Entergy

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Laura Landreaux
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October 30, 2015

Mr. Michael Sappington
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. 2015 Integrated Resource Plan

Dear Mr. Sappington:

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 the following: a) its 2015 Integrated Resource Plan (the "IRP"); b) the presentations made by EAI in connection with its August Stakeholder Meeting; and c) 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) 377-5876 or Jeff McGee at (501) 377-3976.

Sincerely,

/s/ Laura Landreaux

LL
Attachments

c: All Parties of Record

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Entergy Arkansas, Inc.
2015 Integrated Resource Plan

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EXECUTIVE SUMMARY

This document describes Entergy Arkansas, Inc.'s ("EAI" or the "Company") long-term Integrated Resource Plan ("IRP") for the period 2017 – 2036. The uncertainties that dominated EAI's most recent IRP, filed with the Commission on October 31, 2012 (*e.g.*, uncertainties associated with EAI's transition to post-System Agreement operation and planning for EAI as a single electric utility), have been replaced to some extent with other uncertainties, such as potential environmental regulations, advances in renewable resource technologies, and future natural gas prices. Based on the IRP analysis, EAI's total generation capability may be short of its peak customer demand plus reserve target by as soon as the summer of 2017. The deficit expands over time as expected customer demand increases and older generating units reach the end of an assumed useful life.

The 2015 IRP utilized a futures-based approach by which three future worlds were constructed to reasonably bookend a broad range of uncertainties. An economically optimal portfolio of supply-side resources was developed for each of the three future worlds analyzed in the 2015 IRP. A summary of those portfolios is shown below.

Based on the work conducted as part of the IRP analysis, it is reasonable to conclude that EAI's supply-side resource additions will likely consist of natural gas fired resources and renewable energy resources. The total amount of supply-side capacity that will be needed, and exactly when that capacity will be needed, is uncertain. There is even more uncertainty associated with exactly how much of each supply-side technology should be added to EAI's fleet. Because of that uncertainty, EAI has not established specific targets for renewable generation or traditional generation as part of this IRP analysis.

2015 IRP Results	Future 1 Reference Case	Future 2 Low Case	Future 3 High Case
Total Incremental Installed Capacity	4,850 MW	2,000 MW	6,050 MW
CT & CCGT Capacity Additions	73.2%	100%	73.6%
Renewable Capacity Additions	26.8%	0%	26.4%

This point highlights an important point regarding EAI's IRP and the value it provides, particularly given concerns voiced by the Stakeholder Group and reflected in the Stakeholder Comments attached to this IRP. Consistent with the Commission's Resource Planning Guidelines, EAI's IRP analyzes multiple future scenarios, with an optimal portfolio developed for each scenario. However, these portfolios do not represent planning decisions by EAI. Rather, EAI's specific long-term resource planning actions (e.g., capacity additions) typically are subject to review and approval by the Commission. In the same respect, the assumptions as to 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. For example, a renewable resource, although it has limited capacity value relative to traditional generation, may prove to be an economic resource, particularly in a future scenario where carbon is a material element of energy costs.

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 few years based on all the relevant information available at that time.

The 2015 IRP Action Plan consists of six action items which are summarized below.

1. Coal Environmental Compliance	EAI will continue to monitor changes in environmental law at the state and federal level and evaluate options for environmental compliance for the EAI coal units, with Arkansas Public Service Commission ("APSC" or "Commission") review and support before significant capital is expended to comply with applicable environmental regulations.
2. Clean Power Plan	EAI will engage in the Arkansas Clean Power Plan ("CPP") stakeholder process sponsored by the APSC and the Arkansas Department of Environmental Quality, with a 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. In addition, EAI also will continue to analyze the long and complex EPA final rule in order to assess various compliance options open to the State if the rule survives litigation.

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3. Complete the Acquisition of Power Block 2 from the Union Power Plant	The acquisition of Power Block 2 of the Union Power Plant is expected to be completed in later 2015 or early 2016.
4. Continue participation in Energy Efficiency	EAI will continue to offer cost effective Energy Efficiency ("EE") and Demand Response ("DR") programs within the Commission's Rules for Conservation and Energy Efficiency Programs and subsequent future Commission orders, consistent with APSC orders and Arkansas State law.
5. 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 2016 for both short-term and long-term resources. However, the exact scope and timing of the next EAI Request For Proposals ("RFP") is uncertain and is dependent on many factors that have been discussed throughout this report. In addition to market solicitation, EAI will be considering developing self-build proposals for certain supply-side technologies.
6. Stakeholder Engagement Process	An immediate priority will be for EAI to closely review the Stakeholder Comments and develop a detailed plan to address concerns and suggestions.

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I. EAI Resource Planning Background

1. Introduction

This document describes EAI's long-term IRP for the period 2017 – 2036. This is the fourth IRP filed by EAI since the APSC adopted its Resource Planning Guidelines in Order No. 6 in Docket No. 06-028-R. Whereas EAI's previous IRPs discussed EAI's transition from operations under the Entergy System Agreement and the implications of that monumental change on EAI's long-term resource planning, this IRP reflects the fact that uncertainty always 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 2012 IRP filed with the Commission on October 31, 2012 (*e.g.,* uncertainties associated with EAI's transition to post-System Agreement operation and planning for EAI as a single electric utility), have been replaced to some extent with other uncertainties, such as potential environmental regulation, advances in renewable resource technology, and other generation-related issues.

EAI's process for preparing this IRP considered potential future scenarios in which various resource plans could be evaluated. As with EAI's 2012 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 President and Chief Executive Officer, Hugh T. McDonald.

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 few 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 President and Chief Executive Officer Hugh McDonald on May 16, 2012. During the next planning cycle, EAI intends to review and update, if necessary, its planning objectives. Nevertheless, the planning objectives 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 implemented a modified approach to its stakeholder process to incorporate EAI's experience in its stakeholder process conducted for its EE portfolio. This modified approach included reviewing actual study results with stakeholders rather than high-level study assumptions and plans, as EAI did for its 2009 IRP. In July 2012, EAI conducted a lengthy stakeholder meeting during which EAI reviewed its preliminary study results, and then sought input from the stakeholders. Nearly 100 detailed questions were submitted by stakeholders, and EAI provided responses to those questions, following up with another open meeting in early September 2012 to allow stakeholders to ask clarifying questions on those responses.

For this IRP, EAI's stakeholder process was conducted on a more abbreviated schedule. Nevertheless, this process ultimately proved to be far more interactive than prior stakeholder process conducted by EAI, with numerous meetings and conference calls conducted 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 attached to this IRP. These comments reflect the diversity of the views held by various stakeholders, which to their credit appear to have been worked through in a relatively amicable manner.

The Stakeholder Engagement Process began in July 2015 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 were provided to stakeholders in advance of the first in-person stakeholder meeting hosted by EAI. Following the meeting, EAI was invited to participate in four conference calls held by the Stakeholder Group every few weeks. Per request from the Stakeholder Group, EAI completed three additional AURORA portfolio

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

[2] www.entergy-arkansas.com/transition_plan

optimization model runs. The model runs were constructed to respond to the Stakeholder Group's feedback on the installed cost of solar and wind resources, as well as requests to look at alternatives for the future of EAI's existing coal units. All of the additional documentation, materials and model runs requested by the Stakeholder Group have been compiled and are available on EAI's IRP website. To conclude the Stakeholder Engagement Process, EAI hosted a second meeting, in mid-October, to allow the Stakeholder Group to present and discuss their recommendations with EAI.

4. The 2012 IRP Action Plan

The 2012 EAI IRP Action Plan contained eleven action items. Some of those action items are still in progress. The current status of each action item is described below:

1. **MISO Transition –** Integration into the Midcontinent Independent System Operator ("MISO") was completed on December 19, 2013. During the first year of participation in the MISO market, EAI customers are estimated to have saved approximately $46 million.[3] Since joining MISO, EAI has participated in three MISO Planning Resource Auctions and has successfully met the MISO Resource Adequacy requirements. More details about EAI's participation in the Planning Resource Auctions can be found in EAI's 2015 Annual Report of Participation filed June 30, 2015, in Docket No. 10-011-U.

2. **Coal Unit Environmental Compliance –** EAI is continuing to monitor changes in environmental law at the state and federal level. See *infra* Section III of this IRP for a detailed discussion of environmental regulation/compliance issues.

3. **Hot Spring Plant Acquisition –** EAI completed its acquisition of the Hot Spring Combined Cycle Gas Turbine plant in December of 2012, adding approximately 600 MW to EAI's generation fleet.

4. **Purchase Power Agreements from EAI's 2011 RFP –** EAI executed a Purchase Power Agreement ("PPA") with Union Power Partners in October 2012. The Commission reviewed and approved this agreement in APSC Docket No. 12-038-U. This action added approximately 500 MW for the period of December 19, 2013 through May 31, 2017. Contract negotiations for a second proposal

[3] *See* EAI's 2015 Annual Report of Participation filed June 30, 2015, in Docket No. 10-011-U

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selected in the 2011 RFP were concluded without execution of a contact.

5. **Available Wholesale Base Load Capacity –** In APSC Docket No. 12-038-U, EAI offered to add to EAI's portfolio of resources to serve retail customers approximately 286 MW of capacity that had previously been used to serve the wholesale sector. The docket was settled with 154 MW of nuclear-based generation from the Arkansas Nuclear One units being transferred to serve retail customers.

6. **Hydro Peaking Capacity to Retail –** The retail-wholesale allocation factor applied to the EAI hydro capacity was updated in APSC Docket No. 13-028-U to near 100%. This action added approximately 10 MW to serve EAI's retail customers.

7. **Demand-Side Management ("DSM") and EE Expansion –** Since 2012, EAI has added 135 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.

8. **Lake Catherine 4 Reliability / Sustainability –** Lake Catherine Unit 4 is a 516 MW gas-fired steam unit that was originally scheduled to deactivate at the end of 2014. A Reliability/Sustainability program was developed and implemented as a result of the 2012 IRP. With the capital additions contemplated in that program, the unit is currently expected to be available through May 31, 2025.

9. **Older Natural Gas Fired Unit Deactivation Decisions –** Since the 2012 IRP, EAI has deactivated approximately 420 MW of older natural gas and diesel fired generation. Total generation retirements since the 2012 IRP totals approximately 964 MW across 13 units. Additionally, two older units, approximately 28 MW total, are planned to retire at the end of May 2016.

10. **Renewable Energy Assessment –** EAI issued an RFP for both traditional and renewable energy on May 5, 2014. As a result of the RFP, on April 3, 2015, EAI entered into a twenty year power purchase agreement for 81 MW of solar-based generation. Deliveries will begin no later than May 31, 2019, and is expected to add at least 20 MW and maybe as much as 40 MW of capacity to EAI's fleet. Approval of the PPA was obtained from the APSC in Docket No. 15-014-U on September 24, 2015.

11. **Short- and Intermediate-Term RFPs –** EAI elected to issue a RFP for long-term renewable and traditional supply-side resources on May 5, 2014. EAI entered into an asset purchase agreement with Union Power Partners on December 8, 2014, to acquire Power Block 2 which will add approximately 495 MW to EAI's portfolio. APSC approval is pending in Docket No. 14-118-U, as well as required federal reviews/approvals. Also, EAI executed the long-term PPA for a planned 81 MW solar photovoltaic resource discussed above. As indicated in EAI's 2015 IRP Action Plan, EAI continues to evaluate whether to issue a competitive solicitation in 2016 for both short-term and long-term resources.

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II. The 2015 Integrated Resource Plan

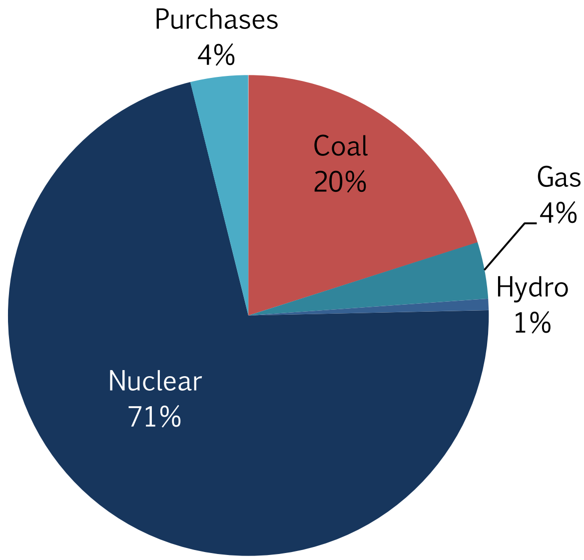
The IRP plays an important role in the planning of EAI's future resource portfolio by providing guidance to EAI planners, as well as stakeholders, on long-term themes and tendencies. While these long-term and forward-looking indicators are important guides to resource planning, the IRP fulfills a distinctly different purpose and process from near-term, specific resource decisions that typically are presented to the Commission for approval.

The study period for the 2015 IRP is 2017 through 2036. 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 the 2012 IRP, the 2015 IRP will be 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 700,000 residential, commercial, industrial, and governmental customers located in 63 of Arkansas' 75 counties, covering over 40,880 square miles. The Company controls, through ownership or through purchase power contracts, a diverse array of generating resources totaling approximately 5,277 MW to serve these native load customers. The Company's nuclear power resources include 1,721 MW in the two-unit Arkansas Nuclear One plant located near Russellville and 307 MW from the Grand Gulf Nuclear Station ("Grand Gulf") near Port Gibson, Mississippi under a long-term purchase power contract. EAI also utilizes 1,031 MW from coal-fired generation at the White Bluff Steam Electric Station ("WB") and Independence Steam Electric Station ("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. (EMI), the AECC, Entergy Power Inc., an Entergy affiliate, and several municipal electric utilities. The Company's generation fleet is rounded out with 94 MW of hydro-electric capacity along the Ouachita River Valley and 2,224 MW of natural gas-fired generation that includes 597 MW from the Hot Spring Plant, 489 MW from the Ouachita Plant and 495 MW from Power Block 2 of UPP, which are modern combined cycle gas turbines ("CCGT"). On the demand side, Figure 1 below shows the percentage, by fuel type, of EAI's energy sources in 2014. Additional information about these resources is available in Appendix B.

FIGURE 1: FUEL MIX



Source: 2014 Billing Data

2. Planned Resources

As discussed in Section 4, EAI has sought regulatory approval for two additional generating resources. First, as a result of EAI's 2014 Request for Proposals[4], EAI has executed a long-term PPA for a planned 81 MW solar photovoltaic resource to be located in Stuttgart, Arkansas, called Stuttgart Solar[5]. The Commission issued Order No. 5 in Docket No. 15-014-U on September 24, 2015, approving the PPA. The 2015 IRP assumes the resource achieves commercial operations by 2019.

Concurrently, but in a separate proceeding before the Commission, EAI is seeking approval to acquire Power Block 2 of the Union Power Partners combined cycle gas turbine plant located in El Dorado, Arkansas.[6] The acquisition would provide approximately 500 MW of capacity to EAI's portfolio. The 2015 IRP assumes the acquisition receives approval and is closed by the end of 2015. In the event the acquisition is not approved, EAI's existing short-term PPA for the same amount of capacity from Union Power Partners would continue through May 31, 2017.

[4] Information on the 2014 Request for Proposals can be found at http://www.entergy-arkansas.com/transition_plan/.
[5] Docket No. 15-014-U
[6] Docket No. 14-118-U

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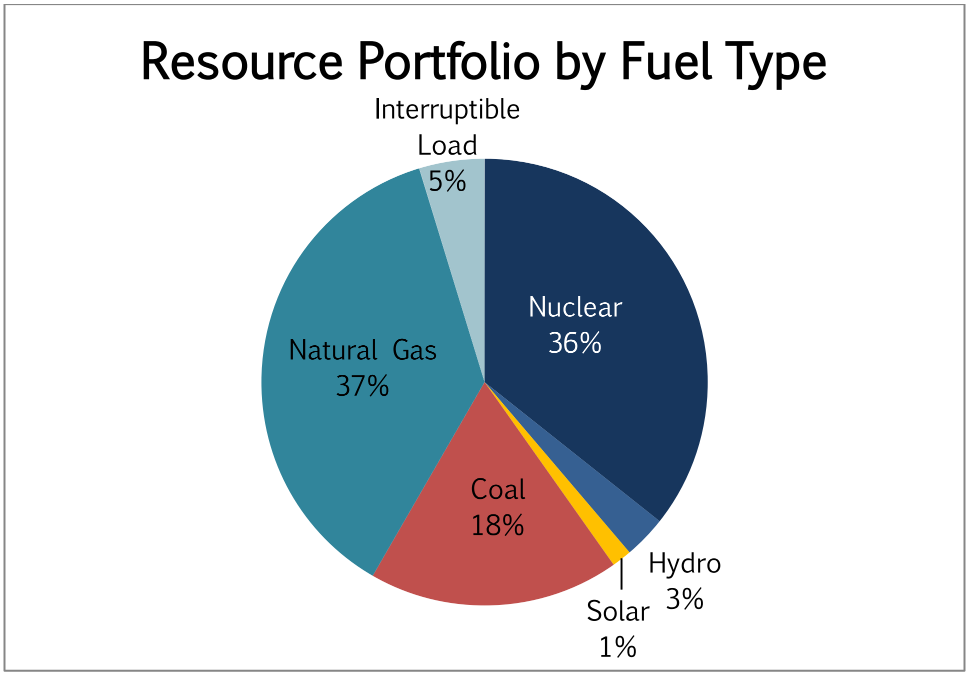
Under the assumption that the planned resources described above proceed as planned, the 2015 IRP assumes a total of approximately 5,600 MW of capacity resources in EAI's portfolio by 2019. The diversity of EAI's currently planned resource portfolio in 2019 is shown in Figure 2 below.

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 the subsequent sections, EAI will review its portfolio of generating resources, discuss the load forecast utilized within this IRP, environmental regulations 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.

Key uncertainties related to environmental compliance 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. In addition, even within rules and regulations that are fairly developed, such as for the Regional Haze Rule, the specifics that will be required for compliance are not known fully at this time. The specific rules and assumptions made in the 2015 IRP are described in later sections of this report.

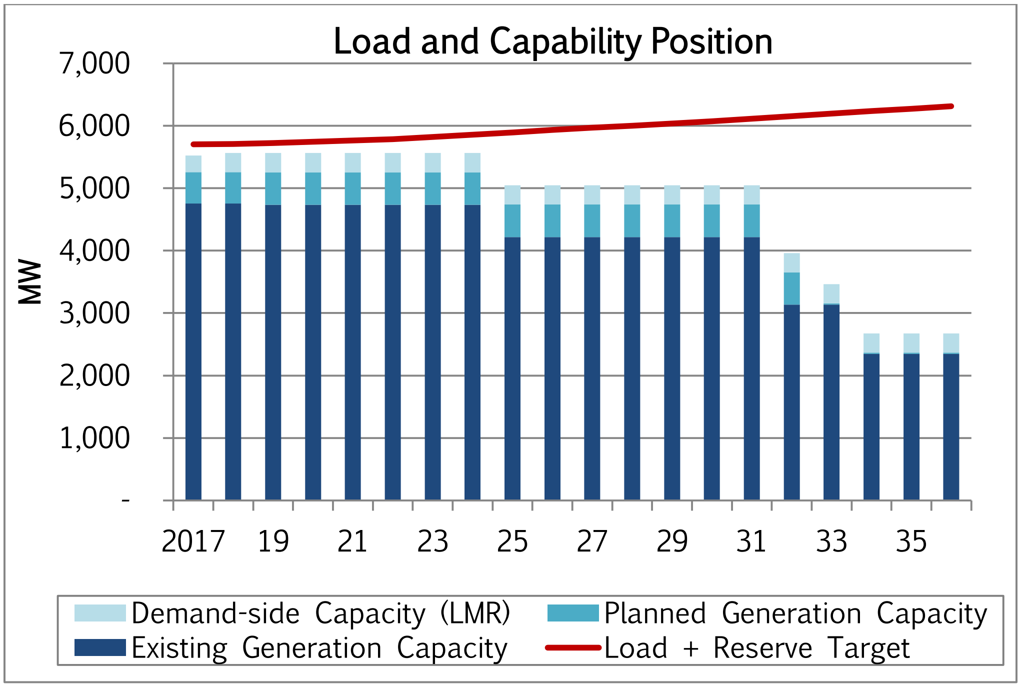
At the risk of repetition, it is important to recognize that assumptions related to these uncertainties about operating lives of existing generating units do not reflect actual decisions regarding the future investment in resources or the actual dates that generating units will be removed from service. 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

Over the 2015 IRP study period, EAI expects to have a need for incremental capacity resources based on a 12% planning reserve target. EAI has determined that a 12% reserve target is appropriate for the EAI generation system given the characteristics of its generation fleet and the planning uncertainties it faces. The figure 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-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 2017.[7] The deficit expands over time as expected loads increase and older generating units reach an assumed end of useful life. Figure 3, however, does not assume any early retirements due to environmental rules. Any retirements of coal-fired units before 60 years of operation would increase the deficit shown in Figure 3. The effects of early retirements to EAI's future resource portfolio are evaluated in the 2015 IRP analytics described in later sections of this document.

[7] Should EAI be prohibited from closing the acquisition of UPP Power Block 2, the need shown will increase by approximately 500 MW.

FIGURE 3: EAI PROJECTED CAPACITY RESOURCE NEEDS



5. Transmission Plan

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 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.

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. 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 Owners 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 insure 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 it will continue to provide EAI customers with reliable and safe service through compliance with all applicable North American Electric Reliability Corporation ("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 concern. 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, 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 Entergy Arkansas transmission system.

These reliability studies result in projects which are presented annually to the 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 verify that the reliability need exists, that proposed solutions solve the reliability need, and to provide stakeholders the opportunity to discuss alternatives. Additionally, MISO performs other studies each year to consider planning issues including market efficiency, 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 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 MTEP14, MTEP15, and in preparation for MTEP16. The EAI projects that were approved for inclusion in Appendix A of MISO's MTEP14 are included below in Table 1. These future transmission projects and other transmission plans developed during the next three years will be important inputs to consideration of future resource needs.

TABLE 1: EAI PROJECTS APPROVED IN APPENDIX A OF MTEP14

Project Driver	Project Name	Year
Transmission Reliability - Meeting Planning Criteria	EAI Underrated Breaker Project: L.R. Alexander 115 kV B0639-CBO	Complete
Transmission Reliability - Meeting Planning Criteria	EAI Underrated Breaker Project: Searcy Price 115 kV B5310-ICBO	Complete
Customer Driven	Smackover Industrial 115 kV Substation: Construct new substation	Complete
Load Growth	Lawson Road: Build new substation	Complete
Load Growth	H.S. Albright: New Distribution Substation	Complete
Transmission Reliability - Meeting Planning Criteria	EAI Underrated Breaker Project: P.B. 34 & Main 115 kV B0957-CBO	Complete
Transmission Reliability - Meeting Planning Criteria	EAI Underrated Breaker Project: P.B. Dierks 115 kV B0938-CBO	Complete
Transmission Reliability - Meeting Planning Criteria	EAI Underrated Breaker Project: L.R. Hindman 115 kV B0988-CBO	Complete
Customer Driven	AECC Shaw POD (Woodlawn Expansion)	Complete
Customer Driven	Benton West 115 kV Substation: Construct new substation	Complete
Load Growth	Cofer Road New Substation	Complete
Transmission Reliability - Meeting Planning Criteria	EAI Underrated Breaker Project: L.R. Industrial 115 kV B0591-CBO	Complete
Transmission Reliability - Meeting Planning Criteria	Woodward-115 kV Bus Reconfiguration	2016
Transmission Reliability - Meeting Planning Criteria	HS EHV-HS Industrial: Upgrade Terminal Equipment	2015

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Transmission Reliability - Meeting Planning Criteria	HS Industrial-HS Union Carbide: Upgrade Terminal Equipment	2015
Transmission Reliability - Meeting Planning Criteria	HS Union Carbide-HS East: Upgrade Terminal Equipment	2016
Load Growth	Macedonia: Build New 115 kV Substation	2016
Transmission Reliability - Meeting Planning Criteria	EAI Underrated Breaker Project: McAlmont 115 kV B0980-CO	2015
Transmission Reliability - Meeting Planning Criteria	EAI Underrated Breaker Project: Jacksonville North 115 kV B3621-CBO	2016
Transmission Reliability - Meeting Planning Criteria	EAI SPOF Projects: Modify relaying at White Bluff 500 kV	2016
Transmission Reliability - Meeting Planning Criteria	EAI SPOF Projects: Modify relaying at ISES 500/161 kV	2016
Transmission Reliability - Meeting Planning Criteria	EAI SPOF Projects: Modify relaying at Mabelvale 500 kV	2016
Transmission Reliability - Meeting Planning Criteria	EAI SPOF Projects: Modify relaying at El Dorado 500 kV	2016
Transmission Reliability - Meeting Planning Criteria	EAI SPOF Projects: Modify relaying at Hot Springs 500 kV	2016
Transmission Reliability - Meeting Planning Criteria	Datto: Add 161 kV capacitor bank. Adjust taps on Datto transformer and reduce size of Pocahontas North capacitor bank	2015
Economic	ANO - Mabelvale 500kV: Replace Substation Equipment	2017
Economic	ANO - Pleasant Hill 500kV: Replace Substation Equipment	2017

The projects that have been evaluated as Appendix A projects in MTEP15 and are anticipated to be approved in December 2015 are included below in Table 2.

TABLE 2: EAI SUBMITTED PROJECTS CONSIDERED FOR APPENDIX A IN MTEP15

Project Driver	Project Name	Current Projected ISD

Transmission Reliability - Meeting Planning Criteria	Jim Hill Area Upgrades Rebuild Jim Hill - Datto line and convert from 115kV to 161kV. Install breakers at Datto	2018
Transmission Reliability - Meeting Planning Criteria	EAI Underrated Breaker Project: Paragould 115kV B7315-TCO	2016
Transmission Reliability - Meeting Planning Criteria	Black Rock to Imboden: Construct new 69 kV transmission line	2016
Transmission Reliability - Meeting Planning Criteria	Jonesboro EHV: Tap ISES - Dell 500kV line and build 500/161kV station near Hergett station	2018
Customer Driven	Conway Middle Road: Construct new 161 kV substation	2016
Customer Driven	Jefferson Industrial: Construct new 115 kV substation	2016
Transmission Service	White Bluff - Keo 500 kV: Upgrade terminal equipment	2016
Customer Driven	Driver 230 kV: Construct new 230/13.8 kV distribution substation	2016

The projects that have been determined to be needed to address reliability issues by EAI and have been submitted to MISO for evaluation in MTEP16 are included in Table 3.

TABLE 3: PROJECTS SUBMITTED FOR STUDY AS TARGET APPENDIX A IN MTEP16

Project Driver	Project Name	Current Projected ISD
Transmission Reliability - Meeting Planning Criteria	Mabelvale-Bryant: Reconductor 115kV line	2019
Transmission Reliability - Meeting Planning Criteria	El Dorado - Add 2nd 500-115 kV auto	2018
Transmission Reliability - Meeting Planning Criteria	Mayflower - Morgan: Rebuild 115kV line	2019
Transmission Reliability - Meeting Planning Criteria	Trumann - Trumann West 161 kV: Rebuild line	2018

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Transmission Reliability - Meeting Planning Criteria	Camden Maguire - Smackover 115 kV: Rebuild line	2017
Transmission Reliability - Meeting Planning Criteria	ISES 161 kV: Reconfigure station to breaker and a half configuration	2017
Transmission Reliability - Meeting Planning Criteria	El Dorado East - El Dorado Jackson 115 kV: Upgrade line	2018
Load Growth	Bono: New 161kV substation	2017
Load Growth	London North: New 161kV substation	2017
Transmission Reliability - Meeting Planning Criteria	Lonoke East 115 kV: 20.5 MVAR capacitor bank	2017
Transmission Reliability - Meeting Planning Criteria	Camden MaGuire 115kV: Reconfigure station	2017
Transmission Reliability - Meeting Planning Criteria	Mabelvale 115kV: Reconfigure station	2019
Transmission Reliability - Meeting Planning Criteria	Pleasant Hill: Add tertiary reactors	2017
Enhanced Transmission Reliability	Newport Industrial Flicker: New 161 kV switching station near Newport Industrial	2018

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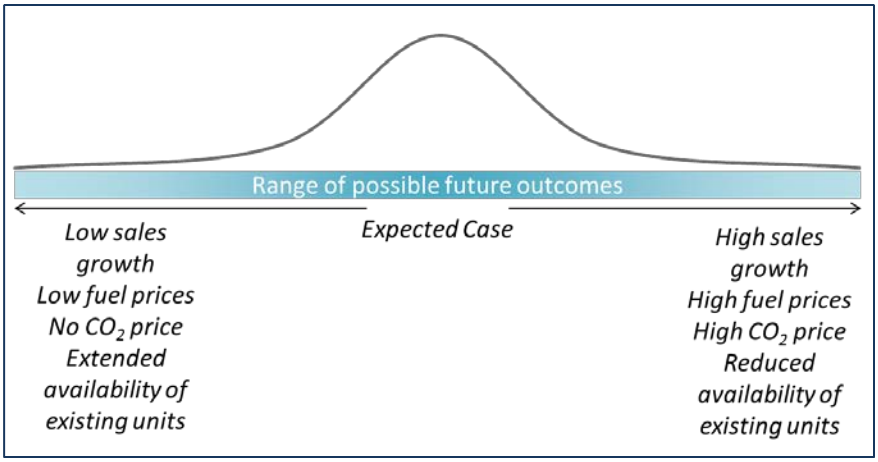
III. 2015 IRP Study

As discussed in the previous sections, EAI is currently facing a broad range of uncertainties that impact planning. Some possible combinations of future outcomes of those uncertainties will drive a higher need for additional generating resources and some combinations will drive a lower need. The 2015 IRP reasonably bookends the range of possible outcomes by utilizing a futures-based approach. The following section describes the inputs and assumptions needed to develop these IRP Futures.



1. Key Inputs and Assumptions

Many inputs and assumptions about the future are required to complete a long-term study like the 2015 IRP. Assumptions for future environmental regulations which may affect both the future availability of existing generating resources as well as the potential for additional cost incurred by operating certain types of resources in the future is a key assumption in developing the 2015 IRP. Also, as discussed earlier in *infra* Section II, EAI is facing a need for incremental capacity during the 2015 IRP study period, and so, the assumed costs for installation of new capacity is a key input. Other key inputs include a range of outcomes for future fuel prices, such as natural gas and delivered coal commodities, as well as future customer energy needs and peak demands. These assumptions and inputs are presented in detail in this section.

1.1 Environmental

As discussed earlier, various environmental regulations have the potential to affect the long-term viability of EAI's existing generating units. Three key areas of regulations are discussed here: Regional Haze Rule, Cross-State Air Pollution Rule and the Clean Power Plan. 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

These environmental regulations were addressed in the Stakeholder Comments in the section entitled Coal and Environmental Compliance. That discussion suffers from a lack of specificity, addressing environmental regulations generally rather than the specific status and/or requirements of each set of regulations, which are critical issues given the varied nature of the status of each set of regulations discussed here. While some of those points may be clarified in the discussion below, EAI is not attempting to address each of the problematic statements contained in that section here.

Regional Haze Rule

EPA proposed a federal implementation plan ("FIP") on April 8, 2015, to address the requirements of the Regional Haze Rule and visibility transport requirements for the State of Arkansas that EPA had previously disapproved. EAI owns and operates three facilities in Arkansas that the EPA proposes to regulate under the FIP through emission limitations that would require emissions controls for sulfur dioxide ("SO_2") ("scrubbers") at WB and ISES coal plants and nitrogen oxides ("NO_X") controls (Low NO_X Burner/Separated Over-Fire Air) at White Bluff and Independence and lesser NO_X controls at one natural gas- and oil-fired plant, Lake Catherine Unit 4. In addition, the EPA is taking comment on requiring only SO_2 scrubbers at Independence. The proposed FIP would require the installation of NO_X controls within 3 years from the effective date of a final FIP and SO_2 scrubbers within 5 years. The final FIP is anticipated to be effective in mid-to-late 2016.

On August 7, 2015, EAI submitted comments in response to the proposed FIP. This effort was the subject of some focus in the Stakeholder Comments in the section entitled Coal and Environmental Compliance, and that section prompts a clarification here. EAI's comments submitted in response to the proposed FIP do not reflect a decision to shut down White Bluff. Rather, EAI has proposed in its comments alternative options than that proposed in the FIP for complying with Regional Haze requirements and EAI expects to seek a public interest finding from the Commission as to the appropriate course of action to take in connection with Regional Haze compliance for White Bluff and Independence.

In its comments in response to the proposed FIP, EAI proposes the following: (1) to accept lower SO_2 emission rate limitations at both White Bluff and Independence; (2) to install NO_X controls on White Bluff and Independence within three years of the final FIP's effective date; and (3) to commit to the permanent cessation of coal-fired operations at White Bluff in 2027/2028. EAI is awaiting EPA response to its proposal and expects EPA to issue the final FIP in mid-to-late 2016.

In the 2015 IRP, Future 3 assumes a scenario consistent with EAI's comments submitted in response to the proposed FIP; however, the other two Futures assume SO_2 scrubbers are installed at both the White Bluff and Independence plants and that both plants operate through a 60 year useful life assumption.

Cross-State Air Pollution Rule (CSAPR)

The EPA finalized the Cross State Air Pollution Rule (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. 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. 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. Energy Ventures Analysis, Inc. ("EVA")[8] also provided the allowance price forecast utilized in the IRP for the NO_X and SO_2 allowance markets under CSAPR. EAI has affected resources located in Arkansas and Louisiana, both of which are only subject to compliance under the seasonal NO_X program; however, EVA also forecasted allowance prices for the annual NO_X program and SO_2 Groups One and Two. The forecast used in the IRP was provided in January 2015. In levelized 2015 dollars per ton through the IRP period (2017-2036), EVA forecasts seasonal NO_X allowance prices at $5.19, annual NO_X at $51.93, SO_2 Group One at $15.09, and SO_2 Group Two at $26.32.

Similar to CO_2 described above, the cost for SO_2 or NO_X emissions are assigned to the emitting unit's variable cost based on its modeled generation. The prices for CSAPR allowances do not vary among the IRP Futures.

Clean Power Plan

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. Currently EPA has issued final regulations using section 111 of the federal Clean Air Act as the

[8] EVA is a consulting firm established in 1981 and located in Arlington, VA. The firm serves a wide variety of customers in the electric, natural gas, coal, emissions, and renewable power industries.

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vehicle. EPA's CPP targets emissions from electric generators, utilizing three building blocks (coal plant heat rate improvements, an increase in dispatch of NGCC plants up to 70% capacity factor, and an increase in zero and low emitting generation) to establish state-by-state emissions rate limits, expressed as lbs. CO_2/MWh. Comments on the proposed rule were submitted in December 2014, and EPA issued the final rule in August 2015. Federal Register publication of the final rule is expected in October 2015, after which parties will have sixty days to file petitions of reconsideration with EPA and petitions of review in the U.S. Court of Appeals for the D.C. Circuit (although litigation concerning the rule already has been filed by several states and companies). The issuance of the CPP may in itself spur additional (and alternative) legislative proposals. EAI's participation in these various processes 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.

The CO_2 POV utilized in this IRP recognizes this uncertainty by presenting a range of potential CO_2 cost outcomes. The range of outcomes extends from a zero direct cost per ton (low or "business as usual" case) up to a high case reflecting a national mass cap program that mimics the goals of Waxman-Markey (and, to a certain extent, the impact of a 111(d) regulatory approach). The high case starts at $25.10/ton (real $2012) in 2020 and escalates to $38.40/ton in 2030. The "reference case" price stream is based on a probability-weighted forecast average of (i) the business as usual case, (ii) a 111(d) equivalent mass cap case translating the proposed rule into a national mass cap but reflecting the goals of the proposed rule, and (iii) the high case as described above.

In the 2015 IRP, the cost of CO_2 emissions were added to an emitting unit's variable cost based on its modeled generation. Each of the three IRP Futures assumes a different one of the CO_2 cases (reference, low and high) described above and shown in Figure 4.

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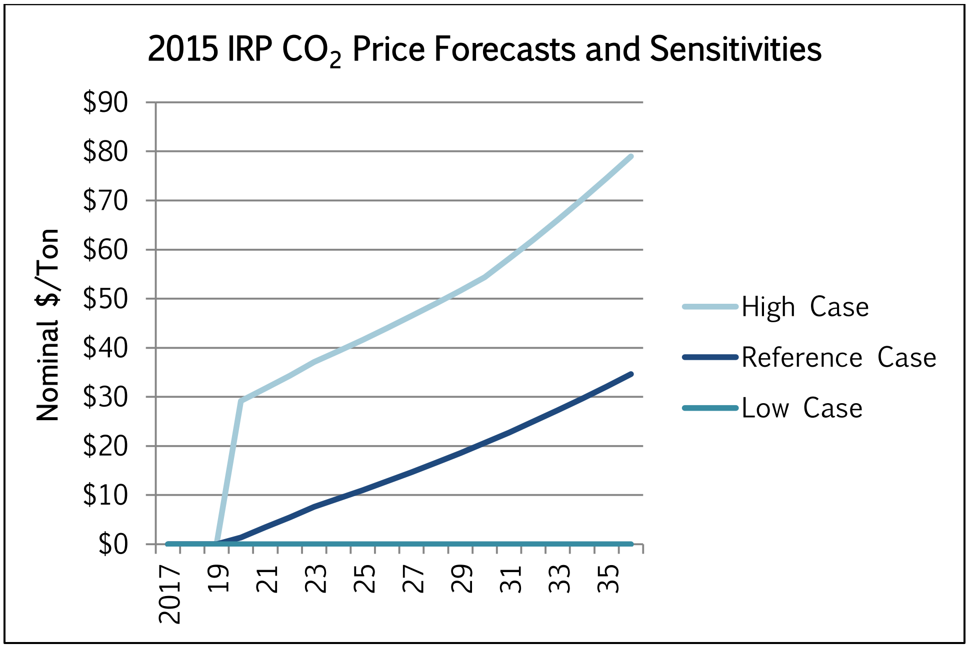
FIGURE 4: CO_2 PRICE FORECASTS



1.2 Technology Assessment

The 2015 IRP process considered a range of alternatives available to meet EAI's planning objectives, including the existing fleet of generating units, potential conventional generation resource additions, and potential renewable generation resource additions. As part of this process, the 2015 Technology Assessment was prepared to identify potential supply-side resource alternatives that may be technologically and economically suited to meet customer needs. The initial screening phase of the 2015 Technology Assessment reviewed the generation technology landscape to identify resource alternatives that merited more detailed analysis. During the initial phase, a number of resource alternatives were eliminated from further consideration based on a range of factors including technical maturity, stage of commercial development, and economics. These resource alternatives will continue to be monitored for possible future development. The following resource alternatives were found to be appropriate for further analysis:

Pulverized Coal	Supercritical Pulverized Coal with carbon capture ("PC" with "CC")
Natural Gas	Simple Cycle Combustion Turbine ("CT") Combined Cycle Gas Turbines ("CCGT")
Nuclear	Generation III Technology

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Renewable	Biomass Wind Solar Photovoltaic ("PV") Battery Storage

Upon completion of the screening level analysis, more detailed analysis (including revenue requirements modeling) was conducted across a range of operating roles and under a range of input assumptions. The analysis and findings are summarized below.

