable NERC standards as well as Entergy's 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 the 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 EAI transmission system.

These reliability studies result in projects which are presented annually to the EAI RPOC and ultimately must be approved by the EAI 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 discuss alternatives. Additionally, MISO performs other studies each year to consider planning issues including market efficiency 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, EAI has submitted projects into MTEP 14, MTEP 15, MTEP 16, MTEP 17, MTEP 18, and is currently in preparation for MTEP 19. The EAI projects that were approved for inclusion in Appendix A of MISO's MTEP 17 cycle are provided in Appendix C, Table 13. Also, submitted Target Appendix A projects for MTEP 18 are located in Appendix C, Table 14, and proposed projects for Target Appendix A of MTEP 19 are located in Appendix C, Table 15. 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

The availability and location of current and future generation on the transmission system can have a significant impact on the long-term transmission plan, requirements for meeting NERC reliability standards, and efficiently delivering energy to customers at a reasonable cost. Like transmission, new generation must be planned well in advance, and due to the interrelationship of generation and transmission planning, looking far enough into the future and addressing potential generation needs is critical in meeting EAI's planning objectives of low cost, improved reliability, and reduced risk.

The continued evaluation and condition of EAI's generation fleet must be taken into account for integrated generation and transmission planning. EAI's planning assumption includes deactivation of existing generation resources during the planning horizon, which will have an impact on transmission reliability requirements without proper replacement generation.

6. Distribution Planning

EAI has put in place programs that have and 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.

Modernization of the distribution system has several key components. One of them is the replacement of existing physical infrastructure and distribution assets to provide more reliable service to our customers. This aspect of modernization is addressed on an ongoing basis through the annual Transmission and Distribution Plan. Additionally, via the modernization of distribution system technology, EAI can gather faster and more accurate data from the distribution system than was previously possible. With this information, the Company can make quicker, more informed decisions about impacts to the system and thereby potentially reduce both the number and duration of outages, improving overall system reliability. For example, improvements to the speed and accuracy of crew deployments during customer outages would improve outage restoration times and ultimately lower costs to customers.

EAI's approach to grid modernization will continue to be a thoughtful and balanced analysis of the costs and benefits for customers, with a preference for technologies that have a track-record of delivering on their promises of benefits. The Company must be able to respond to and implement these emerging technologies in a timely manner.

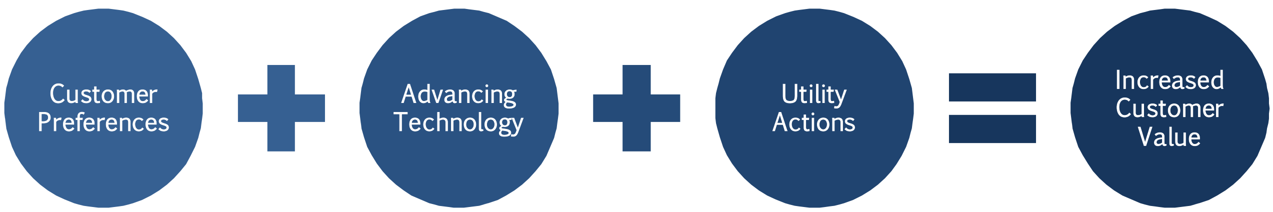
III. The 2018 Integrated Resource Plan

1. Key Inputs and Assumptions Overview

1.1 Changing Utility

Guided by the Resource Planning Objectives, EAI'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. While the landscape within the electric utility industry is changing, the Resource Planning Objectives are as important and relevant as ever, and this IRP offers early insight for opportunities to respond to this evolving environment.

Figure 5: Changes and Opportunities Within the Utility Industry



EAI recognizes the way customers consume energy is changing, so the way the company plans for, produces, and delivers the power customers rely on must continue to evolve as well. EAI strives to have a planning process that provides for the flexibility needed to better respond to this constantly-evolving environment. Below are considerations, changes, and opportunities that have comprised part of EAI's 2018 IRP development.

Customer Preferences

With advancements in technology and evolving priorities, both within and outside of the traditional utility framework, customer expectations will continue to change. The evolution and adoption of customer-centric technology and services has created a shift in customer preferences and expectations—both in terms of how the power they use is generated and the services and offerings they value from utility companies.

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 standards. As specified in the Resource Planning Guidelines, EAI approaches energy efficiency 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.

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. Increasingly, our customers are becoming more interested in sourcing their power from cleaner, more sustainable sources of energy, including natural gas, nuclear, and renewables like solar. As reflected in EAI's AMI proceeding in Docket No. 16-060-U, EAI'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. EAI's interest is in actively engaging its customers to obtain a better sense of those expectations and the ways in which EAI can bring offerings to the marketplace to meet those expectations.

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

- Develop a comprehensive outlook on the future utility environment so we 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 integrating and offering the innovative products and services our customers want and expect as is reasonable.

Advancing Technology

Technological advancements provide the energy industry increased opportunities and alternative pathways to plan for and efficiently meet customers' energy needs. 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 EAI serves. These new technologies also support the continued development and expansion of sustainability efforts while addressing EAI's long-term planning objectives, outlined in further detail below.

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.

Utility Actions

EAI understands that how our customers use energy is changing and these changing needs and expectations will inform the IRP process as well as EAI's approach to customer service. As a utility provider, it is incumbent upon EAI to adapt to the evolving needs of customers. The scope and nature of our business will and must change in response to the changing landscape. EAI's objective is to find, deploy, and integrate the right mix of technology, products, and services that provide solutions to serve the needs of customers while maintaining the reliability they need and expect.

To do that, EAI is evaluating and incorporating new, customer-centric technology, and designing an energy portfolio that leverages a more diverse mix of energy resources—including a greater reliance on what have recently become cost-effective renewable and clean energy sources—to adapt to the changing needs of customers. EAI, as compared to individual customers, is better positioned to efficiently integrate these new technologies and solutions into the electric grid. All the while, EAI is keeping affordability and reliability for its customers at the forefront of its planning.

Increased Customer Value

By combining an understanding of what customers want with sound and comprehensive planning, we can deliver the types of services and products our customers expect while continuing to address the traditional planning objectives of cost, reliability, and risk. 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, large capital commitments, or supply channels. Additionally, by taking advantage of increased and evolving opportunities, EAI continues its effort of modernizing its supply portfolio.

2. Sales and Load Forecasts

As discussed in prior sections, future customer peak load and energy requirements are key determinants of resource needs. A wide range of factors affect electric load in the long-term, including:

- Levels of economic activity and growth, including the rate at which new customers come into or leave a service area;
- The potential for technological change to affect the efficiency of energy consumption;
- Potential changes in the purposes for which customers use electricity (*e.g.*, the adoption of electric vehicles);
- The potential adoption of end-use (behind-the-meter) self-generation technologies (*e.g.*, rooftop solar panels); and
- The level of energy efficiency measures adopted by customers.

Such factors may affect both the level and shape of load in the future, and, as a result, peak loads may be higher or lower than projected levels. Similarly, industrial customer load factors may vary from current projections based on the age of a customer's facility and equipment as well as the economics of the markets in which industrial customers operate. Uncertainties in load may affect both the amount and type of resources required to efficiently meet customer needs in the future.

In order to consider the potential implications of load uncertainties on long-term resource needs, three load forecast scenarios reflecting a range of outcomes were prepared for the 2018 IRP, which forecasts are described below:

- The Reference Case load forecast reflects baseline model and input assumptions, including near-term sales growth from a new industrial customer.

- The Low Case load forecast assumes weaker customer count growth, lower Residential and Commercial usage-per-customer ("UPC") attributable to stronger than forecasted gains in organic energy efficiency, and lower industrial sales volumes tied to potentially worsening economic conditions.

- The High Case load forecast assumes stronger customer count growth, higher Residential UPC attributable to weaker than forecasted gains in organic energy efficiency, and higher industrial sales tied to a strengthening economy.

Forecast Methodology

The same load forecasting process used to develop each of the three load forecast cases described above has also been used in EAI's previous IRPs. That process uses computer software from Itron to develop long-term, hour-by-hour load forecasts. The MetrixND™[7] and the MetrixLT™[8] programs are used widely in the utility industry, to the point where they may be considered an industry standard for energy forecasting, weather normalization, and hourly load and peak load forecasting.

EAI's Retail Energy Forecast ("Sales Forecast") is a primary input for developing the load forecast. Regression models are used for forecasting residential, commercial, small industrial and governmental revenue class electricity ("MWh") sales as well as customer counts on a monthly billed sales basis. EAI's largest industrial customers (the Large Industrial Segment) are forecasted individually.

Economic driver data used in the regression models, both historical and forecasted were obtained from IHS Markit, Inc. and includes customized data for the EAI service region as well as national drivers for a wide variety of variables. Statistically adjusted end-use ("SAE") data from the U.S. Energy Information Administration ("EIA"), which reflect historical electric consumption from appliances, HVAC systems, lighting, and other devices are also used in the regression models. Temperature data is the same as used in the weather normalization analyses and is used in all models except for those instances (such as for industrial class models) where no significant dependence of sales to weather can be established. Actual weather data is used for historical time periods and normal cooling and heating degree days are used for forecasted periods.

The sales forecast for the residential class is derived from separate usage per customer and customer count models, the outputs of which are multiplied together on a monthly basis to produce forecasted total sales volumes. For the other classes, the total usage is directly calculated by the models. The key drivers for the UPC and usage models are generally trends in average consumption such as decreases due to HVAC efficiency or increases due to individuals having more devices to plug-in (phones, computers, etc.) while customer count models are typically based on drivers such as population or numbers of households. Additionally, the residential UPC and commercial usage models incorporate end-use variables such as appliance efficiencies and home size to account for the impact of changing end-use characteristics over time. EAI uses a mix of SAEs and econometric data in its regression models to capture the effects of

[7] MetrixND™ by Itron is an advanced statistics program for analysis and forecasting of time series data.
[8] MetrixLT™ by Itron is a specialized tool for developing medium and long term hourly load shapes that are consistent with monthly sales and peak forecasts.

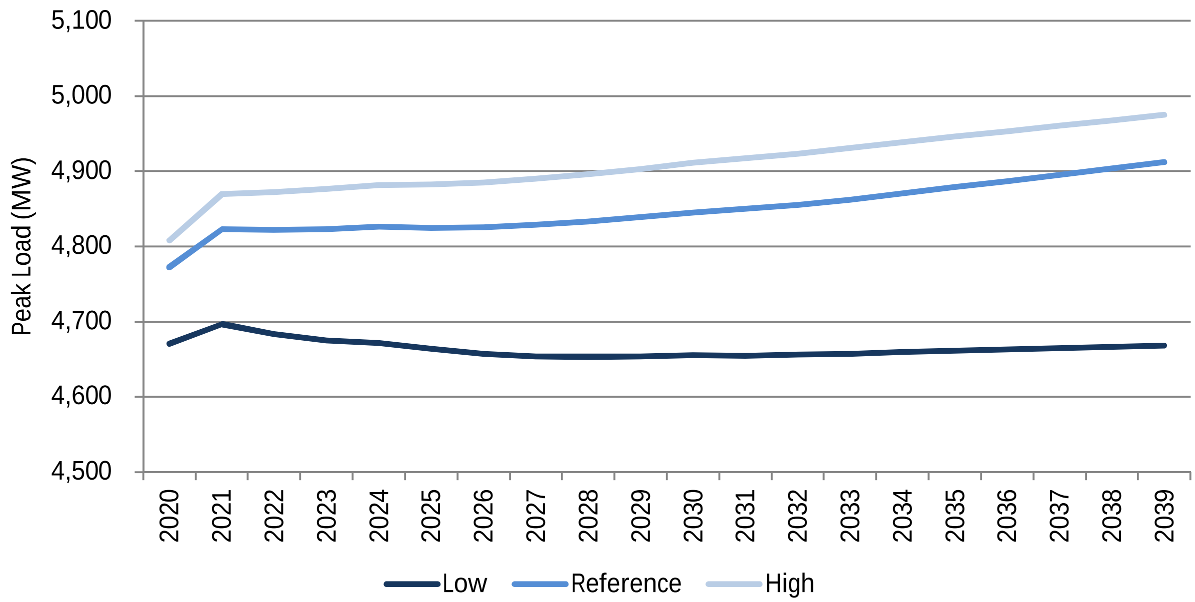
changes in end-use data as well as changes in population, household counts, and other economic drivers.

EAI has had company-sponsored EE programs since 2008 with incremental annual program-year savings that began at 20 GWh, rising to more than 260 GWh in 2017. Due to the increasing levels of these programs over that time, which covers the historical estimation period for the residential and commercial forecasts, EAI has employed a new method since the 2015 IRP to account for the effects of the historical EE programs on sales levels. This updated methodology, referred to as the add-back method or reconstituted sales method, also provides a means to calculate the future effects of continued EE programs as well as the build-up effects from prior years. Historical program EE savings were carried forward based on program measure life, with depreciation applied for future years. These aggregated EE savings were then added back to historical sales in EAI's regression models to produce a forecast trajectory as if there had never been any company-sponsored EE programs. From this point, assuming that future programs continue at current levels, the cumulative effects of historical and future EE programs were decremented from the no-EE forecast to arrive at a final sales forecast. This methodology allows for more understanding of the effects of each EE program as well as more precision on the net effect of future EE program levels.

To develop the load forecast, the monthly Sales Forecast is allocated to each hour based on historical load shapes. Twenty-year "typical weather" is used to convert historical load shapes into "typical load shapes." For example, if the actual sales for EAI's residential customers occurred during very hot weather conditions, the typical load shape would flatten the historic load shape. If the actual weather was mild, the typical load shape would raise the historic load shape. Each customer class responds differently to weather, so each has its own weather response function. MetrixND™ is used to adjust the historical load shapes by typical weather, and MetrixLT™ is used to create the hourly load forecast.

The load forecast is grossed up to account for transmission and distribution line losses. Unique distribution loss factors are applied to each revenue class after the forecast is developed. For example, EAI's residential class is grossed up by a different amount than the commercial class. The transmission line loss assumption is the value calculated by MISO for EAI's Local Resource Zone for the 2018/19 Planning Year, which is 2.5%.

FIGURE 6: EAI IRP LOAD FORECASTS



2.1 Arkansas Economic Outlook

The economic outlook for EAI's service territory, and the state of Arkansas in general, continues to show modest growth but lags behind the US in several key economic performance indicators, including Total Employment, Population, Real Average Wage, and Real Personal Income growth.

Key Performance Indicators, 2018 % Change, Y-O-Y	Employment	Population	Real Average Wage	Real Personal Income
Arkansas	0.59%	0.50%	0.33%	0.33%
United States	1.66%	0.72%	0.82%	1.86%

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As of August 2018, the compound annual growth rate for gross state product for 2014-2021 was 1.4%[9]. Payroll employment[10] across EAI's service territory diverges from sustained strong growth in the Jonesboro area, to modest growth in the Little Rock and Hot Springs areas, with a sharp decline in the Pine Bluff area. The overall economic environment in the EAI service territory is positive, which has historically suggested increased energy demand. However, increasing social and regulatory focus on energy efficiency, including the recent Commission mandate to increase EAI's DSM program savings goal to 1.2%, will temper demand. The bright spot for demand in the EAI service territory comes from a new large industrial customer that has provided a

[9] IHS Markit, Inc.
[10] Bureau of Labor Statistics, *Current Employment Statistics,* August 2018

step change in EAI's base load. In aggregate, higher energy demand from a healthy economy in the EAI service territory is offset by higher energy efficiency and solar adoption, resulting in a modest long term upward trend.

2.2 Demand-side Management

EAI considers Demand-side Management ("DSM") to be a valuable resource when implemented in a cost-effective manner compared to supply-side resources, and the 2018 IRP reflects EAI's continued commitment to DSM. In recent IRPs, EAI has included DSM resource options in four categories: customer-sponsored DSM, existing Utility-sponsored DSM, Utility-sponsored DSM Growth, and potential DSM resources. While the first three categories are discussed here, the fourth category, potential DSM resources, was enhanced in development of the 2018 IRP, which is described in detail later in this section. The potential DSM resources category represents additional investment in resources on the customer side of the meter that may be cost-effective in meeting EAI's long-term resource needs. It is not a decrement to the Sales and Load Forecast, but rather is modeled dynamically alongside supply side resource alternatives, so it is included in the section below which discusses all modeled resource options. DSM planning includes EE, demand response ("DR"), and interruptible loads. Each category is described below.

Figure 7: DSM Categories

Customer-sponsored DSM	Existing Utility-sponsored DSM	Utility-sponsored DSM Growth	Potential DSM Resources
· Improvements in energy efficiency and conservation that occur without Utility involvement. · An assumption for this type of DSM is included in the Retail Sales Forecast.	· Generally, large scale, regulator approved programs that provide incentives to go above and beyond efficiency standards. · An assumption for the impact of existing programs is included in the Retail Sales Forecast.	· Represents the annual incremental savings produced by regulator-approved programs. · An assumption for the impact of incremental programs is included in the Retail Sales Forecast.	· These programs are like existing Utility programs but require regulatory approval to implement. · These resources are modeled like a supply side resource and are not included in the retail sales forecast.

Customer-sponsored DSM

EAI's customers may elect to make EE improvements or take steps to reduce energy usage in their homes, businesses and communities without EAI's involvement. Also, new requirements for EE, such as new construction building codes and appliance or lighting efficiency standards, and new technologies, such as learning thermostats, may reduce customer's electricity usage or change energy usage patterns. This type of DSM is included in the development of the Sales Forecast described in the previous section.

Existing Utility-sponsored DSM

For several years, EAI has maintained and expanded its Arkansas Energy Efficiency Program Portfolio ("EE Portfolio"), which consists of generally large scale, regulator-approved programs that provide incentives to customers to go above and beyond current EE standards. The comprehensive EE Portfolio is reviewed and approved by the Commission and developed in an attempt to meet the Commission's utility EE targets, which are currently set at 0.9% of retail sales (excluding industrial opt-out). As part of its current three-year EE plan, EAI's approved EE targets increase to 1.0% for program year 2019. In July 2018, the Commission set new EE targets of 1.2% of retail sales for program years 2020 through 2022[11].

Impacts of the existing EE Portfolio are included in the Sales Forecast referenced earlier in this section. The MW and MWh savings achieved by existing EE programs for the 2017 Program Year can be found in EAI's Arkansas Energy Efficiency Program Portfolio Annual Report, filed May 1, 2018 in Docket No. 07-085-TF.

In addition to its EE Portfolio, which currently includes two DR programs, Agricultural Irrigation Load Control ("AILC") and Direct Load Control ("DLC"), EAI also offers the Optional Interruptible Service Rider ("OISR"). Each of these programs allows EAI to either reduce participants' usage or send a request to participants to reduce usage during an emergency situation. Although these resources reduce or shift load on the demand side of the meter, EAI treats these resources the same way as its existing supply-side capacity resources in the 2018 IRP analysis, as opposed to including as an offset a decrement to the Sales Forecast. In 2018, the interruptible loads provide 250 MW of total capacity savings. The assumption grows to 319 MW by the first year of the IRP study period (2020) based upon the expansion of a customer taking interruptible service pursuant to a Commission-approved contract.

Utility-sponsored DSM Growth

[11] Order 43 in Docket No. 13-002-U, effective July 13, 2018

Beyond the existing DSM programs, the 2018 IRP assumes that EAI continues to grow its EE Portfolio at an incremental level of 0.9% of retail sales per year, which is approximately 260 GWh of additional savings per year at the meter. Note that the Sales and Load Forecasts used in the 2018 IRP were developed prior to the Commission's approval of new EE targets for the 2020 through 2022 program years. As previously referenced, these new EE targets increased to 1.2% of retail sales.

This assumption is based on several factors. The 2018 IRP incremental Utility-sponsored EE assumption:

1. is based on the historical achievement of EE in a fuel cost environment that is at or lower than the 2018 IRP and with a greater number of Self Direct customers than assumed in the 2015 IRP;
2. is consistent with a perceived desire of state policy makers to moderate the cost of EE on the customer's utility bills; and
3. is based on the belief that the EE market that has been built up over the last 10 years will be sustainable in the foreseeable future.

Of course, there are uncertainties regarding the incremental Utility-sponsored EE assumption. Those uncertainties include:

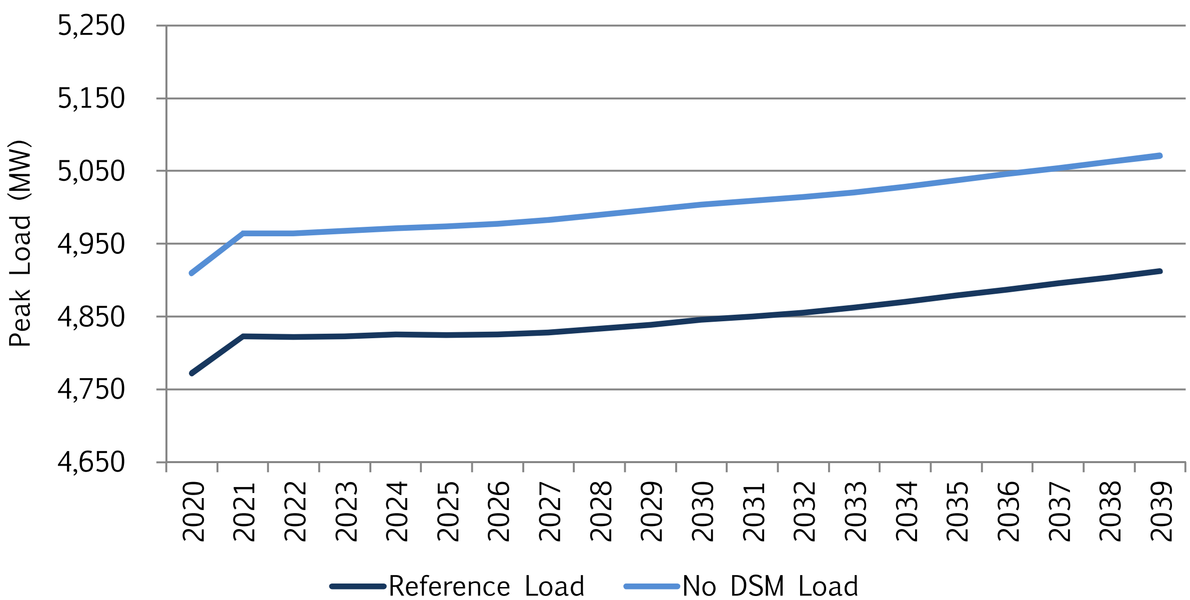
1. DSM and DR technology innovation and market adoption,
2. Future avoided cost projections could change significantly in future years, thus changing the cost-effectiveness and quantity of EE and DR programs,
3. The speed of the Arkansas market's adoption of building and technology standards,
4. Measure assumptions (e.g. variation in actual EE measure performance),
5. DSM and DR program assumptions, and
    a. Costs (e.g. program incentive and implementation cost, the market and policymakers' tolerance to DSM and DR cost impacts to customers' utility bills)
    b. Free-ridership (the portion of the program participants who would have installed the efficient equipment in the absence of the programs)
    c. Participation (e.g. variance in actual market response to EAI's programs)
6. General economic uncertainty (e.g. level of new construction, unemployment rates, etc.).

In addition, in the early stages of EAI's EE programs with the APSC, EAI noted that numerous potential projects would be dependent upon the implementation of AMI or "smart grid" technology. EAI continues to believe that AMI may provide opportunities to enhance EAI's EE Portfolio of programs or measures available to its customers. Once AMI is implemented in EAI's service area, the programs and measures that can be implemented in a cost-effective manner may increase.

The energy and peak-reducing impacts of incremental Utility-sponsored EE programs are included in the development of the Sales Forecast. The energy and peak reductions are the same amounts in each of the three IRP load forecast scenarios (Reference, Low and High Cases).

Figure 8 below shows the estimated impacts of existing EAI-sponsored and incremental EAI-sponsored EE programs to EAI's peak load forecast. The 2018 IRP only utilizes the load forecast sensitivities that include the impacts of EE.

FIGURE 8: LOAD FORECAST DSM IMPACTS



3. CAPACITY RESOURCE OPTIONS

3.1 GENERATION TECHNOLOGY ASSESSMENT

The IRP process considers a range of alternatives available to meet customer energy needs in accordance with planning objectives, including supply-side and demand-side management resource alternatives. As part of this process, a Generation Technology Assessment was prepared to identify a wide range of potential supply-side resource alternatives that merit more detailed analysis due to their potential to meet EAI's planning objectives of balancing reliability, cost, and risk. Alternatives evaluated (see Figure 9) are technologically mature and could reasonably be expected to be operational in or around the EAI service territory. Demand-side resources are discussed later in this section.

FIGURE 9: TECHNOLOGY SCREENING CURVE ILLUSTRATION

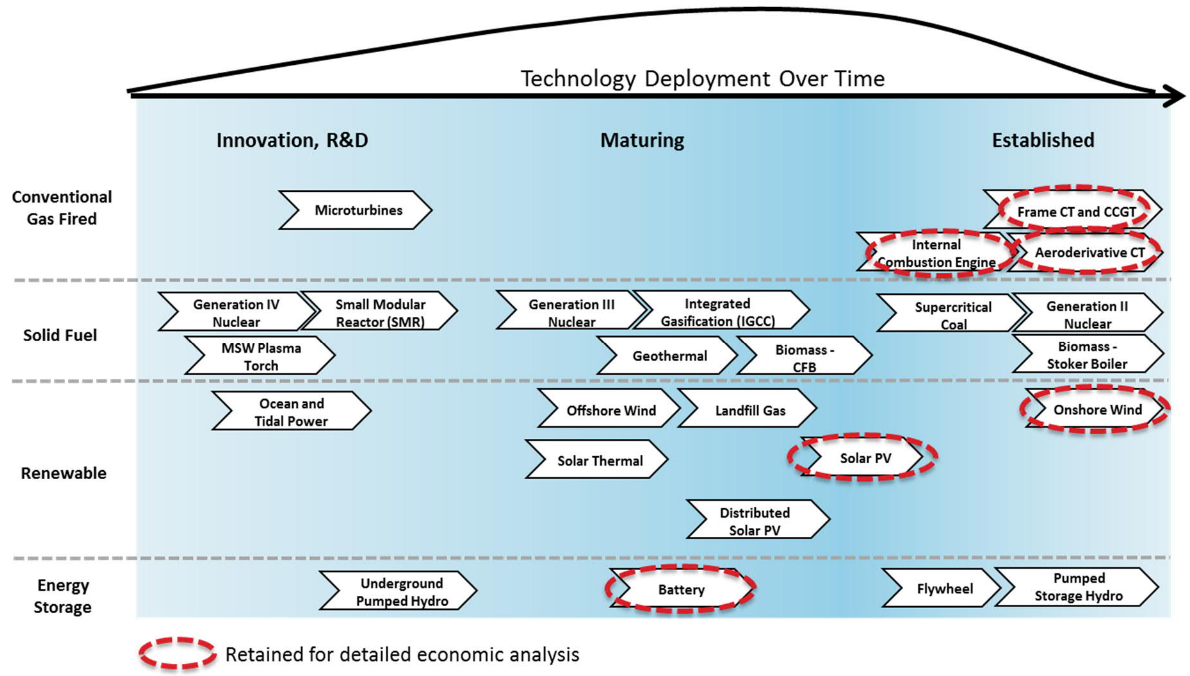


TABLE 1: 2018 IRP TECHNOLOGY CATEGORIES

Natural Gas	Simple Cycle Combustion Turbine (“CT”) Combined Cycle Gas Turbines (“CCGT”) Aeroderivative CT Reciprocating Internal Combustion Engine (“RICE”)
Renewable	Wind Solar Photovoltaic (“PV”)
Energy Storage	Battery Storage

Each of these technologies has relative advantages and disadvantages to consider when designing a resource portfolio to meet customers’ energy needs. The information in Table 2 below summarizes some of these considerations.