1. Among conventional generation resource alternatives, CCGT and CT technologies are the most economically attractive. The gas-fired alternatives are economically attractive across a range of assumptions concerning operations and input costs. Table 4 below shows the cost and performance assumptions for combined cycle applications and is followed by Table 5 which shows the same information for peaking applications.

TABLE 4: COST & PERFORMANCE ASSUMPTIONS FOR COMBINED CYCLE TECHNOLOGIES

Cost & Performance Appropriate For Technology Deployment in MISO South	Units	1x1 F Frame CCGT	2x1 F Frame CCGT	1x1 G Frame CCGT	2x1 G Frame CCGT
Net Max Capacity (Summer)	(MW)	382	764	450	900
Installed Cost, 2014 (Summer)	($/kW)	$1,095	$1,045	$1,100	$900
Full Load Heat Rate (Summer)	(Btu/kWh)	6,900	6,750	6,650	6,650
Typical Capacity Factor	(%)	65%-85%	65%-85%	65%-85%	65%-85%
Fixed O&M (Summer)	($/kW-yr)	$17.50	$15.00	$15.50	$10.00
Variable O&M (Summer)	($/MWh)	$2.00	$2.00	$2.00	$2.00
Inlet Air Conditioning Assumption		Evaporative Coolers			

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NOx Control Technology		SCR	SCR	SCR	SCR
NOx emissions, post control	(lbs/MMBtu)	0.01	0.01	0.01	0.01

TABLE 5: COST & PERFORMANCE ASSUMPTIONS FOR PEAKING TECHNOLOGIES

Cost & Performance Appropriate For Technology Deployment in MISO South	Units	F Frame CT	G Frame CT	Large Aeroderivative CT	Internal Combustion
Net Max Capacity (Summer)	(MW)	194	250	102	18.8
Installed Cost, 2014	($/kW)	$820	$700	$1,275	$1,360
Full Load Heat Rate – Summer	(Btu/kWh)	10,200	9,600	9,125	8,440
Typical Capacity Factor	(%)	0%-10%	0%-10%	0%-40%	0%-40%
Fixed O&M	($/kW-yr)	$3.50	$3.00	$14.25	$29.25
Variable O&M	($/MWh)	$10.00	$12.50	$0.75	$2.25
Inlet Air Conditioning Assumption		-	Evaporative Cooling	Inlet Chillers	-
NOx Control Technology		Dry Low NOx burners	Dry Low NOx burners	SCR	SCR
NOx emissions, post control	(lbs/MMBtu)	0.03	0.03	0.01	0.01

2. New nuclear and new coal alternatives are not economically attractive near-term options relative to gas-fired technology. The low price of gas and the uncertainties around emissions regulation make coal technologies unattractive. Nuclear is currently unattractive due to both capital and regulatory requirements. Table 6 below shows the cost and performance assumptions for coal and nuclear solid fuel applications.

TABLE 6: COST & PERFORMANCE ASSUMPTIONS FOR SOLID FUEL TECHNOLOGIES

Cost & Performance Appropriate For Technology Deployment in MISO South		PC With 90% CCS	Nuclear
Net Max Capacity	(MW)	800	1,310
Installed Cost, 2014	($/kW)	$4,900	$8,000
Full Load Heat Rate – Summer	(Btu/kWh)	13,200	10,200
Levelized Fuel Cost	($/mmbtu)	$3.12	$0.90
Typical Capacity Factor	(%)	85%	90%
Fixed O&M	($/kW-yr)	$140.00	$115.60
Charging Cost	($/MWh)	n/a	n/a
Expected Useful Life		40	40

3. Among renewable generation alternatives, wind and solar are the most cost competitive. Further improvements and capital cost reductions in solar are expected and may allow for expanding the role of solar. However, uncertainties with respect to various tax credit extensions[9], capacity credits allowed for these resources by MISO, and implementation and timing of CO_2 and other environmental regulations for fossil fuel resource alternatives likely will affect the cost competitiveness of renewable resource alternatives. Apart from a resource's capacity factor, MISO determines the capacity credit value for wind generation based on a probabilistic analytical approach. The application of this approach resulted in a capacity credit value of 14.7% for the 2015-16 MISO Planning Year. EAI's service territory is not favorable for wind generation; therefore, wind resources were modeled at a higher capacity factor (48%) representative of wind resources in the Midwest US. However, this approach does not consider the transmission cost to serve load with wind power from remote resources, which will worsen the economics of wind compared to resources located closer to customer load. For solar resources, the MISO capacity credit value will be determined based on the specific resource's performance data, which is

[9] Refers to the federal renewable electricity production tax credit (PTC) which is currently expired and the federal solar investment tax credit (ITC) which is currently available and scheduled to be reduced starting in 2017.

assumed to be 25%[10] in the IRP analysis. Table 7 below shows the cost and performance assumptions for renewable applications.

TABLE 7: COST & PERFORMANCE ASSUMPTIONS FOR RENEWABLE TECHNOLOGIES

Cost & Performance Appropriate For Technology Deployment in MISO South		Biomass	Wind	Solar PV	Battery Storage (Lead Acid Batteries)
Net Max Capacity	(MW)	100	200	100	50
Installed Cost, 2014	($/kW)	$4,760	$2,050	$2,300	$2,400
Full Load Heat Rate – Summer	(Btu/kWh)	12,900	-	-	-
Levelized Fuel Cost	($/mmbtu)	$3.04	-	-	-
Typical Capacity Factor	(%)	85%	48%[11]	26%	20%
Fixed O&M	($/kW-yr)	$104.60	$22.10	$19.00	$0.00
Charging Cost	($/MWh)	n/a	n/a	n/a	$25.00
Expected Useful Life		30	25	25	20

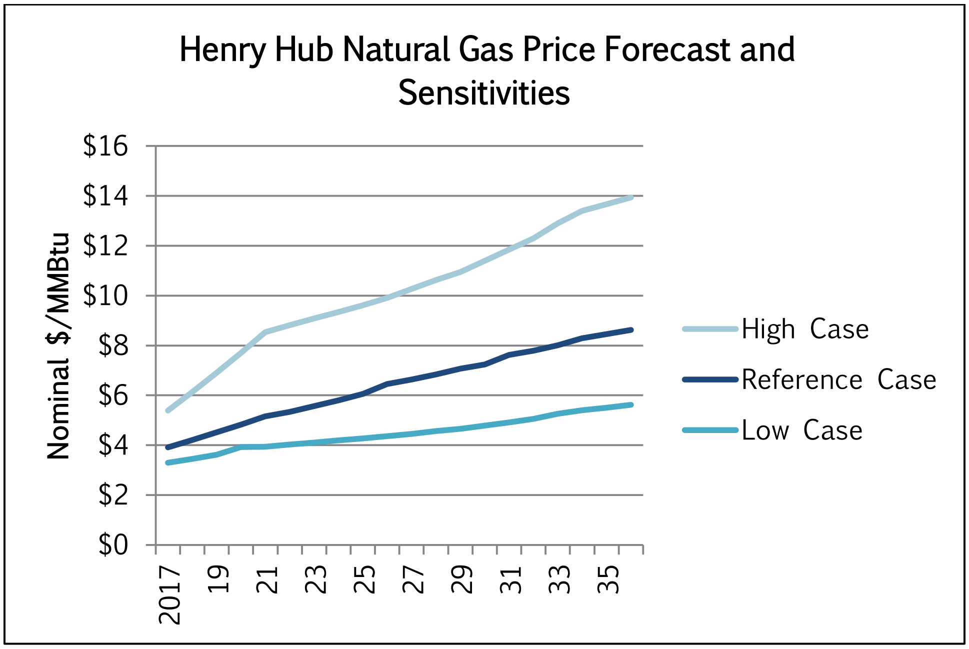
1.3 Natural Gas Price Forecast

The near-term portion of the natural gas price forecast (the first three years) is composed of NYMEX Henry Hub forward prices, which indicate market expectations of future prices. Because the NYMEX futures market becomes increasingly illiquid as the time horizon increases, NYMEX prices are not a reliable predictor of future prices in the long-term. Due to this uncertainty, the long term POV utilizes a consensus average of several expert consultant forecasts. The long term natural gas forecast used in the IRP also includes cases for high and low gas prices to support analysis across a range of future scenarios. To develop these cases, several consultant forecasts are utilized, as well as publicly available information, to determine long term price consensus. In levelized 2015 dollars per MMBtu through the IRP period (2017-2036), the reference case natural gas price forecast is $4.89, the low case is $3.50, and the high case is $7.68.

[10] Since the IRP modeling was completed, in October 2015, MISO has proposed to its stakeholders using a 50% capacity credit value for a new solar resource in its first year of operation, and actual output in the following years.
[11] Capacity factor for wind is representative of resource located in the Midwest geographical region.

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

FIGURE 5: NATURAL GAS PRICE FORECAST



1.4 Coal Price Forecasts

The Delivered to Entergy Coal Price Forecast is prepared in two parts. The first five years of the forecast are derived from inputs from EVA and internal forecasting groups. These inputs include existing purchased coal contracts, transportation rates, and inventory information, as well as EVA Spot Price Forecasts. In levelized 2015 dollars per mmBtu through the IRP period (2017-3036), the reference volume weighted delivered to EAI Coal Price is $2.43, the low case is $2.12, and the high case is $3.54. The low and high cases were provided by EVA; these cases were developed using EAI's Diesel Price Forecast to adjust transportation rates. The delivered coal price forecast for non-Entergy plants comes directly from the EVA Forecasts and prices vary by plant.

Described in more detail later in this section, each of the IRP Futures assumes different delivered coal price forecast sensitivity, as appropriate for the future world assumed in each case.

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1.5 Sales and Load Forecasts

Future customer peak load 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;
- The potential for technological change to affect the efficiency of electric 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. Peak loads may be higher or lower than projected levels. Similarly, industrial customer load factors may be higher or lower than currently projected. 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 2015 IRP, which forecasts are described below:

- The Reference Case load forecast assumes Industrial growth will spur load growth in the industrial class and additional commercial growth will come from the conversion of irrigation wells from diesel fuel to electricity.
- The Low Case load forecast assumes no commercial irrigation well conversions, delays in future industrial projects, and less incremental industrial load due to future projects, which has a spillover effect that dampens growth in the residential and commercial sectors.
- The High Case load forecast assumes a lower risk adjustment to future industrial projects, acceleration of future industrial projects, and greater incremental industrial load due to future projects.

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 a long-term, hour-by-hour load forecast. The

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MetrixND®[12] and the MetrixLT™[13] 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. Econometric models are used for forecasting residential, commercial, small industrial and governmental revenue class electricity (MWh) sales and customer counts on a monthly billed sales basis. EAI's largest industrial customers (the Large Industrial Segment) are forecasted and tracked individually by Account Managers.

Economic driver data used in the econometric models, both historical and forecasted were obtained from Moody's Analytics. The data includes both customized data for the EAI service region as well as national drivers for a wide variety of variables. 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 the historical time periods and normal cooling and heating degree days are used for the forecasted periods.

The econometric sales forecast for the residential class is derived from separate usage per customer ("UPC") 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 gross area economic output (similar to national gross domestic product) or real income, while customer count models are typically based on drivers such as population or 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 through time. These models are generally known as Statistically Adjusted End Use models. In addition, out of model adjustments are added or subtracted from the model outputs as warranted to reflect the impact of such items as company-sponsored DSM programs. Energy savings from company-sponsored DSM programs are

[12] MetrixND by Itron is an advanced statistics program for analysis and forecasting of time series data.

[13] MetrixLT™ by Itron is a specialized tool for developing medium and long run load shapes that are consistent with monthly sales and peak forecasts.

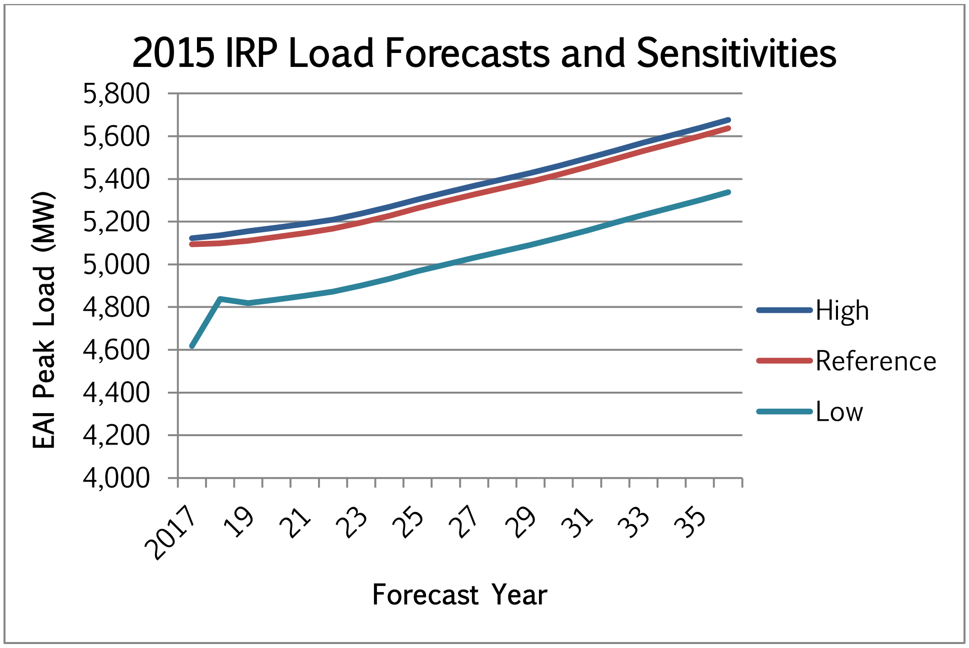
offset from the Sales Forecast. The load forecast uses the decremented energy forecast to develop annual peaks that reflect the savings from such programs

To develop the load forecast, the monthly Sales Forecast is allocated to each hour based on historical load shapes. Fifteen-year "typical weather" is used to convert historic load shapes into "typical load shapes." For example, if the actual sales for an EOC'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 2015/16 Planning Year, which is 2.1%.

Cogeneration loads are included in the Industrial revenue class and a separate peak is not developed for these customers as their loads can be irregular. Econometric models are used to develop the energy forecast for cogeneration loads which are then combined with both large and small industrial customers to create the Industrial energy forecast. Interruptions are in historical data that the forecast models use, but customer specific interruptions are not forecasted as the interruptions are irregular.

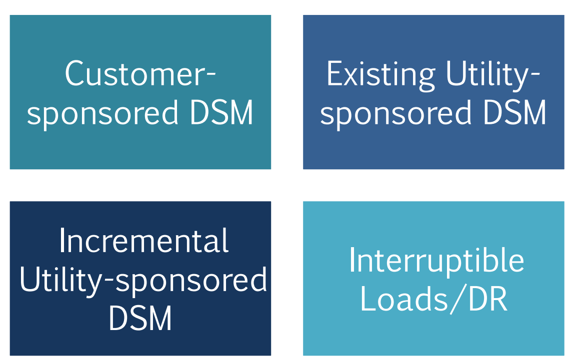
FIGURE 6: EAI LOAD FORECASTS



1.6 Economic Outlook

The economic outlook for the EAI service territory remains healthy. At the time of the development of the 2015 IRP load forecasts, the 2014-24 compound annual growth rate for gross state product was 1.8%.[14] As of September 2015, the compound annual growth rate for the same period (2014-24) had increased to greater than 2.0%.[15] However, federal EE standards, particularly those related to lighting, refrigeration and furnaces will continue to put downward pressure on usage per customer, primarily in the residential and commercial sectors. Also, as discussed in the following section, the success of EAI's EE programs are assumed to continue, which are expected to further dampen energy and peak demands.

1.7 Demand-Side Management



EAI considers DSM to be a valuable resource when implemented in a cost effective manner compared to supply-side resources and the 2015 IRP reflects a strong commitment to DSM resources. In long-term resource planning, EAI evaluates DSM resource options

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[14] Moody's Analytics forecast of EAI service territory, April 2014
[15] IHS forecast of EAI service territory, September 2015

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in four categories. DSM planning includes EE, DR, and interruptible loads. Each category is described below.

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 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 EE Portfolio, which consists of generally large scale, regulator-approved programs that provide incentives to customers to go above and beyond EE standards. The comprehensive EE Portfolio is reviewed and approved by the Commission and developed in attempt to meet Commission's utility EE targets, which are currently set at 0.9% of retail sales (excluding industrial opt-out).

Existing DSM programs are included in the Sales Forecast described earlier in this section. The MW and MWh savings achieved by the existing DSM programs for the 2014 Program Year can be found in EAI's Arkansas Energy Efficiency Program Portfolio Annual Report filed April 1, 2015, in Docket No. 07-085-TF.

Incremental Utility-sponsored DSM

Beyond the existing DSM programs, the 2015 IRP assumes EAI continues to grow its EE Portfolio at an incremental level of 0.9% of retail sales per year, which is approximately 165 GWh of additional savings per year at the customers' meter.

This assumption is based on several factors. The 2015 IRP incremental Utility-sponsored EE assumption:

- results in a forecasted level of EE between the Reference and High cases in the 2012 DSM Potential Study, which assumed a higher fuel cost than the 2015 IRP;
- is based on the historical achievement of EE in a fuel cost environment that is at or lower than the 2015 IRP and with a greater number of Self Direct customers than assumed in the 2012 IRP;

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- is consistent with a perceived desire of state policy makers to moderate the cost of EE on the customer's utility bills; and
- is based on the belief that the EE market that has been built up over the last 7 years will be sustainable in the foreseeable future.

Of course, there are uncertainties regarding the incremental Utility-sponsored EE assumption. These uncertainties become important when considering the planning assumption of 0.9% of retails sales versus the Arkansas Energy Efficiency Potential Study, [16] which indicates lower achievable potential for EE in Arkansas. Those uncertainties include:

1. DSM and DR technology innovation and market adoption,
2. Future avoided cost projections could change significantly in future years and thus changing the cost-effectiveness and quantity of DSM and DR,
3. The speed of the Arkansas market's adoption of building and technology standards,
4. Measure assumptions (e.g. the 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 advanced metering infrastructure ("AMI") or "smart grid" technology. EAI continues to believe that

[16] The Study can be found within APSC Docket No. 13-002-U, web address http://www.apscservices.info/EFilings/Docket_Search_Documents.asp?Docket=13-002-U&DocNumVal=222

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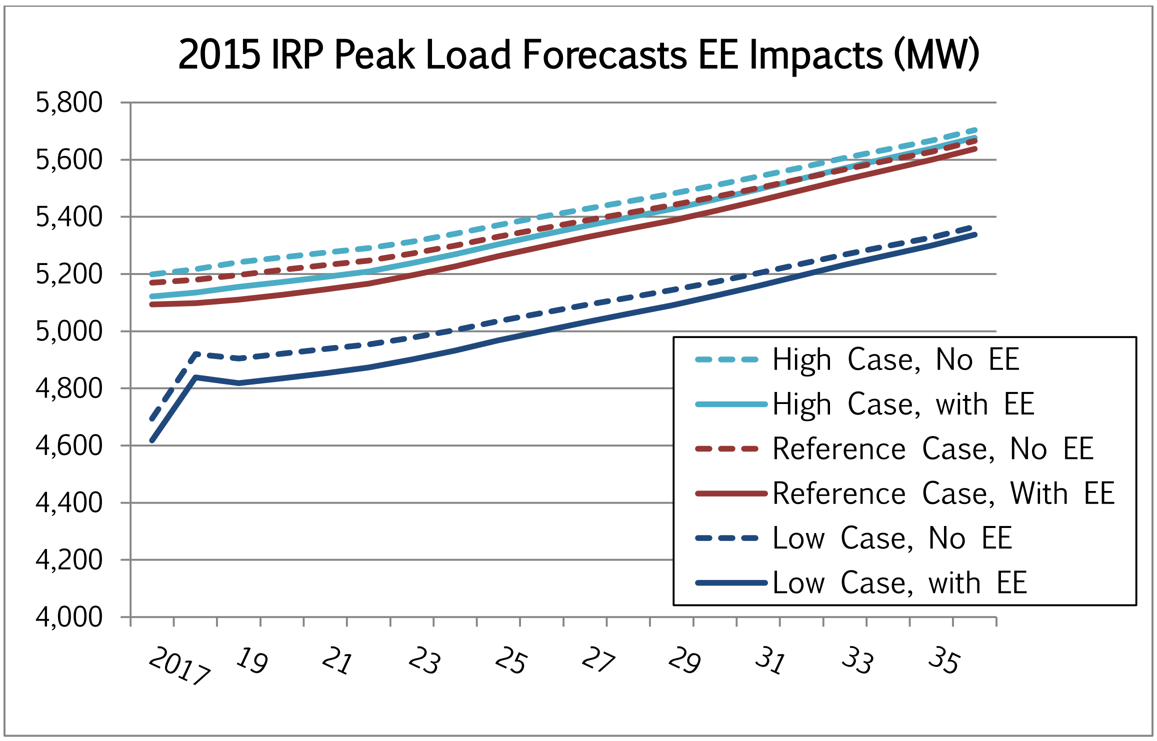
AMI may provide opportunities to enhance EAI's EE Portfolio of programs or measures available to its customers. At this point, AMI investment continues to be analyzed, but adoption of this technology in EAI's service area could increase the programs and measures that can be implemented in Arkansas in a cost-effective manner.

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 impacts of customer-sponsored, existing EAI-sponsored and incremental EAI-sponsored EE programs to EAI's peak load forecasts. The 2015 IRP only utilizes the load forecast sensitivities that include the impacts of EE.

FIGURE 7: LOAD FORECAST EE IMPACTS



Interruptible Loads (including Demand Response)

EAI currently offers two DR programs through its EE Portfolio, Agricultural Irrigation Load Control ("AILC") and Direct Load Control ("DLC"), as well as the Optional Interruptible Service Rider ("OISR"). These programs either allow EAI to 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 2015 IRP analysis, as opposed to including as an offset a decrement to the Sales Forecast. In 2015, the interruptible loads provide 99 MW of capacity savings. The assumption grows to 206 MW by the first year of the IRP study period (2017) based upon the addition of a new customer taking interruptible service pursuant to a Commission-approved contract.

2. Modeling Framework

2.1 Futures-based Approach

In order to reasonably account for a broad range of uncertainty, the 2015 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.

Future 1 – Reference Case

Future 1 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, as shown in Figure 5, and delivered coal prices are assumed at the reference case levels. The Reference Case price for CO_2 is also assumed, which begins in 2020. The Reference Peak Load Forecast is assumed in Future 1.

For EAI's existing units, the CCGT units are assumed to have a 30-year useful life and the coal units are assumed to have scrubber technology installed and continue to use coal through the end of a 60-year useful life, which is beyond the 2015 IRP study period.

TABLE 8: FUTURE 1 ASSUMPTIONS

Future 1 Key Assumptions (prices shown are 2015$, levelized for the period 2017-36)

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White Bluff and Independence	- Assume the currently proposed Regional Haze FIP - Install scrubbers in 2021 - Continue to use coal through end of 60-year useful life
CCGT Units	Assume 30-year useful life
Electric Sales & Load Forecasts	Reference Case
Henry Hub Natural Gas Price Forecast	$4.89/MMBtu
Coal Price Forecast	$2.46/MMBtu (volume weighted average for EAI units)
CO_2 Price Forecast	$10.02/short ton; pricing begins in 2020

Future 2 – Low Supply Additions Case

Future 2 represents a future world in which the need and economics for new supply additions are depressed. In this future, natural gas, as shown above in Figure 5, and delivered coal prices are assumed at the low case levels. The Low Case for CO_2 does not assume any price for CO_2 emissions over the entire study period. The Low Load Forecast is assumed in Future 2, which lowers EAI's need for future supply additions.

For EAI's existing units, the CCGT units are assumed to be available and operating beyond a 30-year useful life and at least through the end of the IRP study period. Also, similar to Future 1, the coal units are assumed to have scrubber technology installed and continue to use coal through the end of a 60-year useful life, which is also beyond the 2015 IRP study period.

TABLE 9: FUTURE 2 ASSUMPTIONS

Future 2 Key Assumptions (prices shown are 2015$, levelized for the period 2017-36)

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White Bluff and Independence	- Assume the currently proposed Regional Haze FIP - Install scrubbers in 2021 - Continue to use coal through end of 60-year useful life
CCGT Units	Assume CCGTs are available and operating through the end of the IRP study period
Electric Sales & Load Forecasts	Low Case
Henry Hub Natural Gas Price Forecast	\$3.50/MMBtu
Coal Price Forecast	\$2.20/MMBtu (volume weighted average for EAI units)
CO_2 Price Forecast	No price for CO_2 throughout IRP study period

Future 3 – High Supply Additions Case

Future 3 represents a future world in which the need and economics for new supply additions are enhanced. In this future, natural gas and delivered coal prices are assumed at the high case levels. The High Case price for CO_2 is also assumed, which begins in 2020 like in Future 1, but at a higher price. The High Load Forecast is assumed in Future 3, which increases EAI's need for future supply additions.

For EAI's existing units, the CCGT units are assumed to have a 30-year useful life. The White Bluff coal plant is assumed to cease using coal beginning in 2028, which makes scrubber installation economically unsupportable under federal air regulations, and thus not required. The Independence coal plant is assumed to cease using coal in 2035, which assumes the final Regional Haze FIP does not require scrubber installation at Independence, but that similar controls are required in a later Regional Haze planning period (2028-38).

TABLE 10: FUTURE 3 ASSUMPTIONS

Future 3 Key Assumptions (prices shown are 2015\$, levelized for the period 2017-36)	

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White Bluff and Independence	Approval of plans to cease using coal at White Bluff by a time certain (2028) that makes scrubber installation economically unsupportable under federal air regulations, and thus not required. Final FIP does not require Independence scrubber installation; assumption that similar controls are required in later Regional Haze planning period (2028-38)
CCGT Units	Assume 30-year useful life
Electric Sales & Load Forecasts	High Case
Henry Hub Natural Gas Price Forecast	$7.68/MMBtu
Coal Price Forecast	$3.67/MMBtu (volume weighted average for EAI units)
CO_2 Price Forecast	$29.68/short ton; pricing begins in 2020

The table below summarizes the assumptions for each future.

TABLE 11: SUMMARY OF ASSUMPTIONS FOR ALL FUTURES

	Future 1 Reference Case	Future 2 Low Case	Future 3 High Case
Existing Resource Portfolio			
Cease to Use Coal at White Bluff	2042	2042	2028
Cease to Use Coal at Independence	2044	2044	2035
Existing CCGTs Useful Life	30 years	Through 2036	30 years
Customer Electricity Requirements			
Energy sales and Load	Reference	Low	High
Commodity Price Forecasts			
Fuel Prices (Natural Gas, Coal)	Reference	Low	High
Environmental Allowances (CO_2)	Reference	Low	High

2.2 Market Modeling

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The development of the 2015 IRP relied on the AURORAxmp Electric Market Model ("AURORA") to simulate market operations, produce a long-term forecast of the revenues and cost of energy procurement and optimizes supply additions under various possible futures.

AURORA is a production cost model and resource capacity expansion optimization tool that uses projected market economics to determine the optimal long-term resource portfolio under varying future conditions including fuel prices, available generation technologies, environmental constraints and future demand forecasts. AURORA's optimization process identifies the set of resources among existing and potential future resources with the highest and lowest market values to produce economically consistent capacity expansion and retirement schedules. AURORA estimates price and dispatch using hourly demands and individual resource-operating characteristics in a transmission-constrained, chronological dispatch algorithm. New resource alternatives are chosen based on the net present value (NPV) of hourly market values. Those values are compared to existing resources in an iterative process to optimize the new set of units.

The first step in the IRP modeling process was to model the overall market under each future world. The scope of the markets modeled in this step is shown in Appendix C.

2.3 EAI Portfolio Optimization

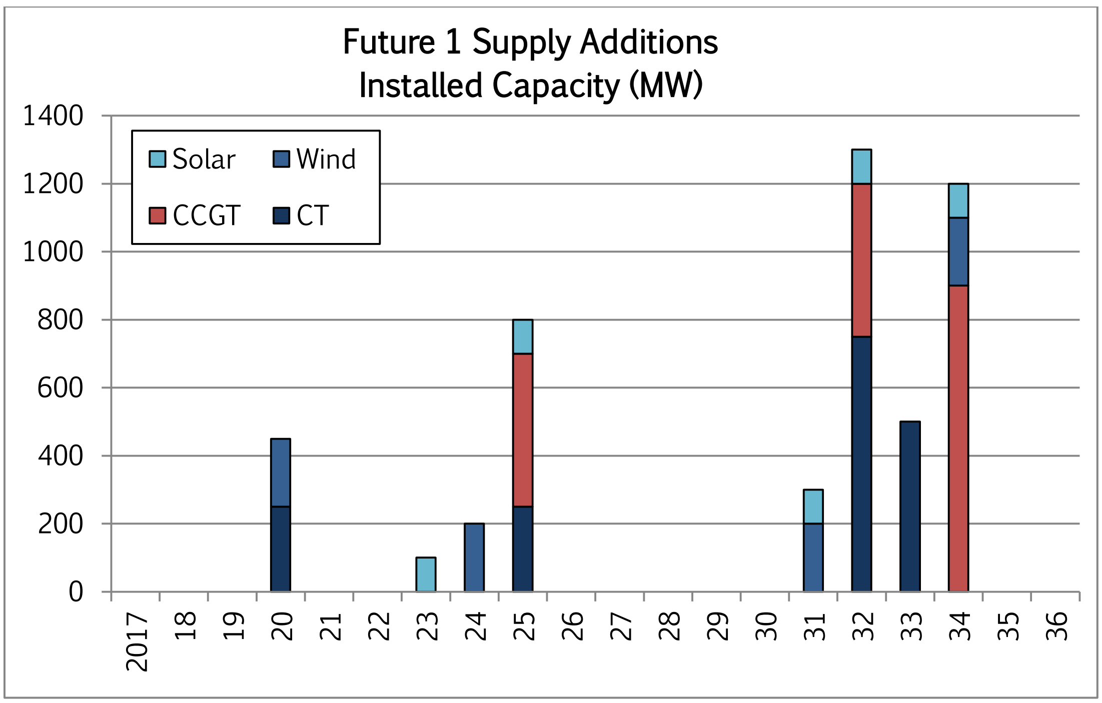
The next step is to utilize AURORA's optimization process to build out EAI's future capacity needs. AURORA estimates price and dispatch using hourly demands and individual resource operating characteristics in a transmission-constrained, chronological dispatch algorithm. For example, the hourly shape of energy production from a solar plant is accounted for in the hourly dispatch. Each of the three futures was modeled in AURORA and each utilized the capacity expansion portfolio optimization tool. The AURORA model determined the timing, amount, type and location of each capacity addition as needed to meet EAI's reliability requirements (target planning reserve margin requirements). Additional resources were added if market price levels were sufficiently high to make an investment in incremental capacity economically attractive. This step resulted in a 20-year capacity expansion build-out plan which is economically optimized to meet the forecasted demand under each future scenario.

3. Study Results

Future 1 Results

A total of 4,850 MW of installed capacity is added to EAI's portfolio in Future 1. On an effective capacity basis, which accounts for the intermittency of solar and wind resources[17], the total capacity addition is 3,793 MW. The first capacity is added in 2020 and is comprised of one CT and one wind resource. Overall, 73% of the supply additions are CT and CCGT resources while the remaining 27% are from wind and solar resources. The total relevant supply cost[18] for the Future 1 optimized portfolio is $10,681 million (2017-36 present value, 2015$).

FIGURE 8: FUTURE 1 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 1

[17] Effective capacity for solar resources is 25% of installed capacity and for wind resources is 14.7% of installed capacity.

[18] 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.

portfolio. The energy mix shown includes energy used to meet native load needs and sales to the market.

FIGURE 9: FUTURE 1 CAPACITY MIX

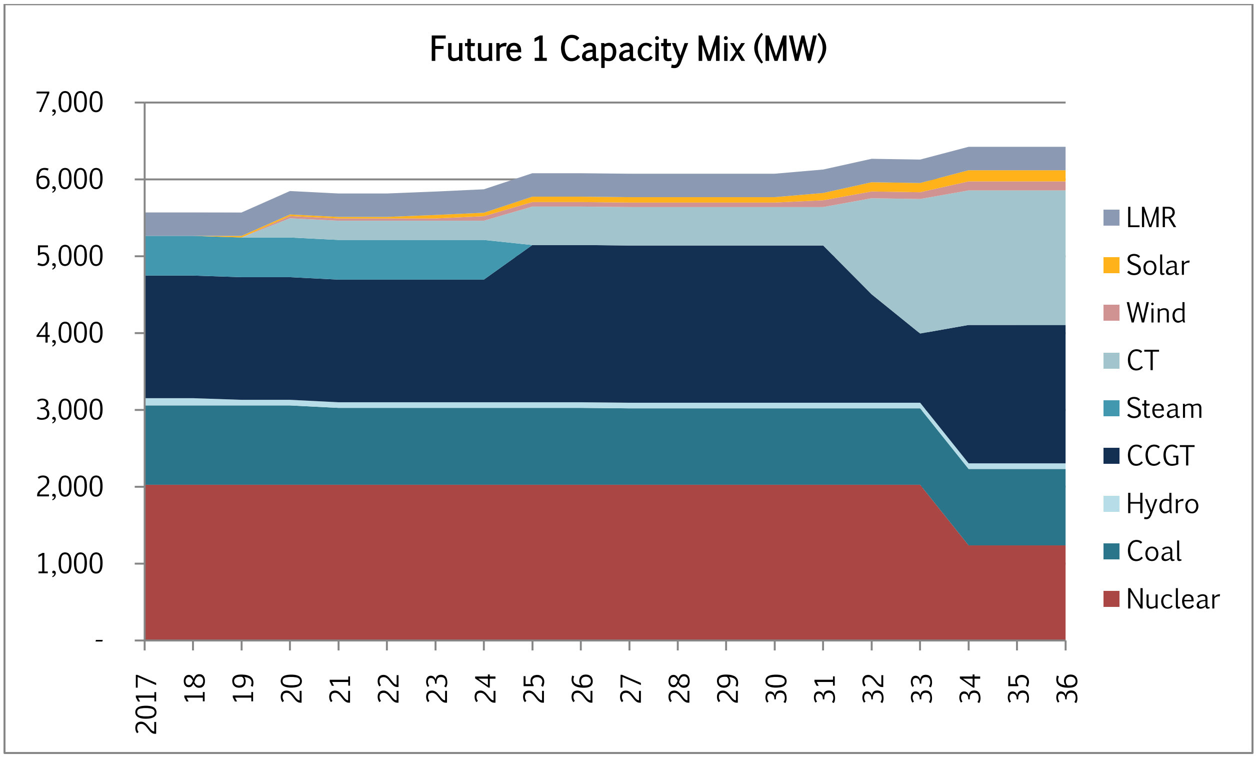
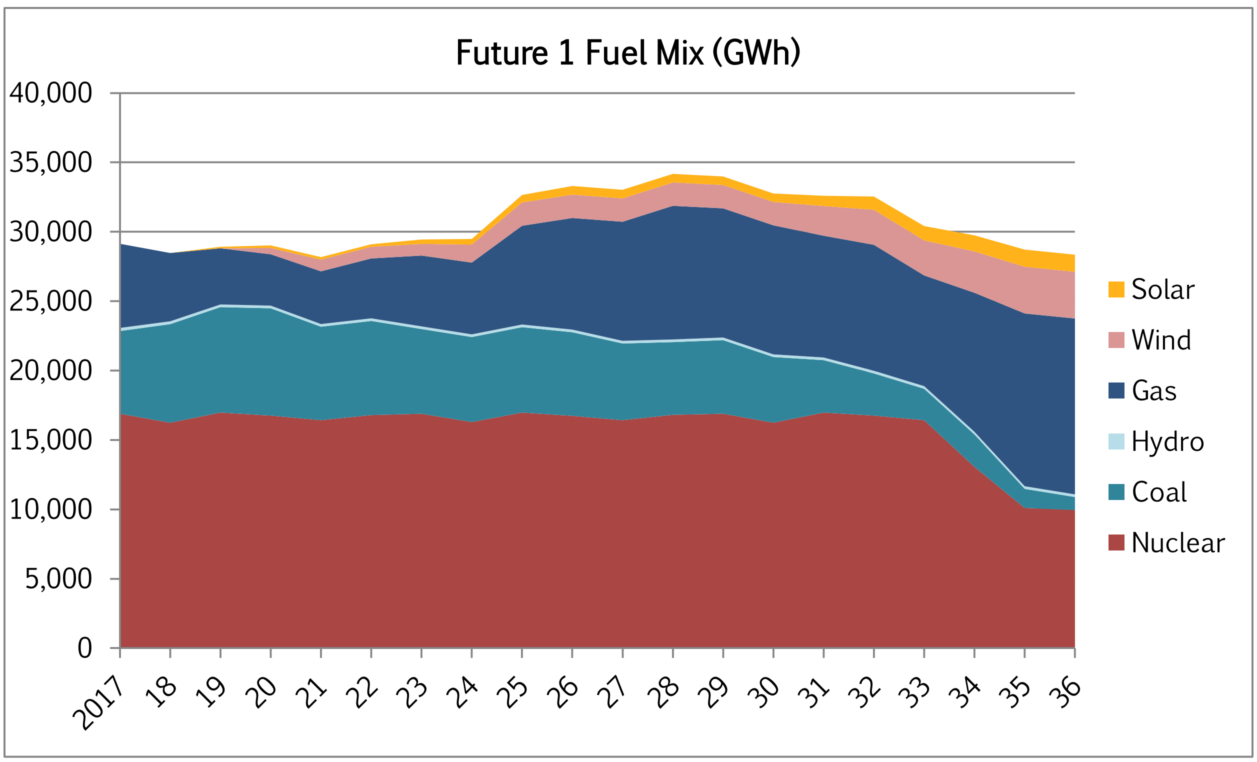


FIGURE 10: FUTURE 1 ENERGY MIX



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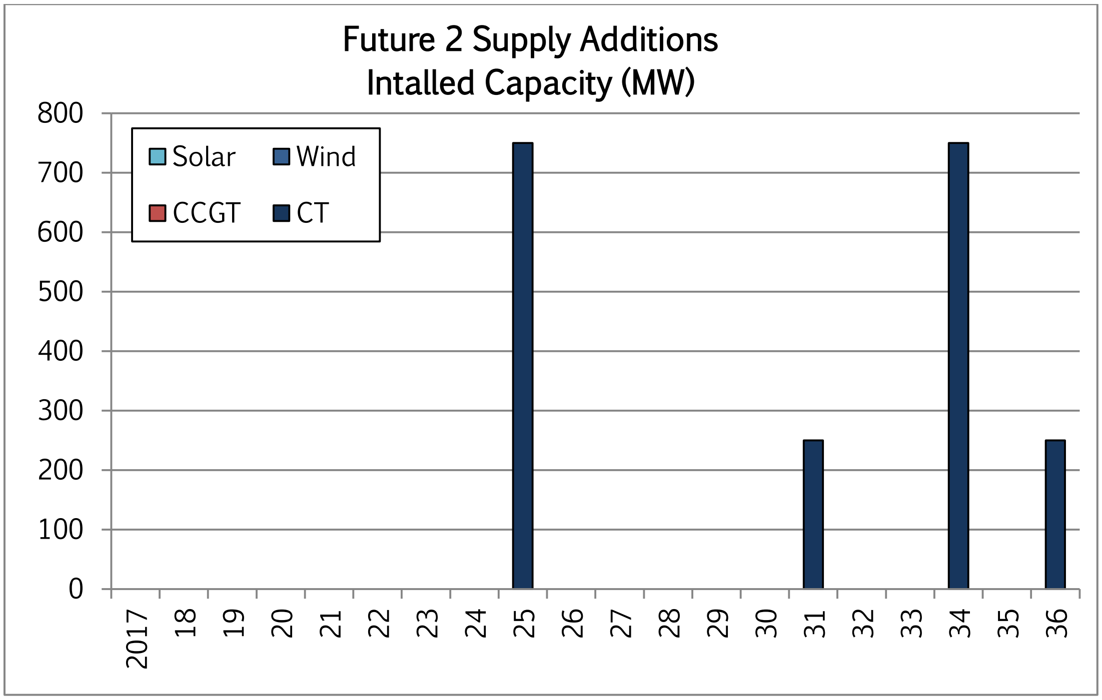
Future 2 Results

A total of 2,000 MW of installed capacity is added to EAI's portfolio in Future 2. Only CT resources were selected in the Future 2 optimized portfolio with the first additions taking place in 2025. The total relevant supply cost for the Future 2 optimized portfolio is approximately 33% lower than Future 1.

FIGURE 11: FUTURE 2 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 1 portfolio. The energy mix shown includes energy used to meet native load needs and sales to the market.

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FIGURE 12: FUTURE 2 CAPACITY MIX

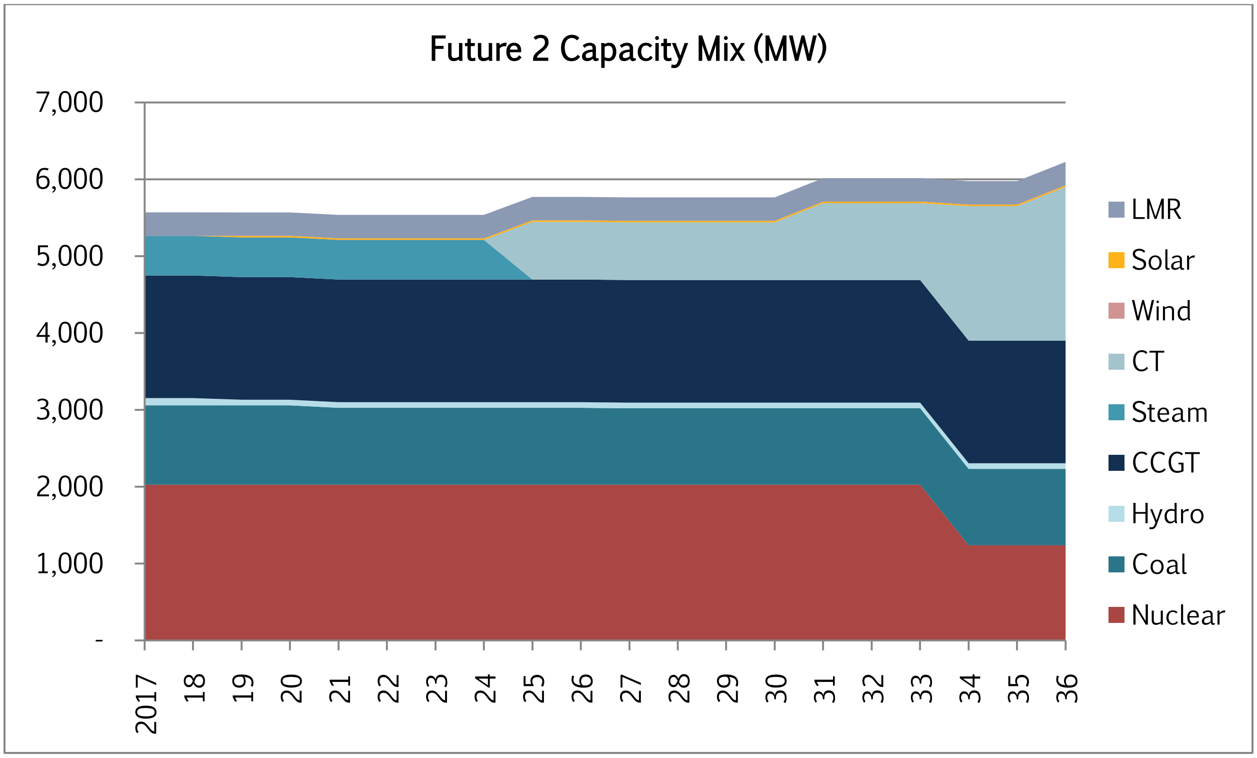
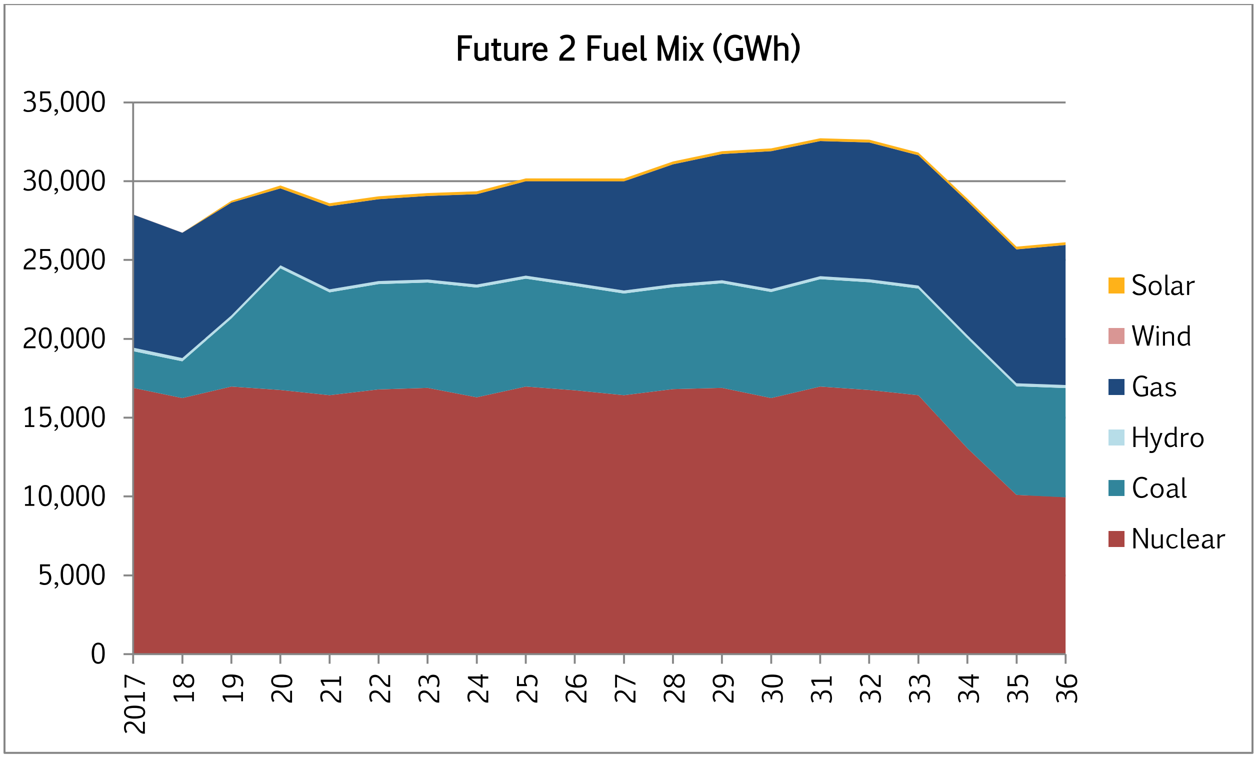


FIGURE 13: FUTURE 2 ENERGY MIX



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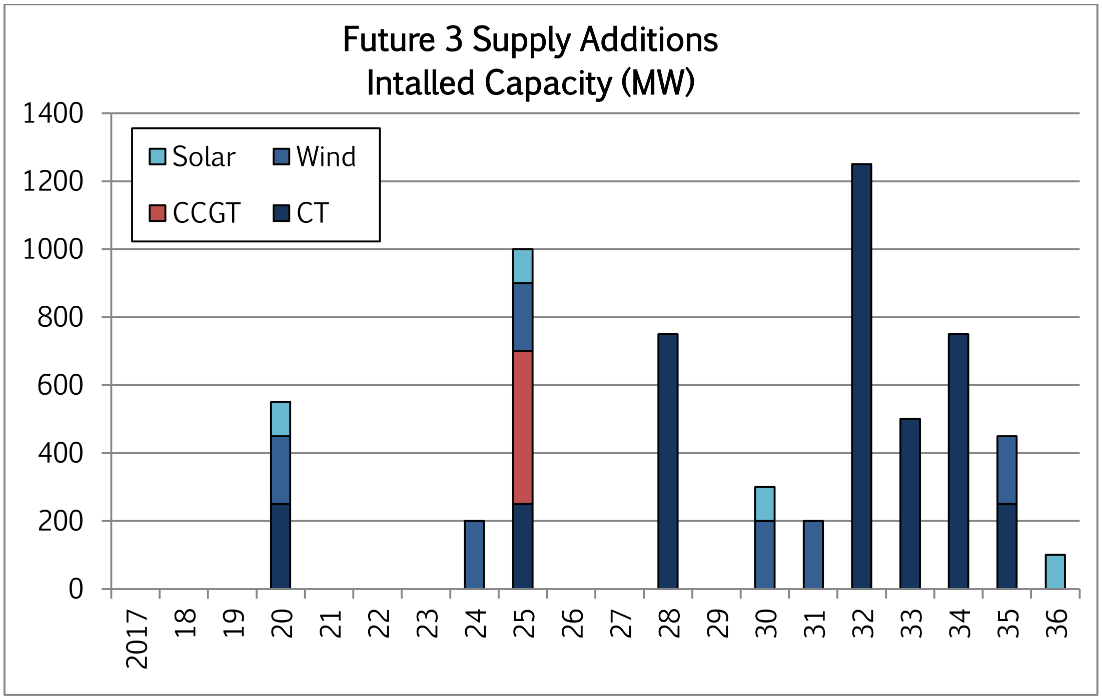
Future 3 Results

A total of 6,050 MW of installed capacity is added to EAI's portfolio in Future 3. On an effective capacity basis, the total capacity addition is 4,726 MW. The first capacity is added in 2020 and is comprised of one CT, one wind resource and one solar resource. Similar to Future 1, overall, 73% of the supply additions are CT and CCGT resources while the remaining 27% are from wind and solar resources. The total relevant supply cost for the Future 3 optimized portfolio is approximately 27% higher than Future 1.

FIGURE 14: FUTURE 3 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 1 portfolio. The energy mix shown includes energy used to meet native load needs and sales to the market.

FIGURE 15: FUTURE 3 CAPACITY MIX

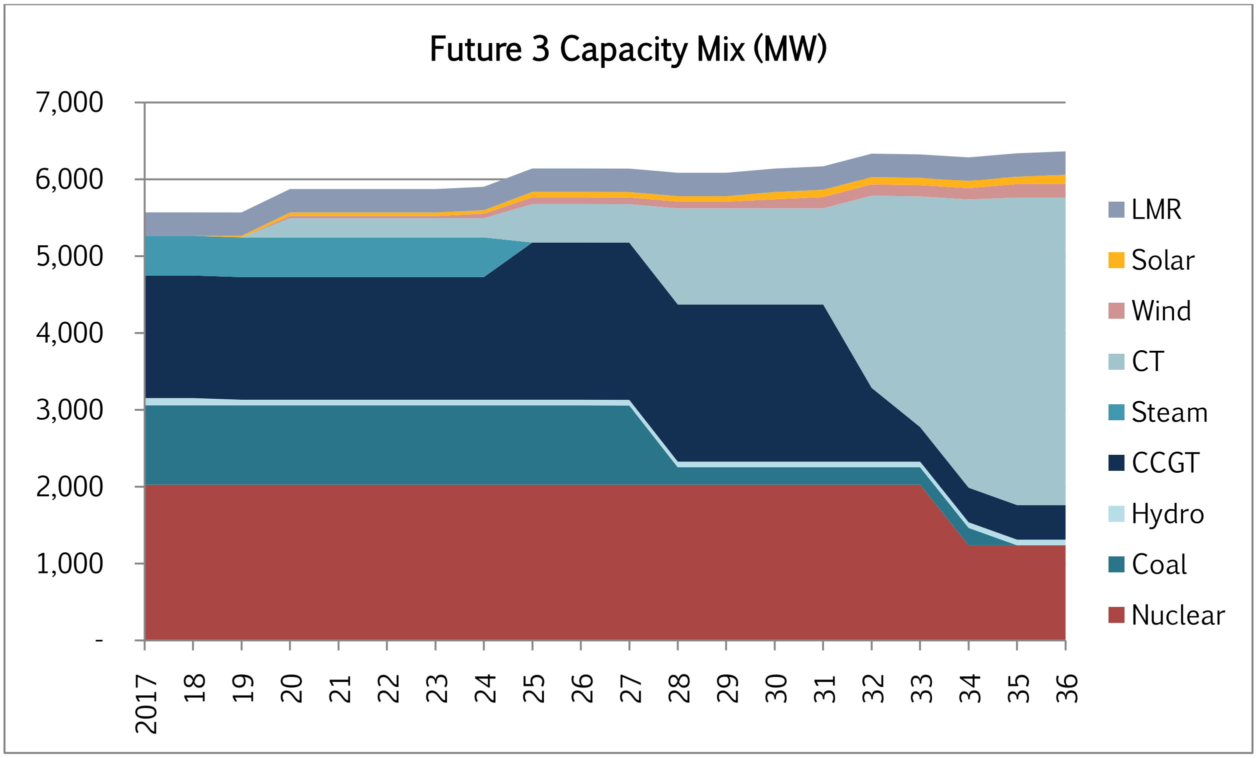
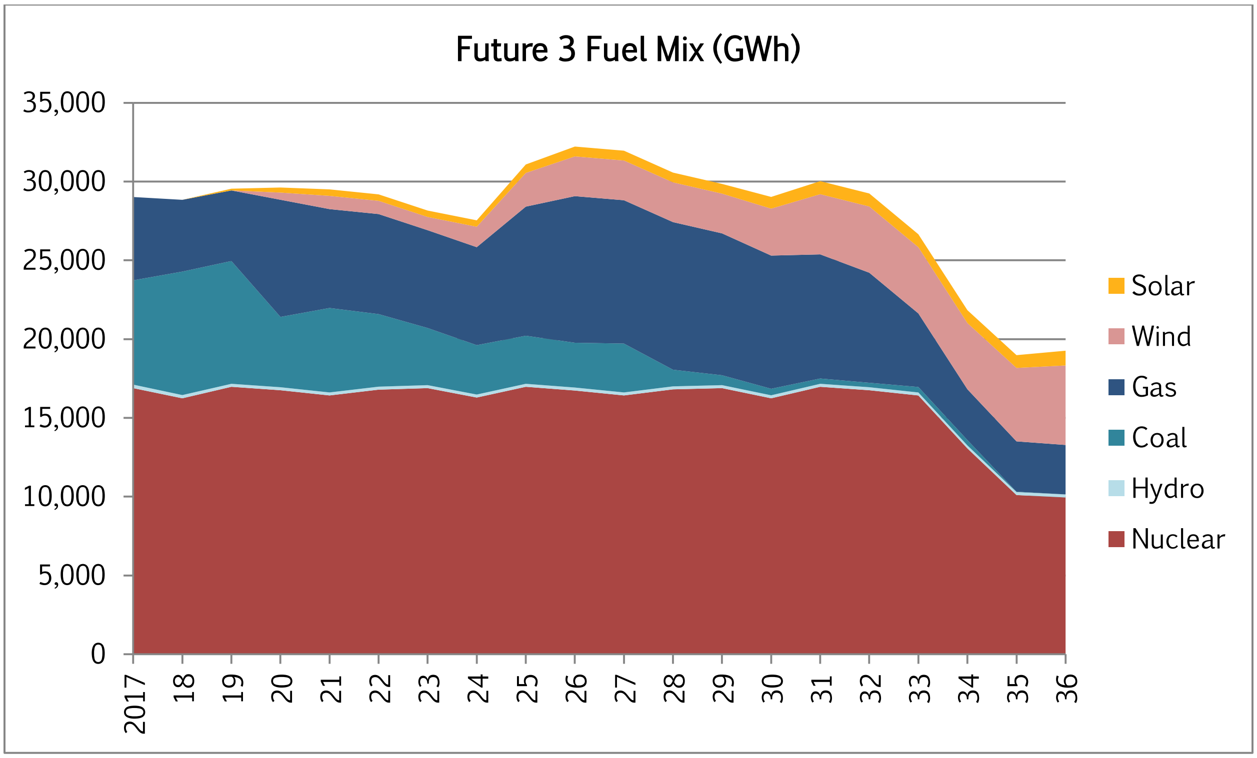


FIGURE 16: FUTURE 3 ENERGY MIX



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Summary of Findings

As discussed above, the AURORA Portfolio Optimization process resulted in three distinct resource portfolios, each of which are economically optimal for the respective futures. When reviewing the results of those three 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 12: SUMMARY OF MODELING RESULTS

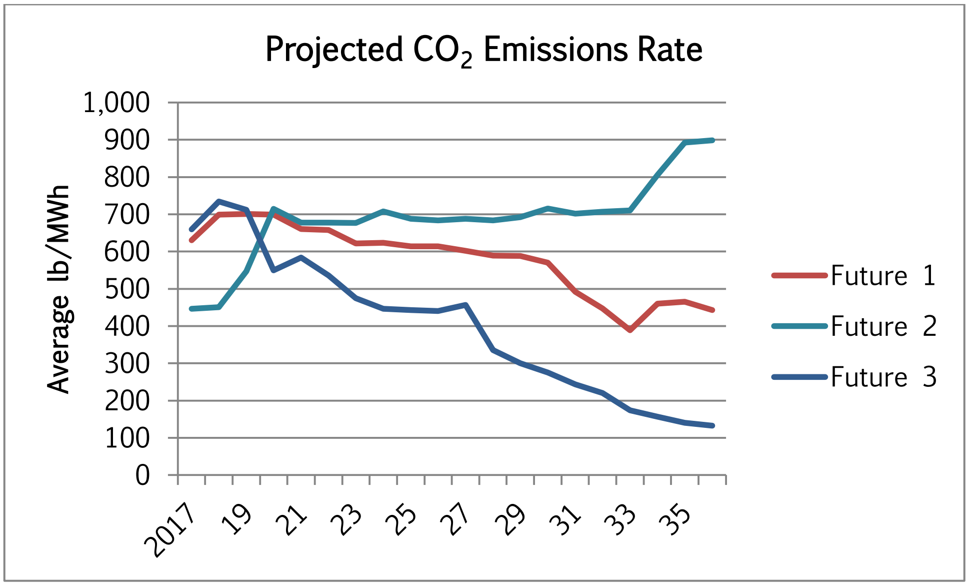
2017-36 Results	Future 1	Future 2	Future 3
Total Incremental Installed Capacity	4,850 MW	2,000 MW	6,050 MW
CT & CCGT Capacity Additions	73.2%	100%	73.6%
Renewable Capacity Additions	26.8%	0%	26.4%
Incremental Capacity Additions Begin	2020	2025	2020
Load + Reserve Target in First Year of Capacity Addition	5,743 MW (2020)	5,564 MW (2025)	5,793 MW (2020)

The optimal portfolio is consistent across the futures. Future 3 adds much more capacity overall than Future 1, but the fuel mix is similar. By the 20th year of the study horizon, the fuel mix between each future's optimal portfolio with the primary difference being the existing coal capacity that persists through the end of Future 1 is replaced by gas-fired capacity in Future 3.

Renewables are not cost-effective in Future 2. One possible reason is that there is no cost charged to CO_2 emissions in Future 2, whereas Futures 1 and 3 each have a nonzero CO_2. Also, Future 2 has a smaller capacity need, as well as lower fuel costs than assumed in the other futures.

Projected Emissions Given the uncertainty around the future regulation of CO_2 emissions discussed in earlier sections of this report, another key output of the 2015 IRP modeling is the projected CO_2 emissions. Figure 18 below shows the projected CO_2 emissions for each optimized future portfolio, which includes EAI's existing resources and the supply additions optimized by the AURORA model.[19]

FIGURE 18: PROJECTED CO_2 EMISSIONS BY FUTURE



[19] Figures shown include emissions from all of EAI's existing generating resources which are physically located in the states of Arkansas, Louisiana (Ouachita) and Mississippi (Grand Gulf) and the supply additions optimized by the AURORAxmp model.

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IV. STAKEHOLDER ENGAGEMENT PROCESS

Per the APSC Resource Planning Guidelines,[20] 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 the service area.

For the 2015 IRP, the Stakeholder Engagement Process began in July 2015 with distribution of a lengthy slide presentation describing proposed assumptions, inputs and modeling framework. The materials, while still preliminary, were posted to EAI's IRP website on July 16, 2015.

The first meeting was an in-person meeting hosted by EAI at the MISO South building in Little Rock on August 7, 2015. During the August 7 meeting, presentations were given by several Entergy representatives covering a broad range of inputs and modeling results for the IRP. EAI received questions and feedback during the meeting and EAI posted the responses to EAI's IRP website on August 14. Also, during the August 7 meeting, the stakeholders organized into a Stakeholder Group and scheduled a follow-up conference call. The Stakeholder Engagement Process continued through mid-October.

At the request of the Stakeholder Group, EAI representatives participated in three conference calls which took place in August and September. During these conference calls, as well as via a written requested submitted to EAI on August 13, EAI received additional questions, feedback and requests for additional analysis. The materials provided to the Stakeholder Group in responses to the requests are attached in Appendix D.

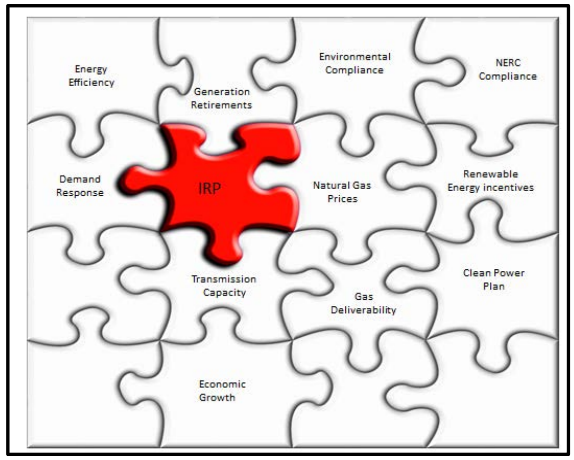
As part of EAI's efforts to facilitate the stakeholders and their role in the IRP development process, EAI completed three additional AURORA portfolio optimization model runs. The model runs were constructed to respond to the Stakeholder Group's feedback on the installed cost of solar and wind resources, as well as requests to look at alternatives for the future of EAI's existing coal units. The additional analyses are not part of EAI's 2015 IRP but rather were provided in response to requests from the Stakeholder Group. The results of the first two model runs were provided to the Stakeholder Group on September 3 and the results of the third model run were provided on September 25. The results of these additional analyses are available in

[20] Docket No. 06-028-R, Order No. 6, Attachment 1

Appendix D. On October 16, 2015, EAI representatives met face to face with the stakeholders so that stakeholder could present their findings and EAI could provide responses.

V. Action Plan

Action Plan Summary



Based on the work conducted as part of the IRP analysis, it is reasonable to conclude that EAI's supply-side resource additions will likely consist of natural gas fired resources and renewable energy resources. How much total supply-side capacity will be needed and exactly when that capacity will be needed is uncertain. There is even more uncertainty associated with exactly how much of each supply-side technology should be added to EAI's fleet. Because of that uncertainty, 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 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.

2015 IRP Action Plan

1. Coal Environmental Compliance	The challenge utilities face with regards to environmental compliance is unprecedented in terms of the numbers of rules coming affecting utilities simultaneously, the compressed time frame for compliance, and the continuing ratcheting down of compliance obligations. Key uncertainties include the requirements related to Regional Haze, ozone standards, 1 hour SO_2 standards, effluent limitation guidelines, among others, the outcome of current litigation, congressional activity and the possibility of extensions of the compliance deadlines. Another key uncertainty is the nation's long-term carbon policy and the recently issued final Clean Power Plan discussed herein. 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 at the state and federal level and evaluate options for environmental compliance for the EAI coal units.

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2. Clean Power Plan	EAI will participate in the Arkansas CPP stakeholder process sponsored by the APSC and the Arkansas Department of Environmental Quality. EAI also continues to analyze the long and complex EPA final rule in order to assess various compliance options open to the State if the rule survives litigation. EAI currently believes the State should engage in the CPP state implementation plan process in the interim at least to the extent of filing the basic initial document required in September 2016 and, at that time, seeking two-year final plan extension allowed under the rule. EAI assumes that Arkansas will continue its litigation against the rule and sees the planning process as an addition to, and not in conflict with, the State's litigation position.
3. Complete the Acquisition of Power Block 2 from the Union Power Plant	Assuming required regulatory approvals are received, the acquisition is of Power Block 2 of the Union Power Plant is expected to be completed in late 2015 or early 2016.
4. 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. Further EAI will monitor and utilize DSM to meet the requirements within the final CPP if appropriate. Finally, EAI is committed to update the IRP in 2018 and will include an update to the future outlook for DSM as well.
5. 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 2016 for both short term and long-term resources. However, the exact scope and timing of the next EAI RFP is uncertain and is dependent on many factors that have been discussed throughout this report. In addition to market solicitation, EAI will be considering developing self-build proposals for certain supply side technologies.
6. Stakeholder Engagement Process	Stakeholder engagement has been extremely positive and helpful throughout 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.

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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

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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	597	100%	597	2002
Independence Unit 1	839	31.5%	228	1983
Lake Catherine Unit 4	516	100%	516	1970
Ouachita Unit 1	247	100%	247	2002
Ouachita Unit 2	241	100%	241	2002
Remmel Units 1, 2 & 3	12	100%	12	1925
White Bluff Unit 1	815	57.0%	400	1980
White Bluff Unit 2	822	57.0%	404	1981

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Purchased Generation	Total Installed Capacity (MW)	Retail Capacity (MW)	Commercial Operations Date
Blakely	86	11	1956
DeGray	78	10	1972
Grand Gulf	1,409	307	1985
Union Power	499	499	2003

Notes:
- The Blakely and DeGray capacity is assumed through 5/31/2019.
- The Grand Gulf capacity is assumed throughout the IRP study horizon.
- The Union Power PPA ends 5/31/2017, but EAI's acquisition of one power block is currently pending regulatory approval and would replace the PPA upon acquisition (see p. 18).

Demand-side Resources	Reduction during Peak Load Hours (MW)
Demand Response	30
Interruptible Load	74
Energy Efficiency	36

Notes:
- Estimates above are total 2015 reductions.
- EAI's demand response includes Residential Direct Load Control and Agricultural Irrigation Load Control programs.
- Demand Response and Interruptible capacity is increased to account for reserve margin and line loss value in the Load and Capability analysis.

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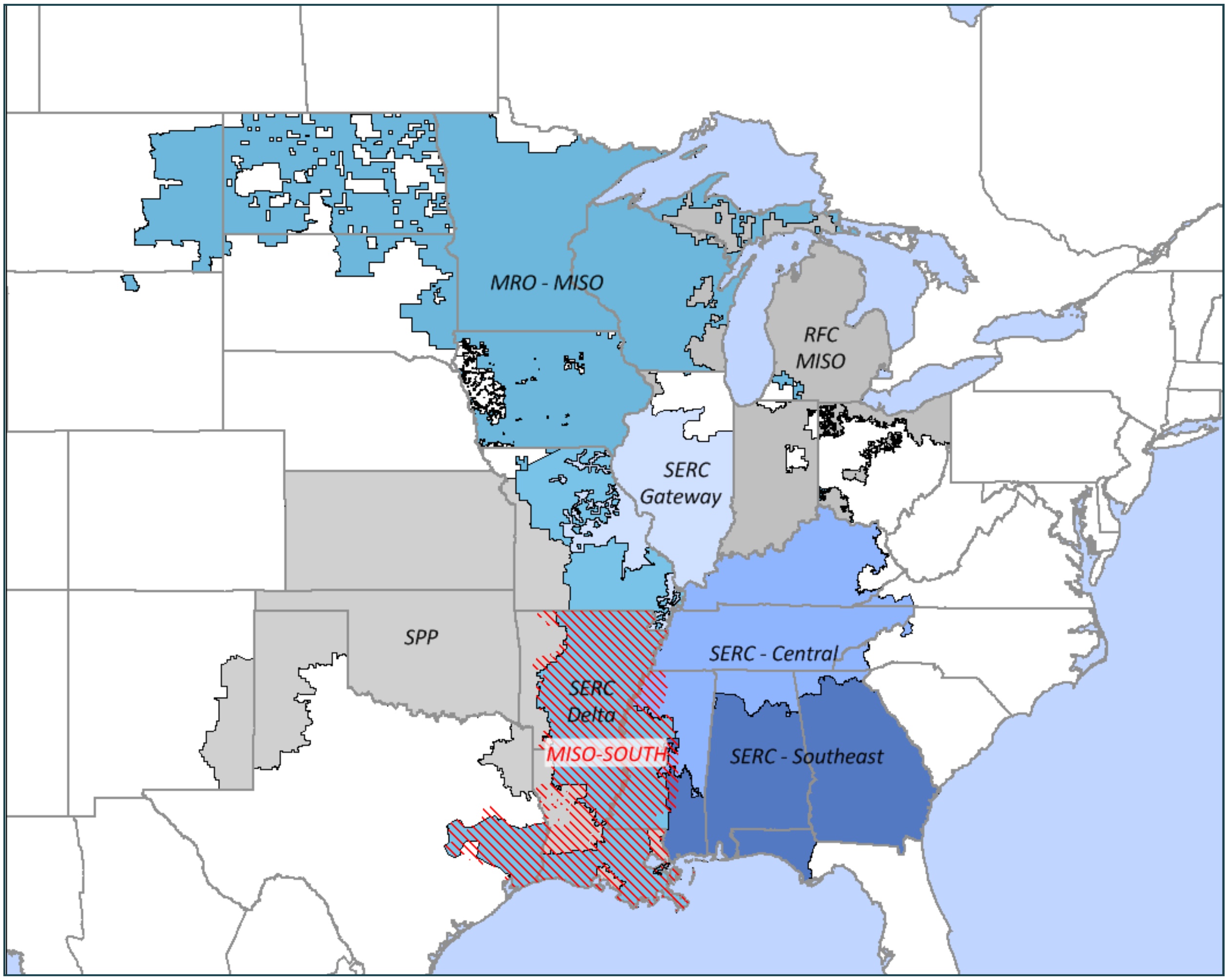
APPENDIX C

SCOPE OF AURORAxmp MARKET MODEL



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Appendix D

Stakeholder Meeting Materials

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Entergy

THE POWER OF PEOPLE®

Entergy Arkansas, Inc.
2015 Integrated Resource Plan

Compiled Presentation Materials

Contents

Per request from the Stakeholder Group, this document is a compilation of all materials that have been presented to the Stakeholder Group and posted to the IRP website so far during EAI's IRP process. This document contains the following materials:

- Preliminary IRP Materials (July 15)
- Stakeholder Meeting Presentation (August 6)
- Follow-up Materials to Stakeholder Meeting (August 14)
- Response to Stakeholder Group Questions (September 3)
- Second Response to Stakeholder Group Questions (September 16)

Entergy

THE POWER OF PEOPLE®

Entergy Arkansas, Inc.
2015 Integrated Resource Plan

July 15, 2015

Preliminary Materials for IRP Stakeholder Meeting

Preliminary | Work in progress

2015 EAI Integrated Resource Plan

Consistent with Section 6.1 of Attachment 1 to the APSC Order No. 6 in Docket No. 06-028-R Resource Planning Guidelines for Electric Utilities, EAI is beginning development of its next Integrated Resource Plan to be filed at the Commission no later than three years from the prior IRP submission, which is October 31, 2015.

The information contained in this presentation is part of the development of the 2015 EAI Integrated Resource Plan:

- Analytical Framework
- Generation Technology Assessment
- Energy and Peak Load Forecasts
- Fuel Price Forecasts
- Emissions Allowance Price Forecasts

The IRP development will be discussed in detail at the upcoming Stakeholder Meeting to be held Friday, August 7, 2015, at the MISO Energy – South Region building.

More information about the Stakeholder Meeting can be found at the website below:
http://www.entergy-arkansas.com/transition_plan/

Stakeholder Meeting Agenda

The preliminary agenda for the August 7th Stakeholder Meeting is below.

Topic	Start Time
Introduction and Meeting Objectives	8:00
Resource Planning Update	8:15
Transmission Planning Update	8:45
Demand-side Management Update	9:00
Overview of Environmental Issues	9:30
Break	*10:00*
IRP Process Overview	10:10
Generation Technology Assessment	10:25
Sales and Load Forecasts	10:50
Preliminary Results and Next Steps	11:15
Lunch	*12:00*
Stakeholder Committee Formation	1:00
Wrap-up	1:45

2012 IRP Action Plan Progress

1. MISO Transition
   - [*Complete*] EAI transitioned to the Mid-Continent ISO on December 19, 2013.
2. Coal Unit Environmental Compliance
   - [On-going] EAI continues to monitor changes in environmental law at state and federal level to evaluate options for compliance.
3. Hot Spring Plant Acquisition
   - [*Complete*] EAI acquired the Hot Spring Plant in December 2012.
4. Purchase Power Agreements from EAI's 2011 RFP
   - [*Complete*] EAI executed a power purchase agreement for Union Power Partners Unit 2 on October 22, 2012.
5. Available Wholesale Base Load Capacity to Retail
   - [*Complete*] In Order No. 12 of Docket No. 12-038-U, EAI received approval to transfer approximately 154 MW of the Available Wholesale Base Load generation to retail rates.
6. Hydro Peaking Capacity to Retail
   - [*Complete*] In Docket No. 13-028-U, 10 MW of capacity was moved to retail rates.

2012 IRP Action Plan Progress

7. DSM and Energy Efficiency Expansion
   – [*On-going*] Since 2012 EAI has added 135 MW[1] of capacity savings and 516,768 MWh of energy efficiency through its Energy Efficiency Portfolio[2].
8. Lake Catherine 4 Reliability / Sustainability
   – [Complete] The unit is now expected to operate through 2024.
9. Older Natural Gas Fired Unit Deactivation Decisions
   – [*Complete*] EAI has deactivated approximately 441 MW of legacy generation.
10. Renewable Energy Assessment
    – [*In progress*] EAI issued an RFP for renewable energy resources in May 2014. EAI is currently pursuing APSC approval of the solar energy resource selected out of the RFP.
11. Short- and Intermediate-Term RFPs
    – EAI has not had a need for a short- or intermediate-term RFP since the 2012 IRP.

1. Capacity savings are adjusted to reflect only the incremental savings added over the 2013-15 time period.
2. Accumulation of 2012, 2013 and 2014 reported and evaluated achievement.

2015 IRP Goals and Objectives

The study period for the 2015 IRP is the 20-year period of 2017 through 2036. A 20-year study period was chosen for the 2015 IRP in order for EAI to evaluate long-term trends under a broad range of possible future outcomes.

EAI established a set of resource planning objectives to guide its development of its 2012 IRP and to meet the requirements of the APSC Resource Planning Guidelines for Electric Utilities[1]. The planning objectives focus on four key areas:

- cost,
- risk,
- reliability and
- sustainability.

The 2015 IRP will also be guided by the resource planning objectives, which are described on the following slides.

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

Resource Planning Objectives (1 of 3)

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.

Resource Planning Objectives (2 of 3)

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 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.

Resource Planning Objectives (3 of 3)

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 and 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.

IRP Analytical Framework

Progress, Objectives, and a Futures-based Approach

Futures-based Approach

For the IRP to reasonably account for a broad range of uncertainty while focusing on an appropriate amount of meaningful, thoughtful modeling iterations, EAI Resource Planning is using a futures-based approach to the IRP analysis.

In this approach, a select number of "futures" were developed that represent different combinations of possible outcomes of many variables.

Major areas of uncertainty to consider:

- Sales and load growth
- Commodity price trends
- Environmental regulation and/or legislation

For each future, the AURORA Capacity Expansion tool will select (i.e., output) a 20-year resource portfolio that is economically optimal for EAI under that set of circumstances.

Overview of IRP Futures

Future 1	Future 2	Future 3
Reference Case Future	**Low Capacity Additions Future**	**High Capacity Additions Future**
• Current proposed FIP[1] scenario • Installation of required controls and use of coal over cost recovery period • Reference level assumptions for commodity price and load forecasts	• Current proposed FIP scenario • Installation of required controls and use of coal over cost recovery period • Assumes sustained reliability through end of study period for the gas units • Low sales and load growth as well as low commodity prices delay and/or decrease new capacity additions	• Approval of plan to cease using coal at White Bluff by a time certain (2028) that makes scrubber installation economically unsupportable under federal air regulations (and thus not required) • Final FIP does not require Independence scrubber installation; Assumption that similar controls required in later Regional Haze planning period (2028-2038) • High sales and load growth drive increased capacity requirements

1. Refers to the Federal Implementation Plan under the U.S. Environmental Protection Agency Regional Haze Program, a regulation to improve visibility in national parks and wilderness areas. More information available at http://www.epa.gov/visibility/actions.html.