TABLE 2: GAS-FIRED TECHNOLOGY CONSIDERATIONS

	CT	CCGT	Aeroderivative CT	RICE

Description	Frame CTs are a mature technology. Low gas prices and continual heat rate and capacity improvements have made CTs the industry's technology of choice for peaking applications. CTs can also help integrate renewables by providing quick start (~10 minutes) backup power.	Modern combined cycle facilities provide efficiencies, moderate flexibility, and improved CO_2 emissions relative to coal plants, making them suitable for a variety of supply roles (baseload, load-following, limited peaking). CCGT efficiency and flexibility is expected to continue to improve.	Aeroderivative CTs trade increased cost for greater flexibility (start time, ramp times), lower heat rates, and higher reliability relative to frame CTs.	RICEs are useful for applications requiring heavy cycling and ramping, as they incur lower O&M penalties when operated in this manner relative to other conventional peaker technologies. As renewable penetration increases, RICEs will likely see increased deployment in North American power markets due to its flexibility and efficiency.
Advantages	• Low capital and staffing costs • Existing operating expertise • Flexible, quick start capability	• Lowest heat rates • Moderate capital cost • Synergies with existing and planned fleet (e.g., parts, staff)	• Higher flexibility • Moderate heat rates • High reliability	• Low heat rates • Highest flexibility • No gas compression needed • Modular additions
Disadvantages	• Higher heat rates • Difficult to neatly match need (blocky additions) • High gas pressure requirements	• Blocky additions • High gas pressure requirements	• Moderate capital cost • High gas pressure requirements • Less experience with technology	• Moderate capital cost • High variable operating cost • Less experience with technology

In addition to the qualitative factors considered above, the table below summarizes the major inputs from the Generation Technology Assessment for gas-fired generation, which were utilized in the portfolio analyses discussed later in the report.

TABLE 3: GAS-FIRED RESOURCE ASSUMPTIONS

Technology		Summer Capacity [MW]	Capital Cost [2017$/kW]	Fixed O&M [2017$/kW-yr]	Variable O&M [2017$/MWh]	Heat Rate [Btu/kWh]	Expected Capacity Factor [%]
CCGT	1x1 501JAC	510	$1,238	$17.02	$3.14	6,400	80%
	2x1 501JAC	1020	$1,090	$11.12	$3.15	6,400	80%
	501JAC	300	$833	$2.84	$13.35	9,400	10%
Aero-derivative CT	LMS100PA	102	$1,543	$5.86	$2.90	9,397	20%
RICE	7x Wartsila 18V50SG	128	$1,642	$31.94	$7.30	8,401	30%

In the last decade, the renewable energy industry has experienced substantial growth, driven in large part by government subsidies and cost declines, technological improvements, and environmental concerns. As shown in Figure 10, solar capital cost declines are particularly evident in utility-scale solar installations within the U.S. over the past five years.[12] Among all technologically-feasible renewable energy options, solar and onshore wind resources are the most cost-effective, commercially-available alternatives to meet EAI's capacity and energy needs.

FIGURE 10: HISTORICAL UTILITY-SCALE SOLAR CAPITAL COSTS

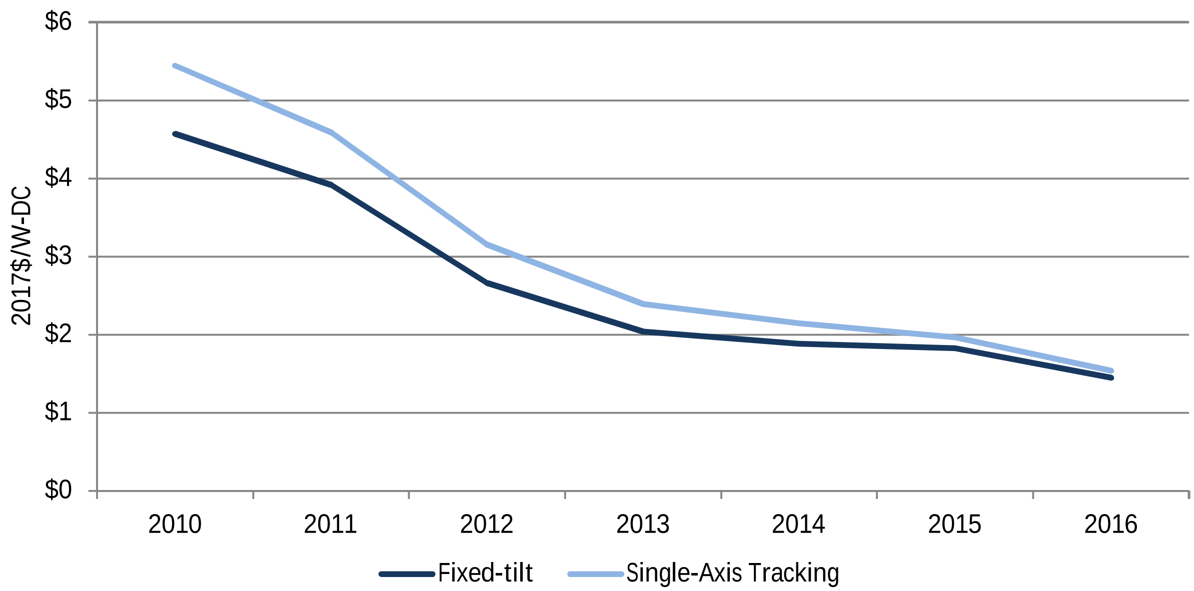


Table 4 below expands upon the relative advantages and disadvantages presented by solar and wind generation. In general, the advantages of renewable energy resources are zero emissions and zero fuel costs (which decreases overall reliance on fuel commodities), increased diversity within the resource portfolio, and decreased risk for the benefit of EAI customers. Disadvantages include increased relative land use compared with traditional alternatives, as well as relative capacity contribution due to the intermittent nature of these energy sources. The inability to effectively dispatch renewable resources to meet the changing instantaneous nature of customer usage and the renewable production curves (e.g., on-peak production versus off-peak production) also affect the value of the resources given EAI's existing generation portfolio.

TABLE 4: RENEWABLE TECHNOLOGY CONSIDERATIONS

	Solar	Wind

[12] Data adapted from NREL U.S. Solar Photovoltaic System Cost Benchmark, Q1 2017.

Description	Solar capital costs have fallen dramatically in the last decade and continue to decline as the industry matures. Solar production roughly aligns with customer load patterns, but grid flexibility and quick start backup generation are necessary to ensure reliability in the absence of large-scale, economic energy storage alternatives. The industry will continue to mature and solar energy is expected to continue to compete with gas-fired generation within the planning horizon, constrained mainly by site-specific performance and market conditions (e.g. construction cost, energy value).	The wind industry is mature relative to the solar industry. Current research focuses more on improving performance, rather than cost, through larger, taller turbines and improved control technologies (e.g. turbine alignment sensors, integrated battery storage). Wind is not likely to see extensive local deployment within the MISO South region, but could play a role in the region's energy mix if storage economics improve or significant high voltage direct current (HVDC) projects are completed.
Advantages	• Zero emissions • No fuel cost • Capital costs continue to decline • Federal investment tax credits (ITCs) • Predictable energy curve	• Zero emissions • No fuel cost • Federal production tax credits (PTCs) • Efficiency continues to increase
Disadvantages	• Capacity value relative to traditional generation • Land-intensive • Integration requirements (responsive, quick start generation is necessary to integrate large amounts of solar PV) • Site-specific performance • Lack of effective instantaneous dispatch capability	• Capacity value relative to traditional generation • Land-intensive • Integration requirements (responsive, quick start generation is necessary to integrate large amounts of wind) • Site-specific performance • Lack of effective instantaneous dispatch capability

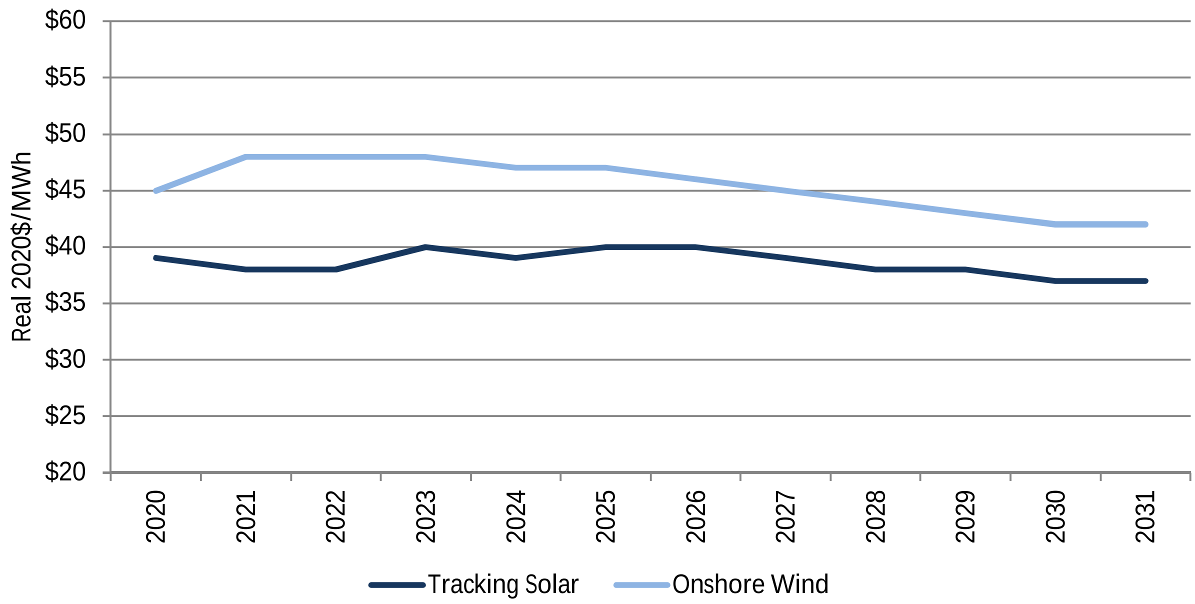
Additional unique qualities associated with renewable generation are summarized below.

TABLE 5: ADDITIONAL BENEFITS OF RENEWABLES

Additional Benefits of Renewables	
Diversity	Renewables add fuel diversity and provide a hedge within gas-centric resource portfolios as EAI's ability to rely on coal for fuel diversity becomes uncertain.
Infrastructure	Reduced infrastructure requirements (e.g., gas pipelines, water supply) increases siting flexibility.
Scalability	Deployment potentially can be scaled up or down to meet capacity needs more easily relative to conventional alternatives, although economics remain a factor.
Carbon	Renewables offer customers reduced exposure to potential CO_2 costs.
Customer Engagement	EAI's experience with renewables will help meet customer expectations with respect to green tariff offerings, community solar, deployment of distributed energy resources (DERs), and the integration of AMI.

As shown in Figure 11, the levelized real electricity costs for utility-scale renewables (wind and solar) are expected to decline over the planning horizon, although solar is expected to maintain its cost advantage over wind on a $/MWh basis.

FIGURE 11: LEVELIZED REAL COST OF ELECTRICITY FOR RENEWABLES



The table below provides a summary of operational costs and performance assumptions for solar and wind technology used within the 2018 IRP.

TABLE 6: RENEWABLE MODELING ASSUMPTIONS

	Solar	Wind
Fixed O&M (2017$/kW-yr)	$16.00	$23.46
Useful Life (yr)	30	25
Capacity Factor	26%	41%
DC:AC	1.35	N/A
Hourly Profile Modeling Software	PlantPredict	NREL SAM

3.2 ENERGY STORAGE SYSTEMS

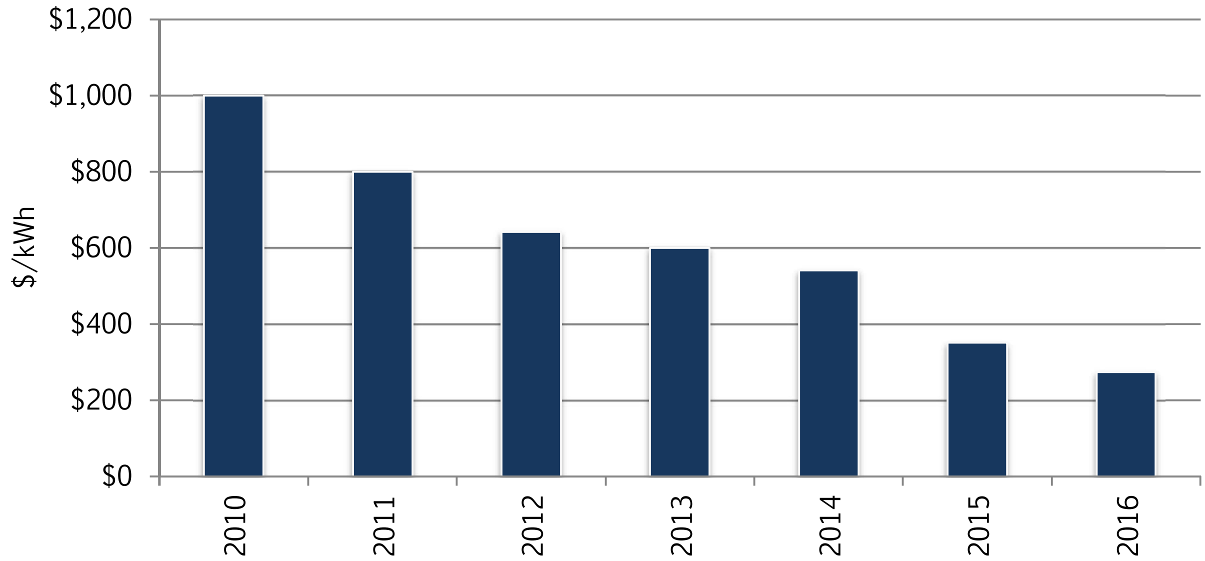
Energy storage, particularly in the case of battery-enabled storage, provides a range of attributes that differ from traditional supply-side options discussed previously, such as:

- the ability to store energy for later commitment and dispatch
- ability to discharge in milliseconds and fast ramping capability
- rapid construction (on the order of months)
- modular deployment providing potential scalability
- portability and capability to be redeployed in different areas
- small footprint (typically less than an acre), allowing for flexible siting
- low round-trip losses compared to other storage technologies (such as compressed air)

Battery storage system benefits lie in the attributes highlighted above and the ability to offer stacked values through MISO markets to benefit customers. Battery storage effectively enables an intra-day temporal shift between energy production and energy use. 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. In addition to energy market attributes, battery storage systems qualify in some markets for various ancillary service applications such as regulation, reserves, and voltage regulation, and qualify for MISO's capacity market, given sufficient discharge duration. Energy storage, when efficiently integrated into the electric grid, can provide transmission benefits by avoiding investments required due to line overloads that occur under peak conditions. In addition to these peak-shaving applications, energy storage sited in location-specific areas provide voltage support, which mitigates the effects of electrical anomalies and disturbances. Lastly, if paired together, battery storage systems 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 operational benefit, this can enhance the capacity and energy value of the solar PV installation and can lower the battery storage cost through use of the investment tax credit.

Similar to what has been seen in recent years within the solar industry, it is expected that battery storage costs will decline within the planning horizon. Therefore, while limited deployment may make sense for EAI customers today, this technology will continue to evolve, and additional applications could present themselves in the future.

FIGURE 12: LITHIUM ION BATTERY COSTS



Source: Bloomberg New Energy Finance

3.3 Potential DSM Resource Assessment

As part of the development of the 2018 IRP, EAI engaged a third-party consultant, ICF International, Inc., ("ICF")[13] to quantify potential opportunities for Utility-sponsored DSM programs to be evaluated as future resource alternatives alongside the supply-side options discussed later in this Section. The potential DSM consists of three DR portfolios and two EE portfolios.

As part of their engagement with EAI, ICF developed Low, Mid, and High DR portfolios with demand savings targets of 25 MW, 50 MW, and 100 MW, respectively. These portfolios consist of a mix of five Residential and Commercial DLC programs and one Commercial Time-of-Use program ("TOU"). ICF produced hourly demand savings and accompanying annual program costs for three assumed program start dates: 2020, 2025, and 2030. The varying demand savings targets and assumed program start dates yielded nine DR portfolios for economic evaluation in the AURORA model. Note that the DR program savings targets build-up; as a result, each of the portfolios are mutually exclusive. The AURORA model cannot select more than one portfolio as a result.

ICF also developed Low and High EE portfolios based on potential savings from self-direct Industrial customers. Rather than setting specific demand savings targets, ICF modeled the portfolios based on assumptions around self-direct customer compliance with APSC EE goals. The Low and High portfolios represent 50% and 25% compliance

[13] http://www.icf.com

with these EE goals, respectively. For example, in the High portfolio ICF's model assumes that self-direct customers achieve 25% of their APSC EE target on their own; the remaining 75% represents opportunity for additional demand savings. As with DR, ICF provided the same 2020, 2025, and 2030 program start dates yielding six EE portfolios for evaluation in the AURORA model. The EE program savings associated with each portfolio build-up and are therefore mutually exclusive.

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

4. 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 EAI's existing generating units. Five key areas of regulations are discussed here: the Regional Haze Rule, Cross-State Air Pollution Rule, Coal Combustion Residuals Rule, Effluent Limitation Guideline Rule, and the Affordable Clean Energy Rule. 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 EPA issued a final Federal Implementation Plan ("FIP") on September 27, 2016, to address the requirements of the Regional Haze Rule and visibility transport requirements for the State of Arkansas that the EPA had previously disapproved. EAI owns three facilities in Arkansas that were subject to the FIP through emission limitations that required sulfur dioxide ("SO_2") controls (scrubbers) at the White Bluff and Independence coal-fired plants and oxides of nitrogen ("NO_x") controls (Low-NO_x Burners/Separated Overfire Air) at White Bluff and Independence, and lesser NO_x controls at one natural gas-fired plant, Lake Catherine Unit 4. The final FIP required installation of the NO_x controls at White Bluff and Independence by April 27, 2018, the NO_x controls at Lake Catherine Unit 4 by October 27, 2019, and the SO_2 controls at White Bluff and Independence by October 27, 2021. On March 17, 2018, the 8th Circuit court of appeals granted Entergy's stay motion for the Arkansas Regional Haze FIP.

Following issuance of the final FIP, the ADEQ commenced an effort to develop a State Implementation Plan ("SIP") to replace the FIP while still addressing the applicable

Regional Haze program requirements for the first Regional Haze planning period. The ADEQ SIP process resulted in two separate SIPs, a Phase I SIP which addressed NO_x emissions from electric generating units ("EGUs"), and a second Phase II SIP which primarily addressed SO_2 emissions.

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

The Arkansas Phase II SIP was finalized by ADEQ and transmitted to the EPA for review in August 2018. This SIP replaces the source-specific FIP SO_2 emission limitations for White Bluff and Independence with a requirement that each unit at these plants achieve SO_2 emission reductions via combustion of low-sulfur coal. In addition, the SIP requires that White Bluff cease to burn coal by December 31, 2028. The SIP also acknowledges the assumed planned retirement of Lake Catherine Unit 4 in 2025, which is consistent with EAI's 2015 and 2018 IRPs, and EAI's planning assumption that Independence will cease to use coal in 2030. EPA review of this SIP is expected to occur throughout late 2018 with final EPA action anticipated in early 2019.

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 NO_x. Affected entities must hold one allowance for every ton of NO_X and SO_2 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.

Coal Combustion Residuals Rule

In April 2015 the EPA published the final Coal Combustion Residuals ("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 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. 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 EPA to date.

Entergy operates CCR units at both White Bluff and Independence which are subject to the CCR rule. Entergy 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.

Effluent Limitation Guideline Rule

The final Effluent Limitation Guideline rule ("ELG") was issued by the EPA on November 3, 2015. This rule applies to the units at White Bluff and Independence and imposes a requirement that there be zero discharge of bottom ash transport water from the site. This 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 intent to reconsider other aspects of the 2015 ELG rule, including the requirements for bottom ash transport water.

Clean Power Plan/Affordable Clean Energy Rule

EAI's Point of View ("POV"), which is based on Entergy's corporate 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 sin 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 is intended to replace the CPP.

The proposed ACE rule would require that each state conduct an analysis of available heat rate improvements at coal-fired electric generating units. The proposal contains a list of candidate technologies to be included in this review. These technologies are: neural network/intelligent sootblowers, boiler feed pumps, air heater and duct leakage control, variable frequency drives, blade path upgrades (steam turbine), and redesign/replace economizer. In addition, EPA also proposed revisions to the NSR program to address potential barriers to implementation of heat rate improvement projects at generating units.

EAI will monitor the development of the final ACE rule. Once the rule is final, it is anticipated that the ADEQ and/or APSC will conduct a stakeholder process to guide implementation of the ACE rule in Arkansas. EAI's participation in the various regulatory processes associated with the ACE rule will, in part, focus on assuring that EAI's customers retain the value of the low-greenhouse gas emissions resources for which they are and/or have been providing cost-support.

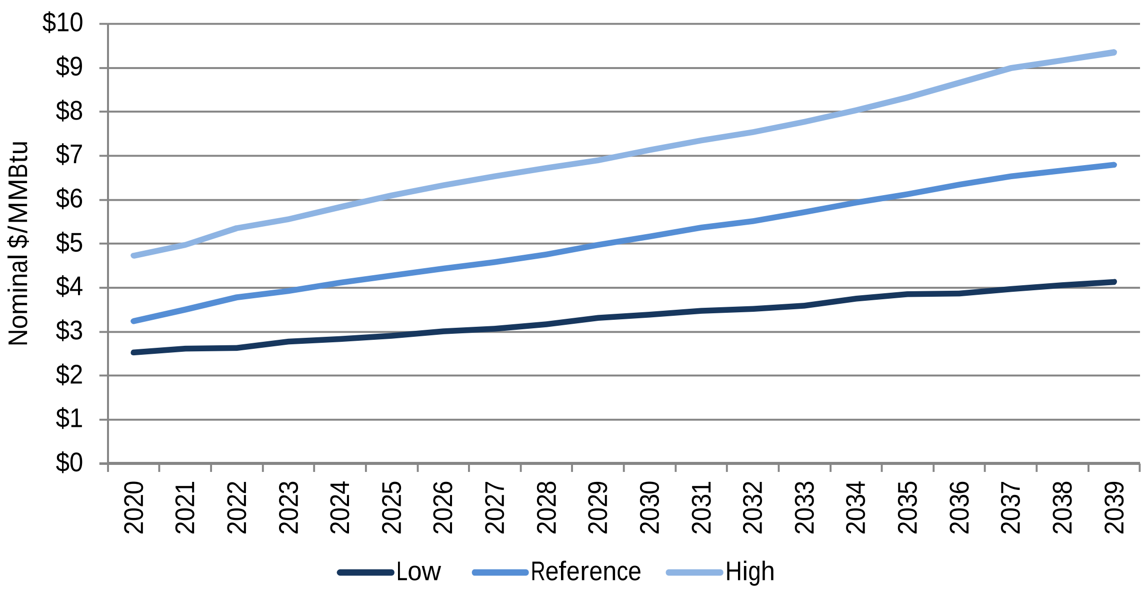
5. Fuel Price Forecasts

5.1 Natural Gas Price Forecasts

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 January 2018. 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 average of several expert independent, third-party consultant forecasts. The long-term natural gas price forecast used in the IRP also includes cases for high and low gas prices to support analysis across a range of future scenarios. In levelized 2018 dollars per MMBtu through the IRP period (2020-2039), the reference case natural gas price forecast is \$3.88, the low case is \$2.59, and the high case is

$5.43. 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.

FIGURE 13: NATURAL GAS PRICE FORECAST AND SENSITIVITIES



5.2 COAL PRICE FORECASTS

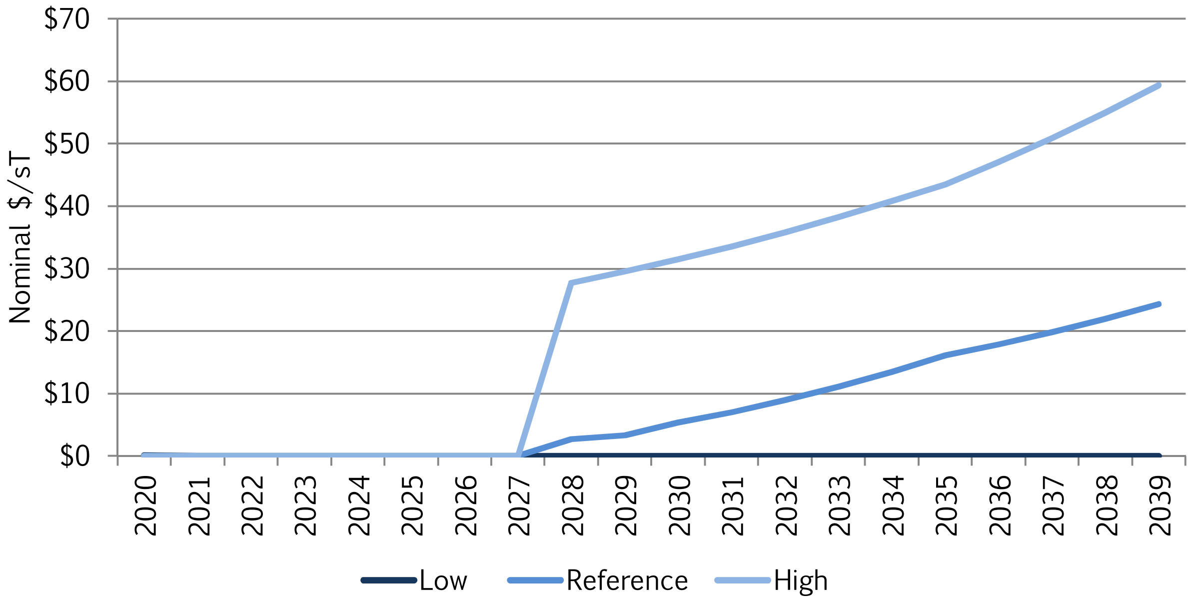
The delivered to Entergy coal price forecast is based on a weighted average price of coal commodity and coal transportation commitments under contract, as well as third-party consultant forecasts of Powder River Basin coal prices for any open coal commodity position. In addition, railcar expenses and 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 2018 dollars per MMBtu through the IRP period (2020-3039), the reference volume weighted delivered to EAI Coal Price is $2.30. The delivered coal price forecast for non-Entergy plants comes directly from the EVA Forecasts and prices vary by plant.

5.3 CO_2 PRICE FORECASTS

EAI's point of view is that national carbon regulation for the power generation sector will occur; however, the timing, design, and outcome of any carbon-control program remain uncertain. The scenarios forecasted and utilized in EAI's evaluations are based on the following three cases:

1. *Low Scenario* – A \$0/ton CO_2 price, representing either no program or a program that requires "inside-the-fence" measures at generating facilities, such as efficiency improvements, that do not result in tradable CO_2 prices.
2. *Reference Scenario* – A "CPP Delay" Mid Case representing a regional mass-based cap consistent with achieving the final CPP requirements, but delayed by approximately 4-6 years due to the federal administration change in 2017 and consistent with the President's executive order in March 2017; and,
3. *High Scenario* – A "National Cap and Trade" High Case assumes a national cap and trade program that begins in 2028 and targets an approximately 80 percent reduction from 2005 sector emissions by 2050.