Assumptions by Future

	Future 1 Reference	Future 2 Low	Future 3 High
Existing Resource Portfolio			
Cease to Use Coal at White Bluff	2042	2042	2028
Cease to Use Coal at Independence	2044	2044	2035
Non-EAI Coal Plants	60 years	60 years	50 years
Customer Electricity Requirements			
Energy sales and Load	Reference	Low	High
Commodity Price Forecasts			
Fuel Prices	Reference	Low	High
Environmental Allowance Prices	Reference	Low	High

Load and Capability

Load Forecast and Existing Resource Portfolio

ALL CAPACITY VALUES SHOWN ARE 2015 GVTC RESULTS

Load Forecast

<u>Summary of Results</u>

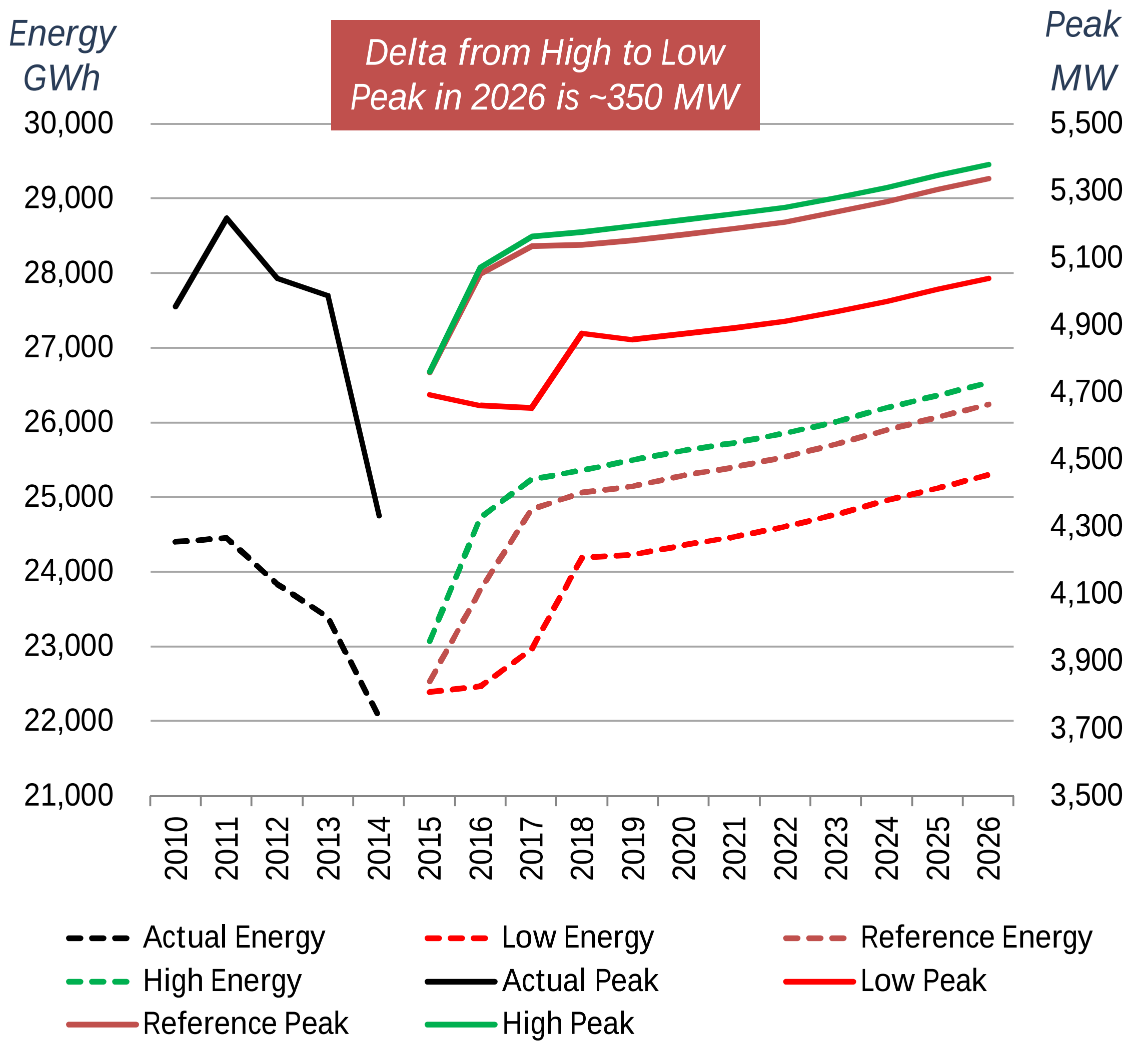
- Low and High cases driven by Economic Development assumptions (see next slide)
- DSM's reduction reaches a maximum of 95 MW in 2019

<u>Weather</u>

- 15-year normal, 2000-2014
- 2015 Peak Date: 8/4/2015
- 2010-12 actual peaks shown are weather normalized; 2013-14 are not weather-normalized

14-24 CAGR	Low	Ref	High
Peak	1.4%	2.0%	2.1%
Energy	1.2%	1.6%	1.7%

*Forecast as of September 1, 2014



Existing Portfolio – 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	597	100%	597	2002
Independence Unit 1	839	31.5%	228	1983
Lake Catherine Unit 4	516	100%	516	1970
Ouachita Unit 1	247	100%	247	2002
Ouachita Unit 2	241	100%	241	2002
Remmel Units 1, 2 & 3	12	100%	12	1925
White Bluff Unit 1	815	57.0%	400	1980
White Bluff Unit 2	822	57.0%	404	1981

Existing Portfolio – Purchased Generation

	Total Installed Capacity (MW)	Retail Capacity (MW)	Commercial Operations Date
Blakely	86	11	1956
DeGray	78	10	1972
Grand Gulf	1,409	307	1985
Union Power	499	499	2003

Notes:
- The Blakely and DeGray capacity is assumed through 5/31/2019.
- The Grand Gulf capacity is assumed throughout the IRP study horizon.
- The Union Power PPA ends 5/31/2017, but EAI's acquisition of one power block is currently pending regulatory approval and would replace the PPA upon acquisition (see p. 18).

Future Portfolio – Planned Resource Additions

	Total Installed Capacity (MW)	Retail Capacity (MW)	Commercial Operations Date
Stuttgart Solar	81	81	TBD
Union Power	499	499	2003

Notes:
- These resources are currently pending regulatory approval.
- Stuttgart Solar is a 20-year PPA assumed to begin 1/1/2017.
- The Union Power capacity is assumed to be acquired by EAI and available throughout the IRP study horizon.

Existing Portfolio – Demand-side Resources

	Reduction during Peak Load Hours (MW)
Energy Efficiency	36

The peak and energy reducing impacts of EAI's Energy Efficiency programs are input to the development of the EAI sales forecast (p. 15).

	Reduction during Peak Load Hours (MW)
Demand Response	30
Interruptible Load	74

The capacity value of the Demand Response and Interruptible Load resources are included in the Load and Capability analysis and count toward EAI's planning reserve target in the same way as supply side resources.

Notes:
- Estimates above are total 2015 reductions.
- EAI's demand response include Residential Direct Load Control and Agricultural Irrigation Load Control programs.
- Demand Response and Interruptible capacity is increased to account for reserve margin and line loss value in the Load and Capability analysis.

Generation Technology Assessment

Cost and Performance

Technology Assessment Process & Overview

- An understanding of generation technology cost and performance is a necessary input to planning and decision support activities. EAI has engaged ESI to monitor and assess generation alternatives on an ongoing basis. This analysis uses a generic long-term capital structure of 11.0% ROE and 7.0% long-term debt and assumes 50% equity and 50% debt.

- The process has two main steps. First a screening level analysis is performed and then a detailed analysis is performed.

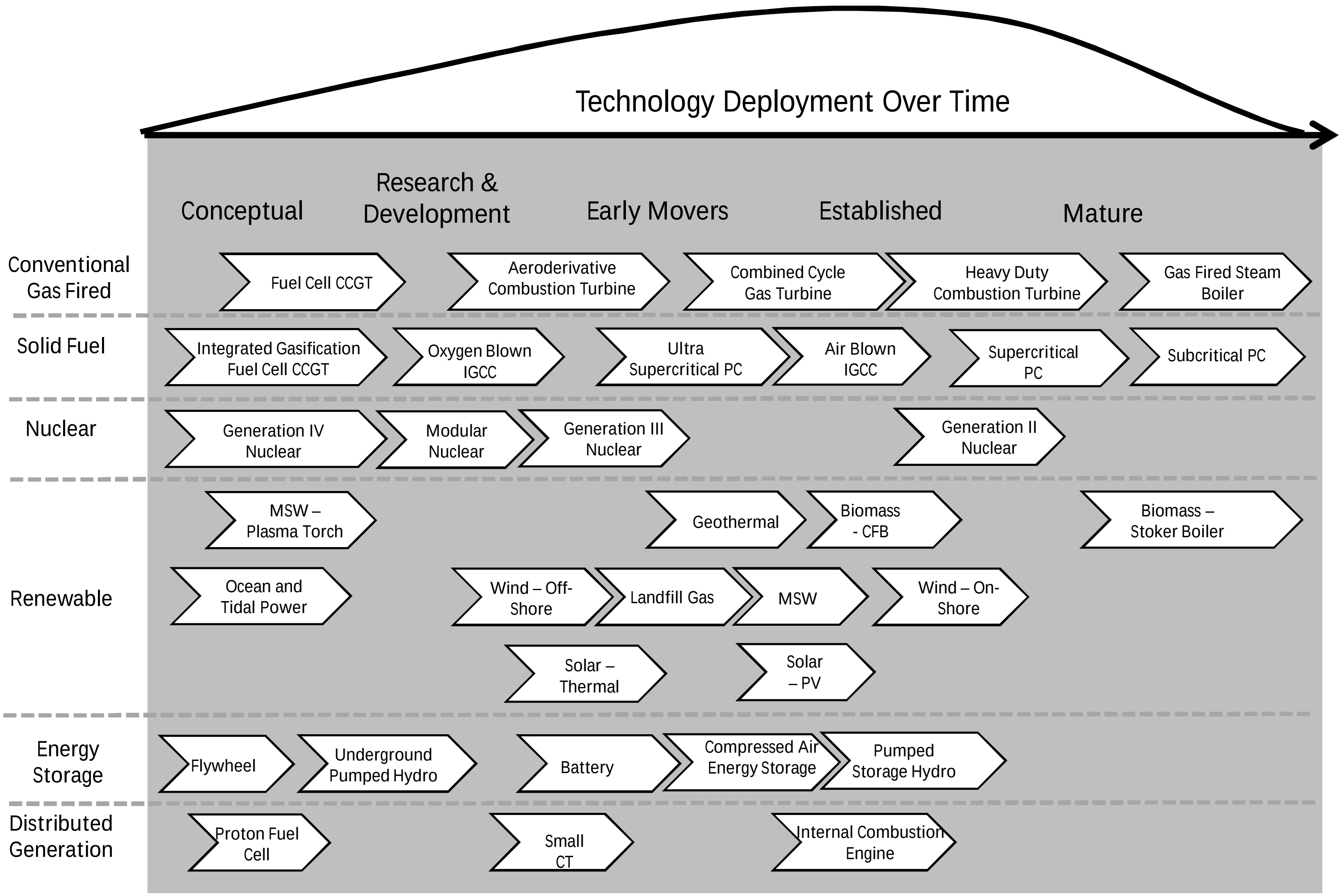
- The 2014 Generation Technology Assessment began by surveying available central state electricity generation technologies, generally those that are two megawatts or greater. The objective is to identify a reasonably wide range of generation technologies. The initial list was subject to a screening analysis to identify technologically mature alternatives which could be reasonably expected to be operational in or around the Entergy regulated service territory, except as otherwise noted.

- EAI prefers technologies that are proven on a commercial scale. Some technologies identified in this document lack the commercial track record to demonstrate their technical and operational feasibility. A cautious approach to technology development and deployment is therefore reasonable and appropriate in order to maintain system reliability and to protect EAI's customers from undue risks. EAI generally does not plan to be the "first movers" for emerging, unproven technologies.

- ESI, through this Technology Screen, has selected certain traditional and renewable generation technology alternatives which may reasonably be expected to meet primary objectives of cost, risk mitigation, and reliability. For each selected technology, Planning Analysis developed the necessary cost and performance parameter inputs into the detailed modeling used to develop the reference technologies comprising the IRP Portfolio.

- ESI will monitor for EAI the technologies eliminated as a result of the initial screen and incorporate changes into future technology assessments and IRPs.

A Variety of Available Alternatives



Technologies Screened

- Pulverized Coal
  - Subcritical Pulverized Coal
  - Supercritical Pulverized Coal
  - Ultra Supercritical Pulverized Coal
- Fluidized Bed
  - Atmospheric Fluidized Bed
  - Pressurized Fluidized Bed
- Integrated Gasification ("IGCC")
  - Oxygen-Blown IGCC
  - Air-Blown IGCC
  - Integrated Gasification Fuel Cell Combined Cycle
- Combustion Turbine / Combined Cycle / Other Natural Gas
  - Combustion Turbine
  - Combined Cycle
  - Large & Small Scale Aeroderivative
  - Steam Boiler
- Fuel Cells
  - Molten Carbonate
  - Solid Oxide
  - Phosphoric Acid
  - Proton Exchange Membrane
  - Fuel Cell Combined Cycle
- Nuclear
  - Advanced Boiling Water Reactor
  - Generation IV
  - Modular Reactors
- Energy Storage
  - Pumped Hydro
  - Underground Pumped Hydro
  - Battery
  - Flywheel
  - Compressed Air Energy Storage
- Renewable Technologies
  - Biomass
  - Solar Photovoltaic (Fixed Tile and Tracking)
  - Solar Thermal
  - Wind Power
  - Municipal Solid Waste
  - Landfill Gas
  - Geothermal
  - Ocean & Tidal

Technologies Selected For Detailed Analysis

The following technologies are being carried forward for development of detailed planning assumptions

- Pulverized Coal
  - Supercritical Pulverized Coal with carbon capture and storage*
- Natural Gas Fired
  - Combustion Turbine ("CT")
  - Combined Cycle Gas Turbine ("CCGT")
  - Large Scale Aeroderivative CT
  - Internal Combustion Engine

**Proposed EPA regulations on CO_2 have effectively eliminated all new coal plants without carbon capture.*

- Nuclear
  - Advanced Boiling Water Reactor
- Renewable Technologies
  - Biomass
  - Wind Power
  - Solar PV (Fixed Tilt and Tracking)
- Battery Storage

Technology Assumptions for Combined Cycle Application

Cost & Performance Appropriate For Technology Deployment in MISO South	Units	1x1 F Frame CCGT	2x1 F Frame CCGT	1x1 G Frame CCGT	2x1 G Frame CCGT
Net Max Capacity (Summer)	(MW)	382	764	450	900
Installed Cost, 2014 (Summer)	($/kW)	$1,095	$1,045	$1,100	$900
Full Load Heat Rate (Summer)	(Btu/kWh)	6,900	6,750	6,650	6,650
Typical Capacity Factor	(%)	65%-85%	65%-85%	65%-85%	65%-85%
Fixed O&M (Summer)	($/kW-yr)	$17.50	$15.00	$15.50	$10.00
Variable O&M (Summer)	($/MWh)	$2.00	$2.00	$2.00	$2.00
Inlet Air Conditioning Assumption		Evaporative Coolers			
NOx Control Technology		SCR	SCR	SCR	SCR
NOx emissions, post control	(lbs/MMBtu)	0.01	0.01	0.01	0.01

- Cost of supplemental capacity (duct firing) assumed to be $250/kW
- Max Capacity, Installed Cost, and Fixed O&M include supplemental capacity. Heat rates reflect base capacity only.

Technology Assumptions for Peaking Applications

Cost & Performance Appropriate For Technology Deployment in MISO South	Units	F Frame CT	G Frame CT	Large Aeroderivative CT	Internal Combustion
Net Max Capacity (Summer)	(MW)	194	250	102	18.8
Installed Cost, 2014	($/kW)	$820	$700	$1,275	$1,360
Full Load Heat Rate – Summer	(Btu/kWh)	10,200	9,600	9,125	8,440
Typical Capacity Factor	(%)	0%-10%	0%-10%	0%-40%	0%-40%
Fixed O&M	($/kW-yr)	$3.50	$3.00	$14.25	$29.25
Variable O&M	($/MWh)	$10.00	$12.50	$0.75	$2.25
Inlet Air Conditioning Assumption		-	Evaporative Cooling	Inlet Chillers	-
NOx Control Technology		Dry Low NOx burners	Dry Low NOx burners	SCR	SCR
NOx emissions, post control	(lbs/MMBtu)	0.03	0.03	0.01	0.01

Technology Assumptions for Solid Fuel Application

Cost & Performance Appropriate For Technology Deployment in MISO South		PC With 90% CCS
Net Max Capacity	(MW)	800
Installed Cost, 2014	($/kW)	$4,900
Full Load Heat Rate – Summer	(Btu/kWh)	13,200
Levelized Fuel Cost	($/mmbtu)	$3.12
Typical Capacity Factor	(%)	85%
Fixed O&M	($/kW-yr)	$140.00
Charging Cost	($/MWh)	n/a
Expected Useful Life		40

Technology Assumptions for Renewable Applications

Cost & Performance Appropriate For Technology Deployment in MISO South		Biomass	Nuclear	Wind	Solar PV (fixed tilt)	Solar PV (tracking)	Battery Storage (Lead Acid Batteries)
Net Max Capacity	(MW)	100	1,310	200	100	100	50
Installed Cost, 2014	($/kW)	$4,760	$8,000	$2,050	$2,300	$2,550	$2,400
Full Load Heat Rate – Summer	(Btu/kWh)	12,900	10,200	-	-	-	-
Levelized Fuel Cost	($/mmbtu)	$3.04	$0.90	-	-	-	-
Typical Capacity Factor	(%)	85%	90%	48%	21%	24%	20%
Fixed O&M	($/kW-yr)	$104.60	$115.60	$22.10	$19.00	$23.00	$0.00
Charging Cost	($/MWh)	n/a	n/a	n/a	n/a	n/a	$25.00
Expected Useful Life		30	40	25	25	25	20

- Capacity for these technologies is not significantly affected by ambient air temperature.
- All O&M is considered fixed.
- Wind capacity factor representative of resources located in mid-west geographical area.

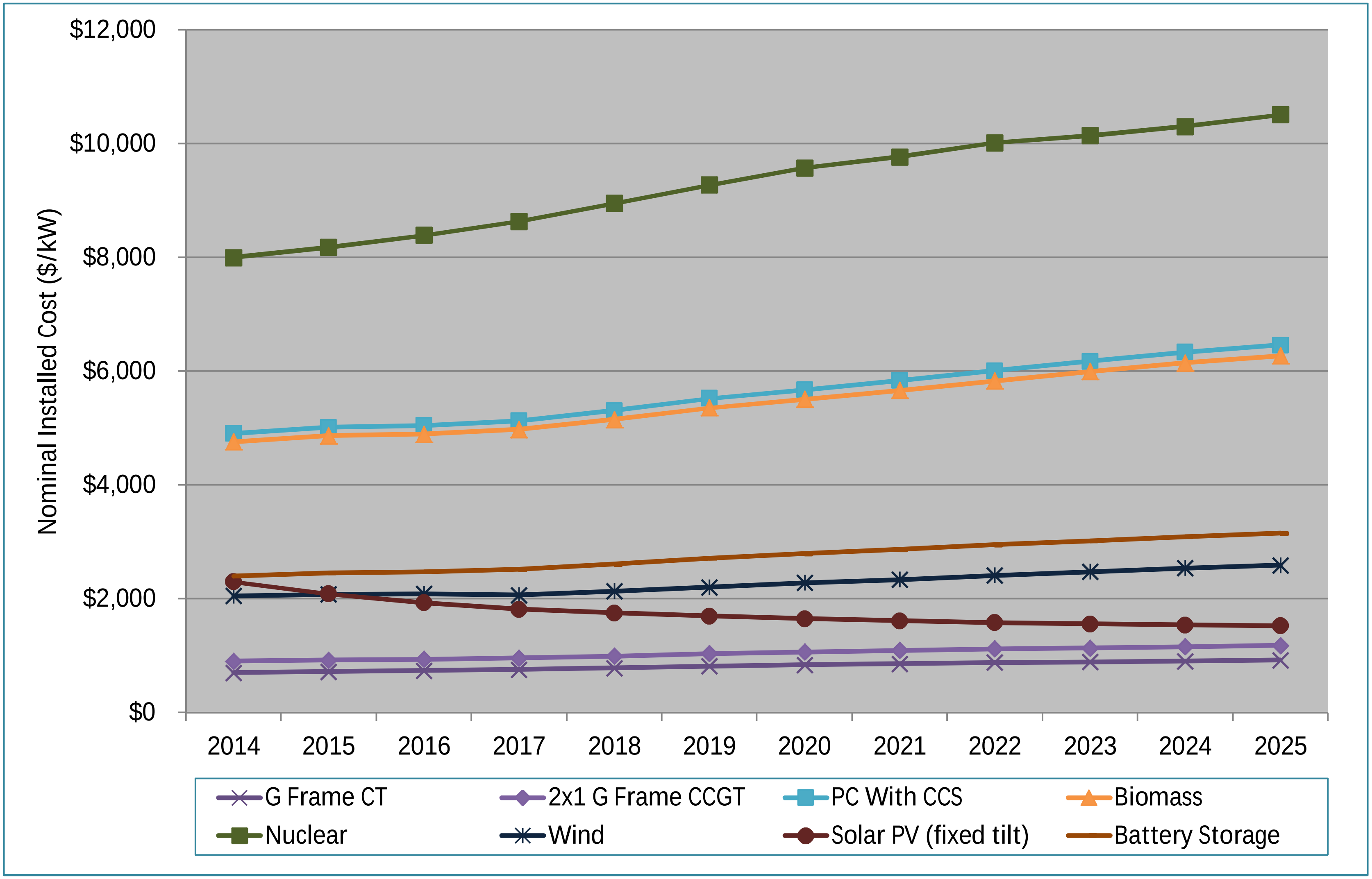
Additional Supply Considerations

Schedule and location can influence which technology is preferred for a given application

Technology	Time to Market	Environmental	Gas Supply	Flexibility
CCGT	◐	●	◐	◐
Frame CT w/ SCR	◕	●	◐	◐
Small Aeroderivative	●	●	○	◕
Large Aeroderivative	◕	●	○	◕
Internal Combustion Engine	●	◐	●	●
Nuclear	○	◕		○
Coal	◔	○		●
Wind	●	●		○
Solar	●	●		○
Considerations included in category	• Permitting Requirements • Lead time of major components • Engineering Required • Installation Time	• Impact of Non-Attainment Zone • NOx Emissions • SOx Emissions • COx Emissions • Residual Fuel	• Gas Pressure Required	• Ramp Rate • Turndown Ratio • Start Time • Performance at Part Load

Considerations are scored relative to each other ● *Most favorable* ○ *Least Favorable*

Capital Cost Projections



Commodity Price Forecasts

Fossil Fuels, Solid Fuel and Air Emissions Allowances

LEVELIZED PRICES SHOWN ARE FOR THE PERIOD 2017-2036

Fuel Price Forecasts

Levelized 2015 $/MMBtu	Reference	Low	High
Henry Hub Natural Gas Price	$4.89	$3.50	$7.68
EAI Coal Plants	$2.43	$2.12	$3.54
Non-EAI Coal Plants in Entergy Region	Reference Case (Price Varies by Plant)	Low Case (Price Varies by Plant)	High Case (Price Varies by Plant)
Coal Plants in Non Entergy Regions	Reference Case (Price Varies by Plant)	Low Case (Price Varies by Plant)	High Case (Price Varies by Plant)

Notes:
- EAI Owned Plants: volume weighted average based on plant specific pricing which includes current contracts
- Forecast as of May 1, 2015

CO_2 Price Forecast

Levelized 2015 $/short ton	Reference	Low	High
CO_2	$10.02 ($CO_2$ pricing begins in 2020)	None	$29.68 ($CO_2$ pricing begins in 2020)

Cross-State Air Pollution Rule (CSAPR) Forecast

Levelized 2015 $/ton	Reference
Seasonal NO_X	$5.19
Annual NO_X	$51.93
SO_2 Group 1	$15.09
SO_2 Group 2	$26.32

Notes:
- Low and High sensitivities were not developed for this program.
- Arkansas is subject to compliance under the Seasonal NOX program only.
- Source: Energy Ventures Analysis, 2015.

THE POWER OF PEOPLE®

Entergy Arkansas, Inc.
2015 Integrated Resource Plan

August 7, 2015
2015 IRP Stakeholder Meeting

2015 IRP Meeting Overview

- Welcome
- Safety
- Introductions

Agenda

Topic	Start Time	Name
Introduction and Meeting Objectives	8:00	Kurt Castleberry
Resource Planning Update	8:15	Matt Wolf
Transmission Planning Update	8:45	Melinda Montgomery
Demand-side Management Update	9:00	Richard Smith
Overview of Environmental Issues	9:30	Kelly McQueen
Break	*10:00*	
IRP Process Overview	10:10	Kandice Fielder
Generation Technology Assessment	10:25	Charles DeGeorge
Sales and Load Forecasts	10:50	Charles John
Preliminary Results and Next Steps	11:15	Kandice Fielder
Lunch	*12:00*	
Stakeholder Committee Formation	1:00	Kandice Fielder
Wrap-up	1:45	Kurt Castleberry

What is the Purpose and Objective of Today's Meeting?

- Discuss EAI's Integrated Resource Plan process, assumptions, preliminary plans and schedule

- Allow stakeholders an opportunity to organize a committee to develop the Stakeholder's Report

What is Integrated Resource Planning?

- *"…..a utility planning process which requires consideration of all reasonable resources for meeting the demand for a utility's product, including those which focus on traditional supply sources and those which focus on conservation and the management of demand."*

- *" The process results in the selection of that portfolio of resources which best meets the identified objectives while balancing the outcome of expected impacts and risks for society over the long run."*

- Source: APSC's Resource Planning Guidelines

Who Comprises the Stakeholder Committee and Why Stakeholder Involvement?

The Stakeholder Committee is comprised of:

"…..retail and wholesale customers, independent power suppliers, marketers, and other interested entities in the service area."

Why?

"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."

- Source: APSC's Resource Planning Guidelines

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EAI and Stakeholder Committee – Roles and Responsibilities

- EAI will:
  - *"organize and facilitate meetings of a Stakeholder Committee for resource planning purposes"*
  - *"make a good faith effort to properly inform and respond to the Stakeholder Committee"*
  - Include a Report of the Stakeholder Committee with EAI's October 2015 Integrated Resource Plan filing

- The Stakeholder Committee:
  - *"shall develop their own rules and procedures"*
  - *"Stakeholders should review utility objectives, assumptions and estimated needs early in the planning cycle"*
  - Develop a report of the Stakeholder Committee and provide to EAI

Stakeholder Process Timeline

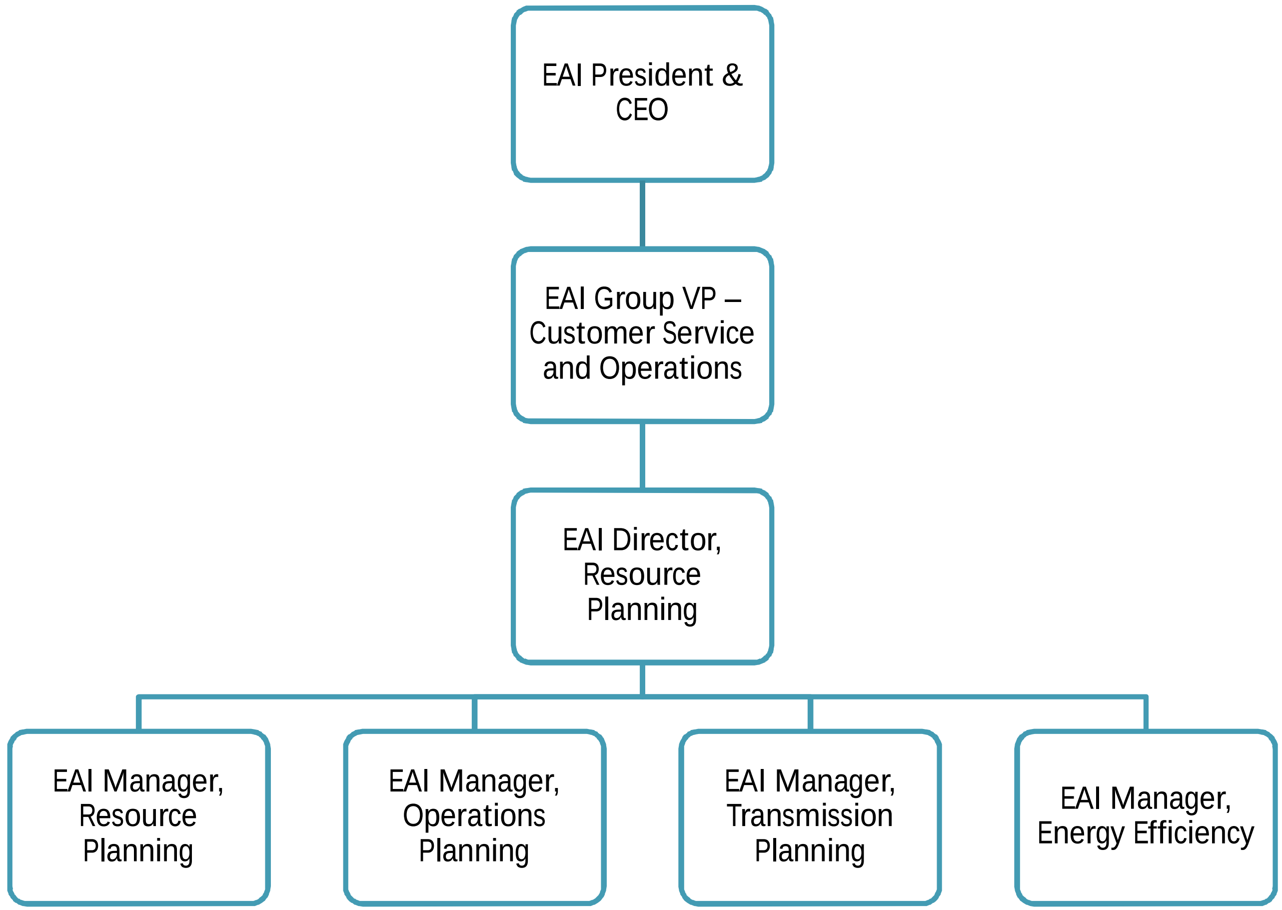
ACTIVITY	DATE
Stakeholder meeting	August 7
Stakeholder / EAI interaction (as needed)	August 7 – October 2
Stakeholders finalize Stakeholder Report and provide to EAI	October 16
EAI finalizes IRP and files written report with the APSC including Stakeholder Report	October 31

Ground Rules

- A lot of material – Need to stay on schedule
- Ask questions but time constraints may limit number of questions allowed. However, EAI will answer ALL stakeholder questions either in today's meeting or the written questions and their answers will be posted @ http://entergy-arkansas.com/transition_plan/
- Cards are available at each table for written questions. Please use these cards for the more extensive questions. EAI will answer these questions at the end of today's session or will post answers at the above link
- Stay on topic – Do not interject questions or comments related to other issues.
- Keep side-bar discussions to a minimum
- EAI will endeavor to respond to questions or get information to Stakeholder Committee members as quickly as is practical

EAI Resource Planning Organization and Governance

EAI Management Structure with Key Roles for Resource Planning and Operations



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EAI Resource Planning and Operations Committee (RPOC)

Chair

EAI Director, Resource Planning and Market Operations

- EAI Vice President Regulatory Affairs (Vice Chair)
- Vice President, Arkansas Nuclear One
- General Manager – Independence Steam Electric Station
- EAI Manager, Transmission Planning
- EAI Manager, Resource Planning
- EAI Manager, Operations Planning
- EAI Manager, Energy Efficiency

Questions / Comments

Resource Planning Update

- Review the Action Plan from EAI’s 2012 IRP Report.
- Update the Stakeholders on key Resource Planning Activities.

2012 IRP Action Plan

1. MISO Transition
2. Coal Unit Environmental Compliance
3. Hot Spring Plant Acquisition
4. Purchase Power Agreements from EAI’s 2011 RFP
5. Available Wholesale Base Load Capacity to Retail
6. Hydro Peaking Capacity to Retail
7. DSM and Energy Efficiency Expansion
8. Lake Catherine 4 Reliability / Sustainability
9. Older Natural Gas Fired Unit Deactivation Decisions
10. Renewable Energy Assessment
11. Short- and Intermediate-Term RFPs

#1 MISO Transition

- Integration into MISO took place on December 19, 2013
- EAI customers saved an estimated $46 Million during the first year
  - Reduced capacity requirements are estimated at 344 MW
- EAI has successfully participated in three MISO Planning Resource Auctions
  - Transitional auction, 2014/15 auction, 2015/16 auction
  - Modified the Optional Interruptible Service Rider (OIS-R) and registered as a Load Modifying Resource (LMR) for the 2015/16 auction.
- EAI recently filed a report detailing EAI participation in the MISO Auctions in APSC Docket No. 10-011-U

Action Items #2, #3 and #4

#2 The Environmental Compliance update will be provided by Kelly McQueen

#3 Hot Springs Plant Acquisition

- EAI completed the acquisition in December 2012.
- Added approximately 600 MW to EAI's portfolio.

#4 Purchase Power Agreements from EAI's 2011 RFP

- EAI executed a PPA with Union Power Partners in October 2012.
- APSC approval was obtained in APSC Docket No. 12-038-U.
- Added approximately 500 MW for the period of December 19, 2013 through May 31, 2017.
- Contract negotiations for a second proposal selected in the 2011 RFP was concluded without execution of a contact.

#5 - Available Wholesale Base Load Capacity

- In APSC Docket No. 12-038-U, EAI offered to move approximately 286 MW of capacity that has previously been used to serve the wholesale sector and 59 MW of capacity from its retained share of the Grand Gulf Nuclear Plant to serve retail customers.

- The docket was settled with 186 MW of nuclear based generation from the Arkansas Nuclear One units being transferred to serve retail customers.

Action item # 6 and # 7

#6 Hydro Peaking Capacity to Retail

- The wholesale allocation factor was updated in APSC Docket No. 13-028-U.
- Added approximately 10 MW.

#7 DSM and Energy Efficiency Update will be provided by Richard Smith.

Since 2012, incremental EE installations have contributed to approximately 135 MW savings across EAI's peak.

#8 - Lake Catherine 4 Reliability / Sustainability

- Lake Catherine 4 is a 516 MW gas fired unit that was originally scheduled to deactivate at the end of 2014.
- A Reliability/Sustainability program was developed and implementation is on-going.
- The unit is currently expected to be available through May 31, 2025.
- Adds approximately 516 MW.

#9 – Older NG Fired Unit Deactivation Decisions

- Since the 2012 IRP, EAI deactivated approximately 420 MW of older natural gas / diesel fired generation.

- Total generation retirements since the 2012 IRP totaled approximately 964 MW across 13 units.

- Two more older units totaling approximately 28 MW are planned to retire at the end of May 2016.

10 – Renewable Energy Assessment

- EAI issued an RFP for both traditional and renewable resources on May 5, 2014.

- EAI entered into a contract on April 3, 2015.
  – 20 year PPA for approximately 81 MW.
  – Energy deliveries to begin no later than May 31, 2019.
  – Expect 20 to 40 MW of capacity at peak.

- Approval of the PPA is pending before the APSC in Docket No. 15-014-U.

11 – Short- and Intermediate-Term RFP

- EAI elected to issue an RFP for long-term renewable and intermediate resources on May 5, 2014.

- EAI entered into an asset purchase agreement with Union Power Partners on December 8, 2014, to acquire power block 2 which will add approximately 495 MW to EAI's portfolio.

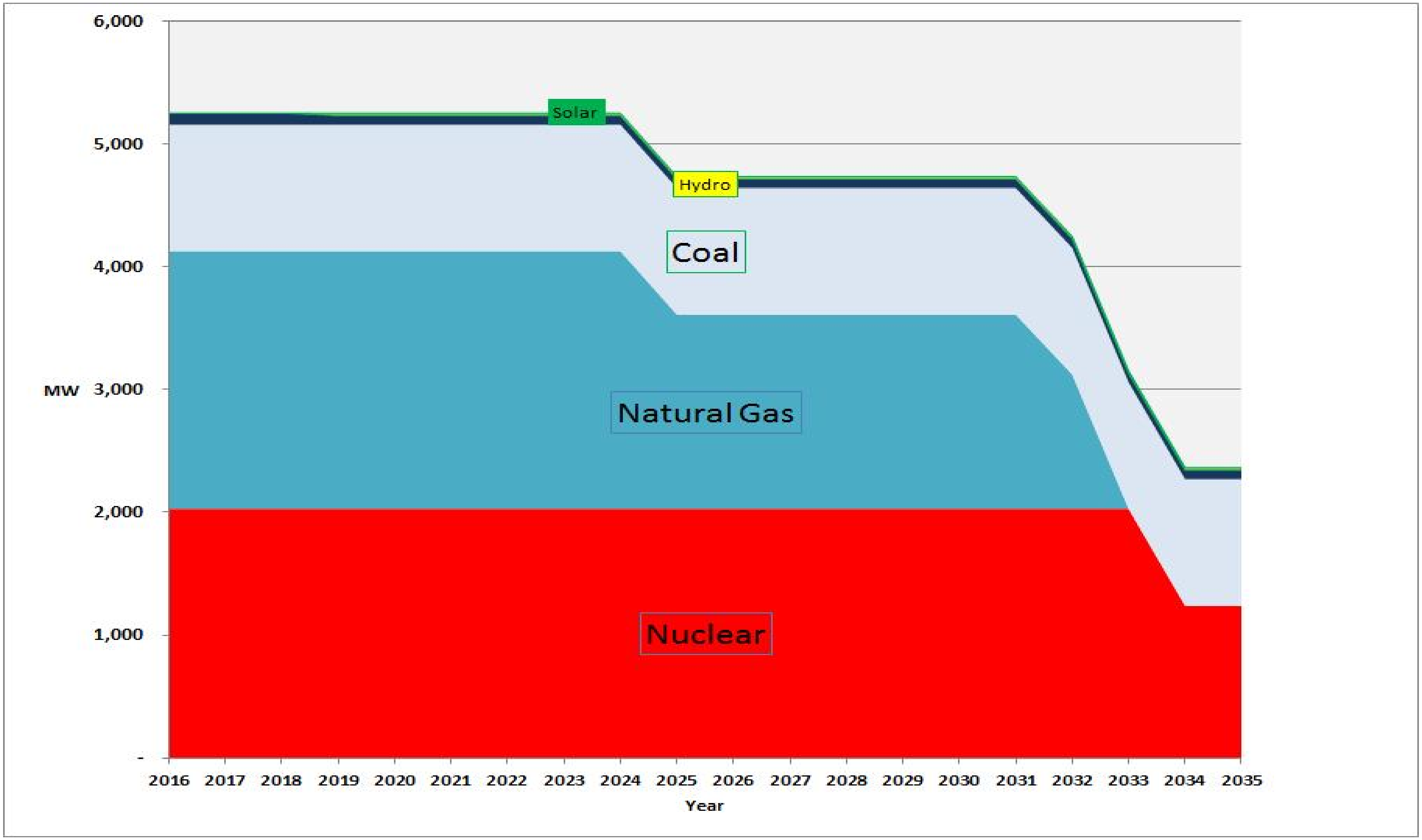
- APSC approval is pending in Docket No. 14-118-U as well as required federal reviews /approvals.

Resource Planning Summary

- Completed: (summer ratings)
  - MISO Membership: +344 MW
  - Hot Spring Power Plant: +600 MW
  - EE / DSM: +135 MW
  - Wholesale Capacity: +186 MW
  - Wholesale Hydro Capacity: +10 MW
  - Lake Catherine 4: +516 MW
  - Retirements: -964 MW

- Planned:
  - UPP Power Block 2: +495 MW
  - Stuttgart Solar PPA: +20 MW

EAI Supply Side Resources – Existing and Planned



Questions / Comments

TRANSMISSION PLANNING UPDATE

Transmission Planning Update

- What has changed since 2012.
- What hasn’t changed.
- Transmission Planning analysis

What has changed since 2012 in Transmission Planning

- EAI joined MISO
  - EAI responsible for its transmission plans, apart from the System Agreement companies
  - New regional and interregional planning processes for transmission projects
  - New economic planning process
- New planning standards that apply to all Transmission Planners

What hasn't changed in Transmission Planning

- EAI is responsible for planning to meet reliability standards and local planning criteria.
- Our focus remains on providing reliable service to customers and maintaining reasonable rates.
- We still use an open and transparent stakeholder process in transmission planning, including discussion of alternatives.

Recent Transmission Projects at a Glance

		APPENDIX A			APP B
	Total	Future/in-progress	Complete	Est. Cost	Studied for Future
Pre-Planned	23	10	13		-
MTEP 14	31	21	8	$66M	2
MTEP 15*	19	8	-	$128 M	5
MTEP 16**	15	9	-	Not yet final	6

Pre-planned projects are those that had already been through the planning process before EAI joined MISO.
*MTEP 15 process is still in progress. Approval of projects to occur in December 2015.
**MTEP 16 local planning is on-going. Projects and costs are not yet final.
Appendix A are those projects approved by the MISO Board, or submitted for study in the current year requesting approval.
Appendix B are those projects that are farther in the future. They are submitted for study but not for approval in the current planning cycle.

Transmission Planning and the IRP

- Should the 2015 IRP Action Plan guide EAI to pursue and evaluate options for additional generating resources (for example, through an RFP), transmission analysis of resource options will be done to determine transmission impact.
- Analysis will include the transmission topology and limit information including planned projects from MISO's regional MTEP plan.

Questions / Comments

Demand-side Management Update

DSM Progress since 2012

This section is to outline the progress EAI has made with DSM and DR since the 2012 IRP.

- In 2011, the Commission established DSM Targets of:
  - 0.25% of retail sales in 2011,
  - 0.5% retail sales in 2012, and
  - 0.75% of retail sales in 2013.
- In 2014, the Commission extended the target 0.75% of retail sales.
- In 2015, the Commission again extended program at a Target level of 0.9% of retail sales.
- All programs are to be based upon the Comprehensiveness orders made in December 2010 and further program design requirements for weatherization and Commercial and Industrial Programs in 2013.
- Going forward, the Commission is requiring the RECC method of determining avoided capacity cost which reduces cost effectiveness of DSM and DR when compared to levelized avoided capacity cost, as is best practices in all other jurisdictions.
- Forward looking targets have not yet been established. However, EAI has planned using a strategy of flat achievement and cost adjusted for inflation in this IRP.

2012-14 DSM Achievement

DSM and Energy Efficiency Expansion

– Since 2012 EAI has added 135 MW[1] of peak period savings and 501,691 MWh of at-the-meter energy efficiency through its Energy Efficiency Portfolio[2].

	Evaluated Achievement		
	2012	2013	2014
Energy Savings (KWH)[3]	107,626,826	188,556,802	205,506,894
Demand Reduction (KW)[3]	23,261	49,900	63,045
DR Budget	$8,669,000	$6,793,000	$7,605,000
DSM Budget	$30,940,000	$51,633,000	$57,849,000
Total Budget	$39,609,000	$58,426,000	$65,454,000
Actual Spend	$28,395,000	$53,032,000	$59,914,000
Percent of Sales (Evaluated)	0.51%	0.90%	1.00%
Total Resource Cost Ratio	1.2	2.2	3.4

1. Peak savings are adjusted to reflect only the incremental savings added over the 2012-14 time period.
2. Accumulation of 2012, 2013 and 2014 reported and evaluated achievement.
3. The savings in the table above do not include T&D adjustment.

2015 DSM Projected Achievement

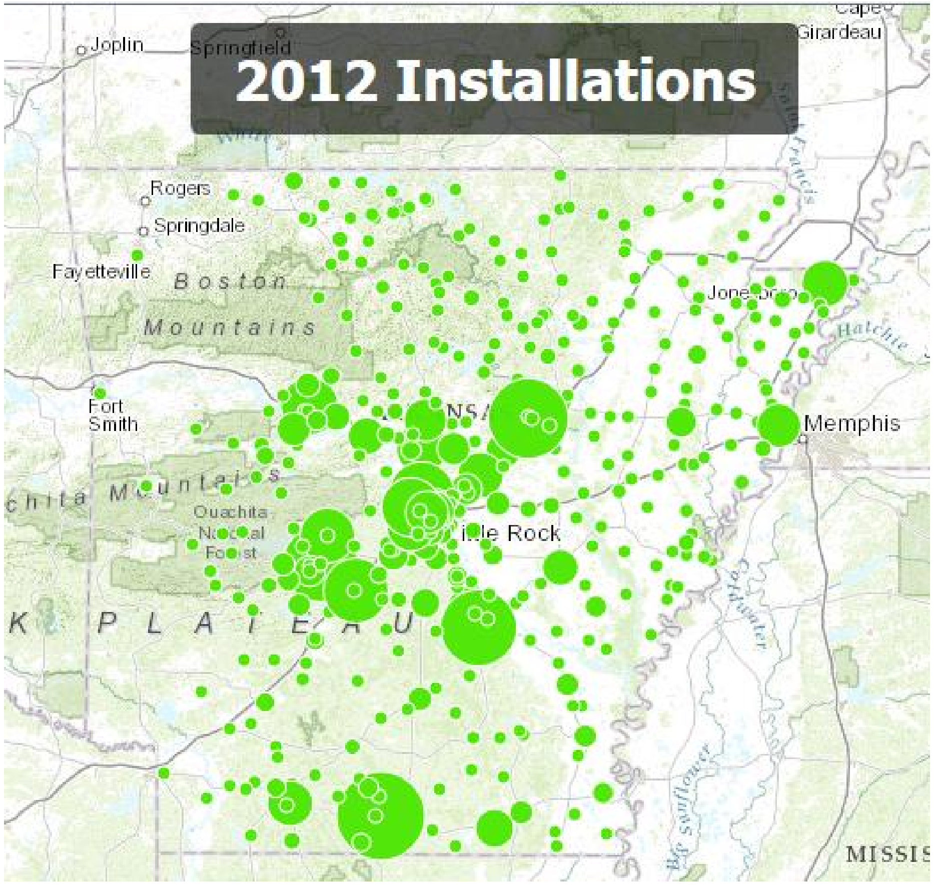
- EAI is on track to achieve and exceed our 2015 DSM and DR target of 178,869 MWHs subject to retroactive Technical Resource Manual ("TRM") updates and Independent EM&V Results.
- The 2015 Plan is demonstrated below:

	2015
Energy Savings (KWH)*	235,798,383
Demand Reduction (KW)*	79,300
DR Budget	$8,929,000
DSM Budget	$62,249,000
Total Budget	$71,178,000
Actual Spend	
Percent of Sales (Evaluated)	1.15%
Total Resource Cost Ratio	1.8

*The savings in the table above do not include T&D adjustment.

Where DSM and DR Are Occurring – 2012

2012 Achievements



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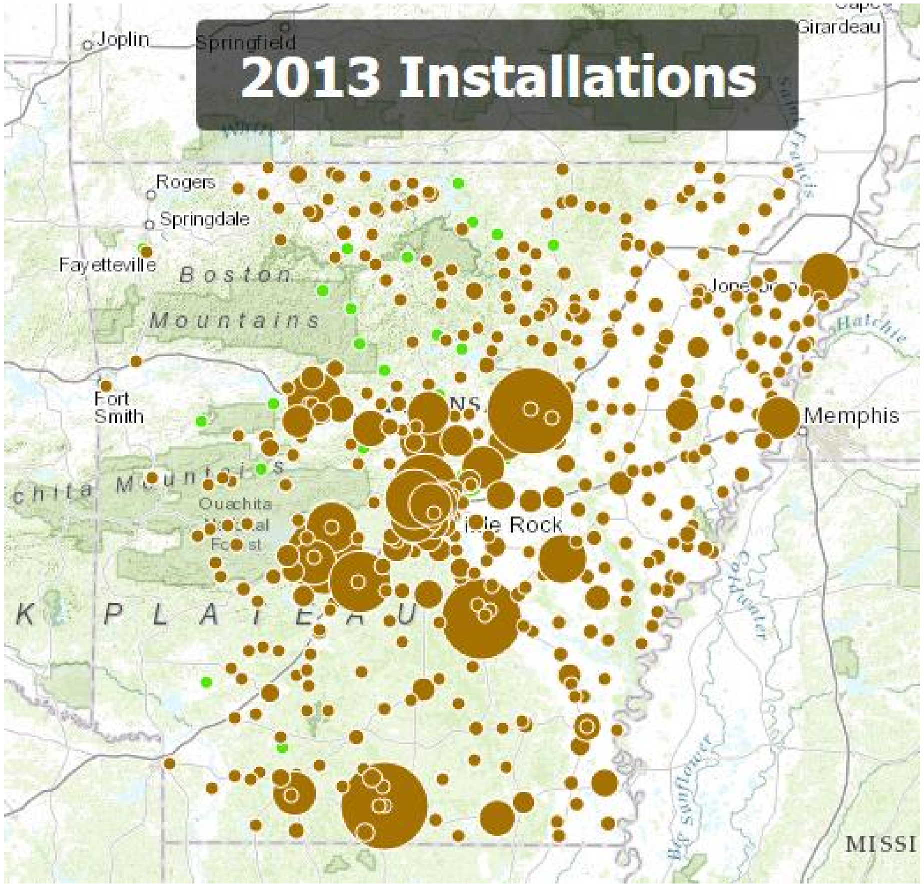
Where DSM and DR Are Occurring – 2012-13

2012 and 2013 Achievements



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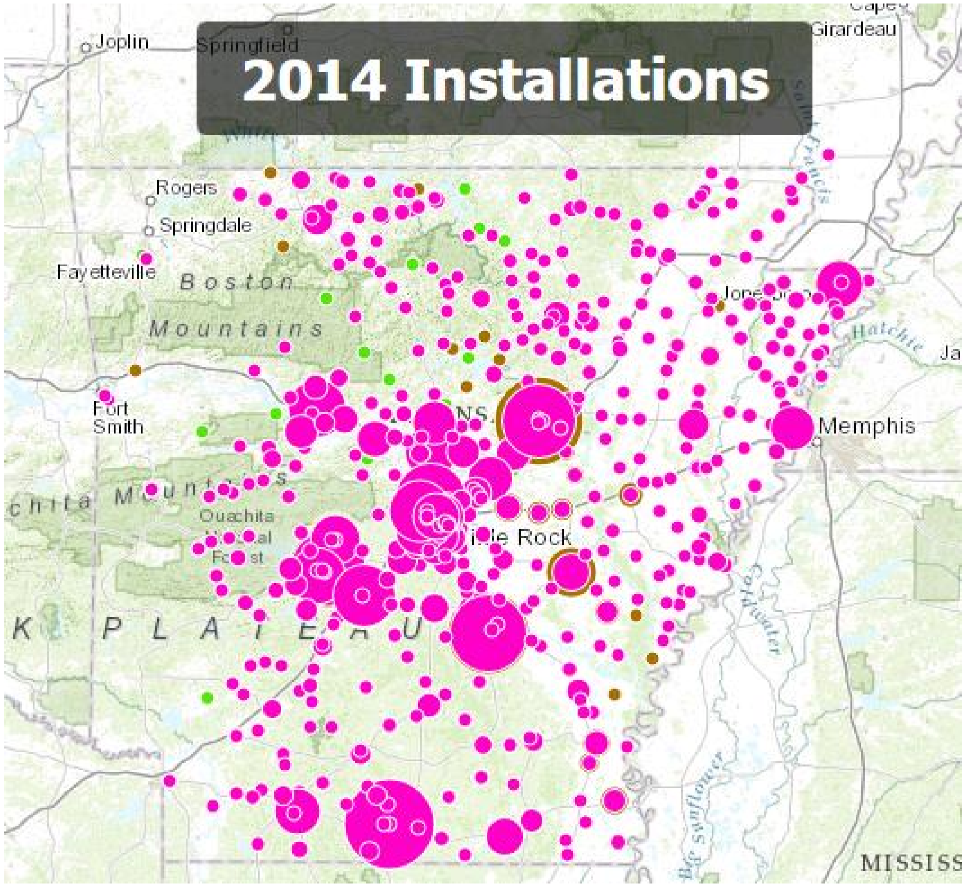
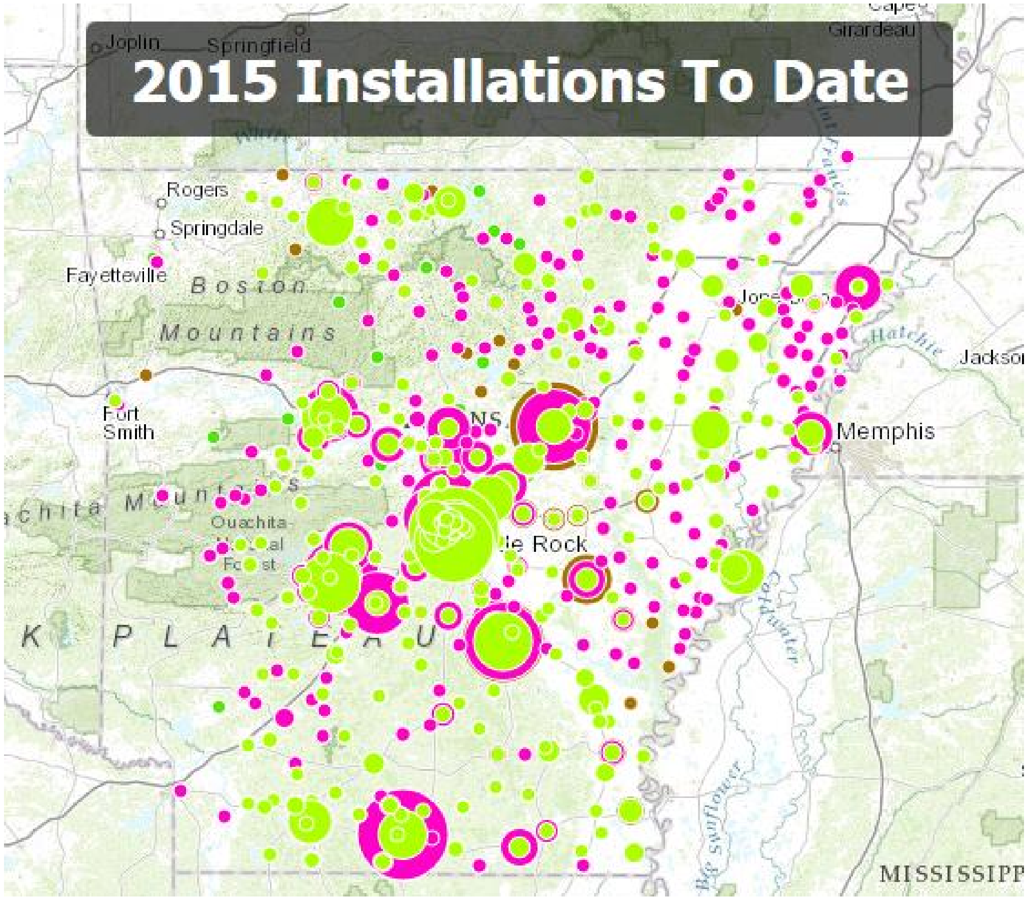
Where DSM and DR Are Occurring – 2012-14

2012 through 2014 Achievements



Where DSM and DR Are Occurring – 2012-15

2012 through 2015 Achievements



Proxy for the Next Three Year Plan

- EAI had prepared to file a Three Year Plan covering 2016 through 2018 before the Three Year Plan filing was delayed until June of 2016.
- Our 2016 DSM and DR plan reflects the first year of the 2016 through 2018 Three Year Plan.
- The 2016 through 2018 Plan included the following:
  - The RECC Method of avoided capital cost,
  - Consideration of EM&V uncertainties,
  - Plan to attempt to maximize performance incentives of 120% of utility target.

Proxy for the Next Three Year Plan

- EAI Proxy for the 2016 through 2018 Three year plan
- Plan is subject to change based upon final regulatory decisions in 2015, TRM and EM&V updates.

	Projected		
	2016	2017	2018
Energy Savings (KWH)*	260,304,000	260,304,000	260,306,000
Demand Reduction (KW)*	100,200	100,200	110,700
DR Budget	$7,163,000	$6,588,000	$7,210,000
DSM Budget	$58,801,000	$59,871,000	$59,261,000
Total Budget	$65,964,000	$66,459,000	$66,471,000
Actual Spend			
Percent of Sales (Evaluated)	1.27%	1.27%	1.27%
Total Resource Cost Ratio	2.3	2.3	2.3

*The savings in the table above do not include T&D adjustment.

Four Types of DSM in Planning

Customer-sponsored DSM	Existing Utility-sponsored DSM	Incremental Utility-sponsored DSM	Interruptible Loads/DR
• 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.	• These programs are like existing Utility programs but require regulatory approval to implement. • An assumption for incremental programs is included in the Retail Sales Forecast.	• Programs that provide the Utility with the right to curtail service to a participating customer. • These resources are modeled like a supply side resource.

2015 IRP Utility-sponsored DSM Assumptions

- Existing Utility-sponsored DSM: The energy saving and peak reducing impacts of these programs are reflected in the actual historical customer usage data which is an input to the Sales and Load forecasts.
- Incremental Utility-sponsored DSM: Since the Arkansas DSM Potential Study was still underway and no direction regarding future DSM Targets was available at the time, EAI assumed 0.9% of retail sales above forecast without DSM (above naturally occurring DSM) as the DSM proxy within the Sales and Load forecasts.
  - This results in an annual incremental reduction in sales of 165,468 MWh[1] and assumes a 10-year measure degradation curve.
  - Any free ridership, or overlap between the Customer-sponsored DSM and the Incremental Utility-sponsored DSM, is also accounted for so that the impacts are not double-counted.

1. Based on 2013 Program Year planned net annual savings, Docket No. 07-085-TF Doc 443

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2015 IRP DSM Assumption Principle Based

EAI remains committed to DSM and DR as long the achievement can be accomplished in a cost effective manner when compared to a utility future avoided or delayed generation cost and full cost recovery remains in place.

Also, EAI continues to investigate opportunities for advance metering infrastructure which may enhance the future DSM and DR portfolio.

Questions / Comments

Overview of Environmental Issues

Overview of Environmental Issues

- Potential Environmental Compliance Timeline
- MATS
- Regional Haze
- CSAPR & NAAQS (SO2 and Ozone)
- Clean Power Plan (CO2)

Potential Environmental Compliance Timeline

2015 2016 2017 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028

Draft RH AR FIP Issued
WB & ISES
(4/2015)

Cross State Air Pollution Rule:
LNB/SOFA
WB
Application Pending
Rule in effect Jan 1, 2015.

CO2:
WB, ISES
Final CO2 ESPS
8/3/15

Final RH FIP
Expected
(1/2016)

MATS:
ACI/ESP Upgrades
WB, ISES
(4/2016)
Potential stay or vacatuer

SO2 & PM2.5 NAAQS:
WB, ISES
(2017+)

Coal Combustion Residuals:
WB, ISES

Regional Haze (RH):
WB, ISES
(2021*)

Ozone NAAQS:
(2020 - 2026)
(depending on NAAQS stringency & area attainment status)

316(b) (Water Intake)
Min. requirements only
(2022)

NO2 NAAQS:
(2022-2025)

RH 3rd Planning Period:
(2028+)

Legend:
National Ambient Air Quality Standards ("NAAQS")
Mercury and Air Toxics Standards ("MATS")
Existing Source Performance Standard ("ESPS")

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Overview of Environmental Issues - MATS

MATS:

- Extensions granted/compliance April 2016
- ACI/ESP upgrades complete – WB/ISES
- Commissioning/testing ongoing
- 6/30/15 Supreme Court decision
- D.C. Circuit to decide whether MATS is stayed, vacated or remains in effect pending remand to EPA
    - Expected decision by end of year 2015

Overview of Environmental Issues – Regional Haze

Regional Haze:

- April 8, 2015 proposed Federal Implementation Plan:
  - Lake Catherine 4: BOOS (BART)
  - White Bluff: LNB/SOFA and dry FGD (BART)
  - Independence: LNB/SOFA and dry FGD (Reasonable Progress)
    - Also taking comment on dry FGD only
- Comment Deadline extended to August 7, 2015
- EAI Comments:
  - Independence should not have been included as AR is below the "Glidepath"
  - Proposes long term, multi-unit approach:
    - White Bluff : Cease to use coal in 2027/2028
    - White Bluff & Independence: LNB/SOFA within 3 years of final FIP and lower SO2 rate in 2018
- Final FIP expected in 1Q2016

Overview of Environmental Issues – CSAPR & NAAQS

CSAPR:
- May 1, 2015: CSAPR begins for seasonal program states
- WB: LNB/SOFA permit application pending
- July 2015: D.C. Circuit overturns state budgets in several states (not AR)

1 hour SO_2 NAAQS:
- Pursuant to consent decree
  - State proposed designations for areas around WB and ISES due: September 2015
  - EPA designation expected: July 2016
- Not expected to be an independent driver of controls at either plant

8 hour Ozone Standard:
- Current standard: 75 ppb (primary and secondary standards)
- Court ordered deadlines:
  - December 1, 2014 – Proposed revised NAAQS
  - October 1, 2015 – Final revised NAAQS
- Not expected to be an independent driver of controls at either plant

Overview of Environmental Issues – Clean Power Plan

Clean Power Plan:

- June 2015 Proposed Rule
- August 3, 2015 Final Rule issued along with:
  - Final New Source Performance Standards
  - Proposed Federal Plan
- Still under review

	Proposed interim rate	Final Rule interim rate	Proposed Final rate	Final Rule final rate
AR	968	1304	910	1130

Overview of Environmental Issues – Clean Power Plan

Clean Power Plan Timeline

Summer 2015	• August 3, 2015 - Final Clean Power Plan
1 Year	• September 6, 2016 – States make initial submittal with extension request or submit Final Plan
3 Years	• September 6, 2018 - States with extensions submit Final Plan
7 Years	• January 1, 2022 - Compliance period begins
15 Years	• January 1, 2030 - CO_2 Emission Goals met

Questions / Comments

BREAK

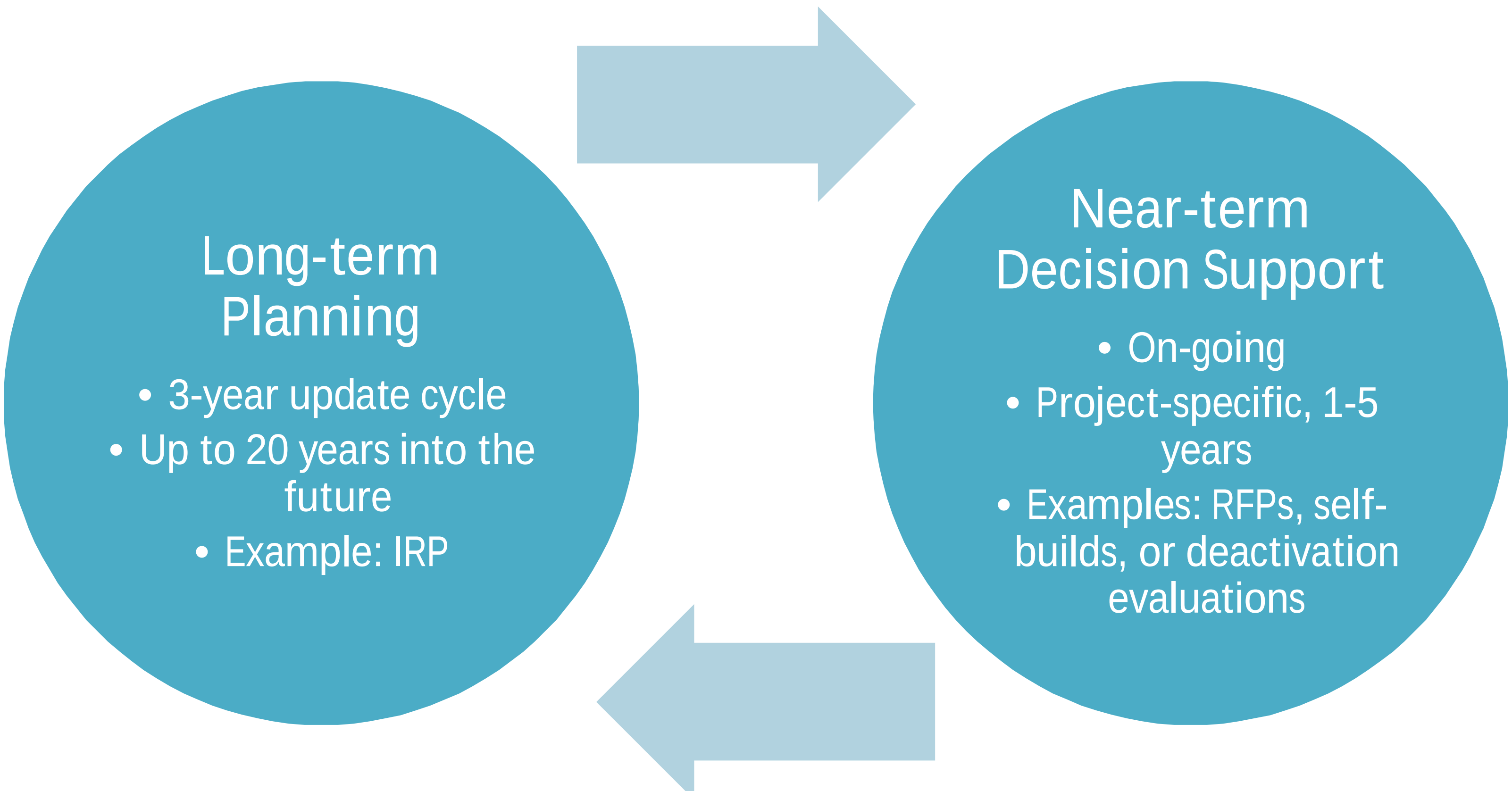
IRP PROCESS OVERVIEW

Agenda

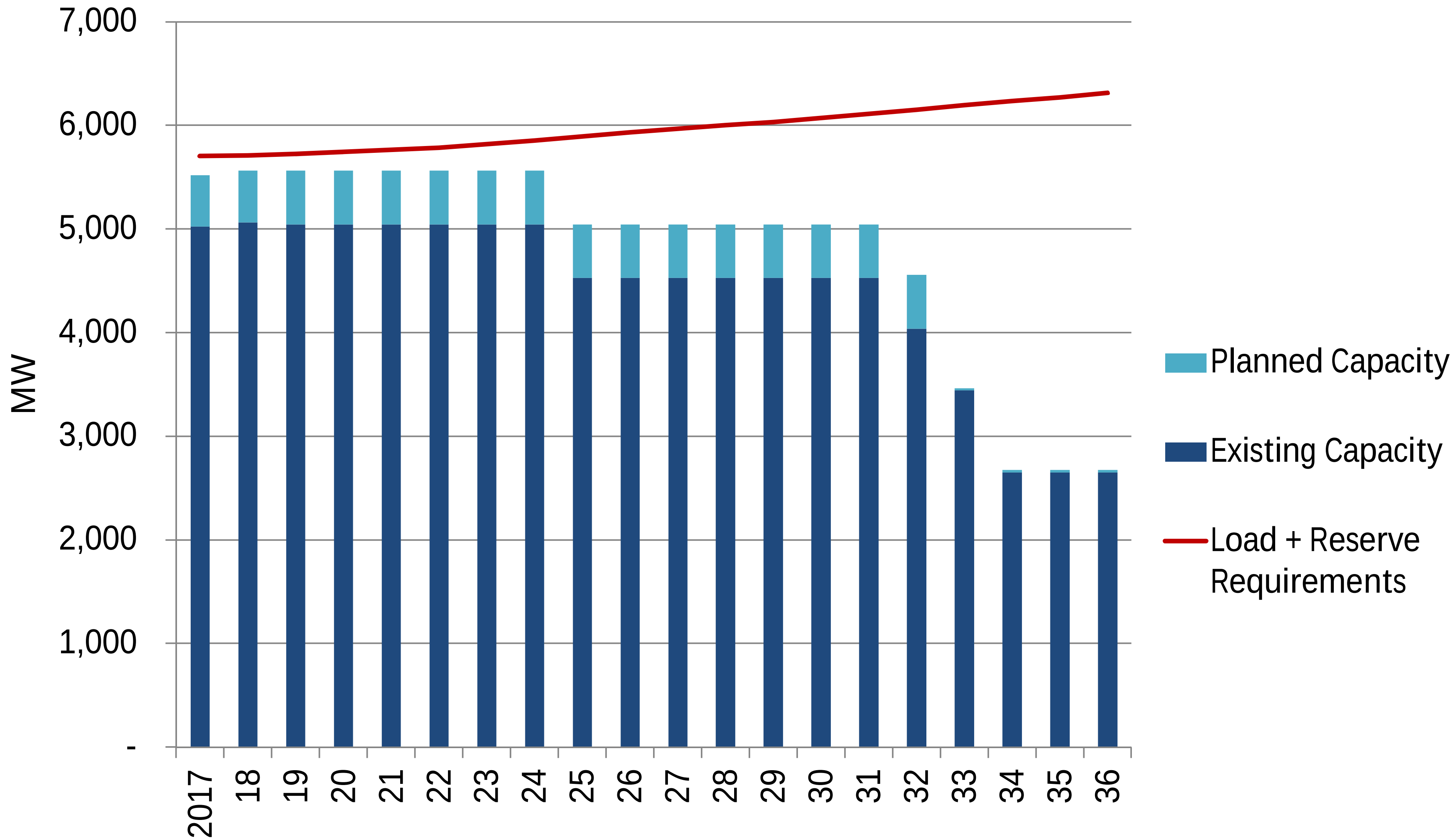
Topic	Start Time	Name
Introduction and Meeting Objectives	8:00	Kurt Castleberry
Resource Planning Update	8:15	Matt Wolf
Transmission Planning Update	8:45	Melinda Montgomery
Demand-side Management Update	9:00	Richard Smith
Overview of Environmental Issues	9:30	Kelly McQueen
Break	*10:00*	
IRP Process Overview	10:10	Kandice Fielder
Generation Technology Assessment	10:25	Charles DeGeorge
Sales and Load Forecasts	10:50	Charles John
Preliminary Results and Next Steps	11:15	Kandice Fielder
Lunch	*12:00*	
Stakeholder Committee Formation	1:00	Kandice Fielder
Wrap-up	1:45	Kurt Castleberry

Resource Planning Process

The IRP has an important role in EAI's resource planning by providing guidance on long-term themes and tendencies. However, the nature of the IRP analysis is not appropriate for tactical resource decisions, which follows a separate evaluation process.



EAI's Future Capacity Needs



Questions / Comments

Generation Technology Assessment

Technology Assessment Process & Overview

- An understanding of generation technology cost and performance is a necessary input to planning and decision support activities. EAI has engaged ESI to monitor and assess generation alternatives on an ongoing basis. This analysis uses EAI' capital structure.

- The process has two main steps. First a screening level analysis is performed and then a detailed analysis is performed.

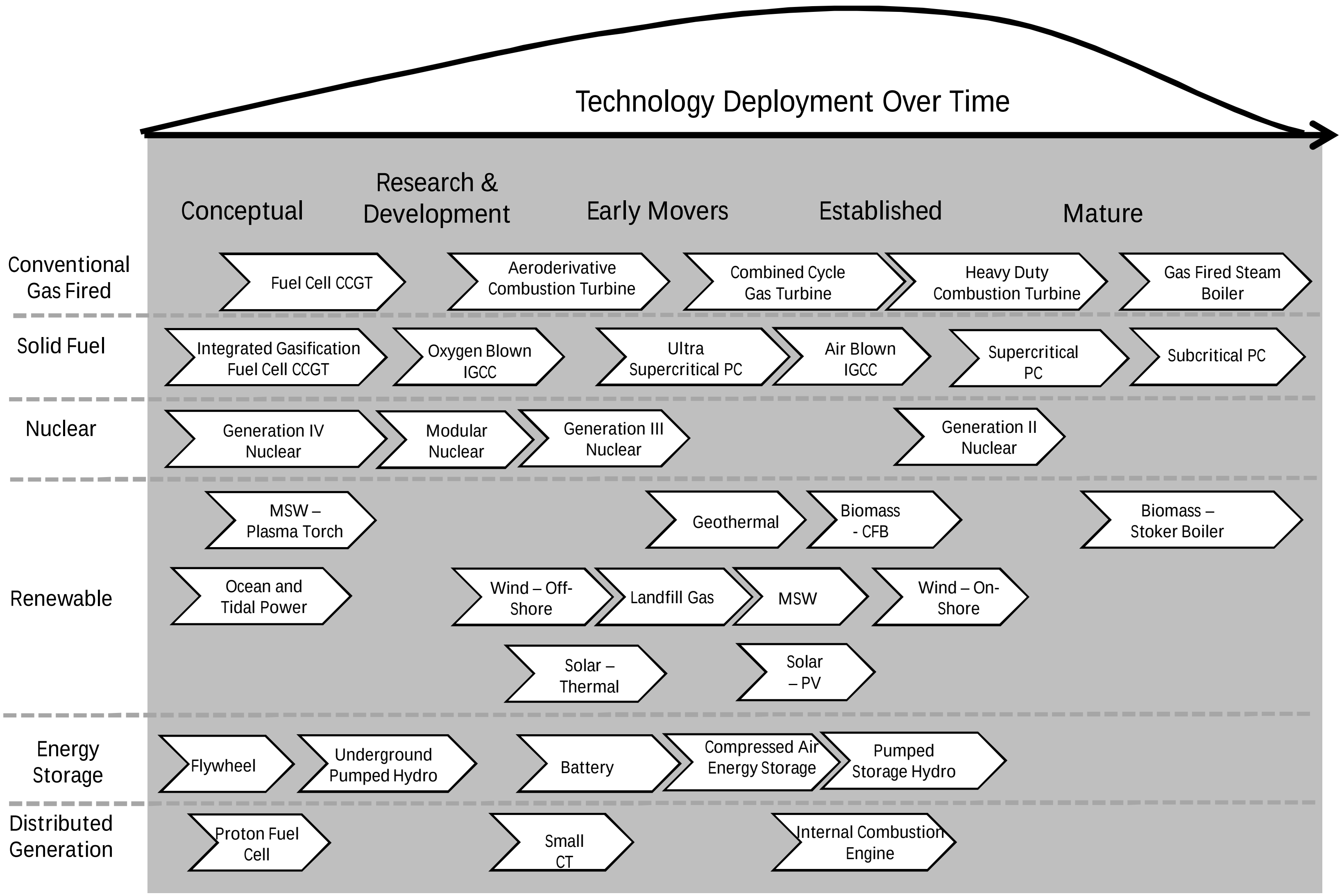
- The 2015 Generation Technology Assessment began by surveying available central state electricity generation technologies, generally those that are two megawatts or greater. The objective is to identify a reasonably wide range of generation technologies. The initial list was subject to a screening analysis to identify technologically mature alternatives which could be reasonably expected to be operational in or around the Entergy regulated service territory, except as otherwise noted.

- EAI prefers technologies that are proven on a commercial scale. Some technologies identified in this document lack the commercial track record to demonstrate their technical and operational feasibility. A cautious approach to technology development and deployment is therefore reasonable and appropriate in order to maintain system reliability and to protect EAI's customers from undue risks. EAI generally does not plan to be the "first movers" for emerging, unproven technologies.

- ESI, through this Technology Screen, has selected certain traditional and renewable generation technology alternatives which may reasonably be expected to meet primary objectives of cost, risk mitigation, and reliability. For each selected technology, Planning Analysis developed the necessary cost and performance parameter inputs into the detailed modeling used to develop the reference technologies comprising the IRP Portfolio.

- ESI will monitor for EAI the technologies eliminated as a result of the initial screen and incorporate changes into future technology assessments and IRPs.

A Variety of Available Alternatives



Technologies Screened

- Pulverized Coal
  - Subcritical Pulverized Coal
  - Supercritical Pulverized Coal
  - Ultra Supercritical Pulverized Coal
- Fluidized Bed
  - Atmospheric Fluidized Bed
  - Pressurized Fluidized Bed
- Integrated Gasification (“IGCC”)
  - Oxygen-Blown IGCC
  - Air-Blown IGCC
  - Integrated Gasification Fuel Cell Combined Cycle
- Combustion Turbine / Combined Cycle / Other Natural Gas
  - Combustion Turbine
  - Combined Cycle
  - Large & Small Scale Aeroderivative
  - Steam Boiler
- Fuel Cells
  - Molten Carbonate
  - Solid Oxide
  - Phosphoric Acid
  - Proton Exchange Membrane
  - Fuel Cell Combined Cycle
- Nuclear
  - Advanced Boiling Water Reactor
  - Generation IV
  - Modular Reactors
- Energy Storage
  - Pumped Hydro
  - Underground Pumped Hydro
  - Battery
  - Flywheel
  - Compressed Air Energy Storage
- Renewable Technologies
  - Biomass
  - Solar Photovoltaic (Fixed Tilt and Tracking)
  - Solar Thermal
  - Wind Power
  - Municipal Solid Waste
  - Landfill Gas
  - Geothermal
  - Ocean & Tidal

Technology Assumptions for Combined Cycle Application

Cost & Performance Appropriate For Technology Deployment in MISO South	Units	1x1 F Frame CCGT	2x1 F Frame CCGT	1x1 G Frame CCGT	2x1 G Frame CCGT
Net Max Capacity (Summer)	(MW)	382	764	450	900
Installed Cost, 2014 (Summer)	($/kW)	$1,095	$1,045	$1,100	$900
Full Load Heat Rate (Summer)	(Btu/kWh)	6,900	6,750	6,650	6,650
Typical Capacity Factor	(%)	65%-85%	65%-85%	65%-85%	65%-85%
Fixed O&M (Summer)	($/kW-yr)	$17.50	$15.00	$15.50	$10.00
Variable O&M (Summer)	($/MWh)	$2.00	$2.00	$2.00	$2.00
Inlet Air Conditioning Assumption		Evaporative Coolers			
NOx Control Technology		SCR	SCR	SCR	SCR
NOx emissions, post control	(lbs/MMBtu)	0.01	0.01	0.01	0.01

- Cost of supplemental capacity (duct firing) assumed to be $250/kW
- Max Capacity, Installed Cost, and Fixed O&M include supplemental capacity. Heat rates reflect base capacity only.