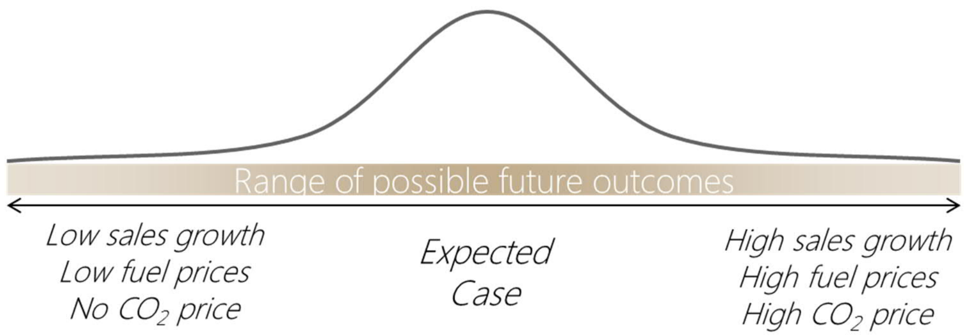
FIGURE 14: CO_2 PRICE FORECAST



6. MODELING FRAMEWORK

6.1 FUTURES-BASED APPROACH

In order to reasonably account for a broad range of uncertainty, the 2018 IRP takes a futures-based approach. In this approach, three "futures" were developed that represent different combinations of possible outcomes of many variables and reasonably bookend the range of possible outcomes. Although EAI does not expect the actual future to materialize exactly like any of the three modeled futures, the futures-based approach provides insight to supply needs and indicates the most attractive options to meet those needs under that future's particular circumstances. This approach to developing various future scenarios is consistent with Section 4.4 of the Commission's Resource Planning Guidelines, which recommends that the planning process identify multiple integrated resource portfolios, each of which meets reliability criteria. To further test the futures, a sensitivity scenario for each future was also modeled to provide insight as to how the optimized portfolios react to changes in assumptions.



Future A – Reference Case

Future A represents a future world which is most closely aligned with the expected outcome, or mid-point of the range of uncertainty, of several unknowns. In this future, natural gas prices and future CO_2 prices are assumed at the Reference Case levels. The Reference Case Peak Load Forecast is also assumed in Future A.

For EAI's existing units, CCGTs are assumed to have a 30-year useful life. The White Bluff and Independence coal units are assumed to cease using coal by 2028 and 2030, respectively.

TABLE 7: FUTURE A ASSUMPTIONS

Future A Key Assumptions (prices shown are 2018$, levelized for the period 2020-39)	
White Bluff and Independence	Assume the proposed Arkansas Phase II SIP White Bluff ceases to use coal in 2028 Independence ceases to use coal in 2030
CCGT Units	Assume 30-year useful life
Electric Sales & Load Forecasts	Reference Case
Henry Hub Natural Gas Price Forecast	$3.88/MMBtu
Coal Price Forecast	$2.30/MMBtu (volume weighted average for EAI units)
CO_2 Price Forecast	$4.15/short ton; pricing begins in 2028
Sensitivity Case	*Low Case Load Forecast* *Extend EAI CCGTs through 2039* *Independence continues using coal through 2039*

To supplement the portfolio optimization results from Future A, additional modeling was performed as a sensitivity case. For the Future A Sensitivity, the load forecast input was changed from Reference Case to the Low Case and the useful life for the CCGT units was extended through the end of the IRP evaluation period. Independence was also assumed to continue operating as a coal plant through 2039. The Future A Sensitivity was designed to reflect more aggressive underlying trends in customer usage patterns and organic energy efficiency penetration as well as acknowledge that existing generation may reliably operate beyond the technology-specific useful life assumptions used for the purposes of the IRP.

Future B – Low Supply Additions Case

Future B represents a future world in which the need and economics for new supply additions are depressed. In this future, natural gas prices, as shown in Figure 13, are assumed at Low case level. Coal prices are assumed at Reference levels given that EAI procures coal via plant-specific contracts, which reduces associated market price variability. The Low Case for CO_2 does not assume any price for carbon emissions over the entire study period. The Low Case Load Forecast is assumed in Future B, which reduces EAI's need for future supply additions.

Assumptions for EAI's existing units align with Future A; existing CCGT units were assumed at a 30-year useful life and White Bluff and Independence are assumed to cease using coal in 2028 and 2030, respectively.

TABLE 8: FUTURE B ASSUMPTIONS

Future B Key Assumptions (prices shown are 2018$, levelized for the period 2020-39)	
White Bluff and Independence	Assume the proposed Arkansas Phase II SIP White Bluff ceases to use coal in 2028 Independence ceases to use coal in 2030
CCGT Units	Assume 30-year useful life
Electric Sales & Load Forecasts	Low Case
Henry Hub Natural Gas Price Forecast	\$2.59/MMBtu
Coal Price Forecast	\$2.30/MMBtu (volume weighted average for EAI units)
CO_2 Price Forecast	No price for CO_2 throughout IRP study period
Sensitivity Case	*Reference Case Load Forecast* *Extend EAI CCGTs through 2039* *Independence continues using coal through 2039*

Additional portfolio optimization modeling was also completed for Future B as a sensitivity case. Complementary to the Future A Sensitivity, for the Future B Sensitivity the load forecast input was changed from Low Case to Reference Case. Also, the useful life for the CCGT units was extended through the end of the IRP evaluation period. Independence was also assumed to continue operating through 2039. The

Future B Sensitivity models a future scenario that effectively extends the current status quo, i.e. persistent low gas prices and energy growth that reflects current trends in customer usage and energy efficiency penetration.

Future C – High Supply Additions Case

Future C represents a future world in which the need and economics for new supply additions are enhanced. In this future, natural gas prices are assumed at the High Case levels. As noted in Future B, delivered coal prices are assumed at the Reference level. The High Case price for CO_2 is also assumed, which begins in 2028 as in Future A, but at a higher price. The High Case Load Forecast is assumed in Future C, which increases EAI's need for future supply additions.

Assumptions for EAI's existing units align with Futures A and B; existing CCGT units were assumed at a 30-year useful life and White Bluff and Independence are assumed to cease using coal in 2028 and 2030, respectively.

TABLE 9: FUTURE C ASSUMPTIONS

Future C Key Assumptions (prices shown are 2018$, levelized for the period 2020-39)	
White Bluff and Independence	Assume the proposed Arkansas Phase II SIP White Bluff ceases to use coal in 2028 Independence ceases to use coal in 2030
CCGT Units	Assume 30-year useful life
Electric Sales & Load Forecasts	High Case
Henry Hub Natural Gas Price Forecast	$5.43/MMBtu
Coal Price Forecast	$2.30/MMBtu (volume weighted average for EAI units)
CO_2 Price Forecast	$14.50/short ton; pricing begins in 2028
Sensitivity Case	*Modified Load Growth Load Forecast*

As with Futures A and B, a portfolio optimization sensitivity was developed for Future C to supplement the baseline portfolio results. The Future C Sensitivity explores how the portfolio of resources changes in response to higher levels of customer investment in rooftop solar or other AMI-enabled activities that reduce usage during traditional peak hours.

The load forecast input was changed from High Case to Modified Load Growth ("MLG"), which was developed specifically for Future C's Sensitivity case using modified DR load shapes produced by ICF. As in Future C, the Sensitivity case assumes high natural gas and environmental costs which yield higher energy costs versus Futures A and B. The MLG forecast envisions a future where EAI's customers are enabled by AMI technology and have a greater economic incentive to adapt their energy consumption given higher relative energy prices. One example of how the Future C Sensitivity could develop is through significant increases in customer investment in rooftop solar or other types of distributed generation.

DR load shapes were decremented from the Reference Load forecast to produce the MLG load forecast. The resulting forecast primarily shifts customer energy usage away from peak hours and into off-peak hours, when energy is less expensive. As a result, annual peak loads are -1.0% to -2.3% lower versus the Reference Load forecast.

6.2 IRP Modeling Overview

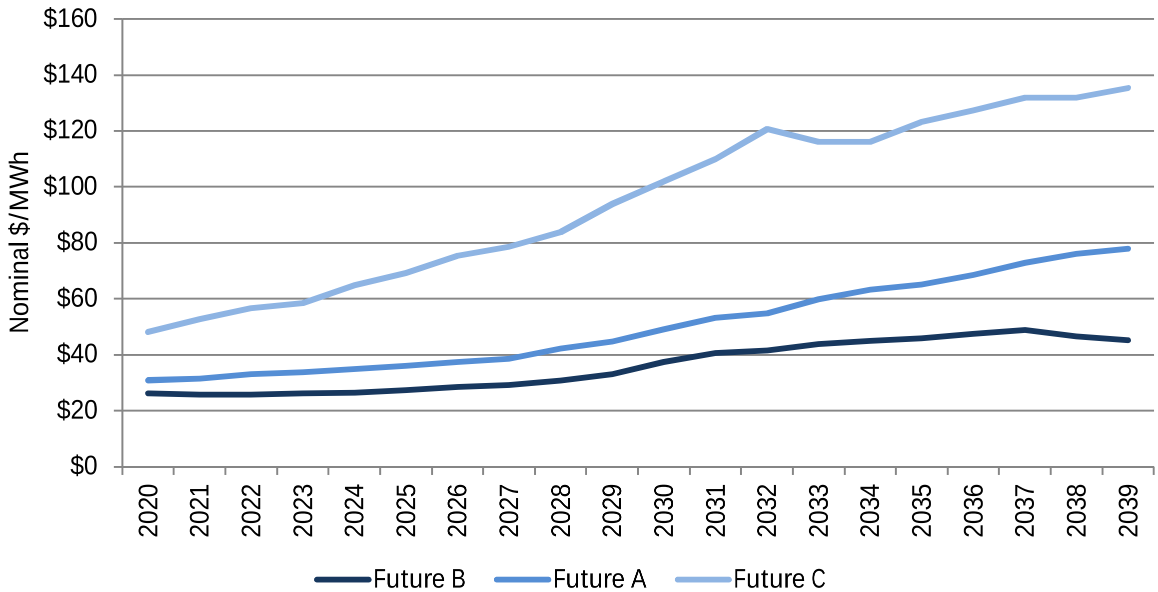
The development of the 2018 IRP relied on the AURORA[14] Energy Market Model to generate market prices (Locational Marginal prices or LMPs) for the MISO energy market and develop optimized portfolios for EAI under a range of possible futures. AURORA is a production cost and capacity expansion optimization tool that simulates energy market operations using hourly demands 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 economically meets the identified requirements given the defined constraints.

6.3 Market Modeling

The first step in the IRP modeling process is to utilize AURORA to develop a projection of the MISO market energy price and operations based on the specific characteristics of each future. The energy market simulation results in hourly energy prices for each of the three futures. The projection encompasses the power market for the entire MISO footprint, excluding EAI. MISO-South (excluding EAI) projected power prices are used to assess potential portfolio strategies for EAI in each future during the capacity expansion optimization step. The scope of the markets modeled in this step is shown in Appendix D.

Figure 15: Average Annual MISO South Non-EAI LMP

[14] The AURORA Model is the primary production cost tool used to perform MISO energy market modeling and long-term variable supply cost planning for EAI. AURORA supports a variety of resource planning activities and is well suited for scenario modeling through hourly simulation of the MISO market. It is widely used by a range of organizations, including large investor-owned utilities, small publically-owned utilities, and regulators.



6.4 EAI Portfolio Optimization

Following the market modeling process, which results in LMPs for the MISO South region excluding EAI, the AURORA long-term capacity expansion logic was used to select resources to meet EAI's future capacity needs. Each of the three futures was modeled in AURORA and the capacity expansion logic was utilized to determine the timing, amount, and type of incremental capacity and incremental DSM to be added to EAI's existing portfolio to meet EAI's reliability requirements (target planning reserve margin requirements), subject to constraints, under each future. This step resulted in a 20-year resource expansion plan which is economically optimized to meet EAI's forecasted demand under each future scenario.

For the 2018 IRP, EAI sought to take into account capacity credit considerations of non-dispatchable, intermittent generation that is provided by solar and wind resources. As the amount of installed renewable resources in the generation portfolio increases, the contribution of an individual renewable resource towards meeting the planning reserve margin may decrease. This is due to solar production potentially shifting a load serving entity's net peak (demand less solar), such that every incremental unit of solar provides less value in supporting reliability needs. The concept that solar provides diminishing returns in capacity and energy value has been further explored in works by CAISO[15] and MISO[16] to great detail.

[15] https://www.nrel.gov/docs/fy16osti/65023.pdf
[16] https://cdn.misoenergy.org/20180605%20RIIA%20Workshop%20Presentation213125.pdf

To account for the diminishing value of non-dispatchable, intermittent resources, EAI used functionality within the AURORA model that considers the impact of solar and wind on the peak load when selecting resources to include in the optimized portfolios. As a result, the capacity contribution of solar and wind within the optimized portfolios is dependent on the amount of incremental solar and wind added, the production profiles of these resources, and the load shape of EAI's customers. The diminishing returns of solar and wind resource additions are accounted for in the AURORA capacity expansion; for the purposes of computing a total supply cost to customers, EAI defaulted to the current MISO practice for new resources without sufficient operating history – 50% capacity credit for solar and 15.6% capacity credit for wind.

6.5 2018 EAI IRP DSM Modeling

Potential DSM Programs were evaluated as resource alternatives alongside supply side resource alternatives in the AURORA capacity expansion optimization in order to identify the most economic combination of DSM programs and supply side resources that meet EAI's customer needs subject to constraints.

Potential DSM programs were evaluated based on the characteristics and attributes described in earlier in this section. Each DSM program was modeled in AURORA based on annual program costs, hourly demand reduction profiles, program start date(s), assumed program life, and program dependencies or mutually exclusive restrictions and evaluated to identify the DSM programs that are economic (i.e. have a positive net benefit). The following potential DSM programs were modeled, totaling 15 potential alternatives:

- DR resource alternatives included three mutually exclusive DR portfolios (low, mid, high) with three discrete start year options (2020, 2025, 2030). Refer to Figure 16.
- EE resource alternatives included two mutually exclusive EE portfolios (low, high) with 3 discrete start year options (2020, 2025, 2030). Refer to Figure 17.

FIGURE 16: DR RESOURCE ALTERNATIVES

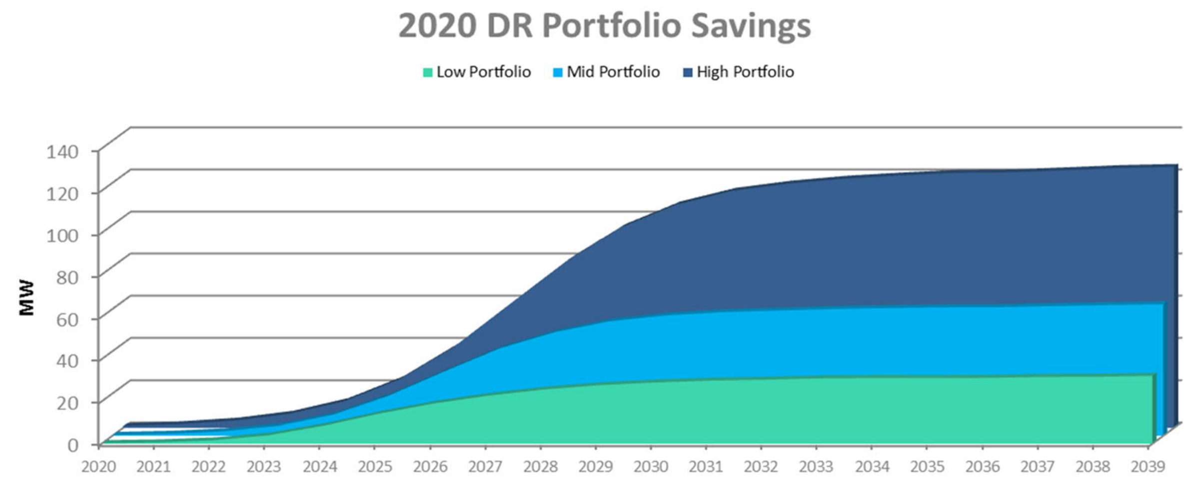
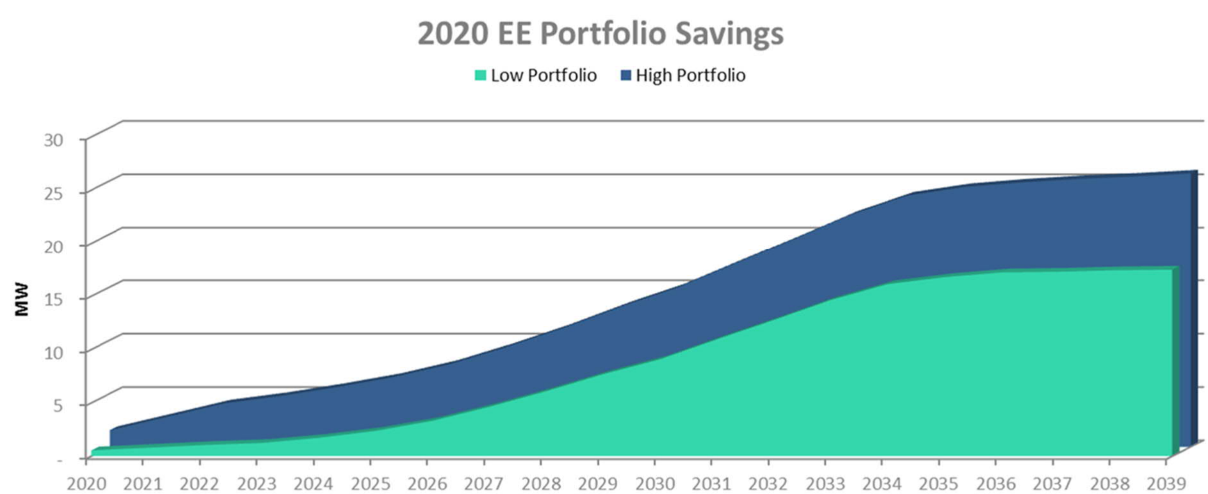


FIGURE 17: EE RESOURCE ALTERNATIVES



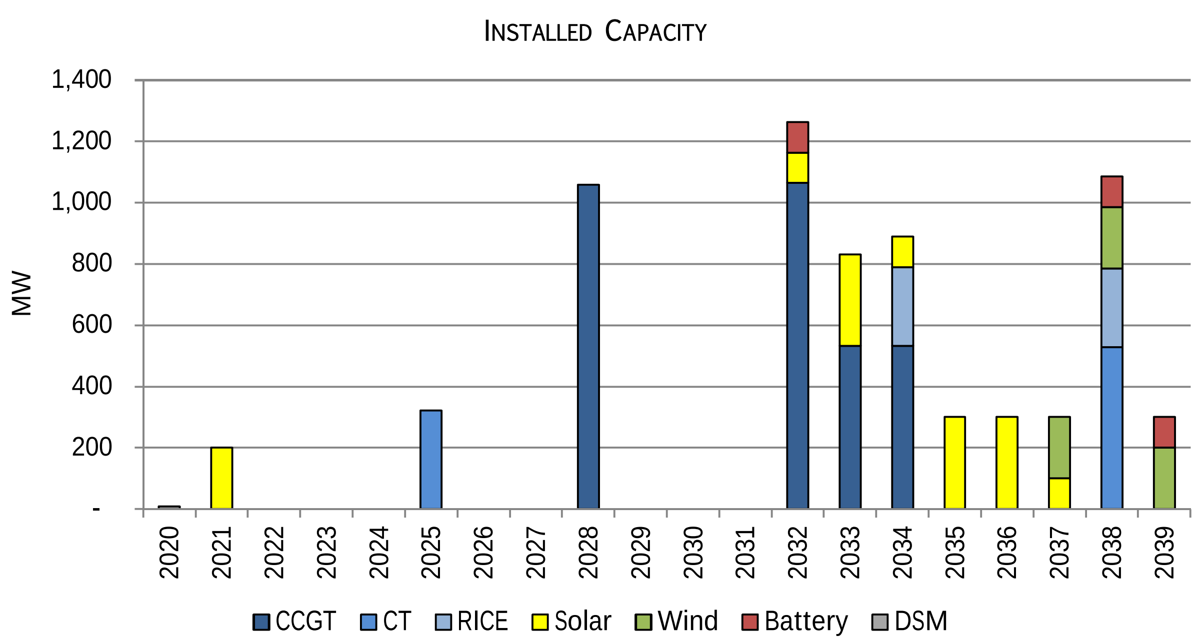
AURORA considers the cost and revenue of energy and capacity in the context of the MISO market for each supply side alternative and each DSM alternative. Selection of DSM alternatives in the model was based strictly on economics in order to avoid non-selection due to a lack of capacity need in the discrete start year options. The capacity credit of selected DSM programs is counted toward meeting EAI's capacity needs through reduction of peak load.

7. Results

7.1 Future A Results

A total of 6,660 MW of installed capacity is added to EAI's resource portfolio in Future A. On an effective capacity basis, which accounts for the intermittency of solar and wind resources, the total capacity addition is 5,545 MW (excluding DSM). The first resource added is the Low EE 2020 portfolio from the Potential DSM Resources. The first generation capacity is added in 2025 and consists of one CT unit; note that the solar capacity additions illustrated in Figure 18 below did not originate from AURORA's capacity expansion model (these resources are discussed in Section II). Overall, 68% of the modeled supply additions are natural gas resources while the remaining 32% are from renewable resources. The total relevant supply cost[17] for the Future A optimized portfolio is $9,050 million (2020-2039 present value, 2020$MM).

Figure 18: Future A Supply Additions



The portfolio mix of capacity resources over the 20-year IRP study period is shown below, followed by the fuel diversity based on energy generated for the Future A portfolio. The energy mix shown includes energy used to meet native load need and sales to the market.

[17] The total relevant supply cost consists of the sum of two components: the variable supply cost for the entire portfolio (existing, planned and incremental resources added via AURORA optimization) plus the fixed cost components of the incremental resources added via AURORA optimization and any other future fixed costs of existing resources that vary among the futures.

FIGURE 19: FUTURE A CAPACITY MIX

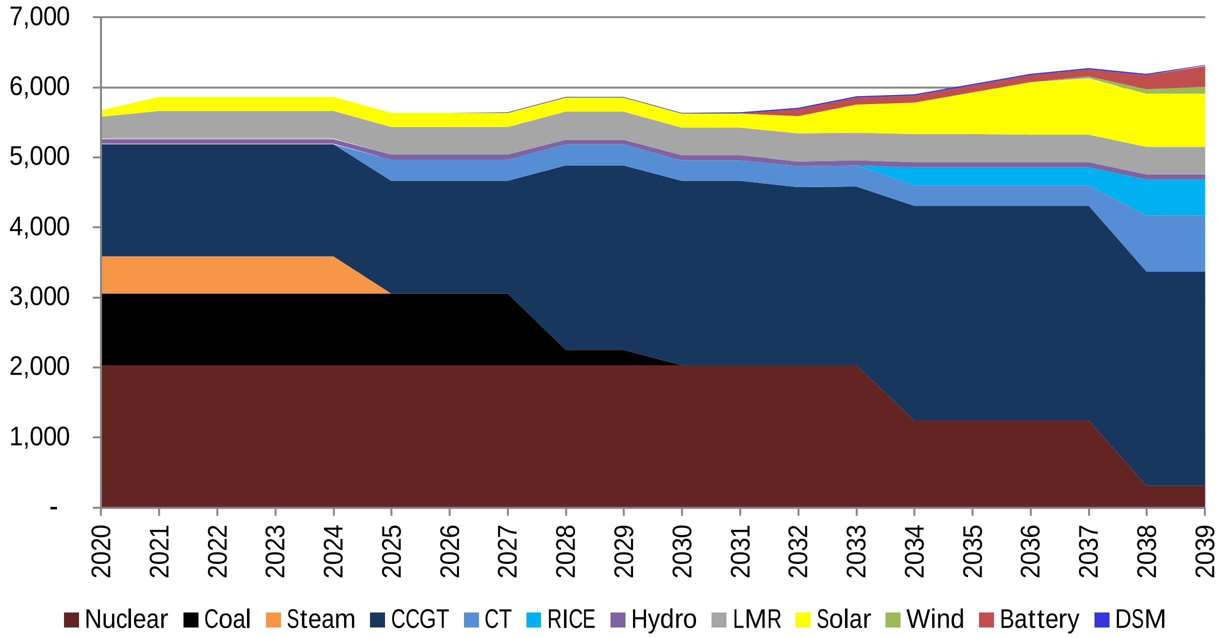
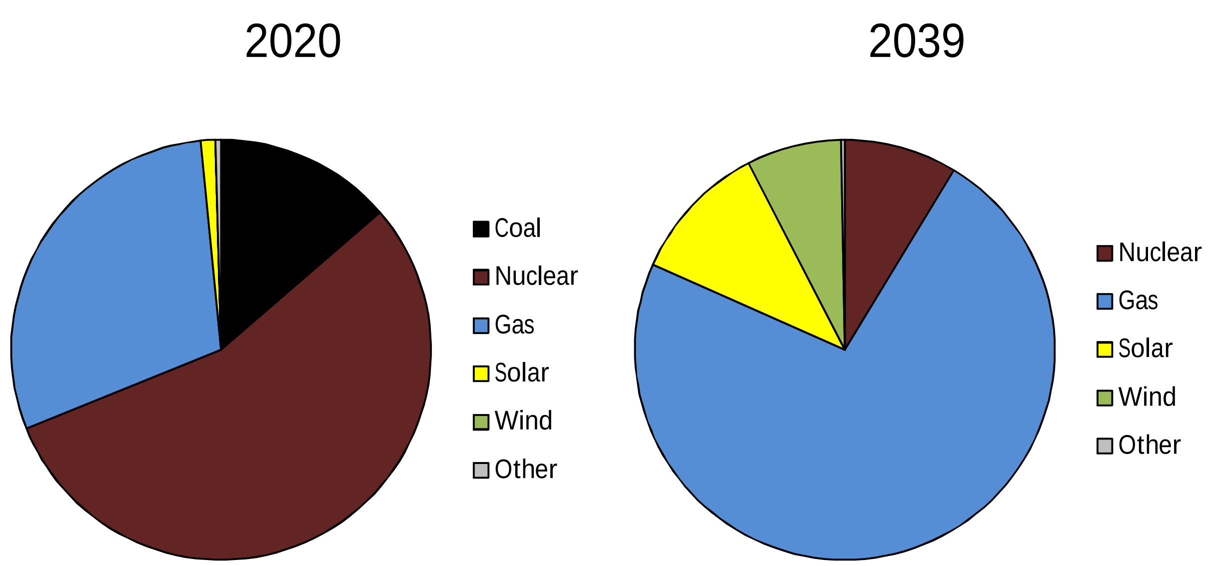


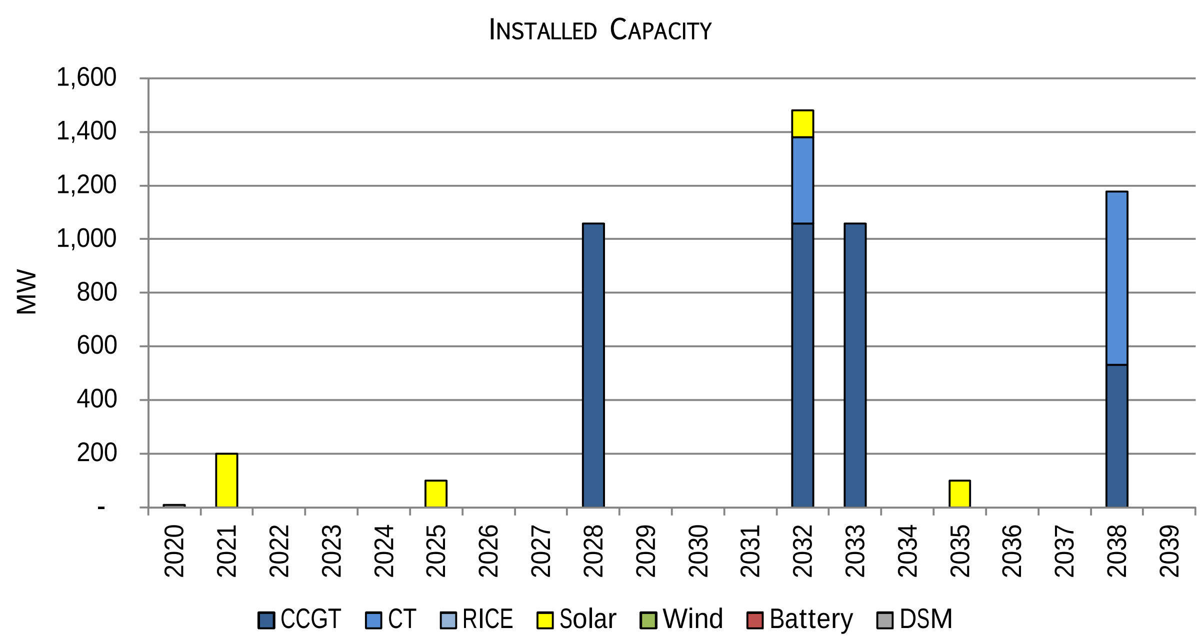
FIGURE 20: FUTURE A ENERGY MIX



7.2 Future B Results

A total of 4,984 MW of installed capacity is added to EAI's resource portfolio in Future B. On an effective capacity basis, which accounts for the intermittency of solar and wind resources, the total capacity addition is 4,825 MW (excluding DSM). The first resource added is the Low EE 2020 portfolio from the Potential DSM Resources. The first generation capacity is added in 2025 and consists of 100 MW of solar; as in Future A, note that the solar capacity additions illustrated in Figure 21 below did not originate from AURORA's capacity expansion model. Overall, 94% of the modeled supply additions are natural gas resources while the remaining 6% are from renewable resources. The total relevant supply cost for the Future B optimized portfolio is $6,673 million (2020-2039 present value, 2020$MM).