Technology Assumptions for Peaking Applications

Cost & Performance Appropriate For Technology Deployment in MISO South	Units	F Frame CT	G Frame CT	Large Aeroderivative CT	Internal Combustion
Net Max Capacity (Summer)	(MW)	194	250	102	18.8
Installed Cost, 2014	($/kW)	$820	$700	$1,275	$1,360
Full Load Heat Rate – Summer	(Btu/kWh)	10,200	9,600	9,125	8,440
Typical Capacity Factor	(%)	0%-10%	0%-10%	0%-40%	0%-40%
Fixed O&M	($/kW-yr)	$3.50	$3.00	$14.25	$29.25
Variable O&M	($/MWh)	$10.00	$12.50	$0.75	$2.25
Inlet Air Conditioning Assumption		-	Evaporative Cooling	Inlet Chillers	-
NOx Control Technology		Dry Low NOx burners	Dry Low NOx burners	SCR	SCR
NOx emissions, post control	(lbs/MMBtu)	0.03	0.03	0.01	0.01

Technology Assumptions for Solid Fuel Application

Cost & Performance Appropriate For Technology Deployment in MISO South		PC With 90% CCS	Nuclear
Net Max Capacity	(MW)	800	1,310
Installed Cost, 2014	($/kW)	$4,900	$8,000
Full Load Heat Rate – Summer	(Btu/kWh)	13,200	10,200
Levelized Fuel Cost	($/mmbtu)	$3.12	$0.90
Typical Capacity Factor	(%)	85%	90%
Fixed O&M	($/kW-yr)	$140.00	$115.60
Charging Cost	($/MWh)	n/a	n/a
Expected Useful Life		40	40

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Technology Assumptions for Renewable Applications

Cost & Performance Appropriate For Technology Deployment in MISO South		Biomass	Wind	Solar PV	Battery Storage (Lead Acid Batteries)
Net Max Capacity	(MW)	100	200	100	50
Installed Cost, 2014	($/kW)	$4,760	$2,050	$2,300	$2,400
Full Load Heat Rate – Summer	(Btu/kWh)	12,900	-	-	-
Levelized Fuel Cost	($/mmbtu)	$3.04	-	-	-
Typical Capacity Factor	(%)	85%	48% *	26%	20%
Fixed O&M	($/kW-yr)	$104.60	$22.10	$19.00	$0.00
Charging Cost	($/MWh)	n/a	n/a	n/a	$25.00
Expected Useful Life		30	25	25	20

- Capacity for these technologies is not significantly affected by ambient air temperature.
- All O&M is considered fixed.

* Wind capacity factor representative of resources located in mid-west geographical area.

Additional Supply Considerations

Schedule and location can influence which technology is preferred for a given application

Technology	Time to Market	Environmental	Gas Supply	Flexibility
CCGT	◐	●	◐	◐
Frame CT w/ SCR	◕	●	◐	◐
Small Aeroderivative	●	●	○	◕
Large Aeroderivative	◕	●	○	◕
Internal Combustion Engine	●	◐	●	●
Nuclear	○	◕		○
Coal	◔	○		●
Wind	●	●		○
Solar	●	●		○
Considerations included in category	• Permitting Requirements • Lead time of major components • Engineering Required • Installation Time	• Impact of Non-Attainment Zone • NOx Emissions • SOx Emissions • COx Emissions • Residual Fuel	• Gas Pressure Required	• Ramp Rate • Turndown Ratio • Start Time • Performance at Part Load

Considerations are scored relative to each other ● *Most favorable* ○ *Least Favorable*

Technologies Selected For Detailed Analysis

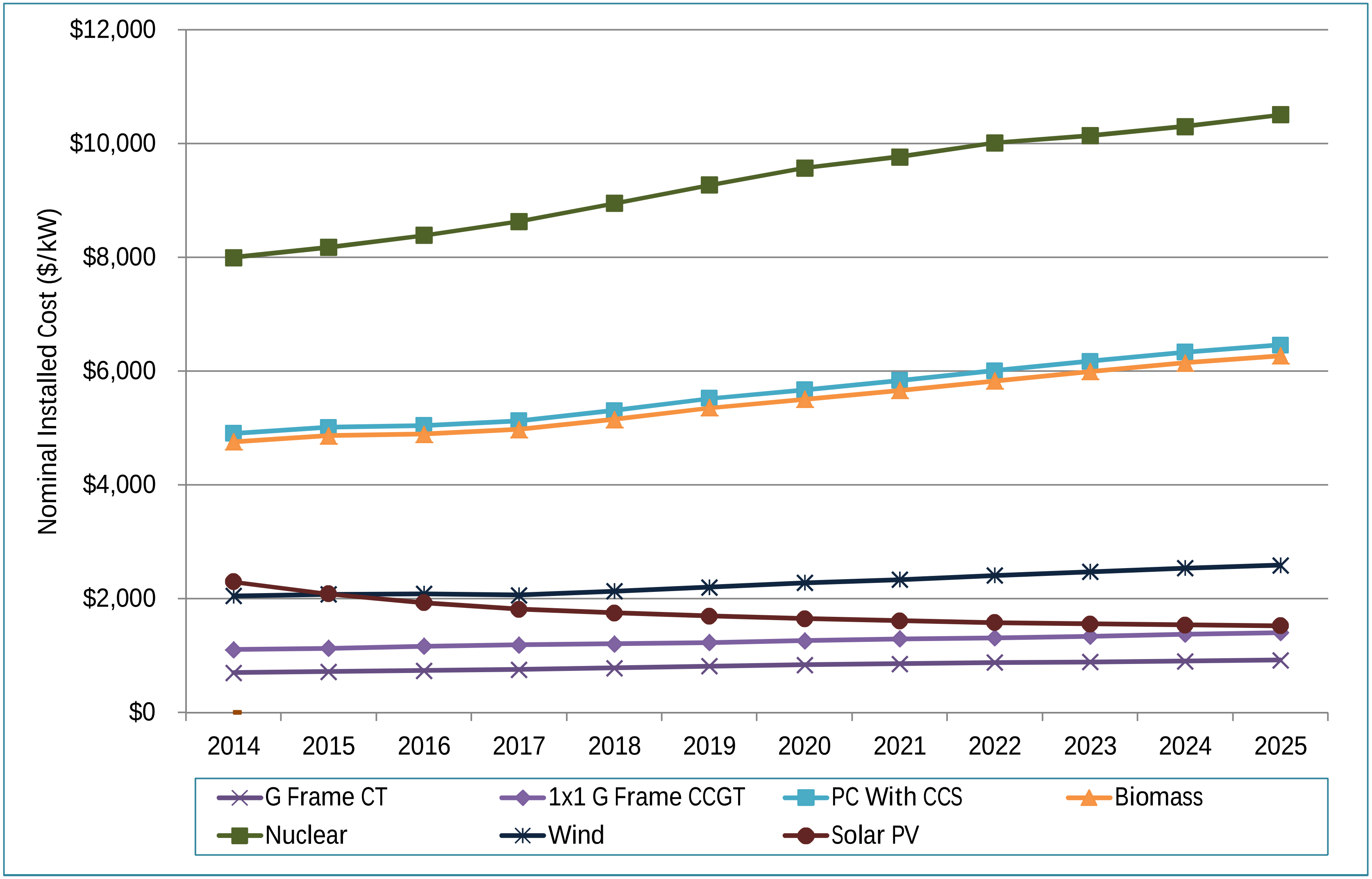
The following technologies are being carried forward for development of detailed planning assumptions and production cost modeling

- Pulverized Coal
  - Supercritical Pulverized Coal with carbon capture and storage*
- Natural Gas Fired
  - Combustion Turbine ("CT")
  - Combined Cycle Gas Turbine ("CCGT")

**Proposed EPA regulations on CO_2 have effectively eliminated all new coal plants without carbon capture.*

- Nuclear
  - Advanced Boiling Water Reactor
- Renewable Technologies
  - Biomass
  - Wind Power
  - Solar PV

Capital Cost Projections



Questions / Comments

Sales and Load Forecasts

Load Forecast Process

- The load forecasting process begins with historical monthly sales volumes
  - 2006 – 2013
  - Theoretically sound, statistically valid

- Calculate a sales forecast using an econometric model meant to determine the relationship between sales, economics, energy efficiency, and weather

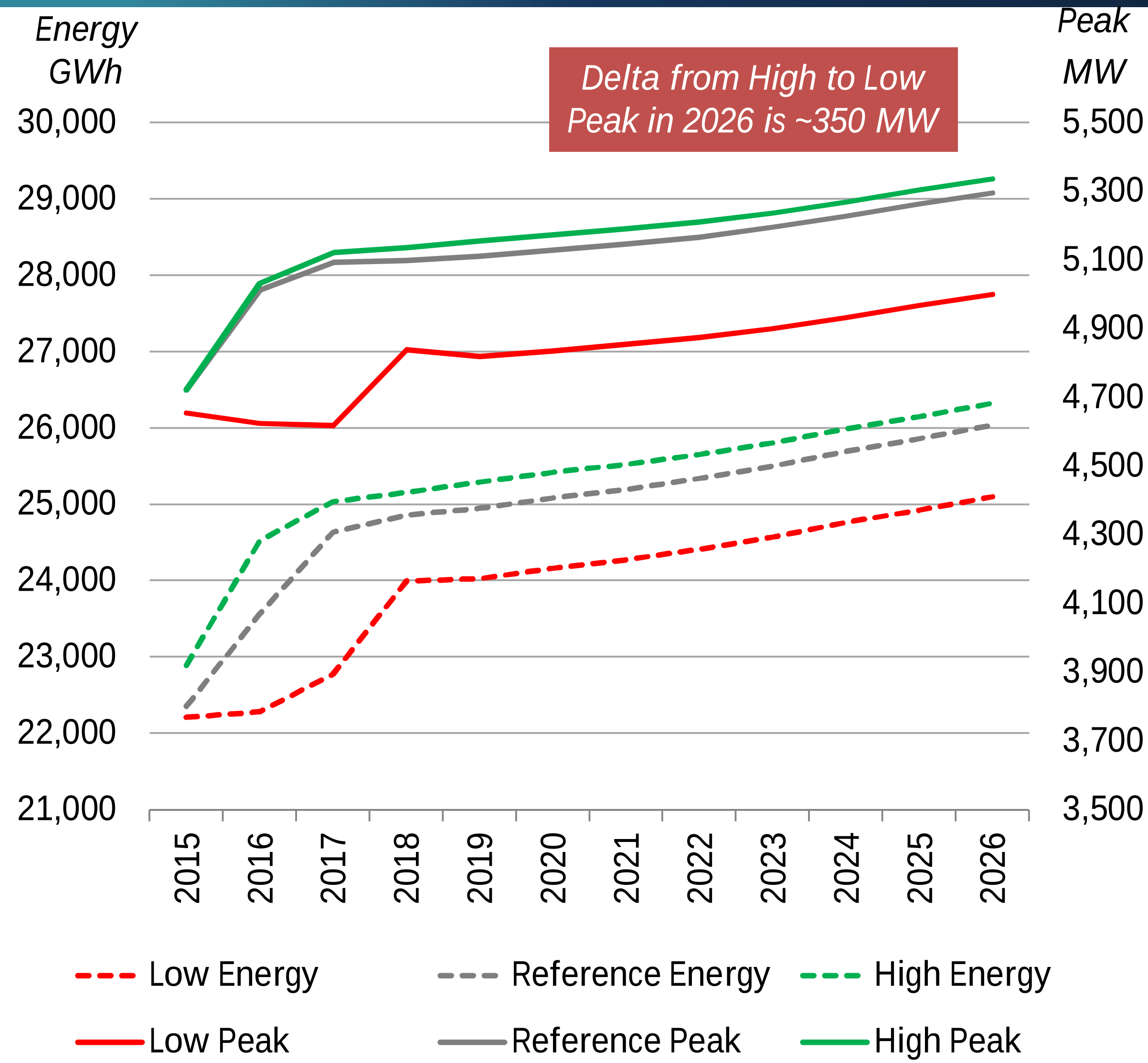
- Apply sales forecast and normal weather to regressions to calculate monthly peaks

EAI Load Forecasts for IRP

Summary of Results
- Low and High cases driven by scenarios around Economic Development assumptions
- Most of growth is concentrated in the Large Industrial segment

Uncertainties
- On-time completion and/or size of ED projects
- Possible changes to DSM targets

14-24 CAGR	Low	Ref	High
Peak	1.4%	2.0%	2.1%
Energy	1.2%	1.6%	1.7%



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Economic Outlook

- The economic outlook for the Entergy region of Arkansas remains healthy.
  - At the time of the IRP load forecast, the 10 year (2014-2024) CAGR for gross state product was 1.8%.
  - The current 10 year CAGR for this same period is 2.0%.

- According to the Federal Reserve, the state's leading index* for May shows expected growth from 0 - 1.5%. For reference, the leading indices for Oklahoma and Louisiana are negative.

- Federal energy efficiency standards – particularly concerning lighting, refrigeration, and furnaces – will continue to put downward pressure on usage per customer, primarily in the residential and commercial sectors.

- The success of EAI's energy efficiency programs is expected to continue which will further dampen peak demand.

** Measure of non-farm payroll, unemployment, wages, and average hours worked in manufacturing; Published by the Philadelphia Fed*

Questions / Comments

Preliminary Results and Next Steps

The 2015 Integrated Resource Plan

The study period for the 2015 IRP is the 20-year period of 2017 through 2036. A 20-year study period was chosen in order for EAI to evaluate long-term trends under a broad range of possible future outcomes.

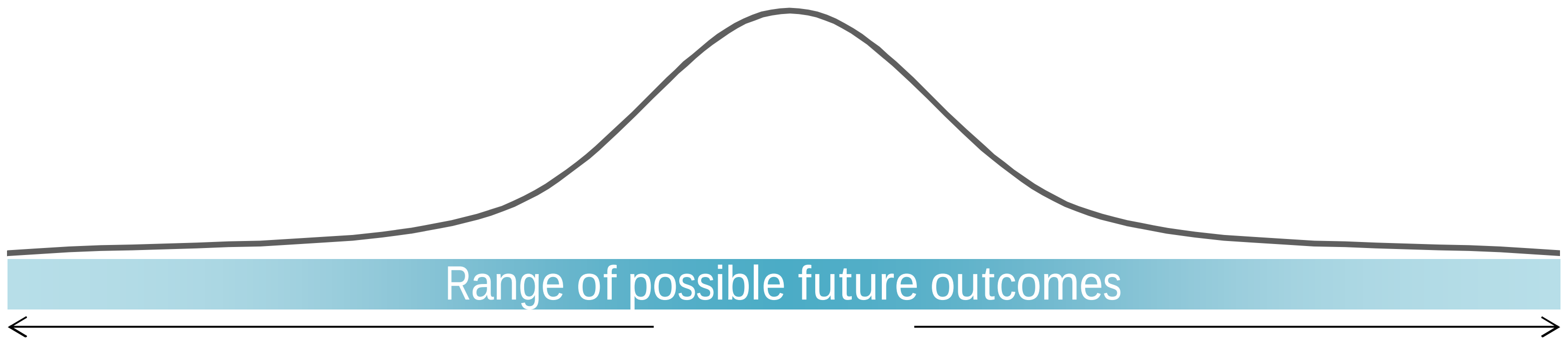
The 2015 IRP will be guided by a set of resource planning objectives EAI originally established to guide its development of its 2012 IRP and to meet the requirements of the APSC Resource Planning Guidelines for Electric Utilities[1]. The planning objectives focus on four key areas:

- cost,
- risk,
- reliability and
- sustainability.

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

Broad Range of Uncertainties

EAI is currently facing a broad range of uncertainties that impact resource planning. Some possible combinations of future outcomes will drive a higher need for additional generating resources and some will driver a lower need. The IRP reasonably bookends this range of possible outcomes.



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Development of the IRP

Long-term Outlooks for the Industry/Region

- Generation technology costs
- Electricity sales/economic indicators
- Fuel and CO_2 Prices

Impact on the Overall Market

- How the long-term outlooks for the industry/region may influence resource additions in the region overall.

Impact on EAI

- How the long-term outlooks and resource additions in the region may influence resource additions for EAI.

IRP Action Plan

- Output of the IRP which provides directional guidance to EAI's planning activities until the next update to the IRP.

Futures-based Approach

For the IRP to reasonably account for a broad range of uncertainty while focusing on an appropriate amount of meaningful, thoughtful modeling iterations, EAI Resource Planning is using a futures-based approach to the IRP analysis.

In this approach, three "futures" were developed that represent different combinations of possible outcomes of many variables.

Major areas of uncertainty to consider:

- Sales and load growth,
- Commodity price trends,
- Environmental regulation and/or legislation.

Future 1 – Reference Case

Future 1 represents EAI's Reference Case, or mid-point, of the range of uncertainties.

White Bluff and Independence	- Assume the currently proposed Regional Haze FIP - Install scrubbers in 2021 - Continue to use coal through end of 60-year useful life
CCGT Units	Assume 30-year useful life
Electric Sales & Load Forecasts	Reference Case
Henry Hub Natural Gas Price Forecast*	$4.89/MMBtu
Coal Price Forecast*	$2.46/MMBtu (volume weighted average for EAI units)
CO_2 Price Forecast*	$10.02/short ton; pricing begins in 2020

*2015$, levelized for the period 2017-36

Future 2 – Low Capacity Additions Case

Future 2 represents EAI's Low Capacity Additions Case, which bookends the lower end of the range of uncertainties in terms of assumptions that would drive the least amount of incremental capacity needs.

White Bluff and Independence	- Assume the currently proposed Regional Haze FIP - Install scrubbers in 2021 - Continue to use coal through end of 60-year useful life
CCGT Units	Assume CCGTs are available and operating through the end of the IRP study period
Electric Sales & Load Forecasts	Low Case
Henry Hub Natural Gas Price Forecast*	$3.50/MMBtu
Coal Price Forecast*	$2.20/MMBtu (volume weighted average for EAI units)
CO_2 Price Forecast*	No price for CO_2 throughout IRP study period

*2015$, levelized for the period 2017-36

Future 3 – High Capacity Additions Case

Future 3 represents EAI's High Capacity Additions Case, which bookends the higher end of the range of uncertainties in terms of assumptions that would drive the highest amount of incremental capacity needs.

White Bluff and Independence	- Approval of plan to cease using coal at White Bluff by a time certain (2028) that makes scrubber installation economically unsupportable under federal air regulations, and thus not required. - Final FIP does not require Independence scrubber installation; assumption that similar controls are required in later Regional Haze planning period (2028-38)
CCGT Units	Assume 30-year useful life
Electric Sales & Load Forecasts	High Case
Henry Hub Natural Gas Price Forecast*	$7.68/MMBtu
Coal Price Forecast*	$3.67/MMBtu (volume weighted average for EAI units)
CO_2 Price Forecast*	$29.68/short ton; pricing begins in 2020

*2015$, levelized for the period 2017-36

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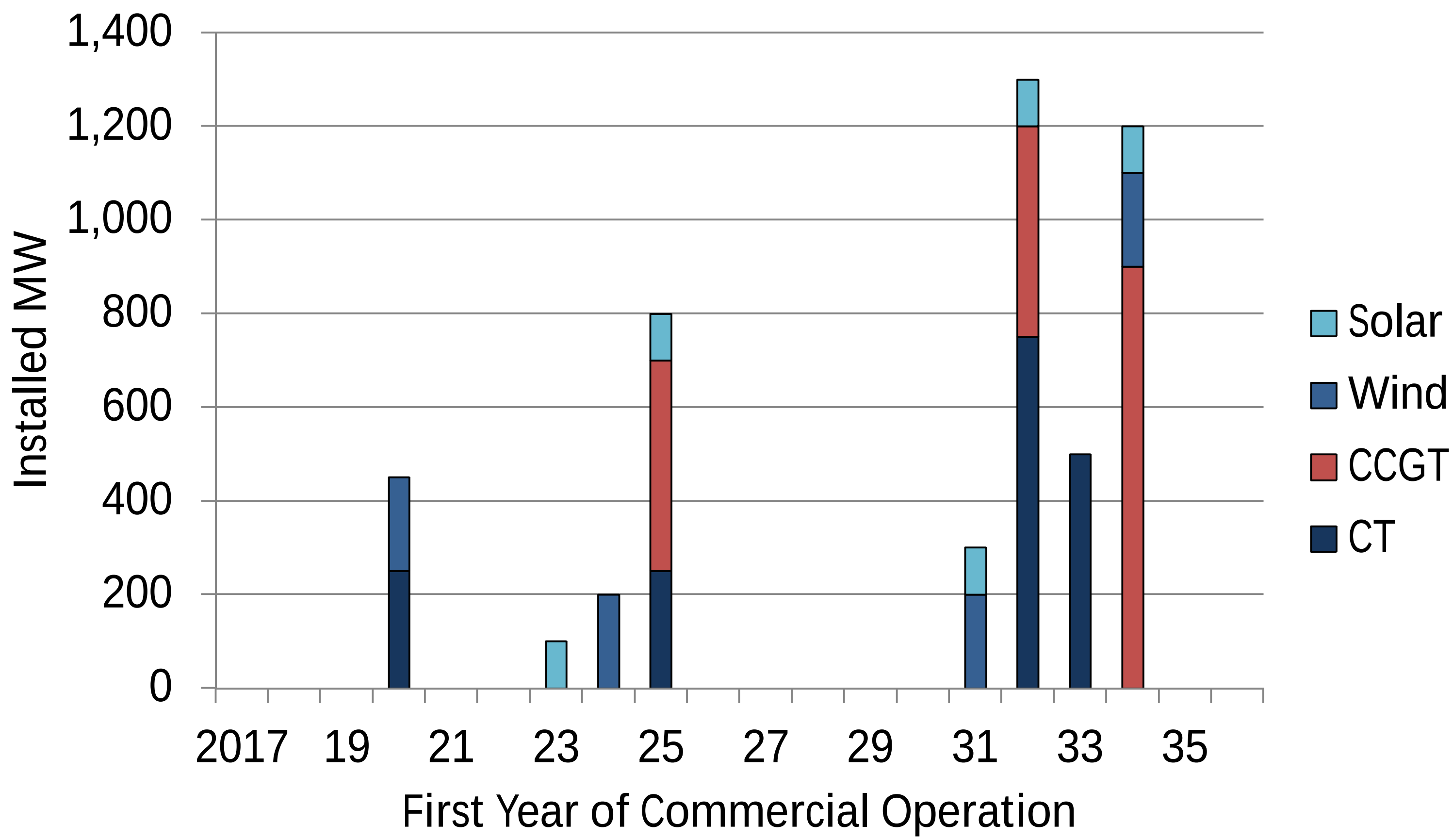
AURORA Portfolio Optimization

For each future, the AURORA Portfolio Optimization tool will select (i.e., output) a 20-year resource portfolio that is economically optimal for EAI under that set of circumstances.

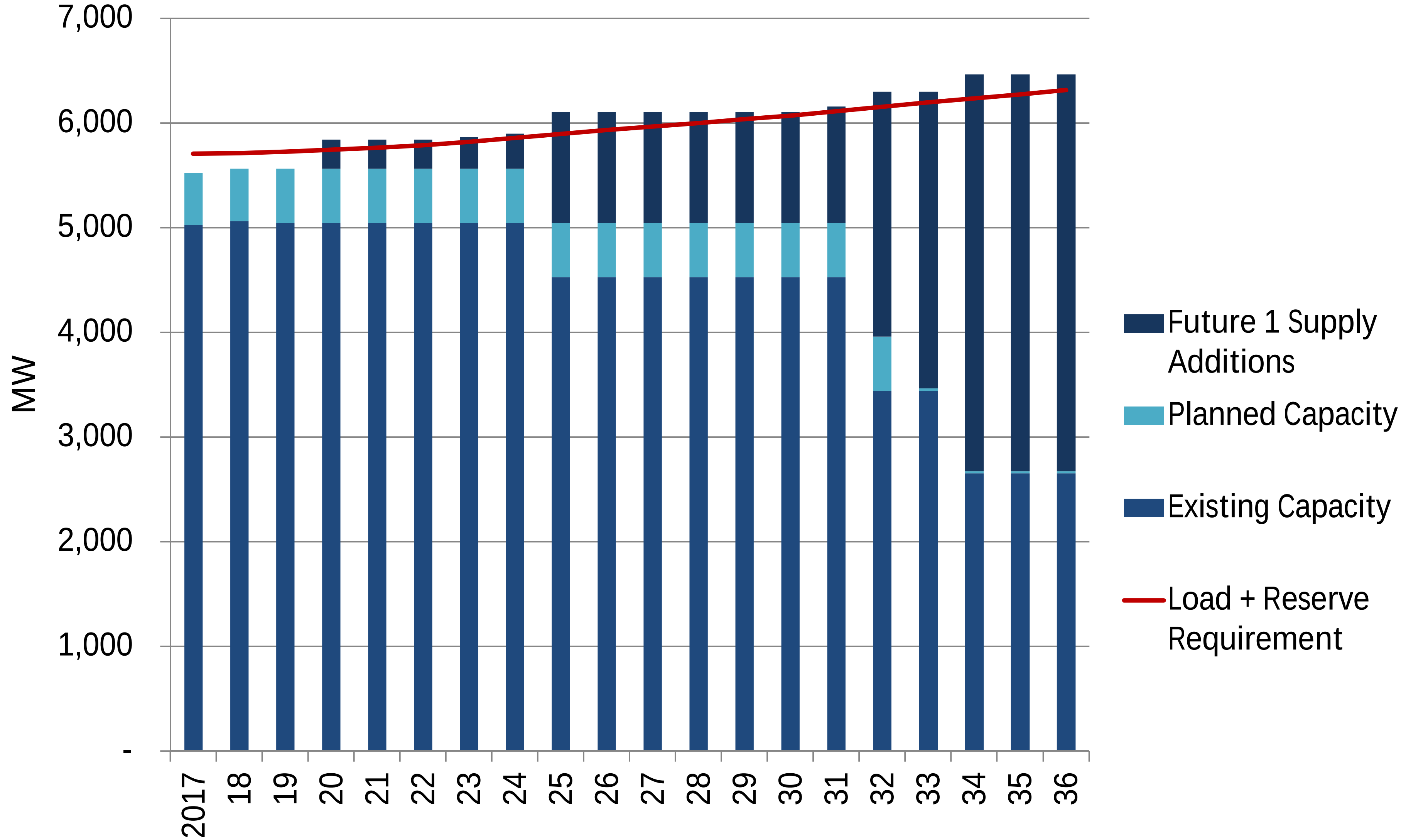
The model adds incremental generating resources whenever needed in order to maintain the target reserve margin (12% of EAI peak load). The model selects the resource alternative that is most valuable in the market.

The following slides show the incremental supply additions select by the AURORA Portfolio Optimization tool as well as the Load and Capability for each future. The model results show installed capacity and the Load and Capability shows effective capacity. The effective capacity is 25% for solar resources, 14.7% for wind resources and 100% for CT and CCGT resources.

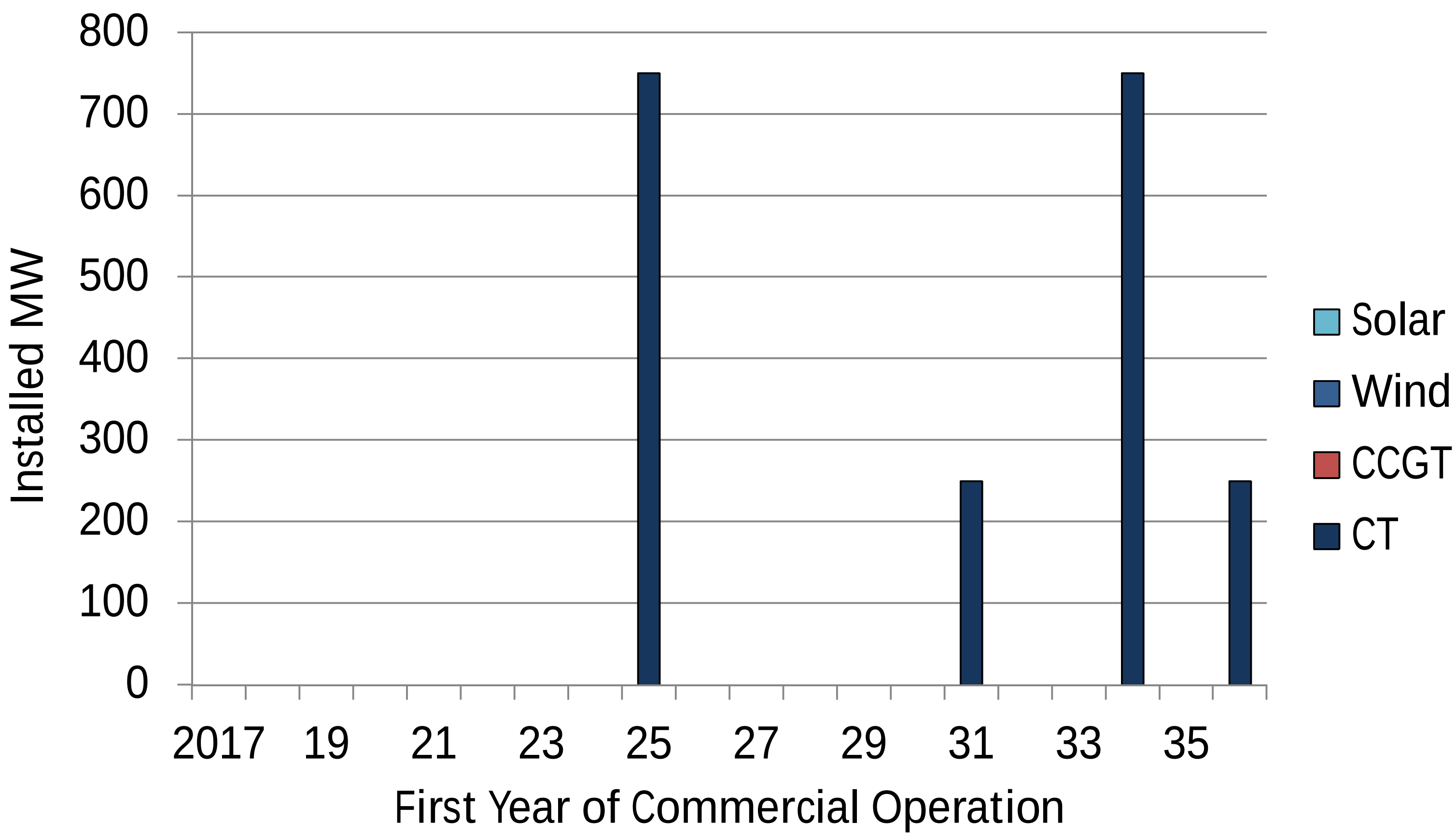
Future 1 – Portfolio Optimization Model Results



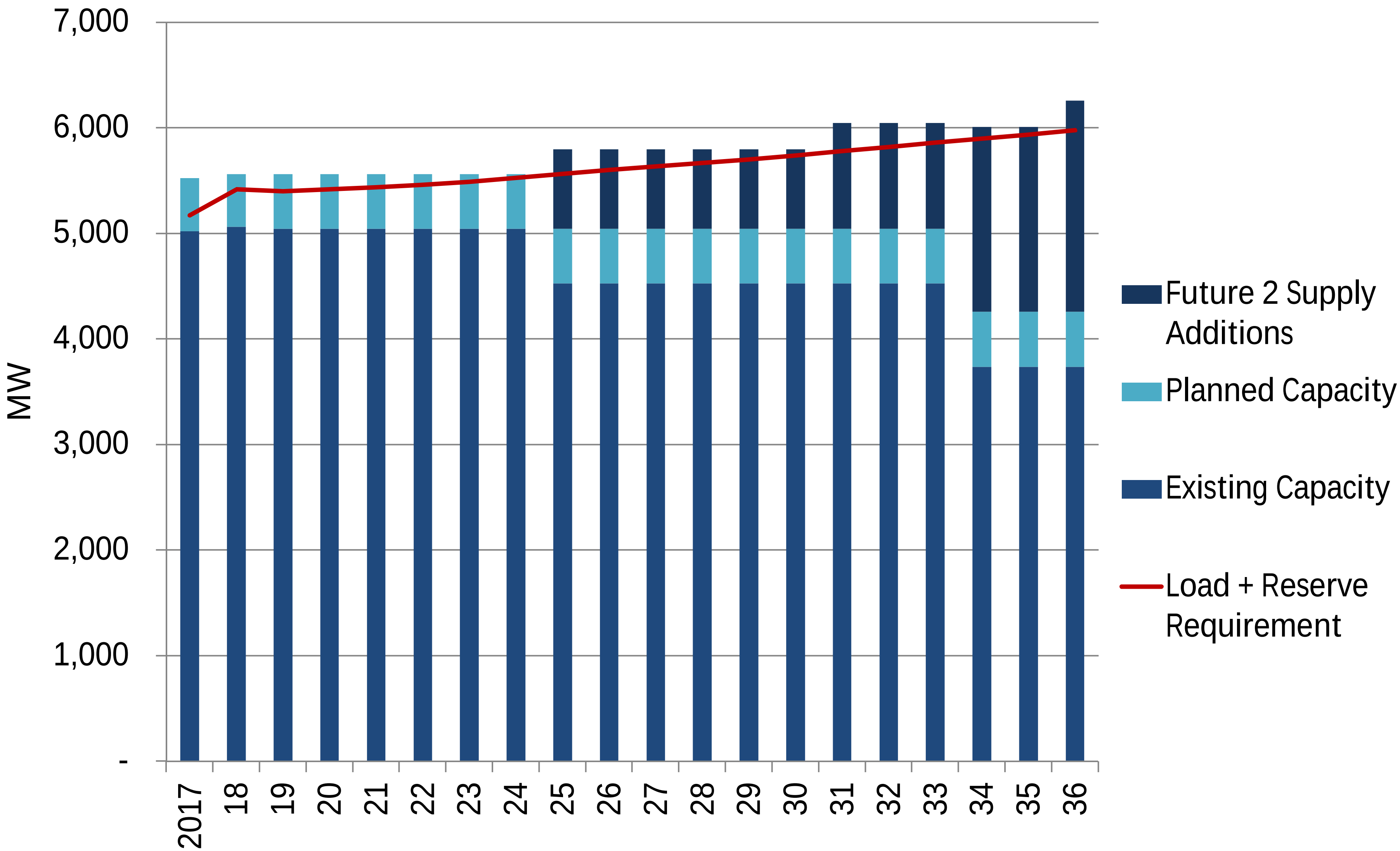
Future 1 – Load & Capability Position



Future 2 – Portfolio Optimization Model Results



Future 2 – Load & Capability Position



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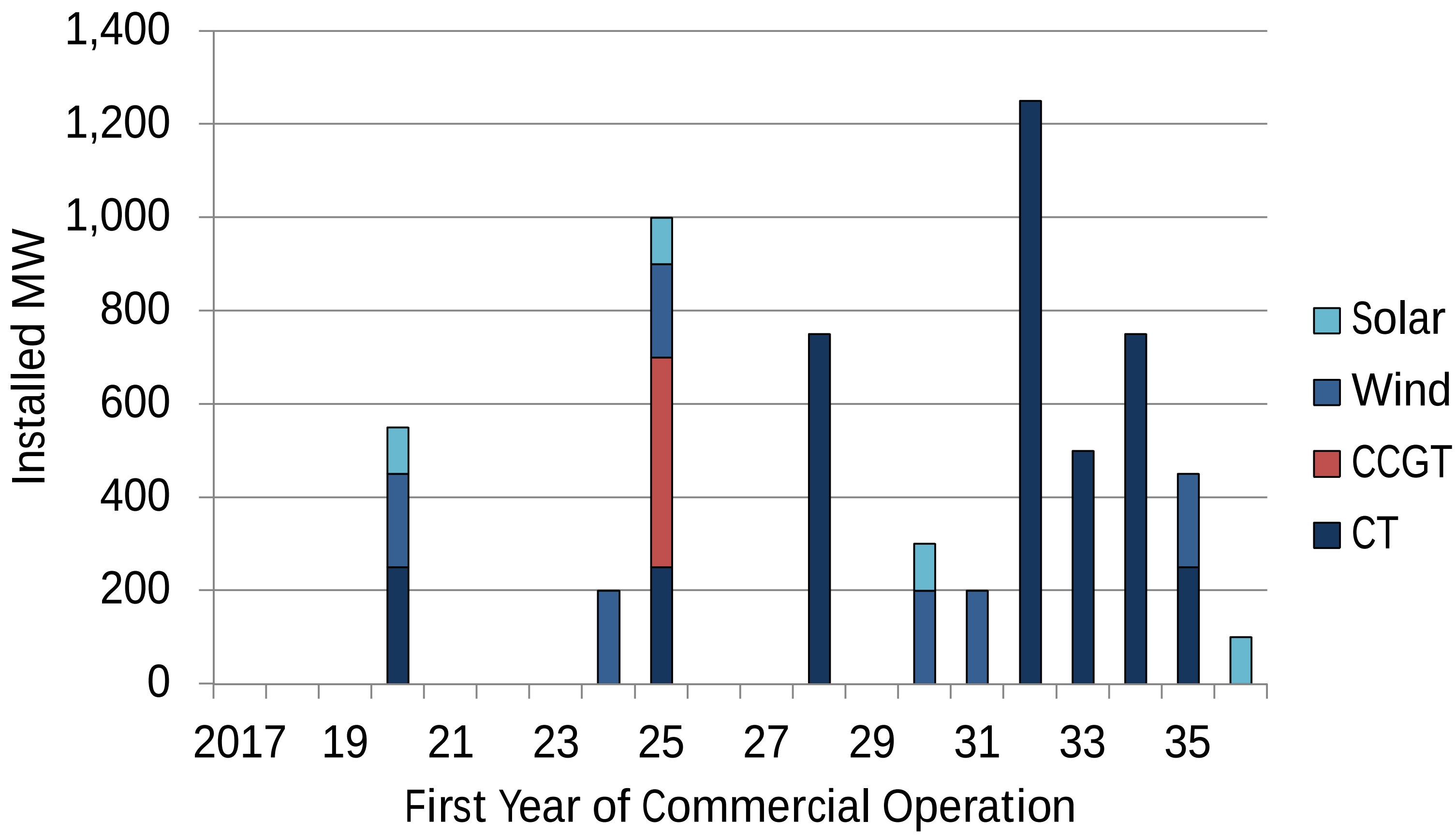
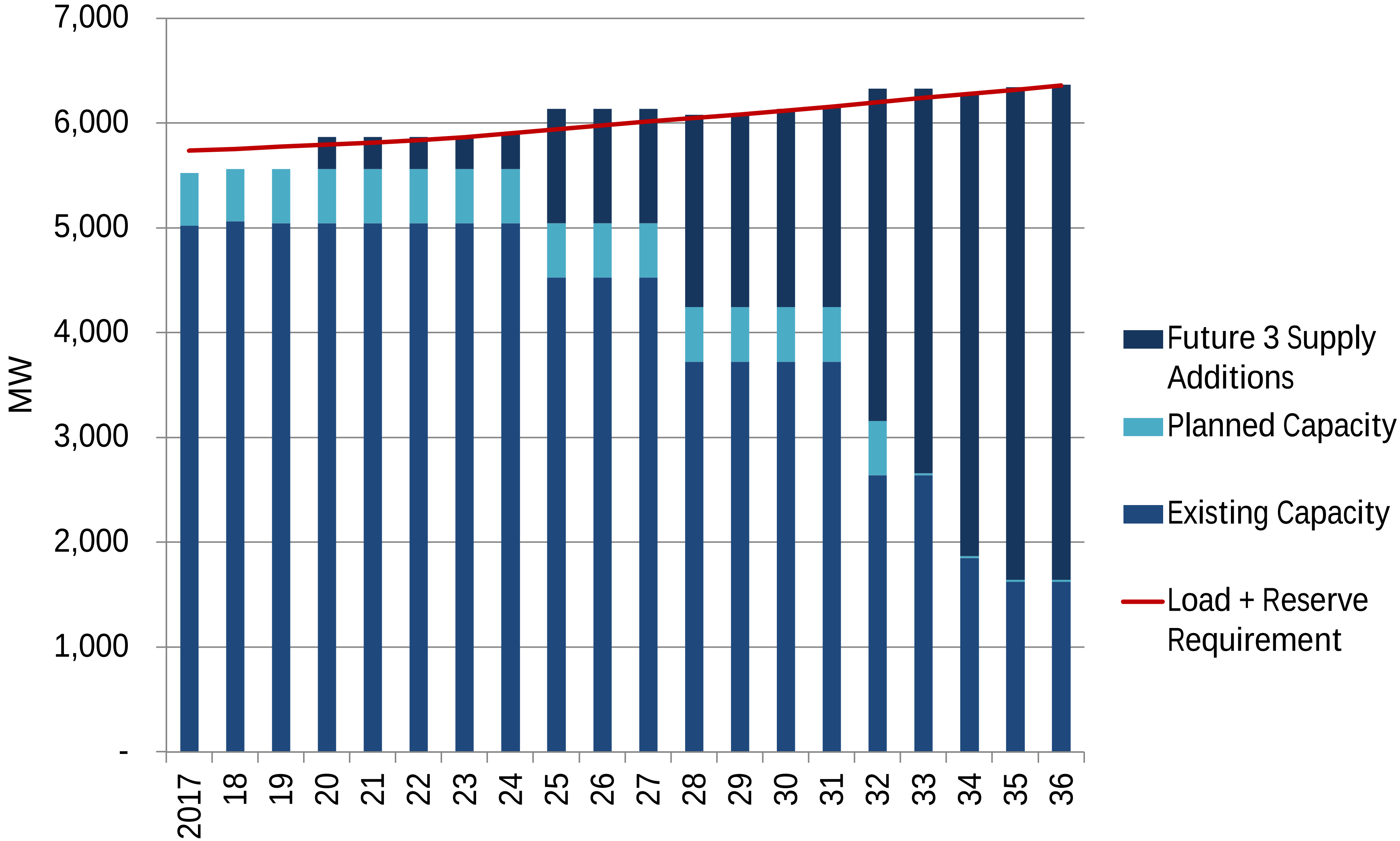
Future 3 – Portfolio Optimization Model Results



Future 3 – Load & Capability Position



Summary of Model Results

While facing a broad range of uncertainty, the EAI IRP analysis reasonably bookends the future and provides a set of data points for EAI Resource Planning to evaluate.