Figure 21: Future B Supply Additions



The portfolio mix of capacity resources over the 20-year IRP study period is shown below, followed by the fuel diversity based on energy generated for the Future B portfolio. The energy mix shown includes energy used to meet native load need and sales to the market.

Figure 22: Future B Capacity Mix

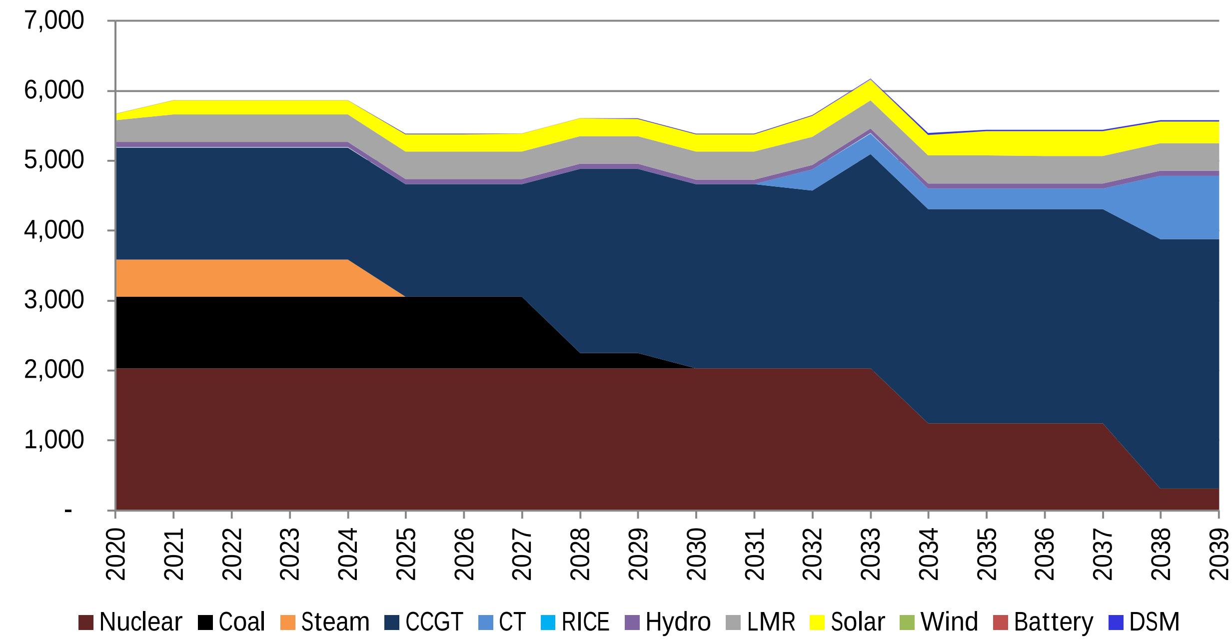
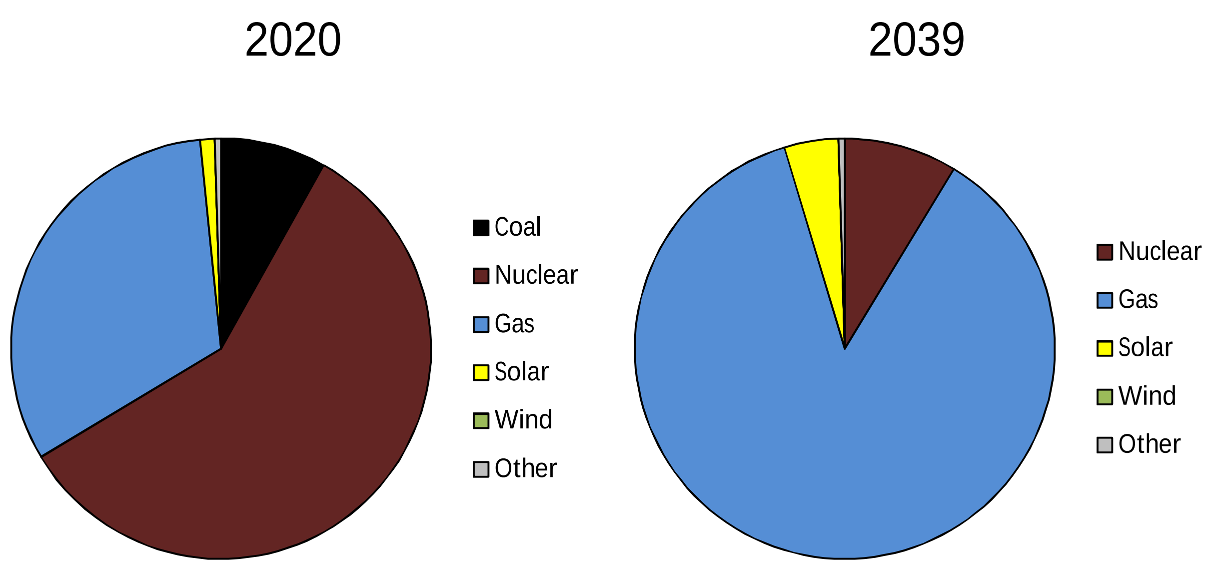


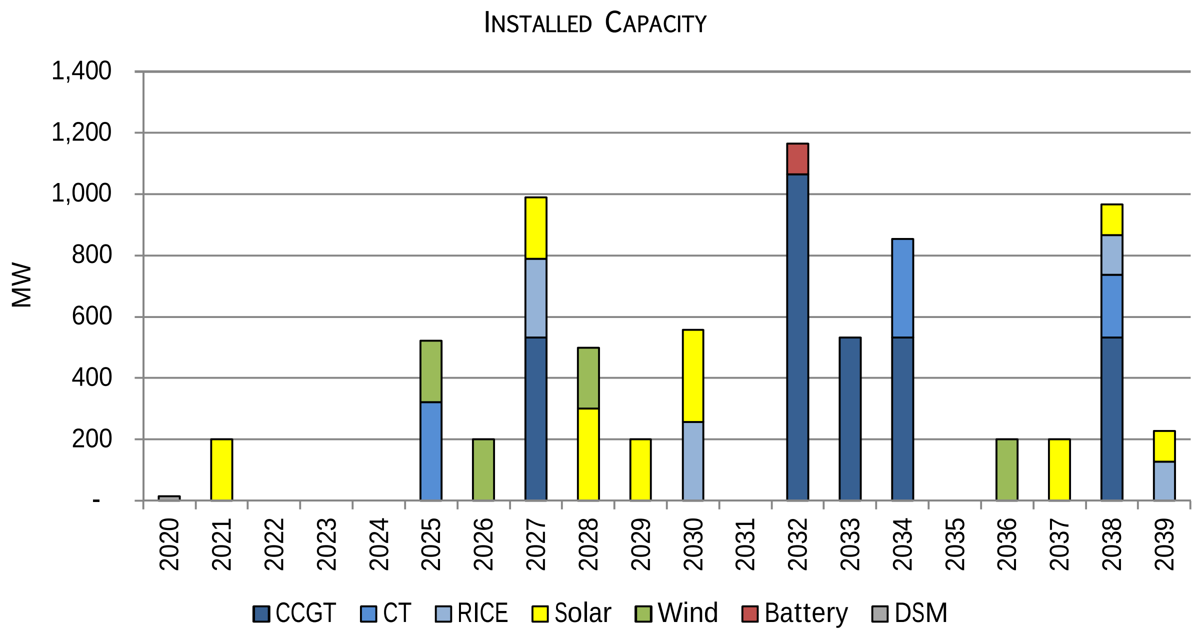
FIGURE 23: FUTURE B ENERGY MIX



7.3 FUTURE C RESULTS

A total of 7,128 MW of installed capacity is added to EAI's resource portfolio in Future C. On an effective capacity basis, which accounts for the intermittency of solar and wind resources, the total capacity addition is 5,739 MW (excluding DSM). The first resource added is the High EE 2020 portfolio from the Potential DSM Resources. The first generation capacity is added in 2025 and consists of one CT unit and 200 MW of wind; as in Futures A and B, note that the solar capacity additions illustrated in Figure 24 below did not originate from AURORA's capacity expansion model. Overall, 68% of the modeled supply additions are natural gas resources while the remaining 32% are from renewable resources. The total relevant supply cost for the Future C optimized portfolio is $10,416 million (2020-2039 present value, 2020$MM).

FIGURE 24: FUTURE C SUPPLY ADDITIONS



The portfolio mix of capacity resources over the 20-year IRP study period is shown below, followed by the fuel diversity based on energy generated for the Future C portfolio. The energy mix shown includes energy used to meet native load need and sales to the market.

FIGURE 25: FUTURE C CAPACITY MIX

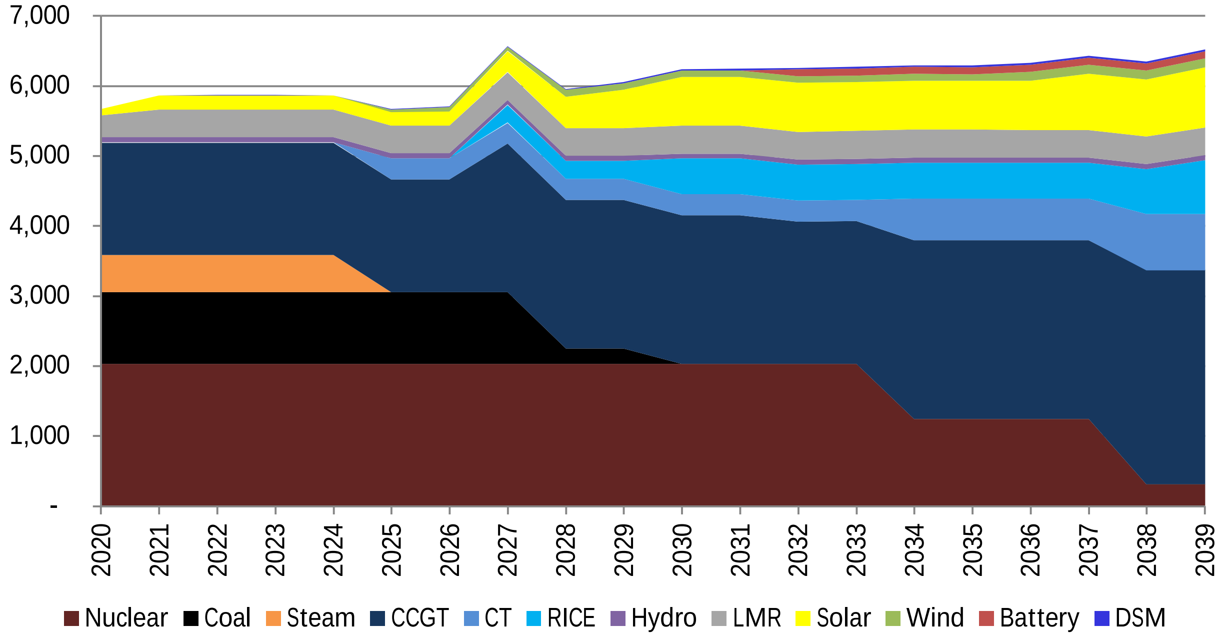
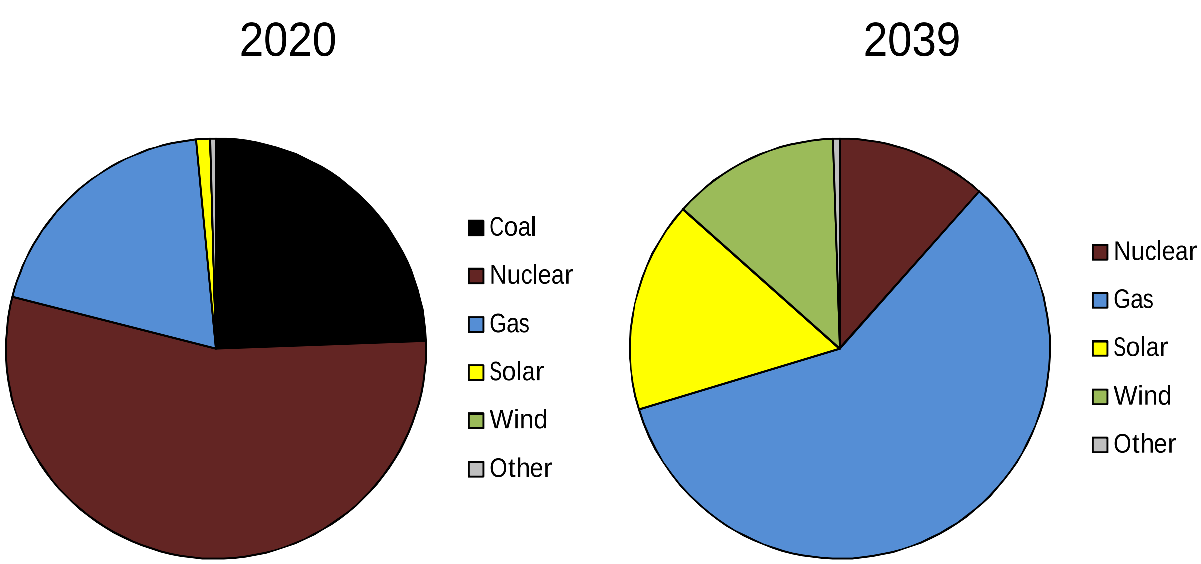


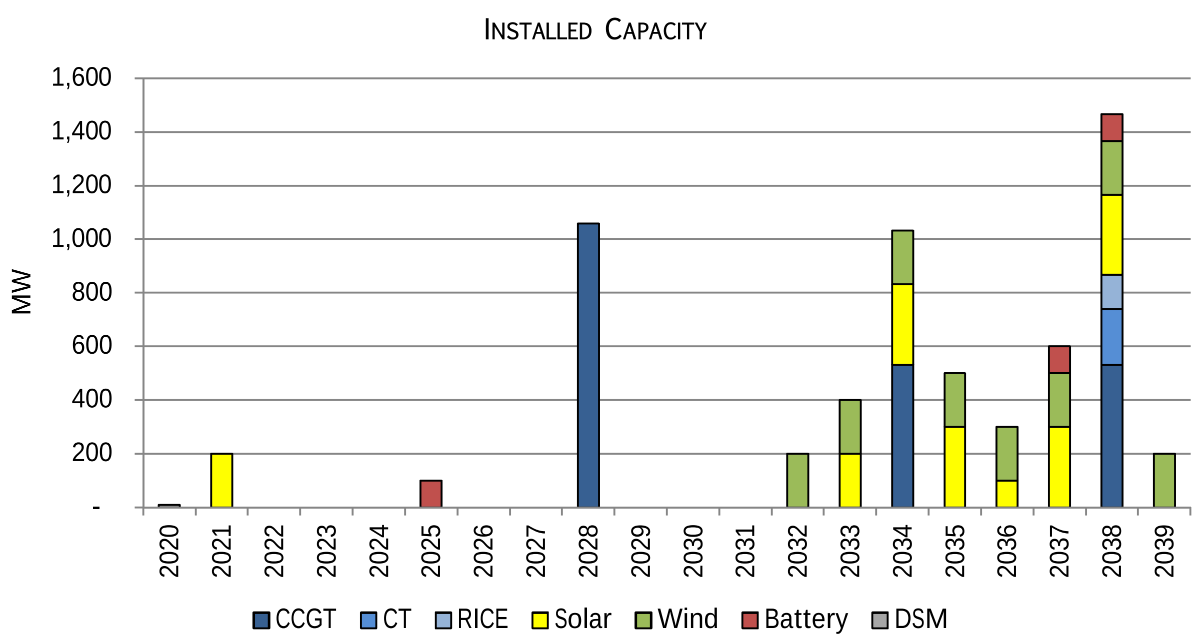
FIGURE 26: FUTURE C ENERGY MIX



7.4 Future A Sensitivity Results

A total of 5,866 MW of installed capacity is added to EAI's resource portfolio in the Future A Sensitivity. On an effective capacity basis, which accounts for the intermittency of solar and wind resources, the total capacity addition is 3,756 MW (excluding DSM). The first resource added is the Low EE 2020 portfolio from the Potential DSM Resources. The first generation capacity is added in 2025 and consists of a 100 MW battery; note that the solar capacity additions illustrated in Figure 27 below did not originate from AURORA's capacity expansion model. Overall, 42% of the modeled supply additions are natural gas resources while the remaining 58% are from renewable resources. The total relevant supply cost for the Future A Sensitivity optimized portfolio is $7,556 million (2020-2039 present value, 2020$MM).

Figure 27: Future A Sensitivity Supply Additions



The portfolio mix of capacity resources over the 20-year IRP study period is shown below, followed by the fuel diversity based on energy generated for the Future A Sensitivity portfolio. The energy mix shown includes energy used to meet native load need and sales to the market.

Figure 28: Future A Sensitivity Capacity Mix

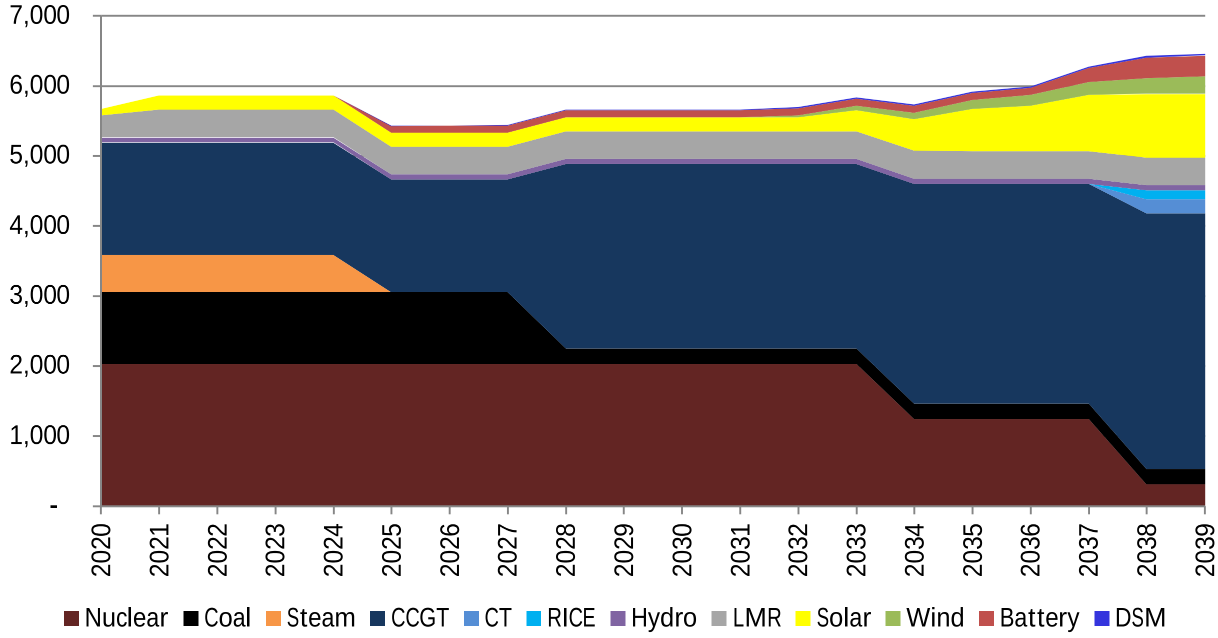
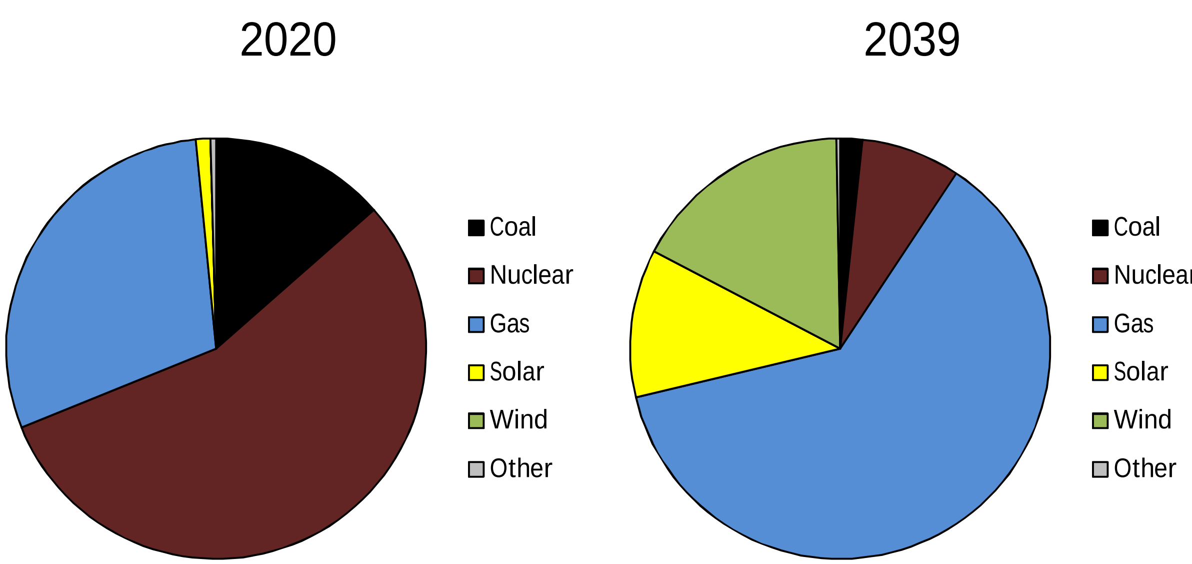


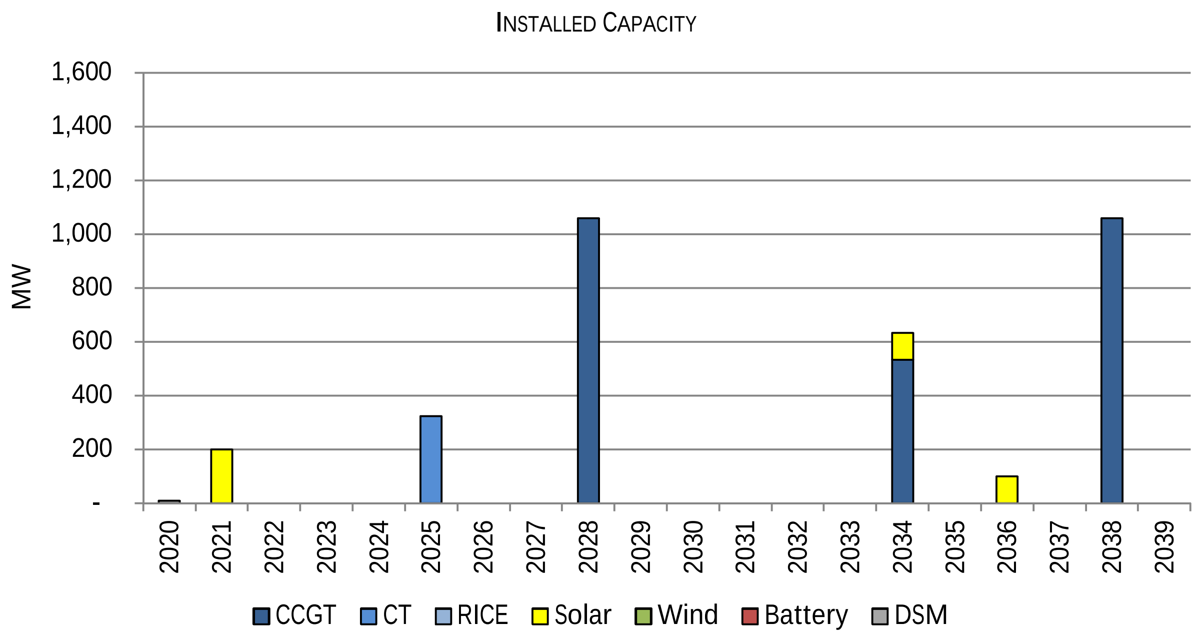
FIGURE 29: FUTURE A SENSITIVITY ENERGY MIX



7.5 Future B Sensitivity Results

A total of 3,180 MW of installed capacity is added to EAI's resource portfolio in the Future B Sensitivity. On an effective capacity basis, which accounts for the intermittency of solar and wind resources, the total capacity addition is 3,071 MW (excluding DSM). The first resource added is the Low EE 2020 portfolio from the Potential DSM Resources. The first generation capacity is added in 2025 and consists of one CT unit; note that the solar capacity additions illustrated in Figure 30 below did not originate from AURORA's capacity expansion model. Overall, 94% of the modeled supply additions are natural gas resources while the remaining 6% are from renewable resources. The total relevant supply cost for the Future B Sensitivity optimized portfolio is $7,064 million (2020-2039 present value, 2020$MM).

Figure 30: Future B Sensitivity Supply Additions



The portfolio mix of capacity resources over the 20-year IRP study period is shown below, followed by the fuel diversity based on energy generated for the Future B Sensitivity portfolio. The energy mix shown includes energy used to meet native load need and sales to the market.

FIGURE 31: FUTURE B SENSITIVITY CAPACITY MIX

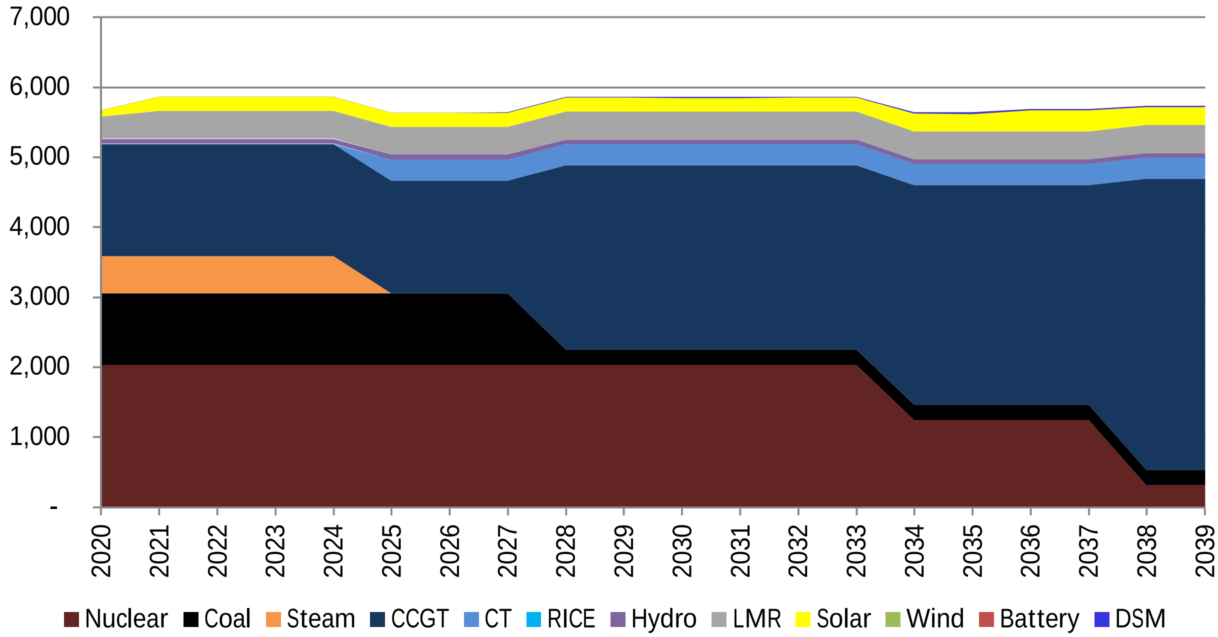
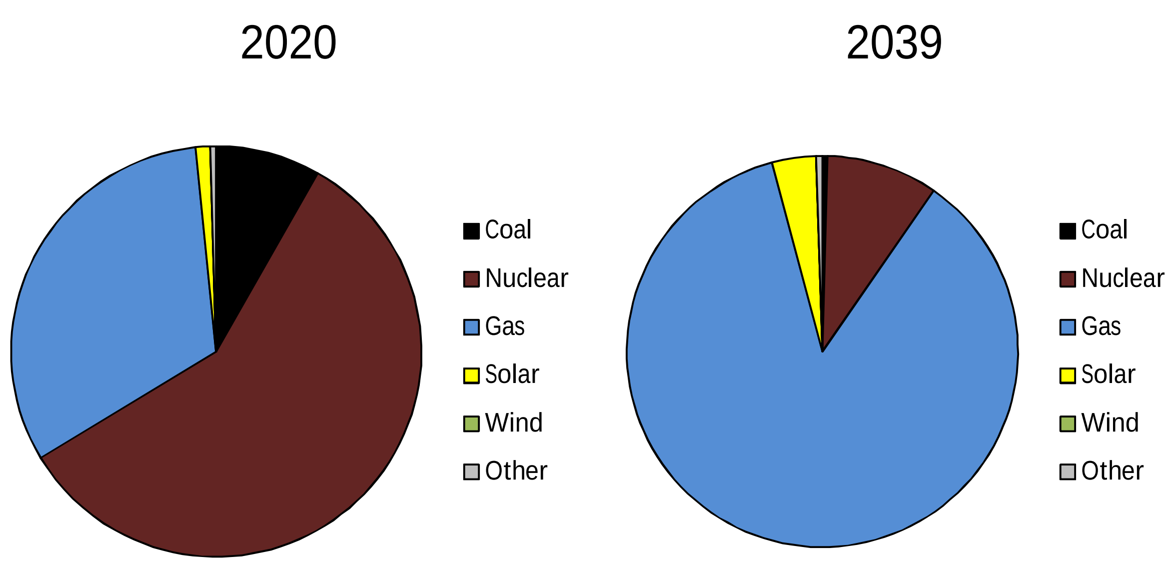


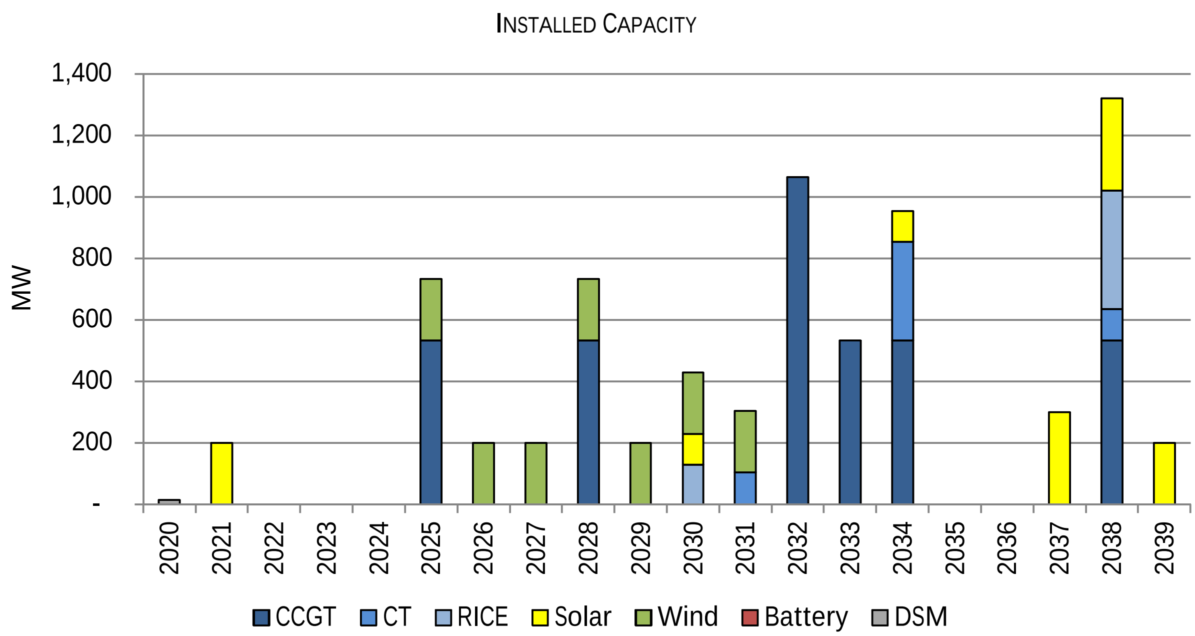
FIGURE 32: FUTURE B SENSITIVITY ENERGY MIX



7.6 Future C Sensitivity Results

A total of 7,181 MW of installed capacity is added to EAI's resource portfolio in the Future C Sensitivity. On an effective capacity basis, which accounts for the intermittency of solar and wind resources, the total capacity addition is 5,485 MW (excluding DSM). The first resource added is the High EE 2020 portfolio from the Potential DSM Resources. The first generation capacity is added in 2025 and consists of a 1x1 CCGT paired with 200 MW of wind; note that the solar capacity additions illustrated in Figure 33 below did not originate from AURORA's capacity expansion model. Overall, 66% of the modeled supply additions are natural gas resources while the remaining 34% are from renewable resources. The total relevant supply cost for the Future C Sensitivity optimized portfolio is $9,228 million (2020-2039 present value, 2020$MM).

Figure 33: Future C Sensitivity Supply Additions



The portfolio mix of capacity resources over the 20-year IRP study period is shown below, followed by the fuel diversity based on energy generated for the Future C Sensitivity portfolio. The energy mix shown includes energy used to meet native load need and sales to the market.

FIGURE 34: FUTURE C SENSITIVITY CAPACITY MIX

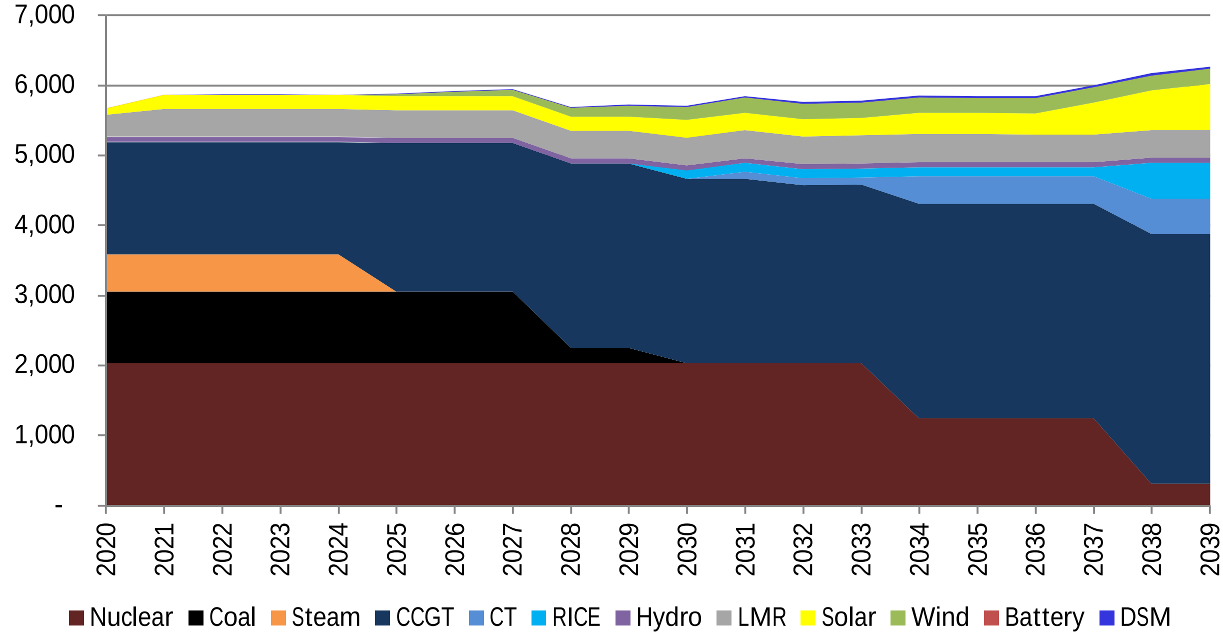
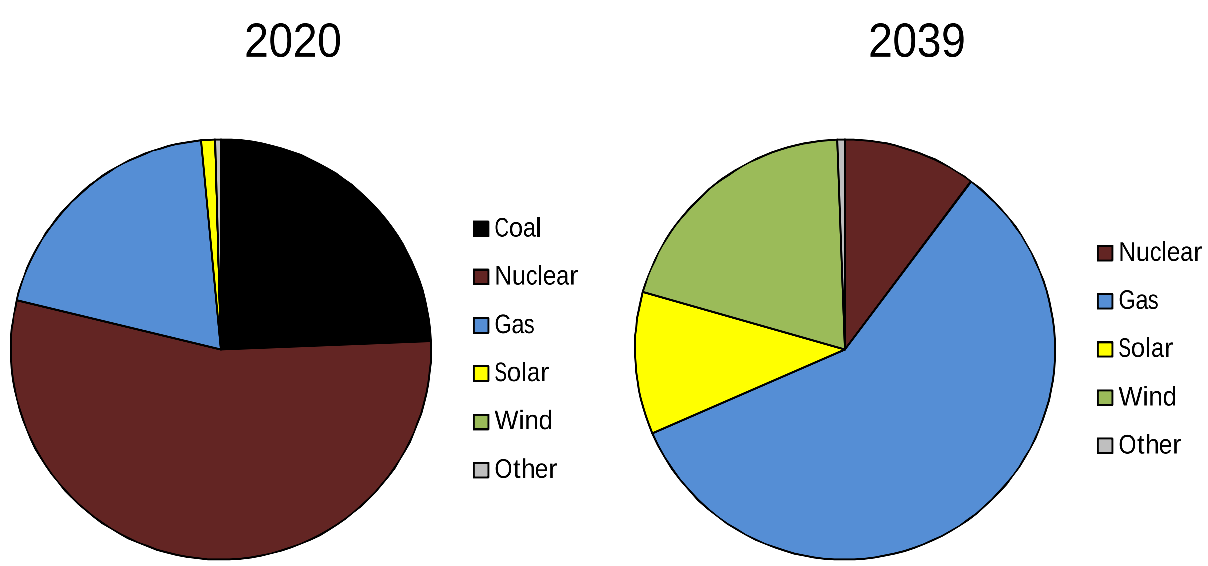


FIGURE 35: FUTURE C SENSITIVITY ENERGY MIX



IV. Action Plan

1. Findings and Conclusions

1.1 Summary of Findings

As discussed above, the AURORA Portfolio Optimization process resulted in six distinct resource portfolios, each of which are economically optimal for the respective future or sensitivity cases. When reviewing the results of those distinct resource portfolios, the many varying inputs across the futures must be taken into consideration. Because it was necessary to capture a broad range of uncertainties in the IRP Futures in order to bookend the range of possible outcomes, caution must be taken when comparing results between the futures. Nevertheless, the table below summarizes the results of the Portfolio Optimization for each future.

Table 10: Summary of Modeling Results

2020-39 Modeling Results	Future A	Future B	Future C
Total Incremental Installed Capacity:	6,660 MW	4,984 MW	7,128 MW
Natural Gas Capacity Additions:	68.4%	94.0%	67.5%
Renewable Capacity Additions:	31.6%	6.0%	32.5%
DSM Capacity Additions:	2020 Low EE	2020 Low EE	2020 High EE
Incremental Generation Capacity Additions Begin:	2025	2025	2025
Incremental Generation Capacity Type:	CT	Solar	CT + Wind

The optimal portfolio is consistent across the futures. Future C adds more capacity overall than Future A, but the fuel mix is similar. Future B has the smallest need for incremental capacity additions and assumptions that favor gas-fired resources, so the resulting portfolio mix is different from the others but is reasonable for that set of assumptions. Overall, the indication is that both renewable and gas-fired resources are cost-effective in the future. The result also affirms the current resource planning protocol of gradually adding cost-effective renewables and monitoring the resource needs as well as external market factors for the appropriate time to add other types of resources.

Renewables have become more cost-effective. As a percentage of incremental resource additions, renewables have increased across all futures since the 2015 IRP. While the increase in the ratios may appear modest, this is even more significant given that the natural gas price forecast has decreased almost 30% since the 2015 IRP. As discussed in the prior section, the 2018 IRP modeling also used functionality within the AURORA model that considers the impact of solar and wind on the peak load when selecting resources to include in the optimized portfolios.

TABLE 11: GAS TO RENEWABLES COMPARISON

Gas to Renewables Ratios	2015 IRP	2018 IRP
Low Case Ratio:	100% / 0%	94% / 6%
Reference Case Ratio:	73% / 27%	68% / 32%
High Case Ratio:	73% / 27%	68% / 32%

Generation is added in 2025 across all futures and sensitivities. The first generation resource addition in each of the three futures, as well as each of the three sensitivities, is added in 2025, though the technology type and size varies ranging from a 100 MW solar resource to 732 MW of combined CT and wind resources. Since resources are added in all futures, including Future B which assumes the Low Load Forecast, this is primarily driven by the deactivation assumption used in the 2018 IRP model for Lake Catherine Unit 4. Also, the recent actions EAI has taken by adding two solar PPAs and issuing a third RFP for solar resources over the past four years have partially mitigated the 2025 capacity need depending on how customer load requirements change over the next few years.

A CCGT is added in 2028 across all futures and most sensitivities. The next common theme across the 2018 IRP portfolios is that a CCGT resource is consistently added in 2028. The exception is Future C, which adds a CCGT resource in 2027 and a similar amount of renewable capacity in 2028. While EAI saw in its 2015 IRP and has seen in this 2018 IRP that the optimal resource portfolio of the future is likely comprised of a combination of renewables and conventional resources, the potential 2028 capacity need (created by the need to replace the coal-fired energy from White Bluff) may need to be primarily addressed by gas-fired, i.e. non-intermittent, generation that can serve the energy requirements of EAI customers.

A demand-side resource alternative is cost-effective in all scenarios. Specifically, varying levels of potential energy efficiency is selected in each portfolio. On the other hand, none of the demand response programs were selected. This result indicates that opportunity may exist for EAI to explore potential cost-effective energy efficiency investments as part of its future portfolio of resources.

2. ACTION PLAN

As was concluded in the 2015 IRP, the 2018 IRP continues to support the conclusion that EAI's future supply-side resource additions will likely consist of a mix of natural gas fired resources and renewable energy resources. Based on the work conducted as part of the 2018 IRP analysis, it is also reasonable to conclude that demand-side resources will continue to be a component of the capacity portfolio. The amount of total capacity that will be needed and exactly when that capacity will be needed are uncertain. There is even more uncertainty associated with exactly how much of each supply-side technology should be added to EAI's fleet and exactly how to identify potential demand-side resources. Because of those uncertainties, EAI will not establish specific targets for renewable generation or traditional generation as part of this IRP analysis. Rather, EAI will take deliberate steps in its Integrated Resource Planning at the appropriate time based on all the relevant information available at that time. For example, supply-side resource additions will be made based on specific project proposals.

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

2018 IRP Action Plan

1. Complete the Build-Own-Transfer of Solar PV	As a result of EAI's 2017 Request for Proposals for Build-Own-Transfer Solar Resources, EAI is currently working toward executing agreements for additional solar generation. Assuming required regulatory approvals are received, the acquisition of additional solar PV generation is expected to take place in 2021.
2. Supply-side Resource Additions	EAI will monitor its load and capability position and take steps to add supply side resources for both traditional and/or renewable resources as warranted. Based on current information, a competitive solicitation may be issued in 2019 for long-term resources. In addition to market solicitation, EAI will be considering developing self-build proposals for certain supply side technologies. However, the exact scope and timing of the next EAI RFP is uncertain and is dependent on many factors noted throughout this report.
3. Potential 2025 Capacity Need	EAI will complete an evaluation of the availability and economics of Lake Catherine Unit 4 past the assumed deactivation date of 2025. In combination with Action Item #2 above, EAI will update the load and capability position in order to monitor the capacity need in 2025.

4. Demand-side Resource Opportunities	EAI will seek and evaluate cost-effectiveness and feasibility for potential projects or programs to gain energy efficiencies in addition to its existing Arkansas Energy Efficiency Program Portfolio. For example, this may be achieved through EE programs with Self-Direct customers or, after implementation of AMI, through AMI-enabled programs or distributed generation resources.
5. Continue Participation in EE	EAI will continue to offer cost effective EE and DR programs within the Commission's Rules for Conservation and Energy Efficiency Programs and subsequent future Commission orders as provided through Arkansas State law, including the recently increased targets that were not available at the time of the 2018 IRP study[18]. Finally, EAI is committed to update the IRP in 2021 and will include an update to the future outlook for DSM as well.
6. Coal Environmental Compliance	The challenge utilities face with regards to environmental compliance is unprecedented in terms of the number of recent and upcoming rules which affect utilities, the compressed time frame for compliance, and the continuing ratcheting down of compliance obligations. Key uncertainties include the requirements related to Regional Haze, ambient air quality standards, coal combustion residuals regulation, effluent limitation guidelines, among others, the outcome of current litigation, congressional activity and the possibility of extensions of compliance deadlines. Another key uncertainty is the nation's long-term carbon policy. The industry needs a satisfactory resolution of both the current regulatory challenges and a long-term legislative solution on carbon. EAI will continue to monitor changes in environmental law and regulations at the state and federal level and evaluate options for environmental compliance for the EAI coal units.
7. Stakeholder Engagement Process	Stakeholder engagement has been an important part of the development of this IRP. An immediate priority will be for EAI to closely review the stakeholder report, which can be found in Appendix E of this report, and take steps to address concerns and suggestions.

[18] Order 43 in Docket No. 13-002-U, effective July 13, 2018

V. Stakeholder Engagement

Per the APSC Resource Planning Guidelines,[19] one part of the development of the IRP is to engage with all of the stakeholders in EAI's long-term planning process. Stakeholders include representatives of retail and wholesale customers, independent power suppliers, marketers, and other interested entities in EAI's service area.

For the 2018 IRP, the Stakeholder Engagement Process began in May 2018 with distribution of a detailed slide presentation describing proposed assumptions, inputs, and modeling framework. The materials, while still preliminary, were posted to EAI's IRP website[20]. Additional meeting materials, which included preliminary modeling results from all three Futures, were provided to stakeholders in advance of the in-person stakeholder meeting hosted by EAI in June 2018.

As noted, EAI hosted an in-person meeting at the MISO South building in Little Rock on June 6, 2018. During the June 6th meeting, presentations were given by several EAI representatives covering a broad range of inputs and modeling results for the IRP. The Company received questions and feedback both during and subsequent to the meeting. Additionally, the stakeholders organized into a Stakeholder Committee during the June 6th meeting.

Both during and subsequent to the June 6th meeting, over 100 detailed questions were submitted to EAI by various stakeholders, to which EAI responded via follow-up postings to the IRP website. EAI's responses were posted in four subsets in order to provide responses as quickly as possible, with most responses posted within a week of receipt. A notification was sent to stakeholders via email at the time of each posting.

At the request of the Stakeholder Committee, EAI hosted a conference call in August 2018 to have a technical discussion of the Committee's feedback regarding EAI's IRP modeling. During the call, EAI offered to provide additional modeling scenarios based on requested assumptions from the Stakeholder Committee. No additional requests from the Stakeholder Committee were presented at that time or following the conference call. Finalized portfolio optimization modeling results for all Futures and Sensitivities were posted by EAI to the IRP website on October 4, 2018. The Stakeholder Committee requested additional time to complete the Stakeholder Report, which was provided to EAI on October 24, 2018. As described in Item 7 of the 2018 IRP Action Plan, EAI will closely review the Stakeholder Report and incorporate

[19] Docket No. 06-028-R, Order No. 6, Attachment 1
[20] http://www.entergy-arkansas.com/integrated_resource_planning

feedback as EAI executes the 2018 IRP Action Plan and prepares for the next IRP cycle.

APPENDIX A – RESOURCE PLANNING OBJECTIVES

PURPOSE:

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

OBJECTIVES:

In developing EAI's IRP, EAI's resource planning and operations staff should consider the following resource planning 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 - EAI PORTFOLIO OF RESOURCES

Owned Generation	Total Installed Capacity (MW)	Ownership (%)	Retail Capacity (MW)	Commercial Operations Date
Arkansas Nuclear One Unit 1	834	100%	789	1974
Arkansas Nuclear One Unit 2	986	100%	933	1980
Carpenter Unit 1	31	100%	31	1932
Carpenter Unit 2	31	100%	31	1932
Hot Spring	606	100%	606	2002
Independence Unit 1	839	31.5%	221	1983
Lake Catherine Unit 4	528	100%	528	1970
Ouachita Unit 1	252	100%	252	2002
Ouachita Unit 2	253	100%	253	2002
Remmel Units 1, 2 & 3	12	100%	12	1925
Union 2	501	100%	501	2003
White Bluff Unit 1	815	57.0%	401	1980
White Bluff Unit 2	822	57.0%	402	1981

Purchased Generation	Total Installed Capacity (MW)	Retail Capacity (MW)	Commercial Operations Date
Blakely	86	11	1956
DeGray	78	10	1972
Grand Gulf	1,409	308	1985
Stuttgart Solar	81	81	2017

Notes:
- Blakely and DeGray capacity is assumed through 5/31/2019
- Grand Gulf Capacity is assumed through the IRP study horizon.
- Stuttgart Solar achieved commercial operations in December 2017; EAI's PPA began effective 6/1/2018.