Observations of long-term trends within and between the futures will guide the development of EAI's 2015 IRP Action Plan which will outline actions for the next one to three years.

2017-36	Future 1	Future 2	Future 3
Total Incremental Installed Capacity	4,850 MW	2,000 MW	6,050 MW
CT/CCGT Capacity Additions	73.2%	100%	73.6%
Renewable Capacity Additions	26.8%	0%	26.4%
Incremental Capacity Additions Begin	2020	2025	2020
Load + Reserve Requirements in First Year of Capacity Addition	5,743 MW (2020)	5,564 MW (2025)	5,793 MW (2020)

Next Steps in IRP Development

- Engage with stakeholders, as requested, through early October
- Develop 2015 IRP Action Plan
- Receive and review Stakeholder Report
- File IRP Report no later than October 31

AFTER LUNCH: STAKEHOLDER SESSION

Stakeholder Process

After lunch, stakeholders will reconvene in the meeting room. Once the stakeholder group has completed their discussions, they'll notify the Entergy group to return to the meeting room.

We'll discuss next steps and answer any remaining questions before adjournment.

Questions / Comments

Wrap-up and Next Steps

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Entergy Arkansas, Inc.
2015 Integrated Resource Plan

August 14, 2015
Follow-up Material to 2015 IRP Stakeholder Meeting

Follow-up Materials to the 2015 IRP Stakeholder Meeting

The following information is provided as a supplement to the information provided during the August 7th Stakeholder Meeting in response to stakeholder questions and feedback from that meeting.

Any additional requests for information may be sent to EAI at EAIIRP@entergy.com.

Lifecycle Resource Cost for 2015 Resources

Levelized $2015/MWh; based on 2015 installation

Based on EAI Cost of Capital [1]		No CO_2			With CO_2 [2]		
Technology	Capacity Factor	Reference Fuel	High Fuel	Low Fuel	Reference Fuel	High Fuel	Low Fuel
G Frame CT	10%	$153	$195	$137	$160	$201	$143
Large Aeroderivative CT	40%	$97	$137	$82	$103	$142	$87
Internal Combustion	40%	$104	$141	$90	$110	$146	$95
1x1 G Frame CCGT	65%	$66	$94	$54	$70	$99	$58
2x1 G Frame CCGT	65%	$61	$89	$49	$65	$94	$53
PC With CCS	85%	$150	$219	$99	$153	$222	$101
Biomass	85%	$167	$316	$133	$167	$316	$133
Nuclear	90%	$134	$146	$134	$134	$146	$134
Wind (No Subsidy)	48%[3]	$54	$54	$54	$54	$54	$54
Solar PV (30% ITC)	26%	$75	$75	$75	$75	$75	$75

1. Includes capacity Levelized Nominal Lifecycle Cost of Resources Deployed in 2015, $/MWh. Lifecycle cost is based on assumed capacity factors for screening purposes. Projected capacity factors calculated by the Aurora production cost model may result in different lifecycle resource costs.
2. CO_2 emissions cost based on IRP reference case; begins in 2020 at $1.39/U.S. ton nominal $, reaches $32.10/ton in 2035
3. Capacity factor representative of mid-west geographical region

Sales & Load Forecasts

- What was the growth from 2004-2014?
  - EAI's weather adjusted retail sales compound annual growth rate from 2004-2014 was 0.4%.

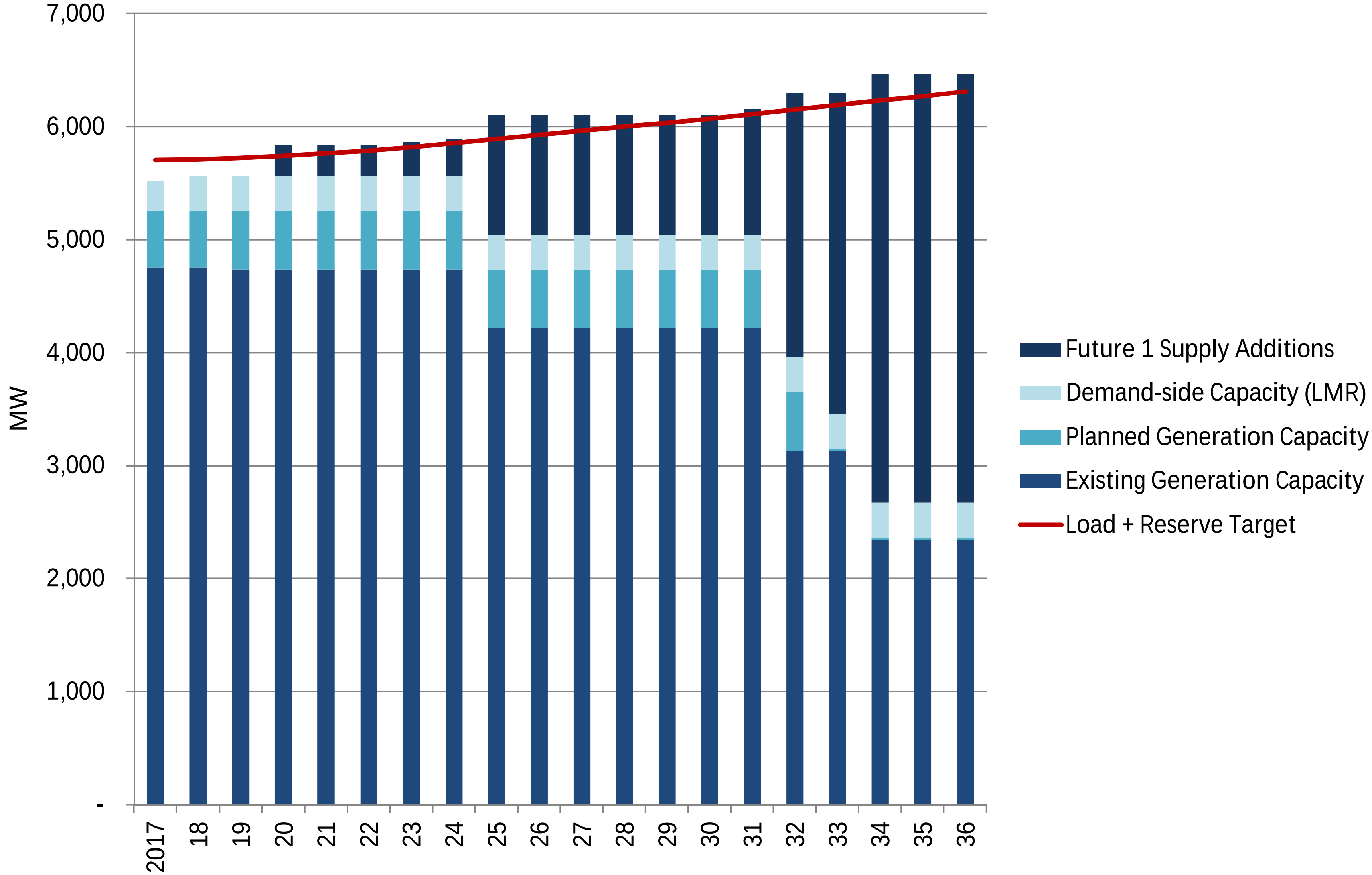
- What is the long term growth rate without the step increases in the load?
  - The 10 year CAGR for load from 2018-2028 for each of the scenarios is around 0.5%, with a slightly lower growth rate of around 0.45% for the low scenario. There are no industrial step increases in the load beyond 2018.

Load & Capability Position

The following three slides show EAI's load plus reserves compared to capacity resources for each of the three IRP Futures. No values have changed from the August 7 presentation; however, the capacity value from EAI's demand side resources has been identified separately for clarification purposes.

The effective capacity is shown, which is 25% for solar resources, 14.7% for wind resources, based on the assumed capacity credit value from MISO, and 100% for CT, CCGT and demand-side capacity resources.

Future 1 – Load & Capability Position



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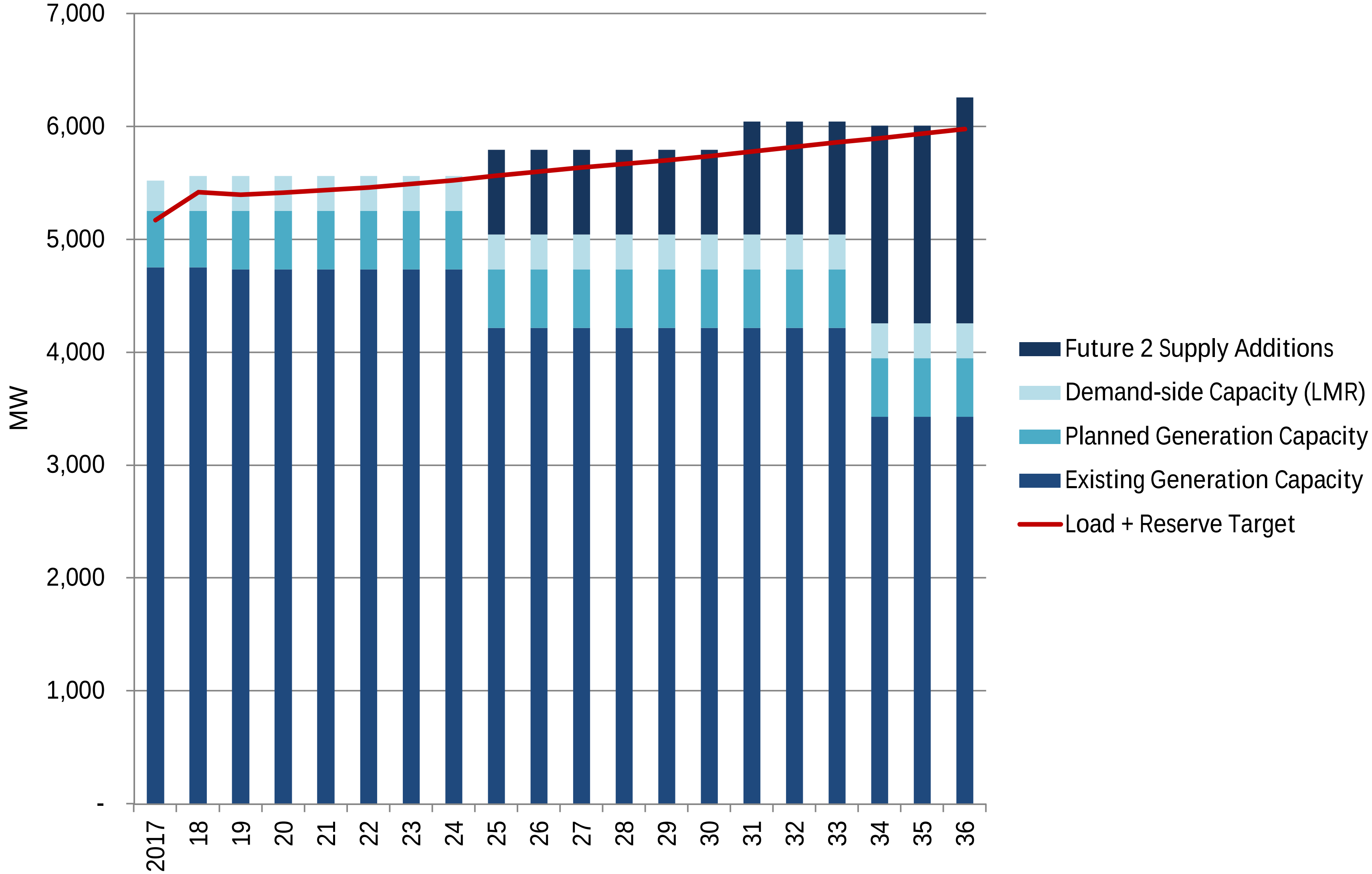
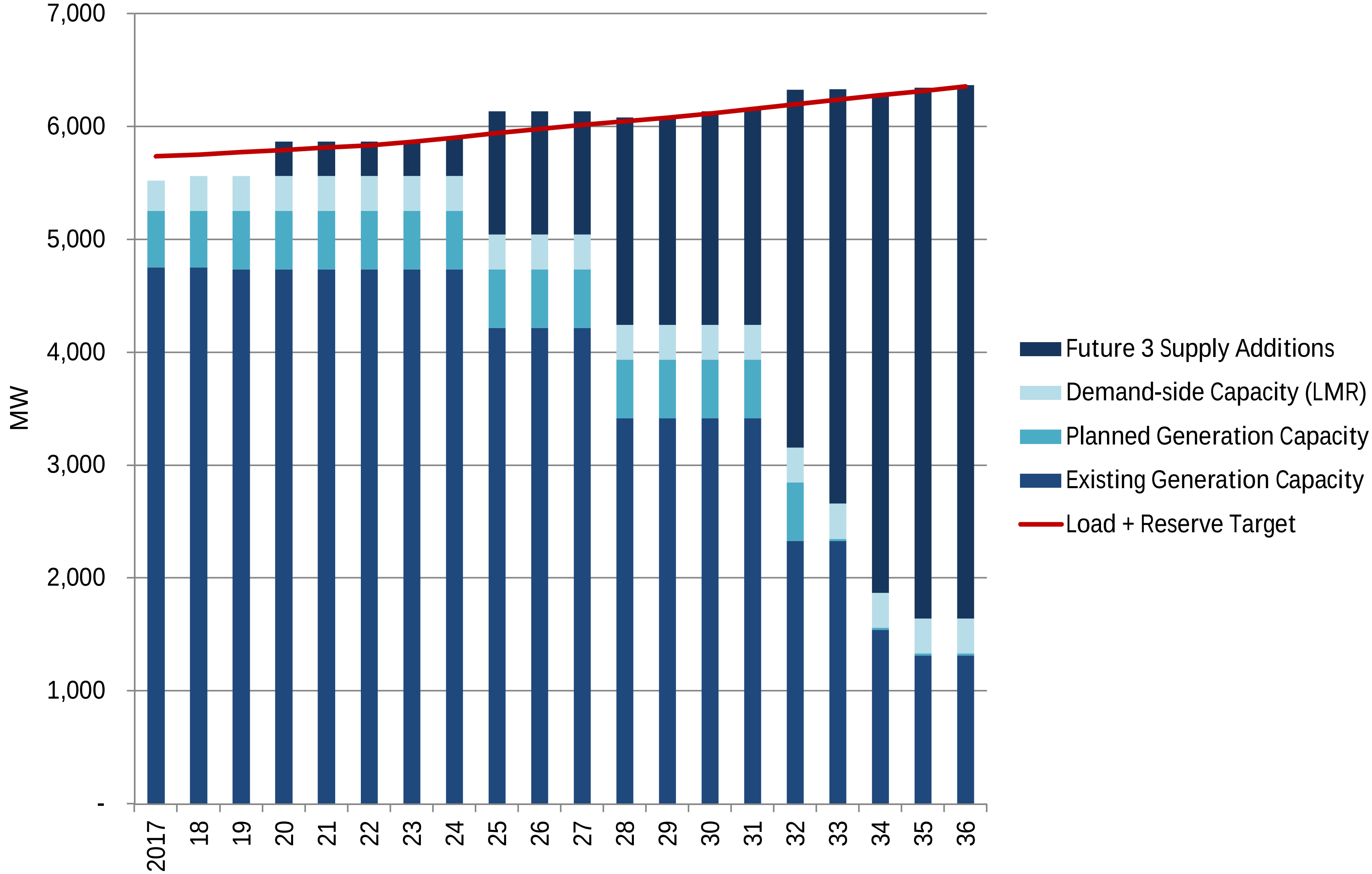
Future 2 – Load & Capability Position



Future 3 – Load & Capability Position

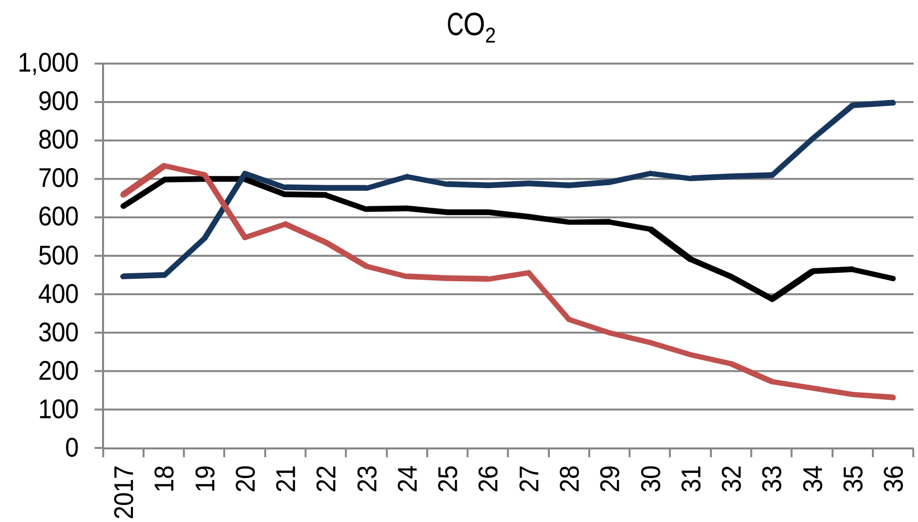


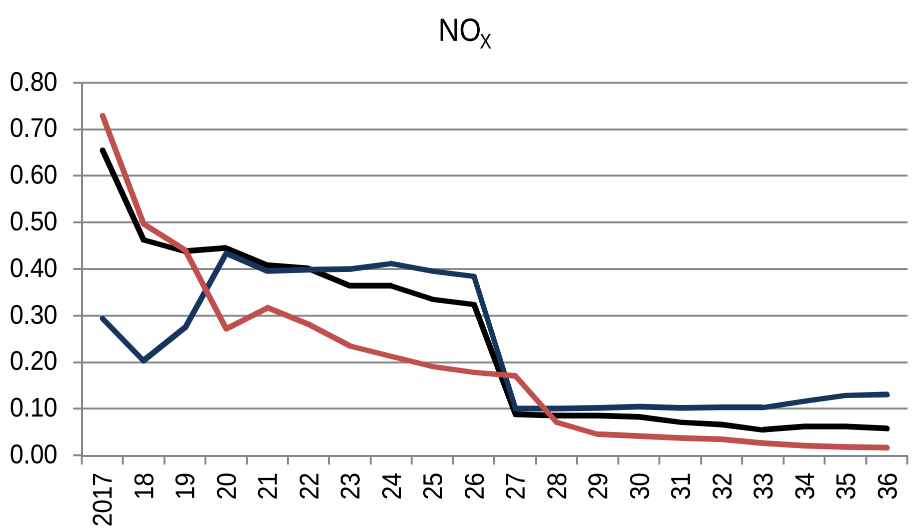
Annual Projected Emissions

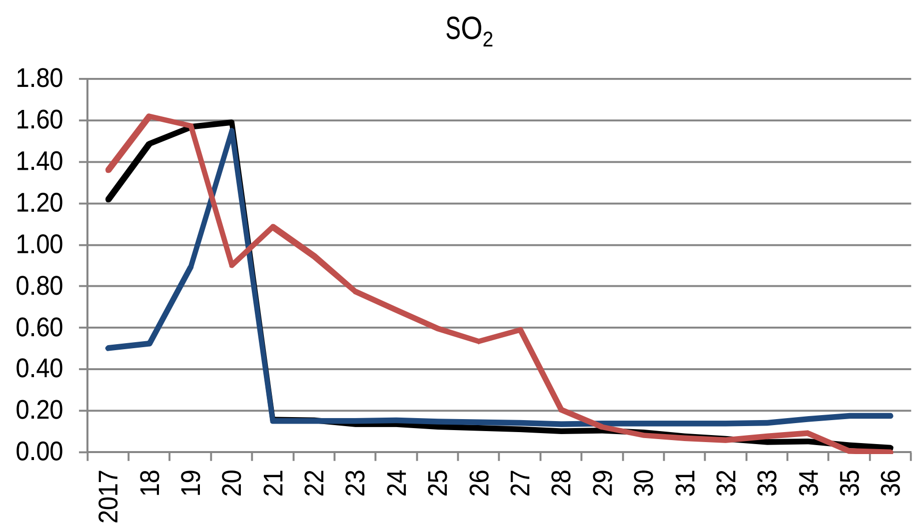
Based on modeled net generation, emissions rates (lb./MWh) have been calculated for each future. The rates are calculated as total emissions from EAI's existing and incremental resources divided by EAI's total existing and incremental generation.

Included in this calculation are all supply side resources including hydro and nuclear resources as well as EAI's resources located outside of Arkansas. No adjustment has been made for assumed demand side (EE) resources.

Future 1 —— Future 2 —— Future 3 ——







Response to Written Questions

- Are the technology capacity factors a net or gross capacity factor?
  - The capacity factors (shown on slide 104) are net capacity factors.

Next Steps in IRP Development

- Engage with stakeholders, as requested, through early October
- Develop 2015 IRP Action Plan
- Receive and review Stakeholder Report
- File IRP Report no later than October 31

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Entergy Arkansas, Inc.
2015 Integrated Resource Plan

September 3, 2015

Response to Stakeholder Group's Meeting Notes

EAI Response to Stakeholder Group

EAI received meeting notes on 8/13/2015 from Ken Smith on behalf of the Stakeholder Group. The notes, compiled by Jim Wimberly, included requests for additional information and analysis.

The following slides are EAI's response to the Stakeholder Group's requests.

Item #1

1. Organizational
   – Kurt Castleberry replied to Ken Smith's email offering to arrange meeting rooms and make EAI folks available to participate in meetings, as needed, with reasonable notice.
   – Stakeholder Report will be completed by October 15.

EAI Response: Item #2 (1 of 3)

2. Alternate future generation scenarios requested by the SG
   - An additional AURORA Portfolio Optimization model run has been completed in response to the SG's request for the future supply additions assuming White Bluff and Independence cease to use coal in 2028. The assumptions for this new model run and preliminary results are shown on the following slides.
   - The SG's request for the future supply additions assuming White Bluff and Independence are fully operational and all CCGT plants are extended is the same as Future 2 as presented at the 8/7/15 IRP Stakeholder Meeting with one difference. The difference is that it would assume no scrubber installations at White Bluff and Independence. This difference would not affect the supply additions.

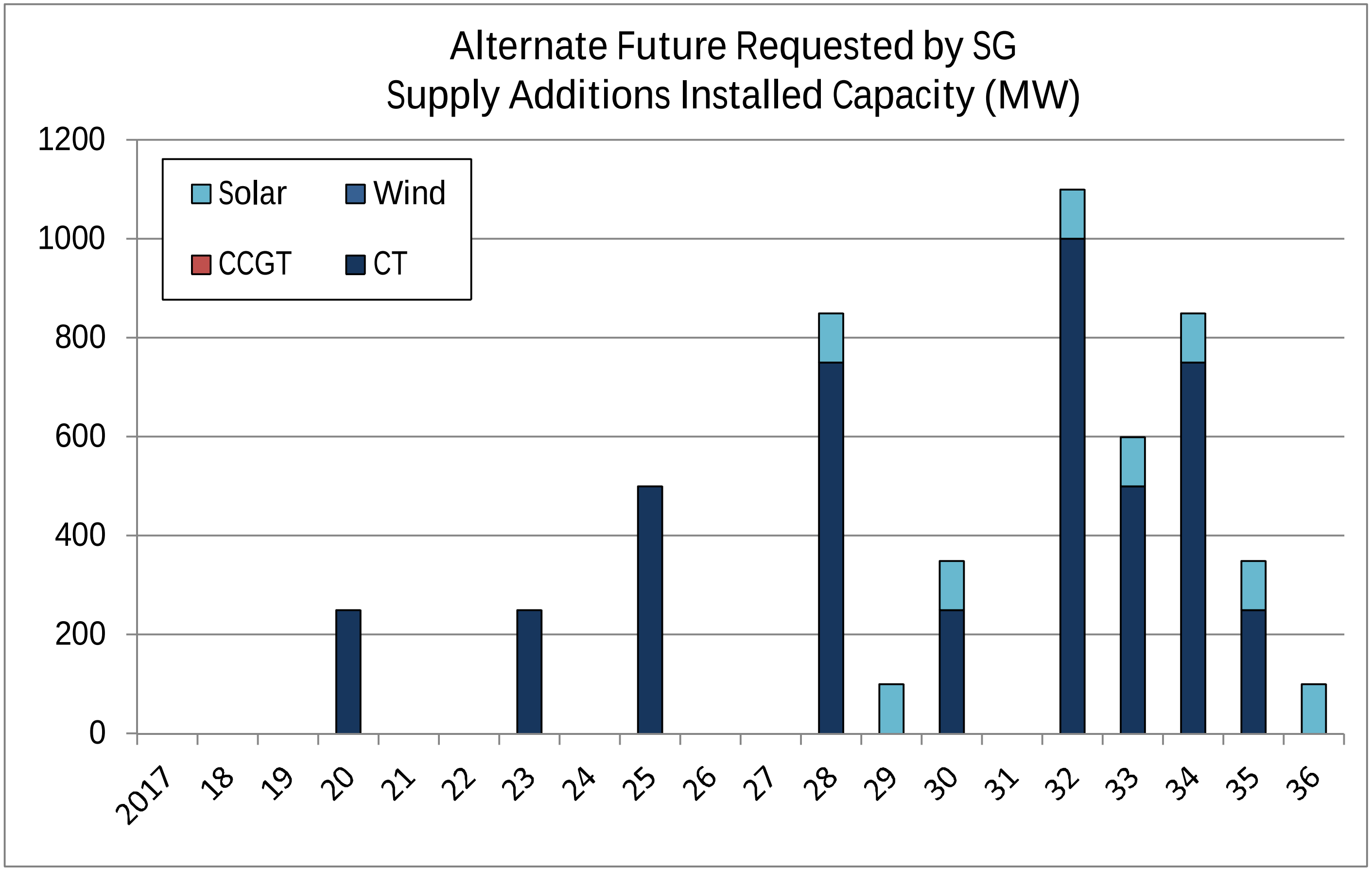
EAI Response: Item #2 (2 of 3)

The alternate future requested by the SG assumes White Bluff ceases to use coal in 2028 and Independence in 2035. EAI is not aware of a potential future outcome that would require Independence cease to use coal or shut down in 2028.

The SG request to vary the cost for solar resources (item #5) is also included in this model run at a 2015 installed cost of $1,400/kW, as opposed to EAI's current long-term point-of-view, which is $2,300/kW.

	Alternate Future
Existing Resource Portfolio	
Cease to Use Coal at White Bluff	2028
Cease to Use Coal at Independence	2035
EAI Existing CCGTs	30 years
Solar Technology Cost	$1,400/kW
Customer Electricity Requirements	
Energy sales and Load	Reference
Commodity Price Forecasts	
Fuel Prices	Reference
Environmental Allowances	Reference

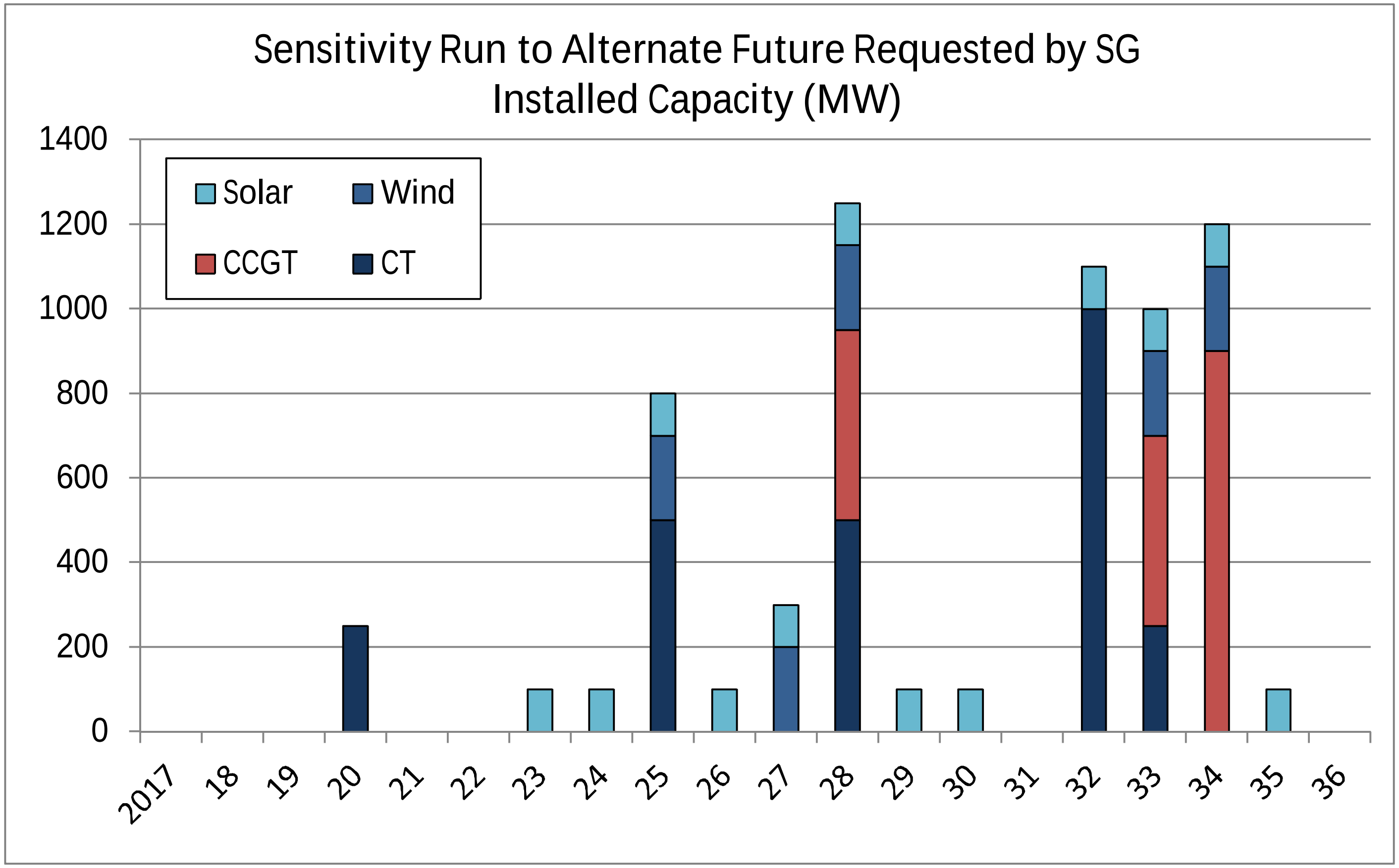
EAI Response: Item # 2 (3 of 3)



EAI Response: Item # 2 Additional Analysis (1 of 2)

- After observing that the Portfolio Optimization model run for the Alternate Future selected eight solar resources, a sensitivity run was completed in which we forced the model to select an additional four solar resources, for a total of twelve solar resources. The rest of the portfolio was optimized by the model.
- The composition of the sensitivity case portfolio is different from the fully optimized portfolio resulting from the initial model run, but the total effective capacity and costs are very close.
- The results of the additional model run is shown on the following slide.

EAI Response: Item # 2 Additional Analysis (2 of 2)



EAI Response: Items # 3 and # 4

3. Graphic Outputs
   – See slides 5 through 9 of the “Follow Up to Aug 7 IRP Stakeholder Mtg.pptx” posted to EAI’s IRP Website on 8/14/2015 or slides 107 through 109 of this document.

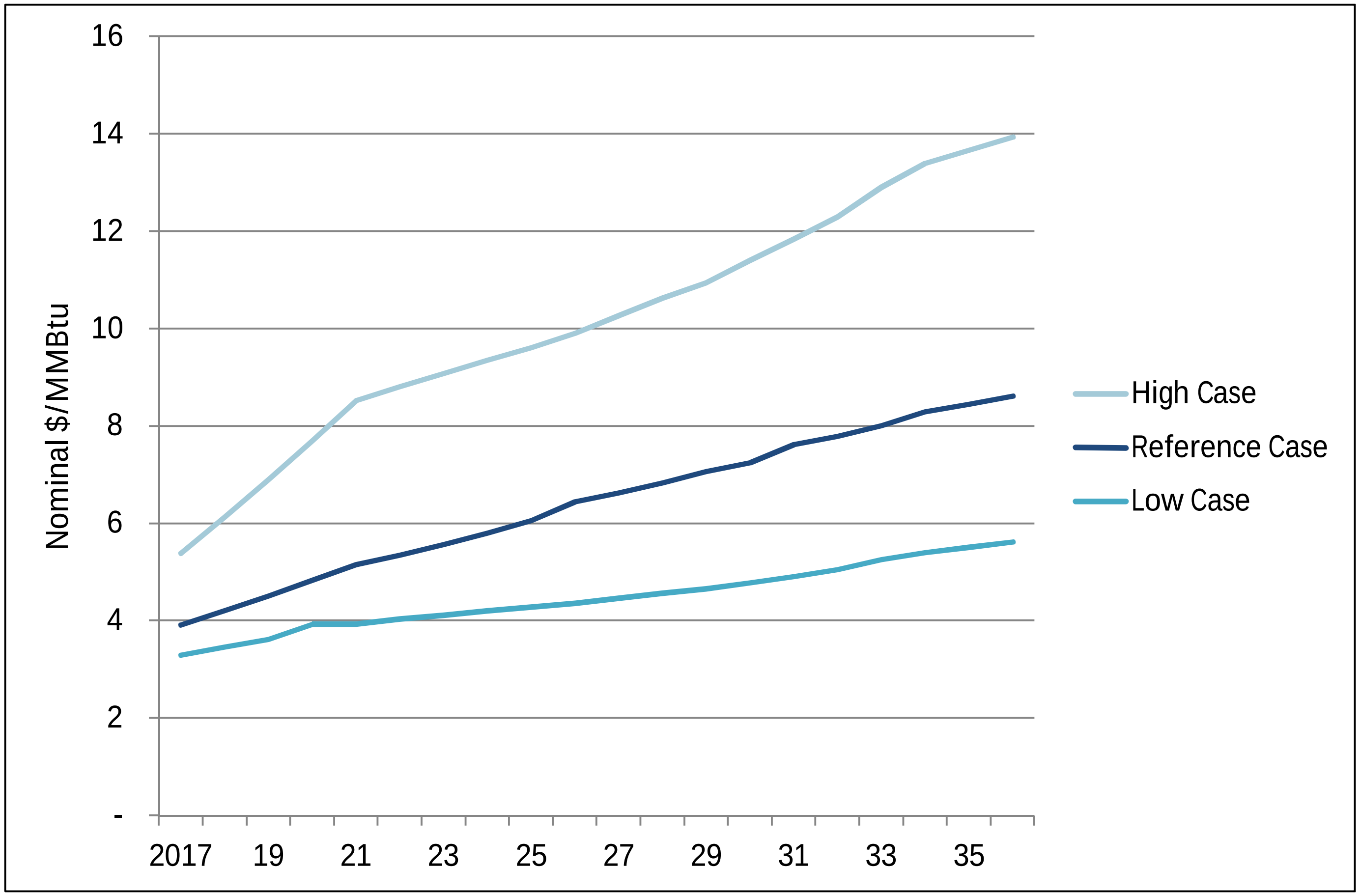
4. Life Cycle Costs
   – See slide 3 of the “Follow Up to Aug 7 IRP Stakeholder Mtg.pptx” posted to EAI’s IRP Website on 8/14/2015 or slide 104 of this document.