Demand-side Resources	Reduction During Peak Load Hours (MW)
Demand Response	59
Interruptible Load	57

Notes:
- Estimates above are 2018 reductions.
- EAI'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 12: EAI PROJECTS APPROVED IN APPENDIX A OF MTEP17

Project Driver	Project Name	Current Projected ISD
Load Growth	LR Kanis: Install 3rd distribution transformer (necessitates station conversion to breaker and a half configuration)	Complete
Load Growth	Greyhawk 161 kV: New Distribution Substation	6/1/2020
Load Growth	Tarleton 230 kV: New Distribution Substation	6/1/2019
Load Growth	MacArthur 115 kV: New Distribution Substation	11/1/2019
Load Growth	Pecan Street 161 kV: New Distribution Substation	11/15/2019
Load Growth	Big Creek 115 kV: New Distribution Substation	5/1/2020
Load Growth	Russellville Industrial 161 kV: New Distribution Substation	12/1/2019
Transmission Reliability - Meeting Planning Criteria	Jacksonville North - Sylvan Hills 115 kV: Upgrade line bay bus at Sylvan Hills	12/1/2018
Transmission Reliability - Meeting Planning Criteria	El Dorado Donan 115 kV: Install 30MVAR capacitor bank	Complete
Transmission Reliability - Meeting Planning Criteria	Independence: Replace 500/161 kV Autos	12/1/2019
Transmission Reliability - Meeting Planning Criteria	West Helena: Install 115 kV breakers	12/1/2019
Transmission Reliability - Meeting Planning Criteria	Russellville East 161 kV: Install 10 Ohm Series Reactor	6/1/2020
Transmission Reliability - Meeting Planning Criteria	Happy Valley - Hot Springs 500 kV Project	6/1/2024

TABLE 13: EAI PROJECTS SUBMITTED AS TARGET APPENDIX A IN MTEP18

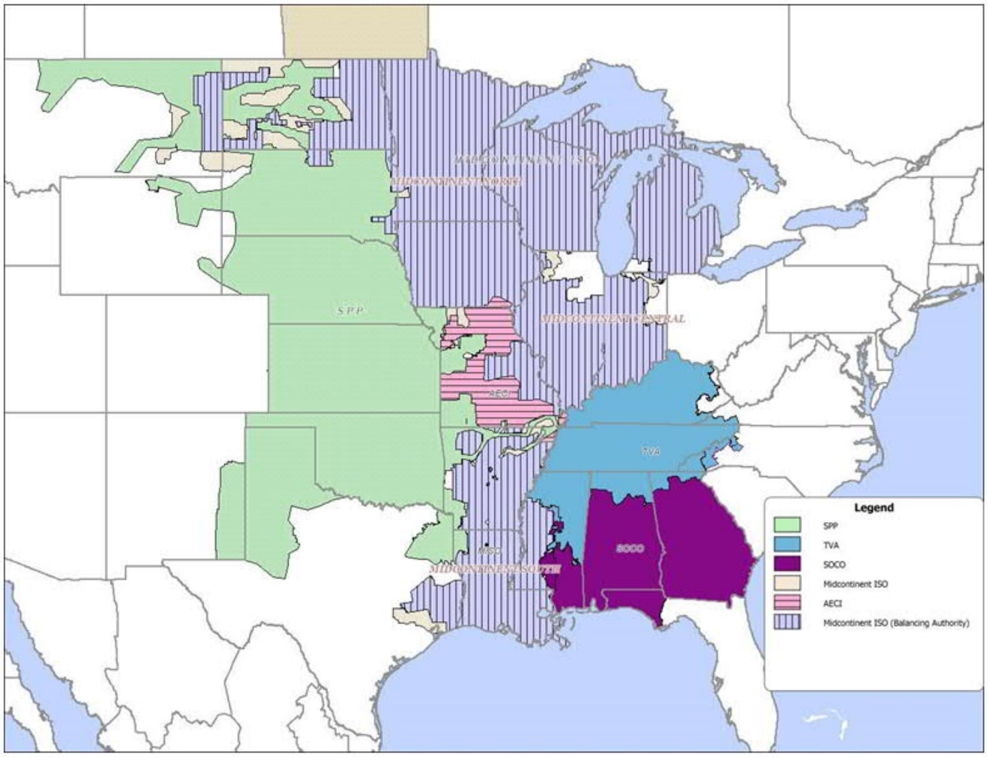
Project Driver	Project Name	Current Projected ISD
Asset Management	Moses 161 kV: New Substation	6/1/2019
Load Growth	Sierra 115 kV: New Distribution Substation	5/1/2020
Load Growth	Skunk Hollow 161 kV: New Distribution Substation	6/1/2021
Load Growth	Social Hill 115 kV: New Distribution Substation	6/1/2021
Load Growth	Palestine 161 kV: New Distribution Substation	6/1/2023
Transmission Reliability - Meeting Planning Criteria	Jacksonville North - Holland Bottom 115 kV: Upgrade line to 100 C operation	12/1/2019
Transmission Reliability - Meeting Planning Criteria	Cheetah - Hot Springs Village 115 kV: Rebuild line	12/1/2020
Transmission Reliability - Meeting Planning Criteria	Conway S. - Conway Ind. 161 kV: Rebuild line	12/1/2020
Transmission Reliability - Meeting Planning Criteria	Camden Maguire - Smackover 115 kV: Rebuild line	6/1/2021
Transmission Reliability - Meeting Planning Criteria	Paragould 161/115 kV: Install station service to enable autotransformer cooling pumps and uprate autotransformer.	12/1/2021
Transmission Reliability - Meeting Planning Criteria	Fourche - Little Rock East 115 kV: Rebuild line	6/1/2021
Transmission Reliability - Meeting Planning Criteria	Hilltop - St Joe 161 kV: Rebuild line	6/1/2023
Transmission Reliability - Meeting Planning Criteria	St Joe - Everton Road 161 kV: Rebuild line	12/1/2024
Transmission Reliability - Meeting Planning Criteria	Everton Road - Harrison East 161 kV: Rebuild line	6/1/2025
Transmission Reliability - Meeting Planning Criteria	Southland - Mt Home 161 kV: Rebuild line	12/1/2023
Transmission Reliability - Meeting Planning Criteria	Norfork - Southland 161 kV: Rebuild line	12/1/2027
Transmission Service	Mabelvale 500 kV: Switch Replacement	11/1/2018

TABLE 14: EAI PROJECTS TO BE SUBMITTED AS TARGET APPENDIX A IN MTEP19

Project Driver	Project Name	Current Projected ISD
Transmission Reliability - Meeting Planning Criteria	Hot Springs Village – Sierra 115kV Rebuild	6/1/2021
Transmission Enhanced Reliability	Little Rock Area Enhanced Reliability – Phase 1 Rebuild L.R. Gaines – L.R. 8th & Woodrow 115kV	12/1/2021
Transmission Enhanced Reliability	Little Rock Area Enhanced Reliability – Phase 2 Rebuild L.R. 8th & Woodrow – L.R. Palm Street – L.R. West 115kV	12/1/2022
Transmission Enhanced Reliability	Amity Tap 115kV Construct Breaker Station	6/1/2024
Transmission Enhanced Reliability	Batesville 161kV Install Breakers	6/1/2024

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 MISO (MISO-Central and MISO-North).



APPENDIX E – STAKEHOLDER REPORT

[ATTACHMENT]

STAKEHOLDER COMMENTS REGARDING ENTERGY ARKANSAS'S 2018 INTEGRATED RESOURCE PLAN

The stakeholders that participated in the Entergy Arkansas Inc. ("EAI") Integrated Resource Plan ("IRP") thank the company for providing information and assisting the stakeholders in understanding EAI's policy and planning objectives of the IRP for the next 20 years. The stakeholders agreed at the start of the IRP process to avoid suppressing contrary opinions and comments. For the purpose of concluding its review of the 2018 IRP, the stakeholders recommend to EAI that it should consider and respond to each issue and recommendation as presented in the comments.

TABLE OF CONTENTS

I. Comment Topic: Stakeholder Process

Simon Mahan, Southern Renewable Energy Association

Other Stakeholders Joining This Comment: Advanced Energy Management Alliance, Arkansas Electric Energy Consumers, Inc., and Sierra Club.

* * *

Arkansas' Integrated Resource Planning (IRP) Guidelines provide a few explicit requirements for utility resource planning.[1] EAI has followed some of the Commission's Guidelines, while others have been left deficient, and others entirely ignored.

A. Evaluation of EAI IRP Process

The Arkansas IRP process is unique compared to processes across the southeast. For instance, individual utilities do not appear to have standard service lists, there are rarely publicly posted information about the IRP processes or timelines, and it is difficult for stakeholders to get engaged in the various IRPs without first initially contacting the utilities ahead of the initial stakeholder meeting. Stakeholders that are unable to make the first (and frequently, only) in-person meeting often have little ability to provide input and interact with Stakeholder Committees after the first meeting. Requests made of the utility at the stakeholder meeting may or may not be documented, and may or may not be responded to. For example, a number of questions at the EAI stakeholder meeting held on June 6, 2018 were not answered and EAI did not provide estimated timelines for when questions would be responded to.

While the Stakeholder Committee is empowered to create its own rules and procedures, those rules and procedures are commonly left unstated and informal due to insufficient time. Stakeholder Committees frequently lack a "point person" to pull together the Committee's

[1] http://www.apscservices.info/Rules/resource_plan_guid_for_elec_06-028-R_1-7-07.pdf

requests of a utility, and development of Committee milestones or goals also frequently do not occur.

The current Stakeholder Committee on this EAI IRP requested the company not rely on capacity-only resource planning, that renewable energy prices be lowered to reflect current market realities, and that certain power plant retirements be accelerated in various sensitivity scenarios. None of those requests were fulfilled, and it was only until mid-October when EAI provided its final set of IRP information that the Stakeholder Committee realized that the company would not be fulfilling any of these requests.

When compared to the SWEPCO Arkansas IRP process, this EAI process underscores significant deficiencies in this current EAI process, and the Arkansas IRP Guidelines broadly.

- EAI did provide slides ahead of the June 2018 stakeholder meeting; however, the company did not provide preliminary results prior to the meeting. As such, stakeholders learned of some of the modeling problems at the meeting itself and had to interpret the results in real time.
- EAI did provide a number of responses to those questions in four sets of “Follow Up” material and one “Modeling Update”; however, Stakeholders were not provided with a timeline for when information would be provided, and even if all requests would be responded to.
- A number of requests were not addressed by EAI. For example, stakeholders requested current unit heat rates and operational costs. EAI responded regarding that information in its second Follow Up, and stated the information “constitute market sensitive data.”[2] However, Stakeholders were able to find such information, publicly available and provided by Entergy to its annually published Investors Guide.[3] Similarly, renewable energy capital cost assumptions were also deemed market sensitive and kept confidential.

B. SWEPCO Comparison

Several Stakeholders have also been involved with the SWEPCO IRP process in Arkansas. The SWEPCO IRP process is truly a cooperative effort between the utility and the

[2] http://entergy-arkansas.com/content/IRP/2018/Follow-Up_Materials_Set_2.pdf
[3] http://www.entergy.com/content/investor_relations/docs/2017_Investor_Guide.pdf

Stakeholder Committee; whereas the EAI IRP process has been marked with lackluster utility engagement, poor information exchange, and insufficient research. SWEPCO IRP Stakeholders have been allowed to provide two sets of questions, along with a list of model sensitivity run improvements – virtually all of which have been responded to by SWEPCO, by a clear deadline set by SWEPCO. SWEPCO staff have earnestly engaged in dialog, and even provided stakeholders a webinar to present information and allow an additional opportunity for engagement. Because SWEPCO has conducted a robust and collaborative stakeholder process, that stakeholder report is likely to be highly supportive of SWEPCO's findings and minor in content. The fact that Stakeholders can have such drastically different experiences between the EAI and SWEPCO IRPs suggests that the IRP rules themselves are deficient in providing a standard quality of engagement, and that Stakeholders are almost entirely dependent on utility staff being earnest, interested and eager to cooperate.

C. IRP Guidelines Ignored

While the Arkansas IRP Resource Guidelines are not prescriptive, they do suggest several deficiencies:

- APSC Guidelines Section 3 states, "Resource planning will be relevant to future resource investment decisions and approval proceedings, as well as revenue requirements and rate design." However, in several occasions at the Stakeholder Meeting, EAI staff seemed to indicate that the IRP would mostly be ignored and is not considered a driving-force for future decisions.
- It does not appear that EAI formally established the Resource Plan objectives. Per the APSC Guidelines, Section 4.1, "The utility shall clearly state and support its objectives. The objectives of the Resource Plan include, but are not limited to, low cost, adequate and reliable energy services; economic efficiency; financial integrity of the utility; comparable consideration of demand and supply resources; mitigation of risks, consideration of environmental impacts; and consistency with governmental regulations and policies."
- Per APSC Guidelines Section 4.3 "The utility should assess existing resources based on their cost effectiveness and considering the utility's planning objectives." However,

Stakeholders are unable to help provide assessment of existing resources based on their cost effectiveness without relevant information, such as heat rates and operational costs.

- EAI has not provided economic comparisons between the various futures, as required by APSC Guidelines Section 4.4, which states that, “The portfolios should be compared on the present value of the cost of each.”
- Stakeholder comments specifically requested EAI evaluate power purchase agreement (PPA) options, as well as purchases in the MISO Market. Indeed, those items are required by APSC Guidelines Section 4.6 “A self-build option must be compared to market opportunities.” Yet, such comparisons have not been made.

D. <u>Stakeholder Questions and Requests Ignored</u>

Per the APSC’s Resource Planning Guidelines, “The reason for stakeholder involvement is to open up the planning process and provide an opportunity for others with an interest in the planning process to provide input as a check on the reasoning of a utility during the development of the resource plan.” However, if stakeholder questions and observations are ignored, unanswered, or unresolved, stakeholder involvement in the IRP process has failed to serve as “a check”. There is no recourse for stakeholders to resolve unresolved issues. Here is a synopsis of some questions and requests asked of EAI that went unresolved:

- Wind/solar prices should continue to decline over time.
- The PTC/ITC for wind and solar is not accurately reflected.
- EAI should model PPA versions for wind/solar.
- Provide megawatt values for various scenarios regarding the MISO market futures.
- Provide planned unit deactivated in the MISO market based on the 60, 55 and 50 year lifetimes.
- How are variables tied together – in a low economy, it’s possible the economy is low due to high fuel prices, but there seems to be no connection between any of those variables in the narrative.
- Provide MW values of market coal/gas deactivations, and MW values of incremental market resources, including on a unit-level.
- EAI should incorporate MISO capacity purchases as a resource option.
- EAI should evaluate an expanded MISO North/South connection as a resource option.

E. EAI Devalued the IRP Process

Stakeholders raised significant concern over EAI's capacity-only planning methodology. EAI staff explained that the modeling software would only evaluate capacity solutions, meaning, until pre-determined capacity needs were inserted into the modeling parameters, no new generation resources would be procured. In fact, that explanation was borne out in all three futures in the preliminary results presented on June 6, 2018, whereby no new generation was added until 2025, when the Lake Catherine Unit 4 was pre-determined to retire in the model. Concern was raised at the stakeholder meeting by several stakeholders that capacity-only planning would eliminate low-cost energy solutions that may reduce overall operational costs, and costs to ratepayers. As a model alternative, stakeholders recommended using the Plexos suite of software tools as opposed to the AURORA modeling software. SWEPCO already uses Plexos, as does MISO, in resource planning. EAI staff strongly suggested that business decisions made by EAI are not bound by the IRP, and thus the IRP outcomes are not the only resource planning results; however, these statements which were meant as reassurances, were suggestive that EAI would simply ignore the IRP results, further weakening the value of the IRP process as well as stakeholder involvement.

Stakeholders also encouraged EAI to evaluate MISO capacity and energy purchases as opposed to only evaluating self-build options. EAI responded that the MISO capacity and energy markets were too short-term, and that the company would only look at long-term solutions. However, when Stakeholders suggested that Demand Response opportunities should be properly valued, EAI staff cited low-cost MISO capacity prices as a justification to devalue those resources. EAI staff rather flippantly also stated that the company planned to eliminate the DR program altogether because MISO capacity prices were so low.

Conclusion

Given the extensiveness of these comments along with the additional Stakeholder Committee report, the Stakeholder Committee believes that EAI has failed APSC Guidelines Section 4.8, that "[t]he utility shall make a good faith effort to properly inform and respond to the Stakeholder Committee." The APSC Guidelines provide little recourse for a deficient IRP process, only stating that Section 4.8 "If comments concerning the process and results warrant, the Commission may require the utility to re-evaluate and resubmit its Resource Plan for the current planning cycle to address concerns raised in the comments." The Stakeholder Committee encourages the APSC to exercise its option in requiring an updated IRP by EAI. The Stakeholder Committee also recommends to the APSC to open a new docket to reform the IRP rules in an effort to fix the deficiencies experienced in this IRP process.

II. Comment Topic: Modeling Deficiencies

Simon Mahan, Southern Renewable Energy Association

Other Stakeholders Joining This Comment: Advanced Energy Management Alliance, Arkansas Electric Energy Consumers, Inc. (only the section regarding MISO capacity market purchases), and Sierra Club

*   *   *

Entergy has developed multiple IRPs in 2018, including for Entergy Arkansas (EAI), Entergy Louisiana (ELL) and Entergy Mississippi (EMI), as well as ongoing work in the Entergy New Orleans (ENO) market. While the focus of these comments is on EAI and the IRP process in Arkansas, there are lessons to be learned from the other Entergy subsidiaries and processes. In some instances, data sets have been provided in one proceeding while blocked in others (such as renewable energy cost assumptions), methodologies have been written in narrative form or at least documented, and comparisons may provide information to fill knowledge gaps. Overall, it appears Entergy performs a fairly consistent IRP process across its entire footprint, making a comparative analysis not only more informative, but more accurate in identifying potential deficiencies in processes. The current process suffers from several modeling deficiencies, including:

- Does not optimize for low-cost energy procurement
- Does not result in retirement recommendations
- Does not model sub-hourly generation and load
- Does not incorporate MISO capacity purchases as a power resource option
- Does not use MISO-developed futures

A. <u>AURORA Modeling Deficiencies</u>

Entergy Arkansas (EAI) relies heavily on the "capacity planning" software called AURORA. Regarding modeling software and capabilities, EAI should develop a study detailing the various benefits and limitations of its current modeling software. In 2017, Puget Sound Energy (an electric utility in Washington state), conducted a brief overview of AURORA versus Plexos software, highlighting the benefits of using the Plexos software. AURORA is a capacity-centric modeling product, whereas Plexos appears to have greater flexibility in evaluating lowest cost energy resources, capacity resources and sub-hourly ancillary services. Capacity-centric planning tends to focus on generator-based solutions (retirements, new construction or general ramping capabilities). Based on analysis by Puget Sound Energy, the AURORA suite of products focuses on hourly capacity-based operations; however, Plexos can provide sub-hourly operational capabilities. Such modeling software flexibility is exceptionally important for variable energy resources (such as wind energy and solar energy) which have sub-hourly ramping capabilities, and energy storage systems, which can provide ancillary services on a sub-hourly basis. Currently, Plexos appears to be better software compared to AURORA. For comparison, both MISO and SWEPCO uses Plexos software.

At the EAI stakeholder meeting in June 2018, the IRP team noted that there are significant deficiencies in the IRP modeling software program itself and its negative implications for renewable energy resources. EAI stated, "Reference Case Future: ***the proportion of renewables as part of the future portfolio is smaller than in the 2015 IRP*** Capacity Expansion Modeling (Future 1) ***even though the technology cost assumptions are lower***. Several factors are contributing to this result, but ***the biggest impact is coming from recently added AURORA dynamic modeling enhancements***…Based on the initial evaluation of results from the 2018 IRP modeling, it appears that AURORA is seeing the capacity shortage in the afternoon/evening as demonstrated in the example on the previous slides. ***The model seems to be addressing this shortage by building gas technologies rather than renewables, even if its first preference is renewables***."[4] (emphasis added).

When deficiencies regarding the AURORA model have been presented by stakeholders, Entergy's common response has been that the utility has relied on AURORA for a number of IRPs and finds no need to change. ELL has stated, "ELL adopted AURORA for long-term energy price forecasting and production costing in 2013 and has used AURORA for several resource certifications and IRPs that were accepted by the LPSC. ELL regularly reviews the software alternatives available to meet its long-term energy price forecasting and production costing needs and currently it has determined that AURORA best meets those needs."[5] Since Entergy adopted the use of AURORA in 2013, MISO South has been developed.

[4] http://entergy-arkansas.com/content/IRP/2018/June_6_Stakeholder_Meeting_Materials.pdf
[5] http://www.entergy-louisiana.com/content/irp/2019/ELL_IRP_2019.pdf

B. Current Capacity Planning Does Not Identify Opportunities for Deactivation or Retirement

In keeping with capacity planning, without a formal *input* of a capacity need, a model will not return a result showing new capacity being built. Such inputs are frequently planned retirements or deactivations. Entergy appears to conduct retirement and deactivation studies outside of the IRP context. The Entergy IRPs rely on these previously determined retirement schedules and dates as inputs to the IRP models, and it does not appear that the IRPs have any bearing on identifying units for possible retirement or deactivation.

- EAI has stated, "The market price of energy is one of several factors that may influence a particular deactivation opportunity. Such an evaluation is part of a separate planning process, and the result of that process is an input to the IRP model."[6]
- ELL has been requested by the Louisiana PSC to effectively provide these analyses, and ELL has stated, "As a part of its robust and iterative long-term planning processes, the Company continually monitors and studies the condition of units, market conditions, and economics to evaluate whether legacy units are candidates for deactivation or retirement. Consistent with the LPSC directive from the February 21, 2018 open session, ELL will conduct a comprehensive evaluation to assess the continued operations and role of its legacy fleet."[7]
- EMI has stated, "Recently, a cross-functional evaluation team conducted assessments and analyses of the units at the Baxter Wilson facility, which consisted of a comparison over a particular time frame of the cost of continuing to maintain and reliably operate the specific units to the cost of deactivating the units and obtaining newer, reliable replacement capacity over that same time frame. … The result of that effort found that it was reasonable to adjust the Baxter Wilson unit 2 deactivation date to 2018 and to adjust the Baxter Wilson unit 1 deactivation planning assumption to an earlier-than-previously-assumed deactivation date. …In addition to the analysis of Baxter Wilson unit 2, EMI also reviewed the economics associated with required improvements to continue to operate Rex Brown 3 in a safe and reliable manner. That review concluded the costs associated with continued operation of Rex Brown 3 in addition to the near-term assumed deactivation date of 2019 for the unit, made further investment uneconomic. Based on the results of the review, EMI retired Rex Brown 3 in 2018."

Retirements and deactivations are therefore "baked in" assumptions for IRP planning purposes across the Entergy footprint. Capacity-centric planning, as performed by Entergy in its

[6] http://entergy-arkansas.com/content/IRP/2018/Follow-Up_Materials_Set_2.pdf
[7] http://www.entergy-louisiana.com/content/irp/2019/ELL_IRP_2019.pdf

IRPs, is not optimizing energy purchases nor identifying existing generation for possible retirement.

C. Capacity Planning Ignores Low-Cost Energy Resources

The preliminary results provided to stakeholders at the June 2018 meeting suggested that EAI would add no new capacity until approximately 2025, when the utility plans to retire Lake Catherine Unit 4. For comparison, ELL's capacity position shows a capacity need in roughly 2027. After the addition of a new CCGT in 2023, EMI's capacity position does not show a capacity need until the year 2030. When asked directly, "Will the AURORA model select a low cost energy resource if no capacity need exists?" EAI responded, "No; AURORA only selects/builds resources based on capacity need."[8] Stakeholders have asked as a hypothetical, if a $0/MWh energy resource were readily available would AURORA select the resource? Entergy staff have stated in several fora that the AURORA model would not select those resources without a capacity need. As a follow-up, some Entergy staff have stated that despite this deficiency in the AURORA model, that Entergy would ignore the results of the IRP to procure low-cost energy resources, if such resources were made available. As such, Entergy's current capacity-only planning methodology is ignoring potentially lower cost energy resources, such as renewable energy resources, that may reduce overall system costs.

In fact, the renewable energy capacity additions provided in Entergy's IRPs do not match with Entergy's own investor analysts' presentations and announcements. Based on IRPs from Entergy Arkansas (EAI), Entergy Louisiana (ELL) and Entergy Mississippi (EMI), and Entergy New Orleans (ENO), Entergy plans to add roughly 200-300 MW of solar power by 2025. Rod West, Entergy's Group President of Utility Operations, stated on June 21, 2018 that Entergy's

[8] http://entergy-arkansas.com/content/IRP/2018/Follow-Up_Materials_Set_3.pdf

five-year plan includes renewable energy with "~1,000 MW in various stages of development".[9] While this summary of IRPs does not include Entergy Texas (ETI), it seems infeasible that the remaining quantity of announced renewable energy would be covered solely in Texas. Effectively, due to IRP planning deficiencies, Entergy plans to ignore its IRPs.

D. MISO Capacity Market is Ignored

In all three IRPs, Entergy ignores the MISO capacity market as a potential resource. Entergy claims that the MISO capacity market is too short-term to be of any value for evaluation. For example, Louisiana Public Service Commission staff requested that ELL "include information detailing how excess capacity available through MISO and potential purchase power agreements were considered as available alternative resources in the Company's analysis." ELL's response was that, "Excess capacity available through MISO is not guaranteed long-term and partially a function of proactive planning actions of regulated utilities such as ELL. Accordingly, excess market capacity is not considered as an option for meeting long-term planning objectives such as the reserve margin. Resource alternative inputs to the model are developed from a financial perspective assuming utility ownership." EMI similarly states, "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 EMI's long-term resource needs." EAI similarly does not evaluate MISO capacity purchases.

While Entergy excludes MISO capacity as a potential resource in its modeling, Entergy simultaneously uses low-cost MISO capacity as a justification to de-value Demand Response (DR) programs. At the EAI meeting in June 2018, Entergy staff flippantly mentioned the utility

[9] Entergy (June 21, 2018). Utility, Reimagined. Analyst Day. [https://entergycorporation.gcs-web.com/static-files/5adf1e57-d0f1-469f-bac8-ca188b0f4d2e]

was planning on eliminating DR programs. EAI stated that, "… the continued low capacity prices in MISO South are negatively impacting the cost-effectiveness of the DR programs."[10]

Entergy's contradictory positions on evaluating MISO's capacity likely lead to model runs that incorporate more costly new generation resources, while ignoring lower cost capacity purchases and DR programs.

[10] http://entergy-arkansas.com/content/IRP/2018/Follow-Up_Materials_Set_2.pdf

		Load Growth	Coal/Gas Age Deactivations	MISO Market Conversion	Conversion Mix	CO2 Price	Gas Price
Future 1	EAI	Ref.	60 years	12%x2028	34% RE/66% Gas	Ref.	$5.01
Future 1 Future 2	ELL	Ref.	60 years	12%x2028	34% RE/66% Gas	Ref.	$4.81
	EMI	Ref.	Ref.	N/A	34% RE/66% Gas	Ref.	Ref.
	EAI	Low	55 years	31%x2028	25% RE/75% Gas	Low	$3.40
Future 2 Future 3	ELL	High	55 years	31%x2028	25% RE/75% Gas	None	$3.27
	EMI	High	"Moderate"	N/A	25% RE/75% Gas	None	Low
	EAI	High	50 years	54%x2028	50% RE/50% Gas	High	$6.78
Future 3 Future 4	ELL	Low	50 years	54%x2028	50% RE/50% Gas	High	$3.27
	EMI	Low	"Accelerated"	N/A	50% RE/50% Gas	High	Low
	EAI						
Future 4	ELL	High	55 years	31%x2028	50% RE/50% Gas	Ref.	$6.70
	EMI	High	"Moderate"	N/A	50% RE/50% Gas	Ref.	High

E. Futures Development

EAI, ELL and EMI use a mixture of futures development that are all nearly the same, but without clear explanation regarding interrelations. For example, in the "Reference" Futures 1, all three assume market deactivations of coal and legacy gas units after 60 years of operation, which results in 12% of the MISO market being converted to 33% renewable energy and 64% natural gas by 2028; all use a "reference" CO2 price; and, all use a reference natural gas price of around $5/mmbtu. In the Futures 2 scenarios, EAI, ELL and EMI all use roughly the same metrics; however, EAI assumes low load growth, while ELL and EMI assume high load growth. EAI also assumes a price on carbon dioxide emissions whereas ELL and EMI do not. EAI's Future 3 aligns more closely with ELL's and EMI's Future 4, due to high load growth, high CO2 pricing and high gas prices. It is unclear how, for instance, high gas prices affect individual utility load growth. Presumably higher natural gas prices would likely lead to lower load growth, or that high CO2 prices would lead to significantly more renewable energy development. Stakeholders involved in the EAI process requested a narrative explaining how resources interrelate, however no clear narrative has been provided explaining how seemingly mutually exclusive future assumptions exist together.

In both EAI and ELL IRP stakeholder processes, it has been requested by stakeholders that Entergy should rely on MISO's Futures developed through the MISO Transmission Expansion Planning (MTEP) process. MISO's TEP process is annually updated, and Energy has been heavily involved in all steps regarding the MTEP process, including futures development. Even if Entergy chooses to not adopt the MISO Futures for its own IRP planning, Entergy should develop some sort of comparison between MISO's Futures and its own Futures, to highlight areas of similarity and difference.

One note of importance, it appears that MISO's Futures have a more holistic look at the footprint, in terms of what generators are likely to be retired over the time horizon evaluated. MISO collects information from all of its members regarding actual retirement dates, and uses other methodologies to determine possible retirement dates for units where a retirement date is not yet planned or is unknown. Entergy uses a 60-year, 55-year and 50-year age methodology for retirement assumptions. ELL has noted that, "an Electric Power Research Institute (EPRI) analysis performed in 2012 projected that the average age of natural gas steam turbine retirements as of 2016 would be 52.9 years old. A 2017 study performed by the Lawrence Berkley National Laboratory (and supported by the Department of Energy) produced similar results finding that the most common age of recently retired natural gas steam turbines was between 40 and 50 years. This is consistent with the 52.4 years average life of the Entergy Operating Companies' natural gas steam turbines either deactivated or retired since 2000. Given these trends, there is risk that ELL's legacy gas units may not be economic or feasible to operate through their assumed 60 year useful life." As such, using 60-years as Entergy's "reference" case for existing legacy generation units in MISO, or even for itself, may be overly optimistic. It appears MISO has already corrected for this in its Futures.[11]

Recommendations

- EAI should provide a comparative analysis regarding various modeling programs (e.g., AURORA vs. Plexos).
- EAI should conduct long-term planning beyond solely capacity planning. Ideally, EAI would rely on energy-planning, too.
- EAI's IRP should be capable of identifying potential retirement opportunities and those recommendations should be made in this IRP.
- EAI should use MISO's Futures, or at least provide some sort of comparison of similarities and differences.
- EAI should incorporate the possibility of MISO capacity purchases and/or MISO energy purchases.
- EAI should provide futures/portfolio cost estimates, similar to what is done with EMI.

III. Comment Topic: Transmission Assumptions

Simon Mahan, Southern Renewable Energy Association

Other Stakeholders Joining This Comment: Arkansas Electric Energy Consumers, Inc. and Sierra Club

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EAI did not evaluate expanding transmission options in this IRP. With regards to transmission evaluations, it is well known that the MISO North/South interconnection is a severe limitation for power flow between the two regions. By pre-determining the MISO system constraints continue to exist in perpetuity, EAI has ignored a potentially lower-cost alternative to

[11] http://www.entergy-louisiana.com/content/irp/2019/ELL_IRP_2019.pdf

building new generation – namely, building new high capacity transmission to lower-cost resources in MISO North or to SPP. EAI stated, "For the IRP capacity expansion modeling, the import and export limits between MISO regions is an input assumption and is not varied to accommodate future resource additions. The resource additions are based on generic assumptions for EAI-sited resources but do not represent or imply a selection of any specific resource or location. Outside of the scope of the IRP, any evaluation of potential resources located in SPP would be resource-specific and handled individually. Such an evaluation would require inclusion of all the costs required to deliver the energy to MISO South."[12]

During the January and September 2018 Maximum Generation Events, higher levels of North/South flow would have better served MISO South than calling on emergency power purchases from outside the MISO footprint. Several meetings held by both MISO and SPP suggest that when emergency prices were set in both the January and September events, that those exceptionally high emergency prices for imported power would be "uplifted" to the entire MISO footprint. Stated another way, MISO North is likely to subsidize MISO South's Maximum Generation Events. Given that two Maximum Generation events occurred in the same year during historically non-peak periods, the likelihood of further Maximum Generation Events appears to be exceptionally high, with no clear plan to resolve these issues in the future. Currently, there appears to be few venues for MISO to evaluate transmission expansion based on these extreme events; thus, absent such analysis from MISO, MISO South utilities should conduct some minor levels of evaluating expanding transmission connections between the North and South.

[12] http://entergy-arkansas.com/content/IRP/2018/Follow-Up_Materials_Set_2.pdf

Modeling higher levels of interconnectivity between MISO North/South and SPP should not be difficult. For instance, EAI could have developed cost metrics for installing a new transmission line, and possible cost allocation scenarios, coupled with average hourly LMP from MISO North or SPP, or perhaps a flat-cost wind power purchase agreement. These metrics, when added together, would appear much like a new power station in MISO South. As such, transmission resources could serve the same or similar purposes as new-build power generation, and should have been evaluated.

Recommendation

- EAI should develop a transmission expansion plan, in addition to what MISO and SPP perform.
- EAI should evaluate the effect of potentially expanding the MISO North/South interconnection. Such an evaluation could look at an expansion of 1 GW, 5 GW, 10GW and 20 GW to create a broad set of sensitivities.

IV. Comment Topic: Renewable Energy Assumptions

Simon Mahan, Southern Renewable Energy Association

Other Stakeholders Joining This Comment: National Audubon Society and Sierra Club

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A. Renewable Energy Data Assumptions

The National Renewable Energy Lab (NREL) publishes its Annual Technology Baseline (ATB) as a resource for "realistic and timely set of input assumptions (e.g., technology cost, fuel costs), and a diverse set of potential futures (standard scenarios) to inform electric sector analysis in the United States. The products of this work, including assessments of current and projected technology cost and performance for both renewable and conventional electricity generation technologies, as well as market projections of more than a dozen scenarios produced with

NREL's Regional Energy Deployment Systems (ReEDS) model…."[13] NREL's ATB is one of the most comprehensive, and accurate, resources for various energy resource inputs. NREL's ATB is used by regional transmission organizations (RTOs) including the Midcontinent Independent System Operator (MISO)[14] and PJM.[15] NREL's ATB data should be used for model inputs and future forecasts. Given that future purchases of renewable energy resources would take several years before power production, NREL ATB data starting in 2019 or 2020 is recommended, as well as incorporating future pricing and performance levels. NREL's ATB is updated annually, usually in July or August.

1. Wind Energy

NREL's ATB evaluates wind energy resources as "techno-resource groups" (TRGs) that effectively provides a scale of various wind energy opportunities.[16] For example, TRG 1 resources are anticipated to be the lowest cost and highest performance wind energy resources, and are mostly concentrated in the Central US. A fair amount of wind energy capacity potential in the Southeast opens in TRG 5, with the entire Southeastern region opening up with TRG 7. Based on the current market, the "low" values for NREL ATB's land-based wind resources should be used, beginning in 2019 or 2020. Evaluating these three different wind energy resources provides an adequate range of wind energy resources available to the Southeast.

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[13] NREL (National Renewable Energy Laboratory). 2018. 2018 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/analysis/data_tech_baseline.html.

[14] Midcontinent Independent System Operator (March 20, 2018). "MTEP19 Futures Development Workshop." [https://cdn.misoenergy.org/20180320%20MTEP19%20Futures%20Workshop%20Presentation150635.pdf]

[15] Muhsin K. Abdur-Rahman (April 25, 2016). "PJM's Clean Power Plan Modeling Reference Model and Sensitivities," PJM. [https://www.pjm.com/-/media/committees-groups/committees/mc/20160425-webinar/20160425-item-02-clean-power-plan-reference-model-results.ashx]

[16] National Renewable Energy Lab (November 2016). Regional Energy Deployment System (ReEDS) Model Documentation: Version 2016. [https://www.nrel.gov/docs/fy17osti/67067.pdf]

Evaluating multiple types of wind energy resources, and not solely evaluating the lowest cost options (e.g., TRG 1 resources), may help identify different generation profiles that more closely align with a particular utility's demand load. Geographic diversity of renewable energy resources is anticipated to generally increase capacity value of a particular resource and reduce overall generation variability. Hourly and sub-hourly wind energy generation profiles are available from the NREL Wind Integration National Database (WIND) Toolkit for up to 122,000 different sites across the country. Data are available from NREL, here: https://www.nrel.gov/grid/wind-toolkit.html

The federal Production Tax Credit (PTC) for wind energy is expiring. The details of the PTC will be discussed later; however, for the chart below, the PTC has been converted into a rough reduction in overnight capital costs. Generally, CAPEX costs below have been reduced by $600/kW in 2019 and 2020, $500/kW in 2021, and $400/kW in 2022.

NREL ATB Wind Energy Pricing Examples With Production Tax Credit as Overnight Cost Reduction ($/kW) by Year

		2019	*2020*	*2021*	*2022*	*2023**	*2024**	*2025**
TRG1	Overnight $/kW	$730	$687	$739	$787	$1,133	$1,075	$730
	Capacity Factor	50%	50%	51%	51%	52%	52%	53%
	LCOE $/MWh	$19	$21	$22	$23	$27	$26	$24
TRG5	Overnight $/kW	$840	$803	$839	$874	$1,208	$1,142	$1,075
	Capacity Factor	44%	45%	45%	46%	47%	48%	48%
	LCOE $/MWh	$25	$26	$27	$28	$31	$29	$28
TRG7	Overnight $/kW	$1,013	$991	$1,023	$1,054	$1,384	$1,313	$1,241
	Capacity Factor	35%	36%	37%	38%	38%	39%	40%
	LCOE $/MWh	$39	$40	$39	$39	$41	$39	$36

Source: based on LBNL 2014, 2018 NREL ATB
*No PTC Value

2. Solar Energy

Costs for fixed-tilt versus single-axis tracking solar projects are estimated to be approximately similar, with minor capital cost and maintenance cost differences; however, capacity factors are anticipated to increase significantly with single-axis trackers. NREL's ATB only evaluates single-axis tracking systems, with the best performing projects achieving an estimated 27% capacity factor (NREL ATB projects located in Daggett, CA). As a proxy for fixed-tilt solar projects, it is recommended that a 20% capacity factor be used (NREL ATB projects located in Kansas City, MO). NREL's ATB converts solar DC power to AC power output for capacity factor purposes, while keeping several financial metrics in $/kWDC units.

To provide a better range of pricing and performance, it is recommended that the "Mid" overnight costs for Kansas City and Daggett utility-scale solar projects from NREL's ATB should be used, along with the 20% and 27% capacity factors, respectively, beginning in 2019.

Due to new guidance from the IRS, solar power projects that qualify for the 30% ITC in 2019, 26% ITC in 2020, or the 22% ITC in 2021 each have until the end of the year 2023 to become operational. A 10% ITC is available for projects that commence construction in or after 2022, and for projects that become operational in or after 2024. At the same time the federal ITC is slated to decline, the NREL ATB shows that solar power installed costs are anticipated to decline, almost in the exact same proportion as the ITC phase-out through 2023. Applying the ITC phase-out to the NREL ATB 2018 overnight capital costs, results in overnight costs of approximately $700/kWDC for projects that begin construction between now and 2021, which are also operational by the end of 2023. By 2024, when the bulk of the ITC has expired, solar pricing is anticipated to decline an equivalent amount, thus overall levelized cost of energy of utility-scale solar projects are anticipated to remain relatively flat from 2019-2030. For utility-scale solar projects with 20% capacity factors, and taking the ITC into account for near-term projects, overall LCOE is anticipated to remain in the mid-$30s/MWh range for the next decade. For projects with 27% capacity factors, LCOE values in the $20s/MWh are anticipated. We have worked with utility-scale solar development companies in the region who have corroborated the view that utility-scale projects in BREC region can be currently be delivered with an LCOE in the mid-$30/MWh range thanks to the ITC value and for the decade ahead with the forecasted future cost-declines following the ITC step-down to 10%.

NREL ATB Utility-Scale Solar Energy Pricing (ITC Included)

		2019	2020	2021	2022	2023	2024	2025
Mid	Overnight $/kWdc	$707	$707	$707	$707	$707	$784	$775
	Capacity Factor AC	20%	20%	20%	20%	20%	20%	20%
	LCOE $/MWhAC	$32	$32	$32	$$32	$32	$38	$38
Low	Overnight $/kWdc	$707	$707	$707	$707	$707	$784	$775
	Capacity Factor AC	27%	27%	27%	27%	27%	27%	27%
	LCOE $/MWhAC	$20	$20	$20	$20	$20	$24	$23

Source: NREL ATB 2018[17], 20-year LCOE, "Mid" is Kansas City, "Low" is Daggett

B. Market-Based Benchmarking

Many utilities have issued requests for proposals (RFPs) for renewable energy resources from around the country; however, not all utilities publicly summarize results from those solicitations. Wherever recent results from renewable RFP solicitations are made public, it is highly encouraged that those data be used as benchmarks when developing IRP data inputs.

It is highly recommended that utilities should develop a request for proposals (RFP) or request for information (RFI) in tandem with IRP development to receive the most recent market information, specific to that utility. Developing an RFP or RFI to coincide with an IRP would create a significant amount of high quality data, while potentially expediting future power purchase agreements, procurements or developments.

1. Xcel Energy Colorado All-Source Solicitation

[17] National Renewable Energy Lab (July 2018). NREL Annual Technology Baseline (ATB) 2018. [https://atb.nrel.gov/]

Xcel Energy, a Colorado electric utility, published the results of its 2017 All-Source Solicitation request for proposals in December 2017.[18] Xcel received over 400 bids representing over 100,000 MW of capacity from a wide variety of technologies; however, most bids provided wind energy or solar power resources. The median bid price or equivalent for stand-alone wind energy resources was $18.10/MWh, suggesting several projects below and above that price. Adding battery storage to wind energy resulted in median bids of $21/MWh. For stand-alone solar energy resources, the median bid was $29.50/MWh. Adding battery storage to solar energy resulted in median prices of $36/MWh. While these prices may be specific to Xcel, the fact remains that these represent real project bids and are aligned with projections by NREL's ATB, Lazard Associates and these comments.

[18] Xcel Energy (December 28, 2017). 2016 Electric Resource Plan, 2017 All Source Solicitation 30-Day Report (Public Version) CPUC Proceeding No. 16A-0396E. [https://assets.documentcloud.org/documents/4340162/Xcel-Solicitation-Report.pdf]

<u>Xcel RFP Responses by Technology 2017</u>

RFP Responses by Technology

Generation Technology	# of Bids	Bid MW	# of Projects	Project MW	Median Bid Price or Equivalent	Pricing Units
Combustion Turbine/IC Engines	30	7,141	13	2,466	$ 4.80	$/kW-mo
Combustion Turbine with Battery Storage	7	804	3	476	6.20	$/kW-mo
Gas-Fired Combined Cycles	2	451	2	451	[redacted]	$/kW-mo
Stand-alone Battery Storage	28	2,143	21	1,614	11.30	$/kW-mo
Compressed Air Energy Storage	1	317	1	317	[redacted]	$/kW-mo
Wind	96	42,278	42	17,380	$ 18.10	$/MWh
Wind and Solar	5	2,612	4	2,162	19.90	$/MWh
Wind with Battery Storage	11	5,700	8	5,097	21.00	$/MWh
Solar (PV)	152	29,710	75	13,435	29.50	$/MWh
Wind and Solar and Battery Storage	7	4,048	7	4,048	30.60	$/MWh
Solar (PV) with Battery Storage	87	16,725	59	10,813	36.00	$/MWh
IC Engine with Solar	1	5	1	5	[redacted]	$/MWh
Waste Heat	2	21	1	11	[redacted]	$/MWh
Biomass	1	9	1	9	[redacted]	$/MWh
Total	430	111,963	238	58,283		

Source: Xcel Energy 2017[19]

2. Northern Indiana Public Service Company Request for Proposals

Northern Indiana Public Service Company (NIPSCO), an electric company in the MISO system, held an integrated resource plan (IRP) meeting on July 24, 2018 to discuss renewable energy options. As part of its IRP process, NIPSCO shared results from an all source request for proposals (RFP) summary. NIPSCO received bids for wind energy, solar energy, energy storage, and amalgamations of those resources together. The company received proposals across five states, predominately via power purchase agreement (PPA), but also as asset sale or option. Resources offered as asset sale or as an option were provided at an average bid cost of $1,151.01/kW for solar energy projects, and $1,457.07/kW for wind energy projects. For PPA's, average bids for solar energy reached $35.67/MWh, and average bids for wind energy reached $26.97/MWh. Solar plus energy storage projects were offered as asset sales at $1,182.79/kW and

[19] Xcel Energy (December 28, 2017). 2016 Electric Resource Plan, 2017 All Source Solicitation 30-Day Report (Public Version) CPUC Proceeding No. 16A-0396E. [https://assets.documentcloud.org/documents/4340162/Xcel-Solicitation-Report.pdf]

also as a PPA at $5.90/kW-Mo plus $35/MWh.[20] These values provide recent market data that are relevant to states in MISO and further south.

<u>NIPSCO RFP Responses by Technology 2018</u>

	Technology	# of Bids	Bid MW (ICAP)	# of Projects	Project MW	Average Bid Price	Pricing Units	Comments
Asset Sale or Option	Combine Cycle Gas (CCGT)	7	4,846	4	3,055	$959.61	$/kW	
	Combustion Turbine (CT)	1						
	Solar	9	1,374	5	669	$1,151.01	$/kW	
	Wind	8	1,807	7	1,607	$1,457.07	$/kW	
	Solar + Storage	4	705	3	465	$1,182.79	$/kW	
	Wind + Solar + Storage	1						
	Storage	1						
Purchase Power Agreement	Combine Cycle Gas (CCGT)	8	2,715	6	2,415	$7.86	$/kW-Mo	+ fuel and variable O&M
	Solar + Storage	7	1,055	5	755	$5.90	$/kW-Mo	+ $35/MWh (Average)
	Storage	8	1,055	5	925	$11.24	$/kW-Mo	
	Solar	26	3,591	16	1,911	$35.67	$/MWh	
	Wind	6	788	4	603	$26.97	$/MWh	
	Fossil	3	1,494	2	772	N/A		Structure not amenable to price comparison
	Demand Response	1						
	Total	**90**	**20,585**	**59**	**13,247**			

Source: NIPSCO 2018.[21]

<u>Recommendations</u>

- EAI should model multiple types of wind energy resource, including resources from SPP, MISO and inside Arkansas.
- EAI should model both fixed and tracking solar energy resources.
- EAI should use NREL's ATB regarding energy pricing, performance levels and forecasts.
- EAI should incorporate the federal Production Tax Credit and Investment Tax Credit.
- EAI should benchmark its data assumptions against publicly available information.
- EAI should immediately issue an RFP for renewable energy resources.

[20] Northern Indiana Public Service Company (July 24, 2018). NIPSCO Integrated Resource Plan 2018 Update Public Advisory Meeting Three. [https://www.nipsco.com/docs/default-source/about-nipsco-docs/7-24-2018-nipsco-irp-public-advisory-presentation.pdf]

[21] Northern Indiana Public Service Company (July 24, 2018). NIPSCO Integrated Resource Plan 2018 Update Public Advisory Meeting Three. [https://www.nipsco.com/docs/default-source/about-nipsco-docs/7-24-2018-nipsco-irp-public-advisory-presentation.pdf]

- This RFP should be completed in a single year. The current RFP process EAI undertook for renewable energy resources was excessively long and likely deterred many good projects from being bid in.
- As shown by the expedited SWEPCO procurement process for the Windcatcher project, Arkansas PSC's approval process can be significantly faster to secure favorable tax credits.

V. Comment Topic: DSM and Demand Response Assumptions

Peter Dotson-Westphalen, CPower Energy Management for Advanced Energy Management Alliance

Other Stakeholders Joining This Comment: National Audubon Society and Sierra Club

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The stakeholders appreciate EAI's incorporation of feedback made in prior IRPs to incorporate Demand Response ("DR") and Demand Side Management ("DSM") into the supply-side for evaluation. However, there appears to be several shortcomings in the Aurora model, as discussed in further detail within the "Modeling Deficiencies" section of the stakeholder comments earlier in this document. Because of these modeling shortcomings, including capacity selection based upon predetermined inputs of planned retirement dates and not looking at sub-hourly time horizons, potential DSM was only selected in 2020 based upon the low case scenario in the initial modeling, none of which came from any new DR.[22] In the subsequent modeling results, the model selected only between 9 to 14 MW of additional installed capacity coming from DSM,[23] all of which are lower than the lowest DSM portfolio additions used within the initial modeling run. No further information was provided by EAI staff as to what changed from the initial modeling runs that reduced the potential DSM that was selected in the second modeling run, or how or why the DSM potential was reduced from the initial model runs.

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[22] http://www.entergy-arkansas.com/content/IRP/2018/June_6_Stakeholder_Meeting_Materials.pdf
[23] http://www.entergy-arkansas.com/content/IRP/2018/Modeling_Update.pdf

The stakeholders believe EAI's cost effectiveness methodology is flawed because DR is modeled solely at the MISO capacity auction price in the short term, which has remained suppressed for some time. There was no clear delineation of when EAI transitioned to their long-term methodology of modeling DR based upon the cost of building a new peaking resource, so stakeholders cannot tell which cost-effectiveness methodology was used with each set of the potential portfolios considered, and whether they aligned with the need for additional capacity resources to be procured. At the initial stakeholder meeting on June 6, 2018, EAI presented results from the Aurora Capacity Expansion Model and stated existing DR and incremental DSM and DR is competing with all other supply-side resources.[24] However, this model does not consider comparing the cost-effectiveness of DR to existing generation resources that may be impacted by higher future operating costs due to environmental compliance regulations and market forces and may not be cost-effective in advance of their modeled retirement dates.

DR is found by many utilities to be a cost-effective resource,[25] and the model's failure to select lower cost resources when it would be in the economic interest to do so appears to be a significant flaw that is prevalent throughout EAI's IRP. Several other utilities within MISO have found DR to be a cost-effective resource within their IRPs. Consumers Energy in Michigan and NIPSCO in Indiana both found that DR was the least-cost resource when compared to any traditional supply-side generation resources within their recent modeling work. Ameren Missouri, which was found to not have a need for new capacity until 2024, took an approach that realized that the suppressed MISO capacity prices will not remain so over the longer term.

[24] http://www.entergy-arkansas.com/content/IRP/2018/June_6_Stakeholder_Meeting_Materials.pdf

[25] Advanced Energy Management Alliance (May 2018). Demand-Response Cost Effectiveness Case Studies. http://aem-alliance.org/download/121151/

Ameren extended a rising cost curve for avoided capacity, energy, and T&D costs,[26] and decided that it could build out DR as a lower cost resource and then sell their excess generation capacity from their existing resources into the MISO capacity market. Matt Michaels, Director of Corporate Analysis for Ameren Missouri provided testimony to the value of DR and DSM, stating, "[d]emand-side resources are generally more cost-effective than supply side-resources and generate net benefits to an extent that most supply-side resources cannot."[27] The DSM resource expansion portfolios developed by ICF International, Inc. ("ICF") for EAI and included in the Aurora Capacity Expansion Model reflect low total expansion opportunity for DR based on scenarios, which consist of five Direct Load Control programs and one commercial Time-of-Use program. The incremental DR from these six new programs ranges from a low of 25 MW up to 100 MW.[28] The stakeholders think these scenarios are not comprehensive of the total DR opportunity available, especially considering EAI is forecasting significant growth in sales and peak load through 2021 which it largely attributes to industrial customers that are typically good candidates for DR. EAI noted in its presentation to stakeholders that none of these incremental DR portfolios were selected in its model runs[29] EAI has not provided any additional details on the study assumptions ICF used to develop these incremental portfolios, and stakeholders have

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26 Ameren Missouri. 2019-2024 MEEIA Plan – Appendix C - 2017 IRP Avoided Costs. [https://www.efis.psc.mo.gov/mpsc/commoncomponents/view_itemno_details.asp?caseno=EO-2018-0211&attach_id=2018020108]

27 Missouri Public Service Commission File No. EO-2018-0211. Surrebuttal Testimony of Matt Michels on Behalf of Union Electric Company d/b/a Ameren Missouri (September 17, 2018). [https://www.efis.psc.mo.gov/mpsc/commoncomponents/view_itemno_details.asp?caseno=EO-2018-0211&attach_id=2019003994]

28 http://www.entergy-arkansas.com/content/IRP/2018/June_6_Stakeholder_Meeting_Materials.pdf -

29 http://www.entergy-arkansas.com/content/IRP/2018/June_6_Stakeholder_Meeting_Materials.pdf

not had the opportunity to review the assumptions to compare to other potential studies to validate whether these assumptions allow the full DR potential to be captured.

EAI's implementation of AMI within the service territory will open up additional DSM program participation potential. EAI stated that they did not model any specific assumptions for new rate or program designs that would capitalize on AMI infrastructure. EAI instead factored in any load reductions attributed to increased AMI to the load forecast and are not assigned any costs within the IRP.[30] Stakeholders believe there is additional value through potential DSM/DR programs that can be tapped into through AMI at a low cost that should be modeled on the supply-side.

Finally, stakeholders are very concerned that EAI staff indicated that EAI may plan to discontinue its existing DR programs based solely on low capacity clearing prices in the MISO market and concluded that these programs are no longer cost effective to operate. As renewable generation penetration increases, the need for more flexible and fast-responding resources will be needed to help maintain reliability. It would be imprudent of EAI to disband their existing DR programs, getting rid of approximately 230MW of LMR resources comprised of over 24,000 EAI customers that are helping to provide capacity and reliability during emergency conditions, especially when EAI's Total Resource Cost (TRC) for their entire portfolio of EE and DSM programs have been cost effective in prior years and appear to be on track to remain cost effective at a TRC of 1.8.[31]

[30] http://www.entergy-arkansas.com/content/IRP/2018/Follow-Up_Materials_Set_3.pdf
[31] http://www.entergy-arkansas.com/content/IRP/2018/June_6_Stakeholder_Meeting_Materials.pdf

Recommendations

- EAI should seek to include T&D and avoided costs in its methodology for valuing its existing DR and DSM programs, and not solely rely on the MISO capacity value for assessing cost-effectiveness of these resources.
- EAI should model existing and potential DR and DSM against current generator operating costs, and not just against the cost of new entry of future generation.
- EAI should include Non-Wires Alternatives that can address localized needs that may reduce the need for T&D investment and increased capacity from traditional generation sources in their IRP modeling.
- EAI should model for additional potential DSM/DR program participation enabled by AMI being rolled out within their territory.
- EAI should not terminate their existing DR programs as these resources will be vital to help maintain a reliable grid today and in the future.

VI. Comment Topic: Energy Storage Assumptions

Simon Mahan, Southern Renewable Energy Association

Other Stakeholders Joining This Comment: Advanced Energy Management Alliance, National Audubon Society, and Sierra Club

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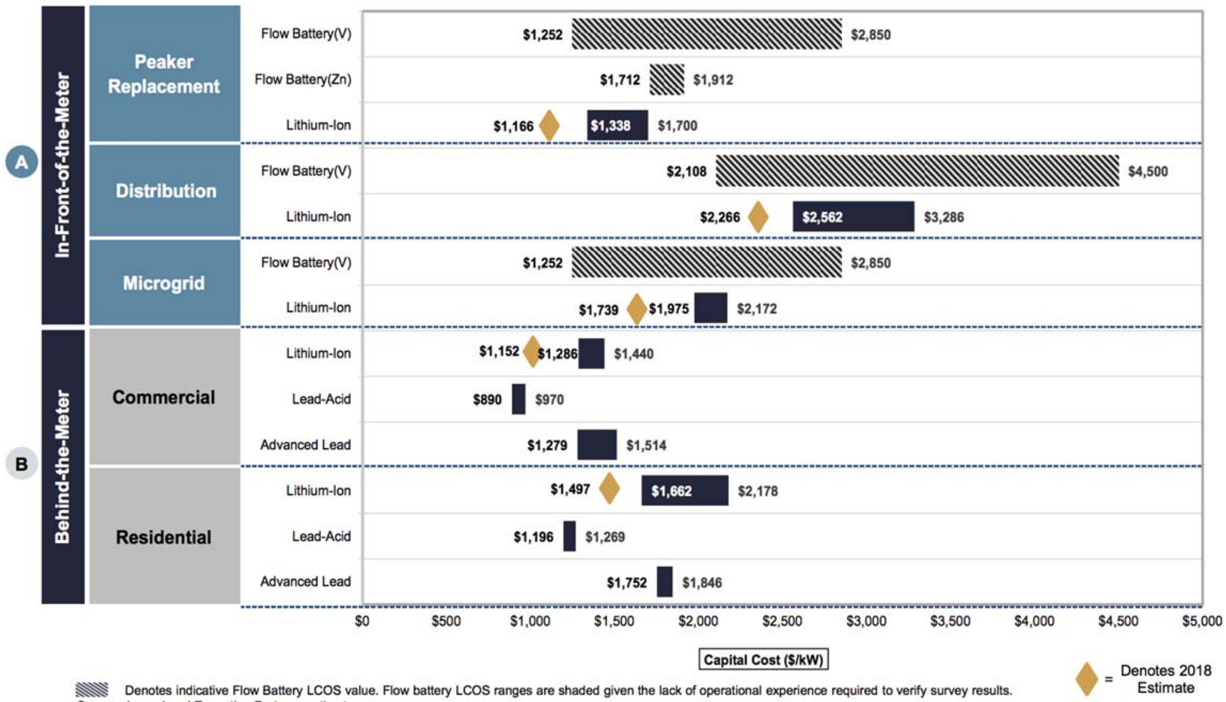
A. Energy Storage Data Assumptions

Lazard Associates' estimated capital costs for various energy storage technologies reaches as low as $1,152/kW in 2018. It is more difficult to assign a particular LCOE for energy storage solutions; not only because of the variety of technology (batteries, fly wheels, etc.) and rapidly declining prices, but because energy storage project finances are highly dependent on the type of services being provided. For example, Lazard Associates notes that, "Although energy storage developers/project owners often include Energy Arbitrage and Spinning/Non-Spinning Reserves as sources of revenue for commissioned energy storage projects, Frequency Regulation, Bill Management and Resource Adequacy are currently the predominant forms of realized sources of revenue."[32] For example, an energy storage project that predominantly provides frequency regulation may appear to be exceptionally costly, on an LCOE basis, compared to a traditional power plant; however, such a facility is providing a highly valued service that may not be accurately reflected in current integrated resource planning processes, models or specific utility markets. Energy storage is not simply a "cost adder" to renewable energy to establish better capacity value.

The design of an energy storage project can also vary based on the specific services desired; for example, a recent presentation by GTM Research showed four-hour and eight-hour energy storage resources compared to peaking power resources. The researchers found that in 82% of planned future peaker plants would be at risk from eight-hour storage projects (e.g., 100 MW/800 MWh).[33] Due to limitations in resource planning practices, LCOE or even capital costs alone will not adequately assess the full benefits of energy storage. As energy storage resources begin to be co-located with renewable energy resources, those energy storage technologies may qualify for federal incentives, such as the investment tax credit. Energy storage pricing, as with renewable energy, is anticipated to continue to considerably decline, while performance is expected to improve, especially over the near-term.

[32] Lazard Associates (November 2017). Levelized Cost of Storage Analysis, Version 3.0. [https://www.lazard.com/media/450338/lazard-levelized-cost-of-storage-version-30.pdf]
[33] Ravi Manghani (March 2018). "Will Energy Storage Replace Peaker Plants?" GTM Research. [https://d3v6gwebjc7bm7.cloudfront.net/event/15/88/96/3/rt/1/documents/resourceList1519927946005/willenergystoragereplacepeakerplantswebinarslides1519927951937.pdf]

Unsubsidized Energy Storage Capital Costs ($/kW)



Source: Lazard Associates 2017[34]

1. Energy Storage Modeling

In February 2018, the Federal Energy Regulatory Commission (FERC) issued Order Number 841 regarding energy storage. FERC stated, "In a November 2016 Notice of Proposed Rulemaking (NOPR), the Commission noted that market rules designed for traditional generation resources can create barriers to entry for emerging technologies such as electric storage resources. Today's final rule helps remove these barriers by requiring each regional grid operator to revise its tariff to establish a participation model for electric storage resources that consist of market rules that properly recognize the physical and operational characteristics of electric storage resources." FERC noted in its rule that, artificial "restriction on competition can reduce

[34] Lazard Associates (November 2017). Levelized Cost of Storage Analysis, Version 3.0. [https://www.lazard.com/media/450338/lazard-levelized-cost-of-storage-version-30.pdf]

the efficiency of the RTO/ISO markets, potentially leading an RTO/ISO to dispatch more expensive resources to meet its system needs."[35] Even though RTO/ISO compliance filings are due to FERC in early December, with tariff implementation due by December 2019, utilities should strive to follow the spirit of FERC Order Number 841 in developing multiple modelling capabilities, sensitivities and analyses around energy storage issues.[36] In keeping with the principles of FERC Order Number 841, it is recommended that multiple energy storage configurations be evaluated (e.g., 2MW/2MWh, 2MW/4MWh, 2MW/8MWh, etc.), using sub-hourly dispatch, with multiple revenue streams (e.g., capacity credit, energy, frequency/voltage control, etc.), as stand-alone projects as well as coupled with generation resources (such as renewable energy resources).

Models that use sub-hourly intervals can better quantify the value of both capacity and flexibility benefits provided by advanced energy storage. By comparing flexibility benefits to the cost of storage—thereby using a "net cost" analysis of capacity investment options—planners can more accurately compare advanced energy storage with traditional capacity resources. Analysis of models that look at system flexibility needs and risk management will be more likely to reduce costs to ratepayers, including through use of storage. In addition to providing an LCOE regarding energy storage options, it is also recommended that values also be provided in $/kW-mo or $/kW-yr terms.

Behind the meter storage capabilities should be taken into consideration as well. As

[35] Federal Energy Regulatory Commission (February 15, 2018). Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators. [Docket Nos. RM16-23-000; AD16-20-000; Order No. 841]. https://www.ferc.gov/whats-new/comm-meet/2018/021518/E-1.pdf

[36] Federal Energy Regulatory Commission (February 15, 2018). FERC issues final rule on electric storage participation in regional markets. [https://www.ferc.gov/media/news-releases/2018/2018-1/02-15-18-E-1.asp#.Wv3-1NOUv-Z]

storage costs decline and customers begin to adopt storage technologies to serve needs and may look to provide grid services as well, these resources should be accounted for within EAIs modeling process.

Recommendations

- EAI should develop a "value stack" for energy storage resources incorporating energy, capacity, frequency response, black-start capability and other attributes available via energy storage devices.
- EAI should explain how it plans to incorporate lessons learned from FERC Order 841 on energy storage in future resource planning.
- EAI should procure significant energy storage assets to better evaluate storage costs and benefits.

VII. Comment Topic: Coal

Jordan Tinsley, Arkansas Electric Energy Consumers, Inc.

Other Stakeholders Joining This Comment: Arkansas Attorney General's Office

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In its 2015 Integrated Resource Plan, EAI acknowledged that its coal-fired power plants should have a useful life of sixty years.[37] At least two of the futures evaluated in the 2015 IRP presumed the operation of EAI's existing coal-fired power plants for a sixty-year useful life.[38] Notably, however, EAI presumed (when evaluating those futures) that it would install costly environmental controls at those plants as the result of a federal implementation plan ("FIP") for the Regional Haze Rule that will likely be superseded by a less onerous state implementation plan ("SIP") that does not require the installation of those environmental controls.[39]

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[37] *See, e.g.*, EAI's 2015 Integrated Resource Plan, APSC Docket No. 07-016-U, Doc. 49, p. 40.
[38] Id. at 40-42.
[39] Id.

Although EAI acknowledges (at least implicitly) that the FIP promulgated by the EPA in October 2016 will probably not survive ADEQ's issuance of a new SIP,[40] EAI has nonetheless presumed early retirements of all its coal-fired capacity in the 2018 IRP process.[41] Slide 6 of the second set of Follow-Up Materials provided to IRP stakeholders clarified that EAI presumes it will deactivate both White Bluff units by 2028; then, in 2030, it will deactivate Independence Unit 1. Slide 7 of the second set of Follow-Up Materials states that White Bluff unit 1 is 38 years old, while unit 2 is 37 years old. It also states that Independence unit 1 is 35 years old. Thus, if EAI retires White Bluff units 1 and 2 in 2028 as planned, EAI will be retiring those units approximately twelve (12) to thirteen (13) years before the expiration of their sixty-year useful lives. If EAI retires Independence unit 1 in 2030 as planned, EAI will be retiring that unit approximately thirteen (13) years before the expiration of its sixty-year useful life.

Collectively, deactivation of those coal-fired power plants will retire over one thousand (1000) megawatts of generating capacity. Of course, EAI plans to pass the cost of obtaining replacement capacity for these early retirements on to its ratepayers. As noted in the comments regarding early coal-plant deactivations AEEC included in EAI's 2015 IRP stakeholder report, EAI's plans to retire its coal plants early will significantly raise electricity rates unnecessarily.[42]

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[40] *See, e.g.,* slides 59-60 of the June 2018 Stakeholder Meeting Materials, which one can access using the following URL: http://entergy-arkansas.com/content/IRP/2018/June_6_Stakeholder_Meeting_Materials.pdf.

[41] *See* slide 12 of the June 2018 Stakeholder Meeting Materials; *see also* slide 6 of the second set of Follow-Up Materials, which one can access using the following URL: http://entergy-arkansas.com/content/IRP/2018/Follow-Up_Materials_Set_2.pdf.

[42] *See* EAI's 2015 Integrated Resource Plan, APSC Docket No. 07-016-U, Doc. 49, p. 263-269.

Further, EAI abdicates its fiduciary duties to its ratepayers under Arkansas law[43] by divesting them of approximately thirteen (13) years of cheap generating capacity without justification.

EAI and other parties attempt to justify the divestment of these assets from ratepayers by emphasizing that these facilities are rarely dispatched in the status quo.[44] The relatively low rate of dispatch for these units, however, results primarily from low natural gas prices. Should natural gas prices increase, the existence of this coal-fired capacity insulates ratepayers against an electricity price spike. Further, since natural gas prices are inherently hard to predict,[45] planning to retire these assets ten years in advance based upon uncertain gas price forecasts seems imprudent. Further, as discussed below, the increased utilization of natural gas as a fuel source for electricity generation continues to inject additional uncertainty into the natural gas market, particularly with regard to extreme cold weather events.

If EAI proceeds with these planned retirements in 2028 and 2030 respectively, it will remove coal as a fuel source from its fleet entirely. This eliminates valuable fuel diversity from the EAI system. EAI's primary resource planner strongly emphasized the value of fuel diversity when justifying the acquisition of the Stuttgart Solar facility in 2015. He stated:

> Diversity means utilizing a mix of generating technologies and fuel sources within the generation portfolio. A diverse generation portfolio *mitigates risk by helping protect customers from fluctuations in the cost and availability of the fuel*

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[43] See Acme Brick Co. v. Arkansas Public Service Commission, 227 Ark. 436, 299 S.W.2d 208 (1957) and City of El Dorado v. Arkansas Public Service Commission, 362 S.W.2d 680, 235 Ark. 812 (Ark., 1962).

[44] For example, slide 7 of the second set of Follow-Up Materials states that White Bluff unit 1 has a capacity factor of sixty eight percent (68%), while the other two coal-fired units have capacity factors of approximately forty three percent (43%).

[45] In APSC Docket No. 12-008-U, a witness for the Staff named Richard Hahn stated the following: "…the uncertainty in fuel prices should be considered. This factor is *very difficult* to assess either quantitatively or qualitatively. *There is simply no way to know with any degree of certainty whether coal prices will remain lower than natural gas prices, or vice versa*. It is true that *historically natural gas prices have tended to be more volatile* than coal prices." Surrebuttal Testimony of Richard S. Hahn, APSC Docket No. 12-008-U, Doc. 145, p. 15 (emphasis added).

> *needed to produce electricity*. For example, *a diverse generation portfolio protects customers from supply disruptions associated with particular fuel sources or delivery channels because alternative fuels are available within the portfolio*. Similarly, *fluctuations in the price of particular fuels are less likely to affect total supply cost*. The effect of changes in the price of any one fuel is less significant because a diverse generation portfolio relies on a variety of fuels and resource types, the prices of which are not likely to move in perfect unison. Increases in the price of one fuel *may be offset or mitigated by other fuels that exhibit declining or stable costs*.[46]

Of course, Mr. Castleberry's argument regarding fuel diversity has as much validity in this context as it did in the context of adding some solar to EAI's diverse portfolio. Notably, the U.S. Energy Information Administration has noted that emphasizing natural gas as a fuel source for electricity generation injects additional volatility into natural gas prices because of fundamental economic realities concerning supply and demand.[47] Therefore, the coal-fired plants that EAI wants to divest from its portfolio thirteen years early actually provide ratepayers with a valuable hedge against volatile natural gas prices.

Recent extreme cold weather events have demonstrated that concerns regarding gas supply reliability are well-founded. For example, during extreme cold weather events, like the polar vortex in 2014, gas plant curtailments may result from various factors. Problems with gas transportation may also occur. NERC undertook an analysis of the polar vortex in the fall of 2014; it stated:

> Increased reliance on natural gas during the polar vortex exposed the industry to various challenges with fuel supply and delivery. This increased reliance,

[46] Direct Testimony of Kurtis W. Castleberry, APSC Docket No. 15-014-U, Doc. 16, p. 15-16 (emphasis added).

[47] "Because there are limited short-term alternatives to natural gas as a fuel for heating and electricity generation during peak demand periods, *changes in supply or demand over a short period may result in large price changes*."
U.S. Energy Information Administration, Frequently Asked Questions, "What are the major factors affecting natural gas prices?," https://www.eia.gov/tools/faqs/faq.php?id=43&t=8 (emphasis added).

> compounded by generation outages during the extreme conditions, increased the risks to the reliable operation of the BPS [bulk power system].
>
> As the industry relies more on natural-gas-fired capacity to meet electricity needs, it is important to examine *potential risks associated with increased dependence on a single fuel type*. The extent of these concerns varies from Region to Region; however, they are most acute in areas where power generators rely on interruptible natural gas pipeline transportation.
>
> Unlike coal and fuel oil, natural gas is not typically stored on site. As a result, real-time delivery of natural gas through a network of pipelines and bulk gas storage is critical to support electric generators. Natural gas is widely used outside the power sector, and the demand from other sectors—particularly coincident end-user gas peak demand during cold winter weather—critically affects gas providers' ability to deliver interruptible transportation service in the power sector. Additionally, demand for natural gas is expected to grow in other sectors (e.g., transportation, exports, and manufacturing).[48]

Since the reliability of natural gas production, transportation, and generation in a world where natural gas serves as the primary fuel source for electricity generation remains unknown, it does not seem prudent for EAI to plan for the total elimination of coal as a fuel source in its generation mix without further development and continued testing of the natural gas infrastructure. As noted by NERC, coal plants do not suffer from some of the challenges posed by natural gas-fired plants in extreme cold weather events. Additionally, FERC has recently noted that natural gas storage inventories are at their lowest level since 2005, which could result in increased natural gas prices as soon as this winter.[49]

Additionally, although EAI and other parties have emphasized the declining cost of renewable generators as partial justification for the abandonment of the coal-fired plants, federal

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[48] North American Electric Reliability Corporation, Polar Vortex Review, September 2014, p. 17, available at the following link: https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.

[49] Federal Energy Regulatory Commission, "2018-2019 Winter Energy Market Assessment," available at the following link: https://ferc.gov/market-oversight/reports-analyses/mkt-views/2018/10-18-18-A-3-presented.pdf?csrt=66746001818521317.

tax incentives driving those declining costs begin to expire soon,[50] and the expiration of those tax incentives may reverse the trend of declining costs.[51] Therefore, EAI should not necessarily presume that it can replace over one thousand megawatts of coal-fired generation with cheap renewable plants.

In conclusion, EAI has reacted to the loosening of environmental regulations regarding its coal plants with plans to accelerate their retirements. Said reaction, which is somewhat counter-intuitive, creates concern that EAI merely hopes to retire those plants early so that it can incur capital costs (and get a return on them) by building replacement capacity. Instead of resource planning with its shareholders in mind, EAI should fulfill its fiduciary duties to its ratepayers by examining the viability of operating its coal plants for the remainder of their sixty-year useful lives.

Recommendation

- EAI should closely examine the economic viability of operating its coal-fired power plants for the remainder of their sixty-year useful lives.

VIII. Comment Topic: Energy Efficiency

Gary Moody, National Audubon Society

Other Stakeholders Joining This Comment: Advanced Energy Management Alliance, Arkansas Electric Energy Consumers, Inc., and Sierra Club

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[50] US Department of Energy, available at the following link: https://www.energy.gov/savings/renewable-electricity-production-tax-credit-ptc.

[51] *See* U.S. Energy Information Administration, "Tax credits and solar tariffs affect timing of projected renewable power plant deployment," May 15, 2018, available at the following link: https://www.eia.gov/todayinenergy/detail.php?id=36212; *see also* U.S. Department of Energy, 2017 Wind Technologies Market Report, p. xii, available at the following link: https://emp.lbl.gov/sites/default/files/2017_wind_technologies_market_report.pdf.
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A. EAI Treatment of EE in 2018 EAI IRP

The Stakeholder Group commends EAI for their leadership in EE program development and deployment. Since the adoption of comprehensive energy efficiency targets in 2011, Entergy Arkansas has been the leader among their peers in achieving efficiency savings. During the 2015, EAI IRP process, stakeholders encouraged modeling EE as a resource. Stakeholders commend EAI for working to implement that suggestion and offer the following comments as an opportunity to further improve EE treatment in the IRP process moving forward.

The 2018 draft IRP as presented to the Stakeholder group considers four types of DSM: Customer-sponsored DSM, Existing Utility-Sponsored DSM, Incremental Utility-Sponsored DSM, and Interruptible Loads/DR. The draft IRP includes assumptions for the impacts of Customer-Sponsored DSM and existing Utility-Sponsored DSM as modifiers to their Retail Sales Forecast, while Incremental Utility sponsored DSM and Interruptible Loads/DR are modeled as a supply side resource.

B. EE as a resource

The Stakeholders commend EAI for working with ICF to treat incremental Utility-sponsored EE as a supply-side resource, and allowing it to compete dynamically in the model for future utility investment against other capacity resources as recommended in the 2015 IRP Stakeholder report.

Stakeholders note that one of the two available EE portfolio options was selected by the model in all futures modeled at the earliest date available (2020). As EAI has noted that APSC approval will be needed for these additional resources, we encourage EAI to begin that process as soon as is practicable.

The Stakeholder group would also encourage EAI to continue to refine and expand their EE modeling process for future IRP processes.

C. Stakeholder Concerns

Despite the above noted improvement, the Stakeholder group does want to express one concern related to EAI's treatment of EE in the IRP draft. The estimate for Existing Utility – Sponsored DSM is likely too conservative. With little explanation EAI chose to use 1.0% of retail sales as the DSM proxy within the Sales and Load forecasts, despite significantly higher achieved savings for recent years and the subsequent APSC order increasing targets to 1.2% of annual sales. Planning on 1.0% savings despite actually achieving 1.57% savings in 2016, 1.49% for 2017, and estimated savings of 1.8% for 2018 - drastically underestimates the likely impact of EE on future load. At a minimum EAI should use 120% of the current EE Savings target as a reasonable proxy as they have indicated their planning and budgets for the next 3 year plan will be designed to achieve at least that level of cost-effective savings. Underestimating EE this substantially will lead to over estimating future capacity needs and increased costs for consumers.

IX. Comment Topic: Coal

Tony Mendoza, Sierra Club

Other Stakeholders Joining This Comment: Advanced Energy Management Alliance, National Audubon Society

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Entergy Arkansas co-owns and operates two large coal-burning power plants, the two-unit White Bluff plant near Redfield and the two-unit Independence plant near Newark. As Entergy evaluates how and when to replace these plants, Sierra Club urges the company to rely on "all-source" requests for proposals to determine the most-economical, least-polluting means of meeting customers' power needs.

A. Entergy Arkansas's coal plants are dirty.

Burning coal is the single most environmentally damaging means of producing electricity. At a time when the UN Intergovernmental Panel on Climate Change has warned in its October 2018 report that a climate crisis of inundated coastlines, intensifying droughts, food shortages, and powerful storms is approaching as soon as 2040, coal remains the most carbon-intensive means of producing electricity. White Bluff and Independence are by far the largest single sources of carbon pollution in Arkansas. In 2017, White Bluff emitted 9,143,967 tons of carbon and Independence emitted 7,989,772 tons, according to U.S. EPA data.

In addition, White Bluff and Independence are the top two sources of sulfur dioxide ("SO_2") and nitrogen oxides ("NOx") pollution in the state of Arkansas and are among the largest in the United States. The four Independence and White Bluff units are the largest in the United States that lack post-combustion controls for both NOx and SO_2. According to U.S. EPA data, White Bluff emitted 23,212 tons of SO_2 in 2017 and Independence emitted 19,486 tons that year, which made these plants the 9th and 15th largest sources of SO_2 pollution in the entire country. In 2017, White Bluff was the 7th largest source of NOx in the entire United States, emitting 11,418 tons, and Independence was the 25th largest source in the country, spewing 8,694 tons of NOx. Both NOx and SO_2 are harmful to human health.

These plants also produce vast quantities of coal combustion residuals ("CCRs") that are likely to contaminate groundwater for generations, directly on the banks of the Arkansas and White rivers. Entergy Arkansas's public reporting confirms that the CCRs at both plants are likely contaminating the groundwater.

There is therefore a moral imperative for Entergy Arkansas to cease burning coal as soon as possible. Entergy's decision to model the retirement of White Bluff in 2028 and

Independence in 2030 is a positive start in that direction.

B. <u>The economics of Entergy Arkansas's coal plants are deteriorating.</u>

The economics of Entergy Arkansas coal have deteriorated in recent years, as shown in their annual capacity factors. These plants simply do not operate as often as they did before 2014 as more-efficient, less-expensive generation plants dispatch more often in the MISO and SPP energy markets. The lack of any post-combustion controls for NOx and SO_2 and of closed-loop ash handling systems, at both plants is also a significant risk of increased costs at both plants.

Table 1: Annual Capacity Factors for Entergy Arkansas Coal Plants

	2014	**2015**	**2016**	**2017**
Independence	74.64%	35.21%	52.18%	51.63%
1	75.6%	37.81%	52.13%	43.19%
2	73.68%	32.61%	52.22%	60.13%
White Bluff	73.41%	43.35%	39.58%	55.59%
1	75.5%	43.04%	34.34%	67.52%
2	71.25%	43.66%	44.79%	43.75%

Moreover, based on data reported by the MISO and SPP energy markets and by Entergy Arkansas, Sierra Club calculated the approximate revenues each plant generated by producing power in recent years. These estimated revenues were compared to the actual operation costs of the power plants, based on data reported by the owners of the power plants. This comparison can show if the power plants were able to cover their costs to operate by selling electricity into the SPP and MISO markets.

Table 2: Cash Flow of White Bluff and Independence

White Bluff	**2015**	**2016**	**2017**
SPP Energy Revenues	*$37*	*$35*	*$47*
MISO Energy Revenues	*$134*	*$125*	*$177*
MISO Capacity Revenues	*$8*	*$2*	*$1*
Total Revenues	$179	$162	$225
Fuel Costs	*($167)*	*($161)*	*($226)*
Operation Costs	*($15)*	*($15)*	*($14)*
Maintenance Costs	*($26)*	*($20)*	*($25)*
Total Costs	($208)	($196)	($265)
Net Earnings (Losses)	**($29)**	**($34)**	**($40)**

Independence	2015	2016	2017
SPP Energy Revenues	*$44*	*$65*	*$68*
MISO Energy Revenues	*$109*	*$149*	*$158*
MISO Capacity Revenues	*$7*	*$1*	*$1*
Total Revenues	$160	$215	$227
Fuel Costs	*($160)*	*($198)*	*($206)*
Operation Costs	*($13)*	*($9)*	*($11)*
Maintenance Costs	*($21)*	*($19)*	*($22)*
Total Costs	($194)	($226)	($239)
Net Earnings (Losses)	**($34)**	**($11)**	**($12)**

Since the start of 2015, the White Bluff plant is estimated to have generated $119 million dollars of revenue from the SPP energy market, $447 million of revenue from the MISO energy market, and $11 million from the MISO capacity market. However, the cost to operate the coal plant has been in excess of $669 million, meaning the plant has accumulated $103 million in losses that were covered by customers. Independence has similarly been uncompetitive. It is estimated to have generated $177 million dollars of revenue from the SPP energy market, $416 million of revenue from the MISO energy market, and $9 million of revenue from the MISO Capacity market. However, the cost to operate the coal plant has been in excess of $659 million, meaning the plant has lost a cumulative $57 million.

Both SPP and MISO markets have a large excess of available power plant resources, including access to low-cost wind and solar. This market reality means that Entergy Arkansas and the owners of White Bluff and Independence have had, and will continue to have, access to lower cost energy off the market rather than operating the two coal plants.

In fact, during the last three years the cost of energy from the White Bluff and Independence plants has generally exceeded the MISO market energy price. The cost of energy from the MISO energy market was $28.91—$31.34/MWh (nominal) in the 2015—2017 period. The cost of energy from White Bluff was $32.37—$34.07/MWh (nominal) in the 2015—2017 period. The cost of energy from Independence was $29.33—$36.14/MWh (nominal) in the 2015—2017 period. Thus, on the energy side, Entergy clearly has an opportunity to save customers money by shifting away from these coal-burning plants.

C. <u>Entergy Arkansas's coal plants support economic development in Wyoming.</u>

Each year, Entergy Arkansas and the co-owners of White Bluff and Independence spend hundreds of millions of dollars on out-of-state coal, almost exclusively sourced from Wyoming. These costs are ultimately paid by electric customers in Arkansas, and provide an economic boost to the Wyoming and Montana economies, and a corresponding drain on the Arkansas economy via direct payments and the negative multiplier effect.

<u>Recommendation</u>

Sierra Club recommends that EAI issue an "all-source" requests for proposal ("RFP") modeled on the Xcel (2017) and NIPSCO (2018) RFPs to test the market for replacing the energy and/or capacity provided by White Bluff and Independence sooner than 2028 and 2030. If EAI ultimately determines that it will shut White Bluff and Independence in 2028 and 2030, then EAI should use an all-source RFP ahead of those shutdowns to test the market for the most-economical and least-polluting means of replacing these plants. Key attributes of such an RFP should include: i) requesting all solutions regardless of technology, including demand-side options and storage, such that the RFP is truly "all source;" ii) defining a minimum total need of a certain number MW for the portfolio of resources but without a cap, while also allowing smaller resources to offer their solution as a piece of the total need; and iii) seeking bids for asset purchases and purchase power agreements for new and existing resources. Sierra Club asks that EAI provide an opportunity for stakeholders to comment on a draft RFP before it issued.

X. <u>Comment Topic: Advanced Nuclear</u>

Katie Niebaum, Arkansas Advanced Energy Association

Other Stakeholders Joining This Comment: None.

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The Arkansas Advanced Energy Association (AAEA) encourages EAI to consider advanced nuclear energy in its long-term resource planning. Advanced nuclear power technologies are different in that they address many of the concerns that have limited the deployment of commercial-scale conventional nuclear power generation. Some of the benefits of advanced nuclear include:

- **Zero emissions.** Not just GHGs, but also other criteria pollutants such as NOx, SOx, PM, etc.
- **High Capacity Factor.** The U.S. nuclear fleet currently averages >92%.
- **Baseload.** Nuclear generating facilities are reliable and dispatchable.
- **Small scale.** Advanced nuclear systems are available in much smaller increments (e.g., 50-300 MW) than conventional systems.
- **Small land area.** Small physical footprints.
- **Short lead time.** Compared to conventional nuclear technologies, advanced technologies require less lead time for commercial deployment.
- **Improved waste management.** Advanced nuclear technologies can address some of the concerns associated with long-term management of spent nuclear fuel from conventional nuclear plants. In some cases, advanced nuclear systems actually use the spent fuel from conventional facilities as feedstock.

AAEA recognizes that many of the issues associated with conventional nuclear facilities have created a climate of concern and distrust regarding nuclear technology. Nonetheless, the broad range of benefits noted above warrant serious consideration of advanced nuclear energy for future power generation in Arkansas, particularly in light of EAI's plans to decommission the White Bluff, Independence, and Arkansas Nuclear One facilities. AAEA stands ready to work with EAI to evaluate and, potentially, deploy advanced nuclear power generation technologies in Arkansas during the longer-term horizon. Advanced nuclear energy could become a key component of EAI's strategy to replace baseload power while also reducing emissions.