EAI Response: Item #5 (1 of 3)

5. Sensitivity analyses on energy costs
   - The requested additional AURORA Portfolio Optimization model run described on slides 116-117 of this document considers a lower installed cost assumption for new solar resources.
   - The SG refers to SWEPCO's IRP for cost of wind power, which appears to be reasonably aligned with EAI's point-of-view on wind costs for long-term resource planning. EAI's assumption of $54/MWh for a 48% capacity factor is in-line with SWEPCO's assumptions which range from $47-$60/MWh at a 45%-56% capacity factor.
   - Additional information on the natural gas and carbon price assumptions used in EAI's IRP analysis, which cover a reasonably broad range of outcomes, are shown on the following slides.

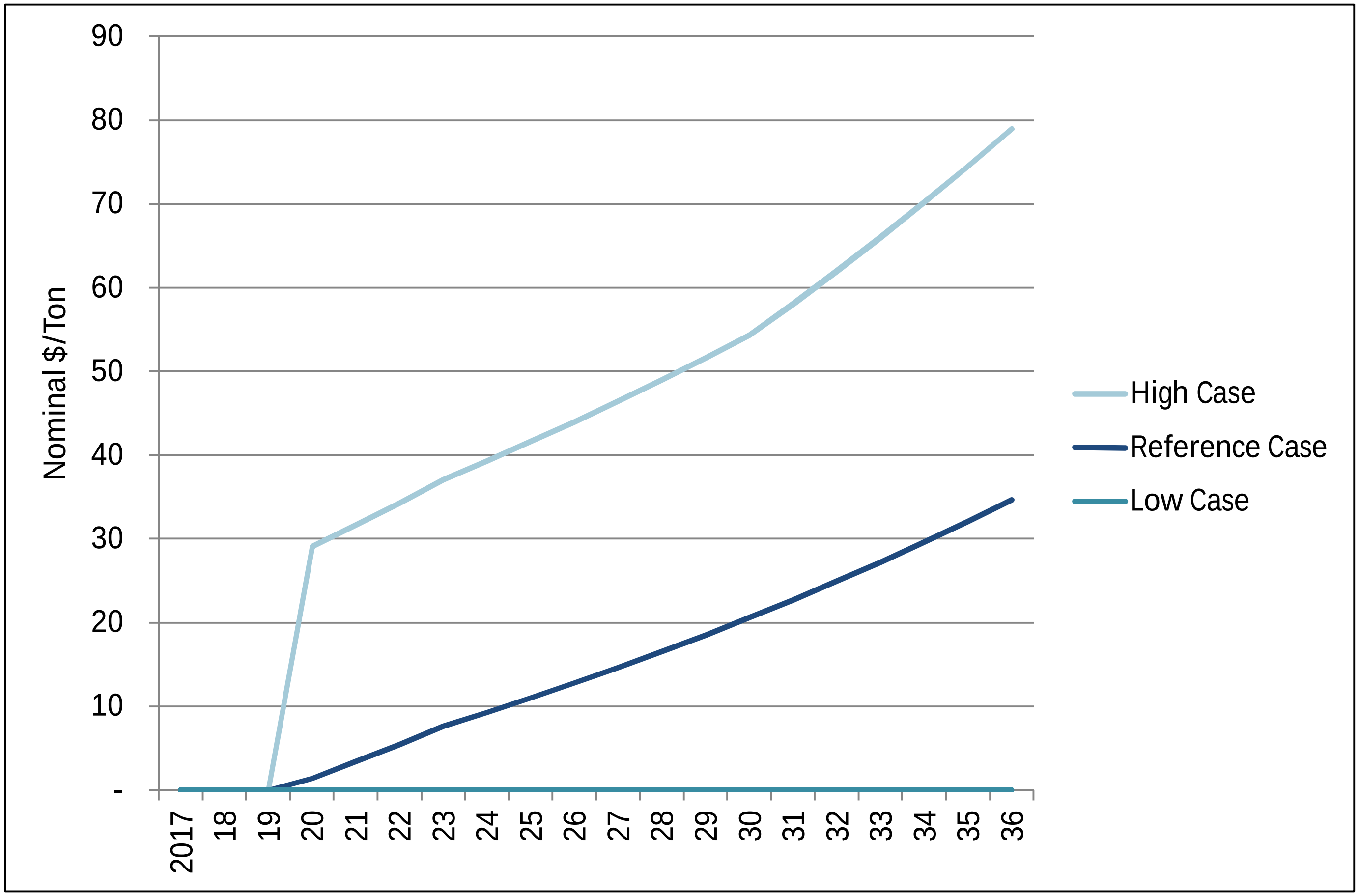
Item #5 (2 of 3)

Henry Hub Natural Gas Price
Reference Case (Future 1), Low Case (Future 2), High Case (Future 3)



Item #5 (3 of 3)

Carbon (CO_2) Price
Reference Case (Future 1), Low Case (Future 2), High Case (Future 3)



Next Steps in IRP Development

- Engage with stakeholders, as requested, through early October
- Develop 2015 IRP Action Plan
- Receive and review Stakeholder Report
- File IRP Report no later than October 31

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Entergy Arkansas, Inc.
2015 Integrated Resource Plan

September 16, 2015
Response to Stakeholder Group's Meeting Notes

EAI Response to Stakeholder Group

During the Stakeholder Group conference call that took place on 9/3/2015, EAI received new requests for documentation and additional analysis.

The following slides are EAI's response to the Stakeholder Group's requests.

Supplemental Documentation (1 of 3)

Q: What are the assumed capacities of incremental resources?

A: This information was originally presented by EAI at the August 7th Stakeholder Meeting in Little Rock and is available on slides 68-71 of that presentation. For reference, a summary of a few of resource types are summarized below. The model is limited to adding one each of solar and wind resources per year.

Technology Type	Net Max Capacity (MW)
Solar	100
Wind	200
CT	250
CCGT	450

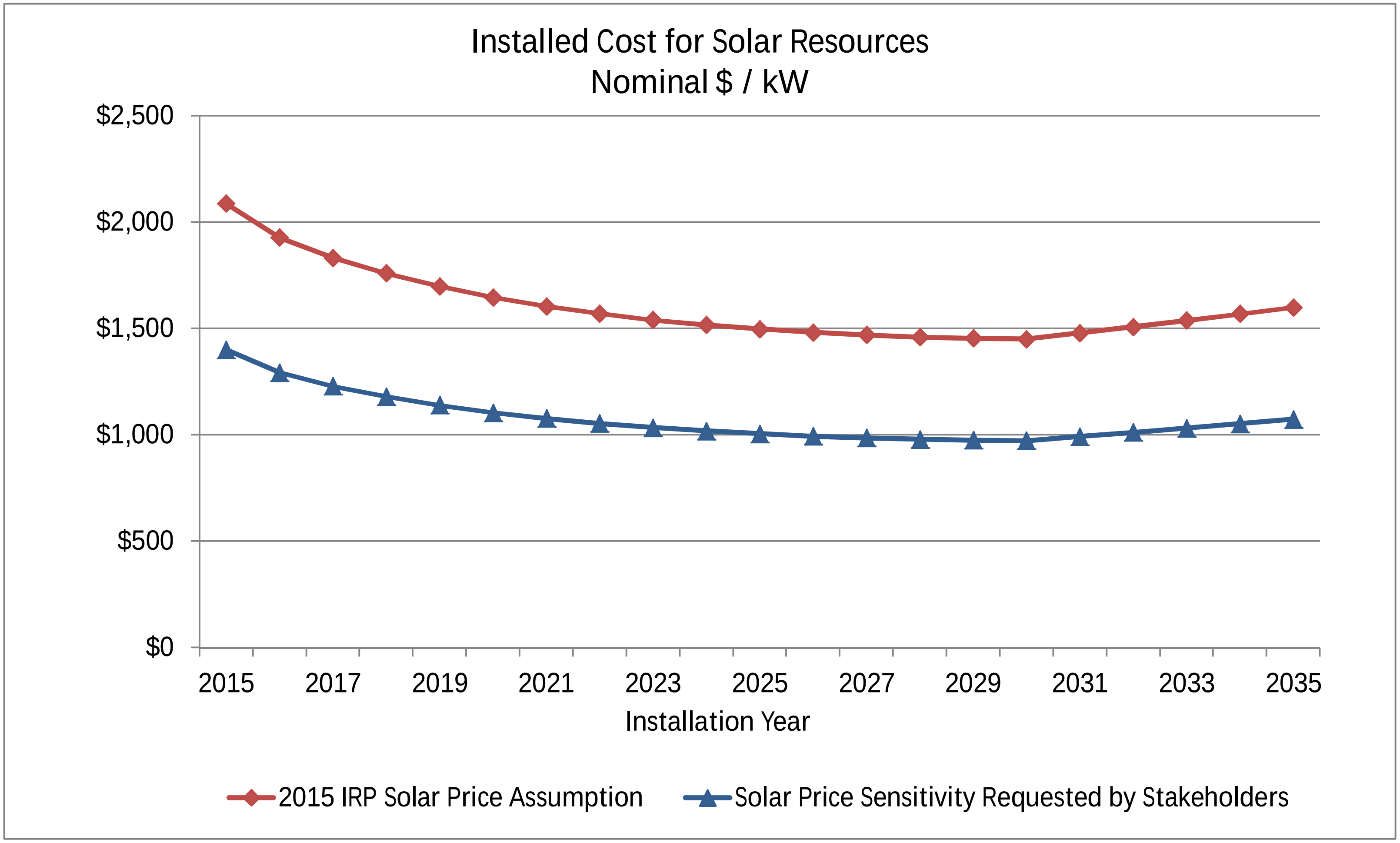
Supplemental Documentation (2 of 3)

Q: What is the forward price curve and LCOE for solar technology in the alternate future requested by stakeholders?

A: The following slide (#166) shows the forward price curve for both the $1,400/kW installed cost assumption that was used in the alternate future provided to the SG on Sept. 3 as well as the assumption used in EAI's 2015 IRP Futures 1-3.

Slide #167 shows the LCOE table provided to the SG on Aug. 14 amended to include additional line items for the solar and wind technologies assumptions used in the alternate futures modeled in response to SG's requests.

Solar Resource Forward Price Curve



Lifecycle Resource Cost for 2015 Resources

Levelized $2015/MWh; based on 2015 installation

Based on EAI Cost of Capital [1]		No CO_2			With CO_2 [2]		
Technology	Capacity Factor	Reference Fuel	High Fuel	Low Fuel	Reference Fuel	High Fuel	Low Fuel
G Frame CT	10%	$153	$195	$137	$160	$201	$143
Large Aeroderivative CT	40%	$97	$137	$82	$103	$142	$87
Internal Combustion	40%	$104	$141	$90	$110	$146	$95
1x1 G Frame CCGT	65%	$66	$94	$54	$70	$99	$58
2x1 G Frame CCGT	65%	$61	$89	$49	$65	$94	$53
PC With CCS	85%	$150	$219	$99	$153	$222	$101
Biomass	85%	$167	$316	$133	$167	$316	$133
Nuclear	90%	$134	$146	$134	$134	$146	$134
Wind (No Subsidy)	48%[3]	$54	$54	$54	$54	$54	$54
Solar PV (30% ITC)	26%	$75	$75	$75	$75	$75	$75
Stakeholder Group Solar PV (30% ITC)	26%	$49	$49	$49	$49	$49	$49
Stakeholder Group Wind (No Subsidy)	48%[3]	$47	$47	$47	$47	$47	$47

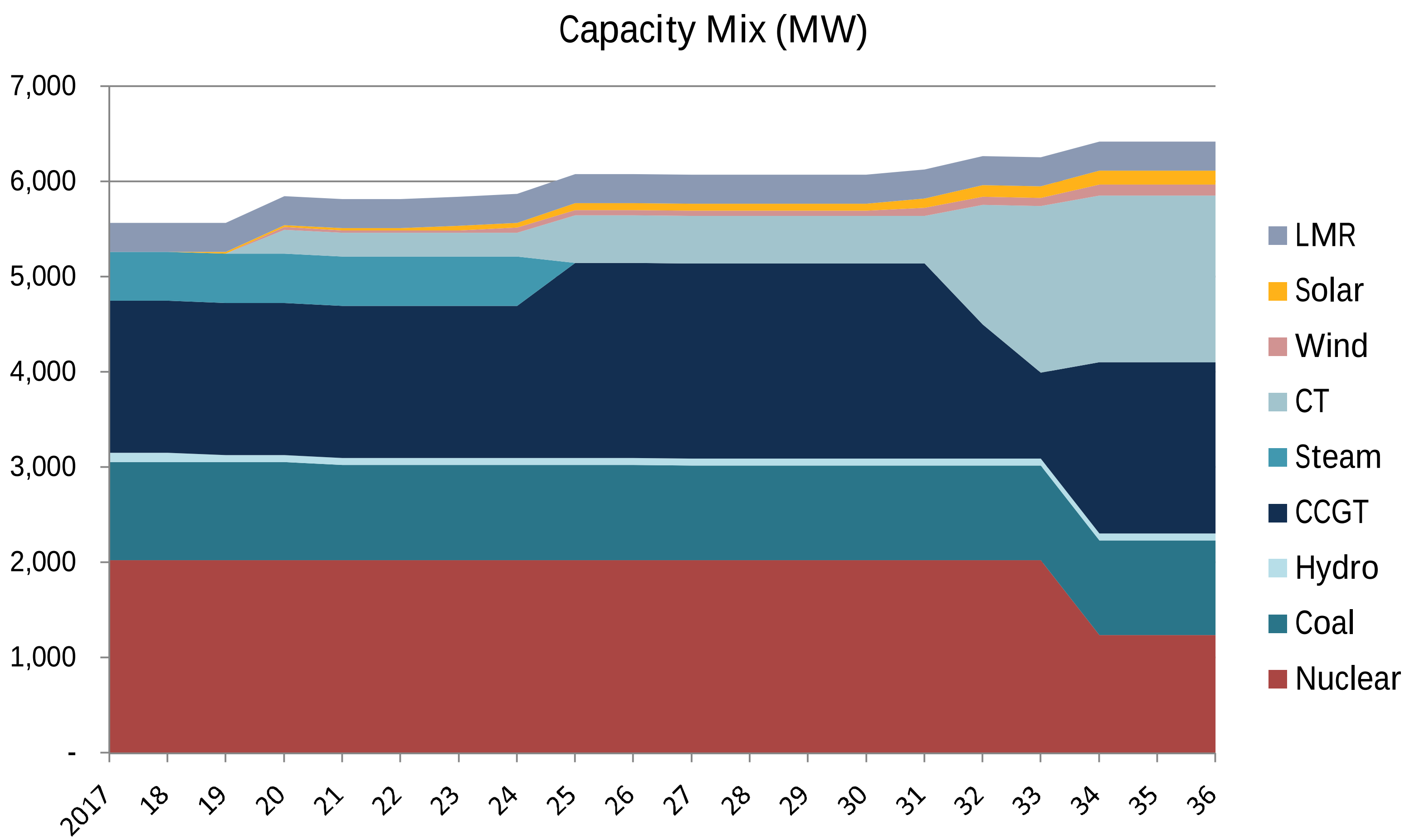
1. Includes capacity Levelized Nominal Lifecycle Cost of Resources Deployed in 2015, $/MWh. Lifecycle cost is based on assumed capacity factors for screening purposes. Projected capacity factors calculated by the Aurora production cost model may result in different lifecycle resource costs.
2. CO_2 emissions cost based on IRP reference case; begins in 2020 at $1.39/U.S. ton nominal $, reaches $32.10/ton in 2035
3. Capacity factor representative of mid-west geographical region

Supplemental Documentation (3 of 3)

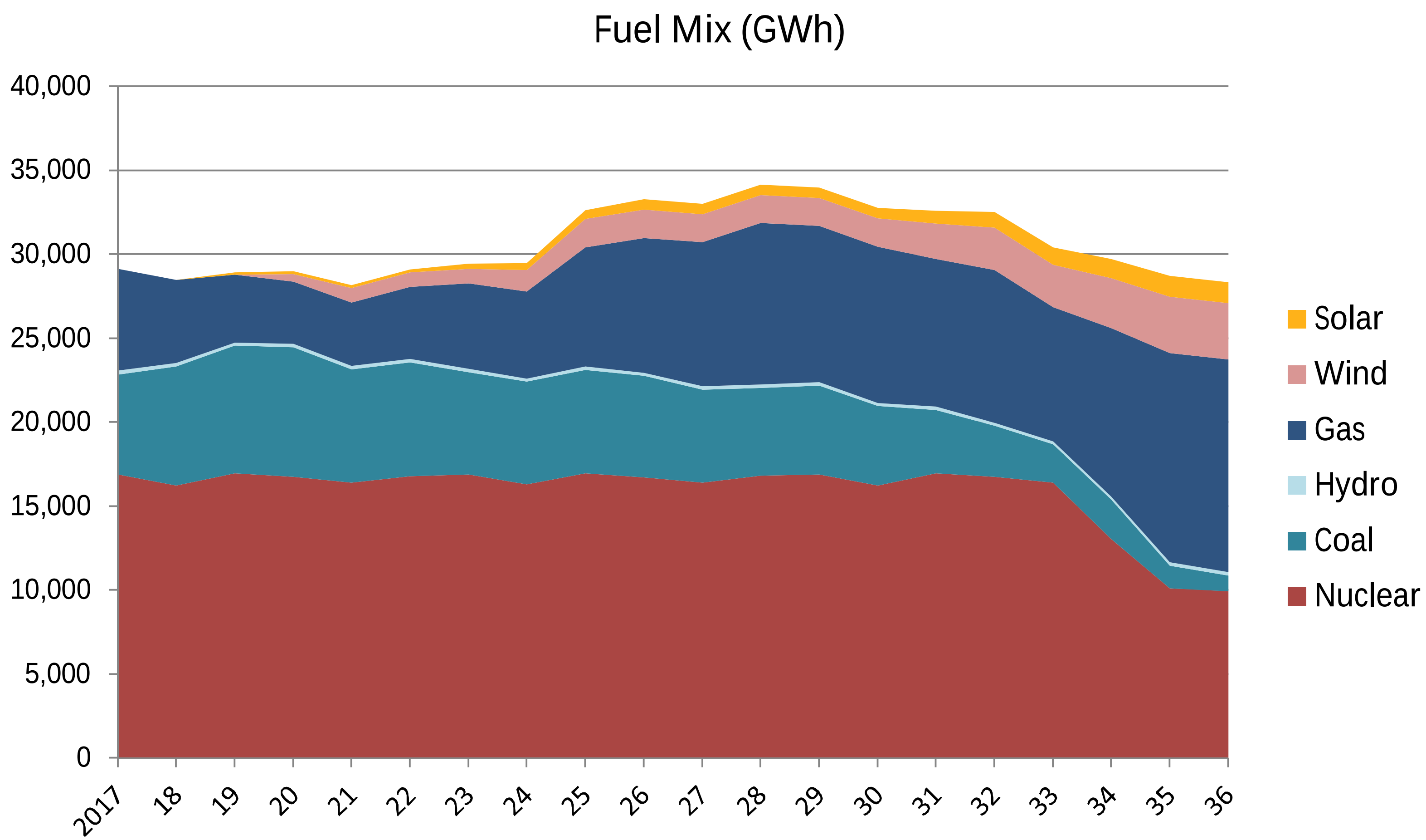
During the SG conference call that took place on Sept. 3, the SG requested that EAI provide charts showing the capacity and generation mix for each future. The following slides (#169-#174) show the mix of capacity (MW) and energy (GWh) from 2017 through 2036 for Futures 1, 2 and 3.

The fuel mix shown on the following slides includes energy used to serve native load and supply sales into the market.

Future 1 – Portfolio Diversity (Capacity)

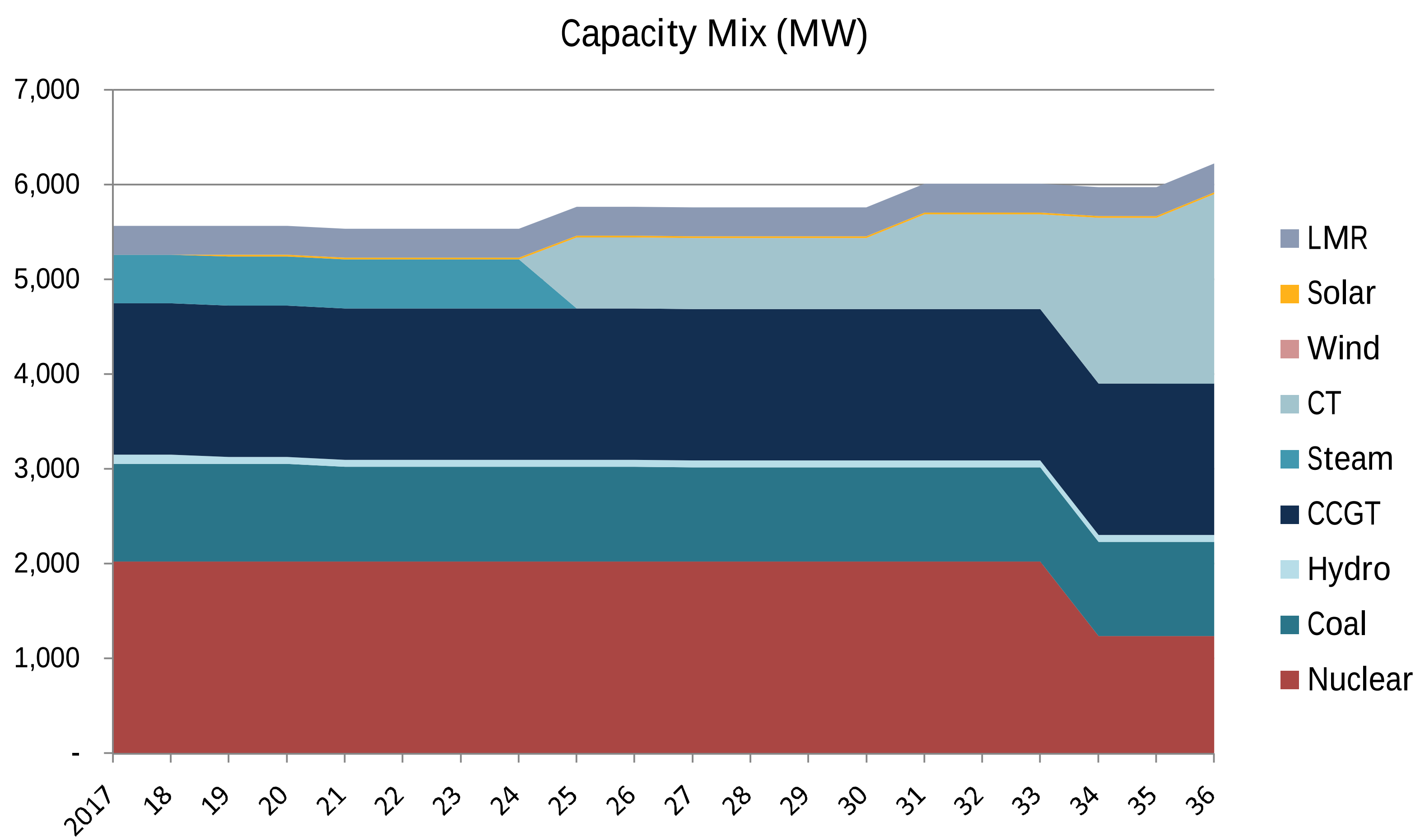


Future 1 – Portfolio Diversity (Energy)

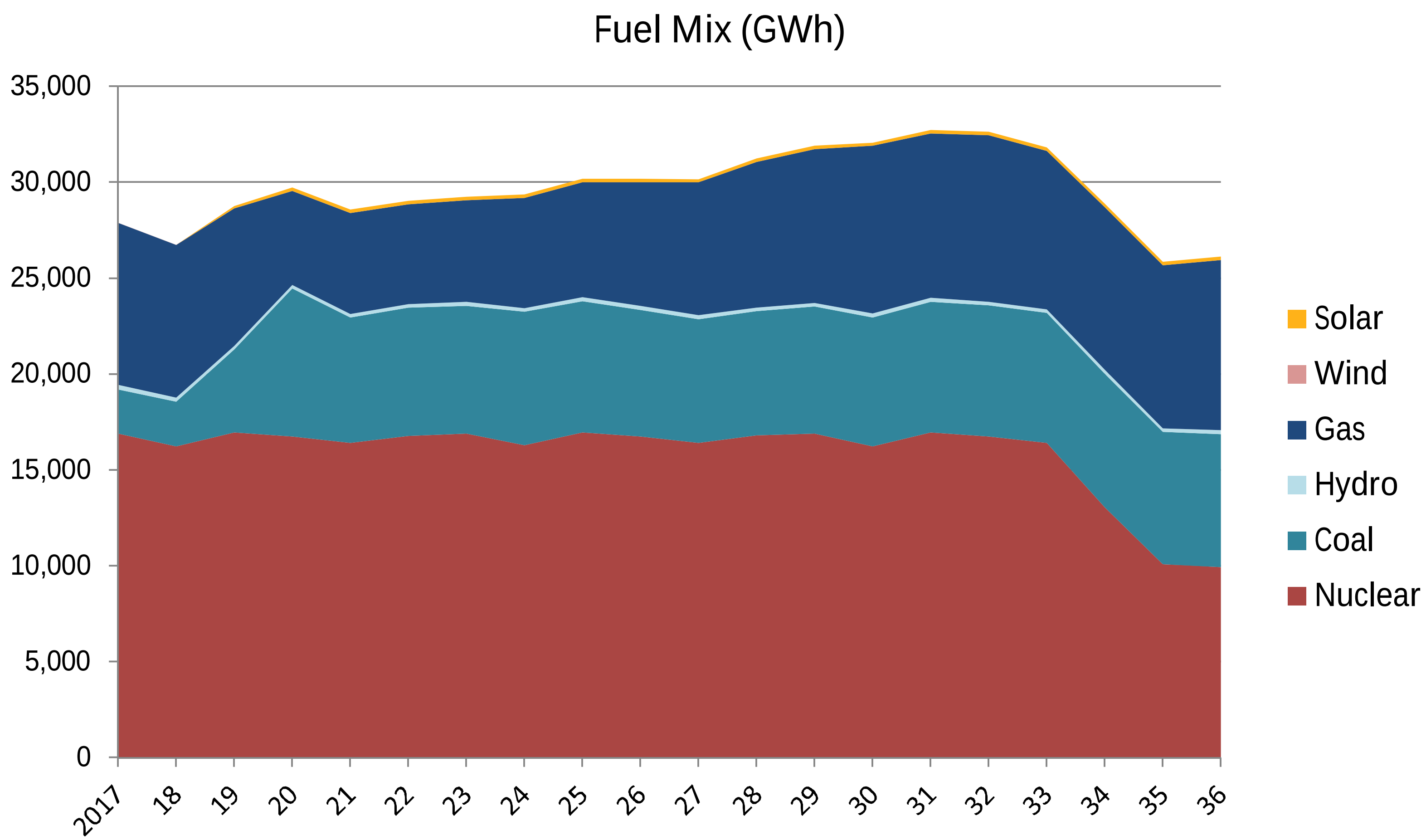


The fuel mix shown includes energy used to serve native load and supply sales into the market.

Future 2 – Portfolio Diversity (Capacity)

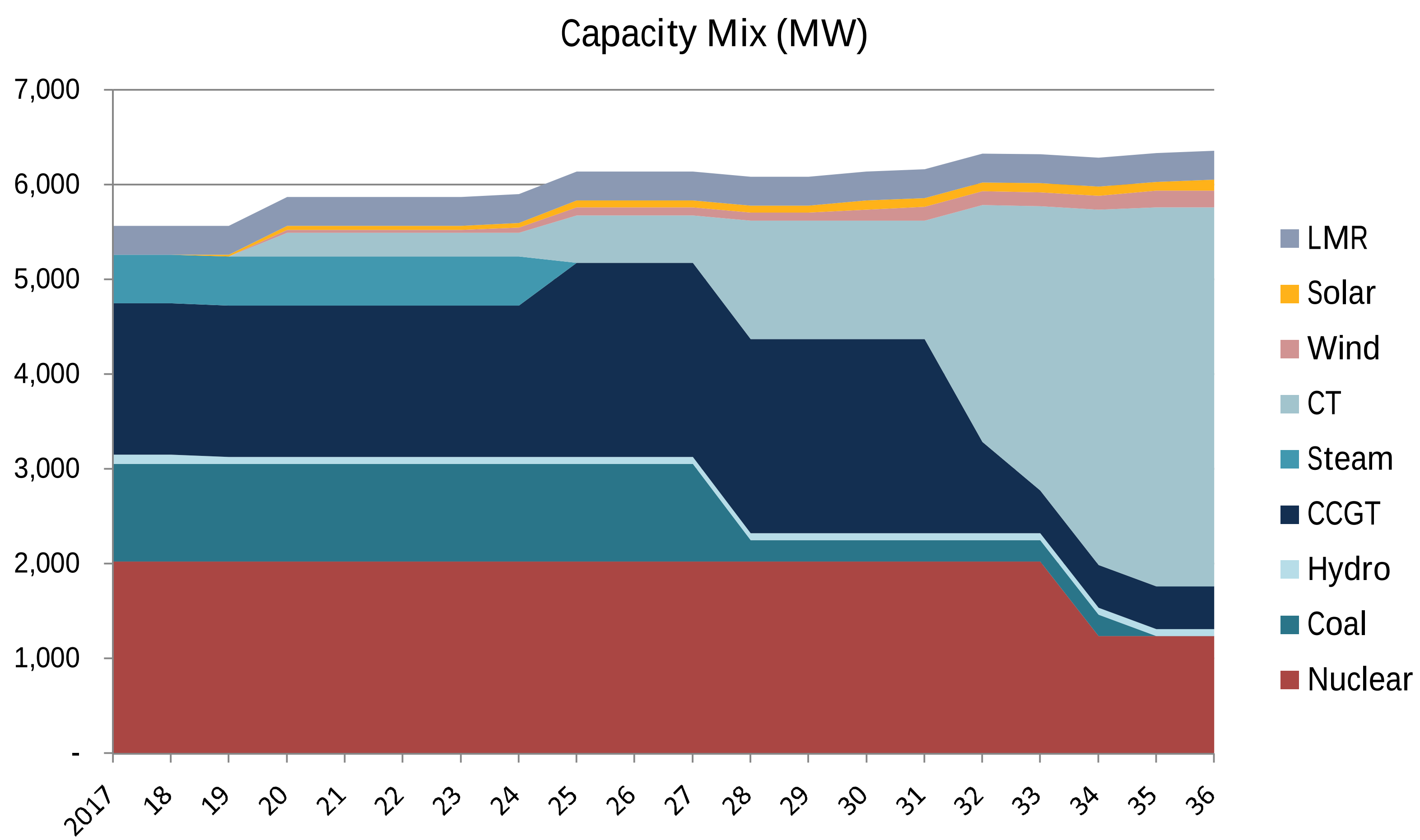


Future 2 – Portfolio Diversity (Energy)

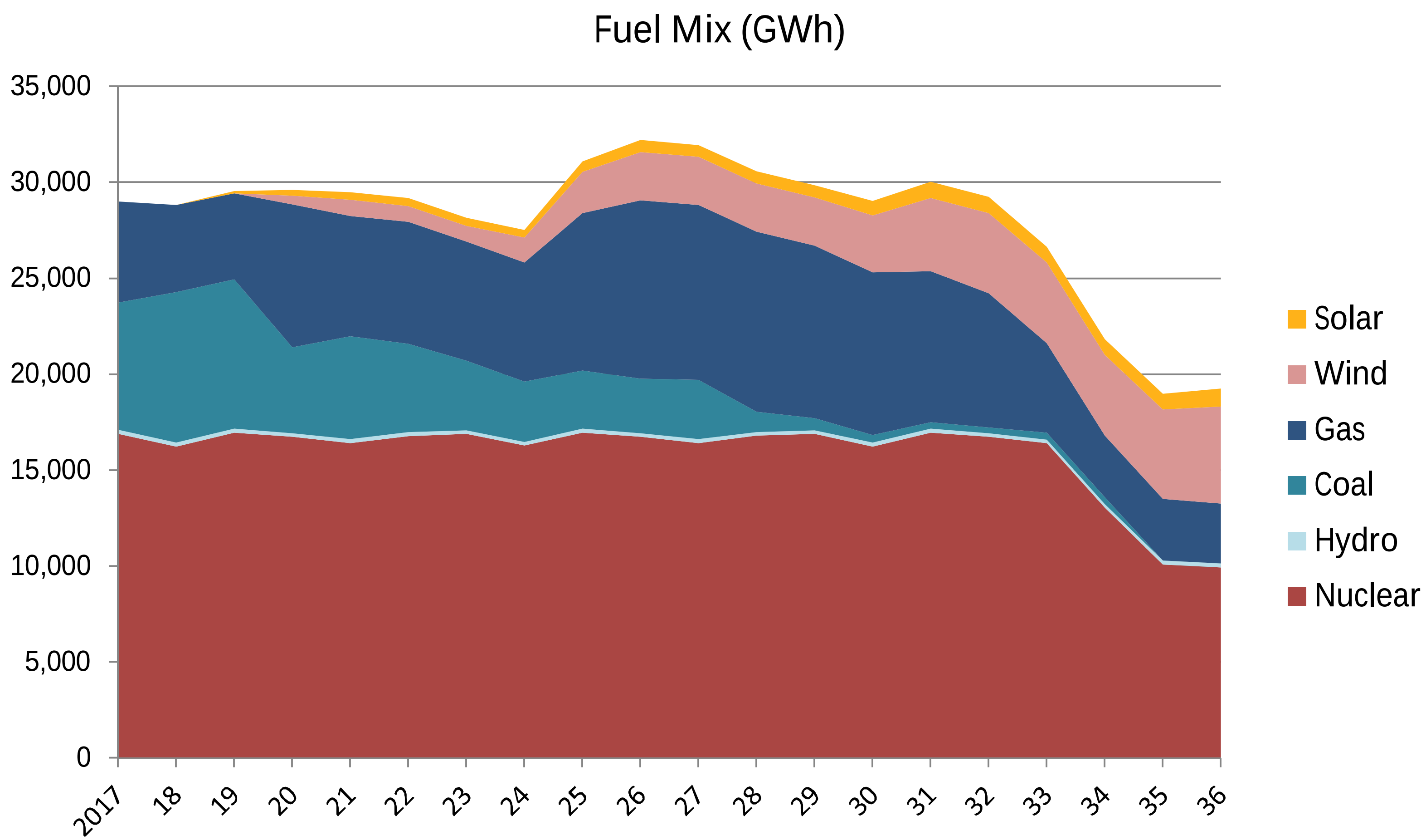


The fuel mix shown includes energy used to serve native load and supply sales into the market.

Future 3 – Portfolio Diversity (Capacity)



Future 3 – Portfolio Diversity (Energy)



The fuel mix shown includes energy used to serve native load and supply sales into the market.

Additional Analysis

Per SG request, an additional AURORA Portfolio Optimization model run is being developed, which is similar to the Alternate Future provided to the SG on 9/3/2015, with one change.

In response to feedback from the SG, an additional pricing option for wind resources is being made available in the model to meet EAI's future supply needs.

	Alternate Future
Existing Resource Portfolio	
Cease to Use Coal at White Bluff	2028
Cease to Use Coal at Independence	2035
EAI Existing CCGTs	30 years
Solar Technology Cost	$1,400/kW
Wind Technology Cost	$1,800/kW and $2,050/kW
Customer Electricity Requirements	
Energy sales and Load	Reference
Commodity Price Forecasts	
Fuel Prices	Reference
Environmental Allowances	Reference

Next Steps in IRP Development

- Provide results of additional Portfolio Optimization run (described on slide #175) as soon as it is available,
- Engage with stakeholders, as requested, through early October
- Develop 2015 IRP Action Plan
- Receive and review Stakeholder Report
- File IRP Report no later than October 31

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Entergy Arkansas, Inc.
2015 Integrated Resource Plan

September 25, 2015

Response to Stakeholder Group’s Meeting Notes

EAI Response to Stakeholder Group

During the Stakeholder Group conference call that took place on 9/17/2015, EAI received a few questions that required a follow-up response.

The following slides are EAI's response to the Stakeholder Group's requests.

Wind Cost Calculation

Q: For the lower cost wind option used in the SG-requested model runs, what are the other inputs that combine with the $1,800/kW to arrive at the $47/MWh levelized cost?

A: The SG requested that EAI perform a Portfolio Optimization model run with the wind pricing used in SWEPCO's recent IRP, which is the basis for EAI using $47/MWh levelized cost for a new wind resource. EAI estimated that $1,800/kW installed cost (in 2014) would yield $47/MWh levelized cost of electricity using all original assumptions and calculations and changing only the installed cost. The primary assumptions that were held constant are EAI's capital structure, 25 year unit life, Fixed O&M, and capacity factor. The effect of lowering the installed cost from $2,050/kW to $1,800/kW while maintaining all other assumptions results in $47/MWh levelized cost of electricity.

LCOE Data

Q. Please provide EAI's thoughts on the report titled *"The levelized Cost of Electricity from Exiting Generation Resources"*? Does EAI have the data needed to perform the calculation for EAI's existing resources?

A. In general, Levelized Cost of Electricity ("LCOE") calculations have limited usefulness in utility resource planning and are generally utilized only in conducting a very high level assessment of technology options. Indeed, the report referenced in the question indicates (at page 3) that it is designed " to provide a baseline from which policymakers can assess the cost of replacing existing plants with new ones." The methodology outlined in the report relies on data that is available to the public via FERC Form 1 data submissions and EIA Survey Form 860 data submissions. EAI bases its planning decisions regarding existing units on unit-specific information, and thus, EAI sees no value in performing LCOE calculations on its existing resources.

Aggregated CHP Facilities

Q. Does EAI have any concerns or know of any regulatory constraints that would prohibit a single PPA from being sourced from two or more Combined Heat and Power ("CHP") facilities?

A. The only retail regulatory constraint of which EAI is aware is that the PPA would have to be determined to be in the public interest by the Arkansas Public Service Commission. EAI would consider such proposals as long as the proposals met the requirements of a specific Request for Proposals, Federal and state regulatory requirements, and MISO tariff and business practice requirements.

Additional Analysis - Assumption

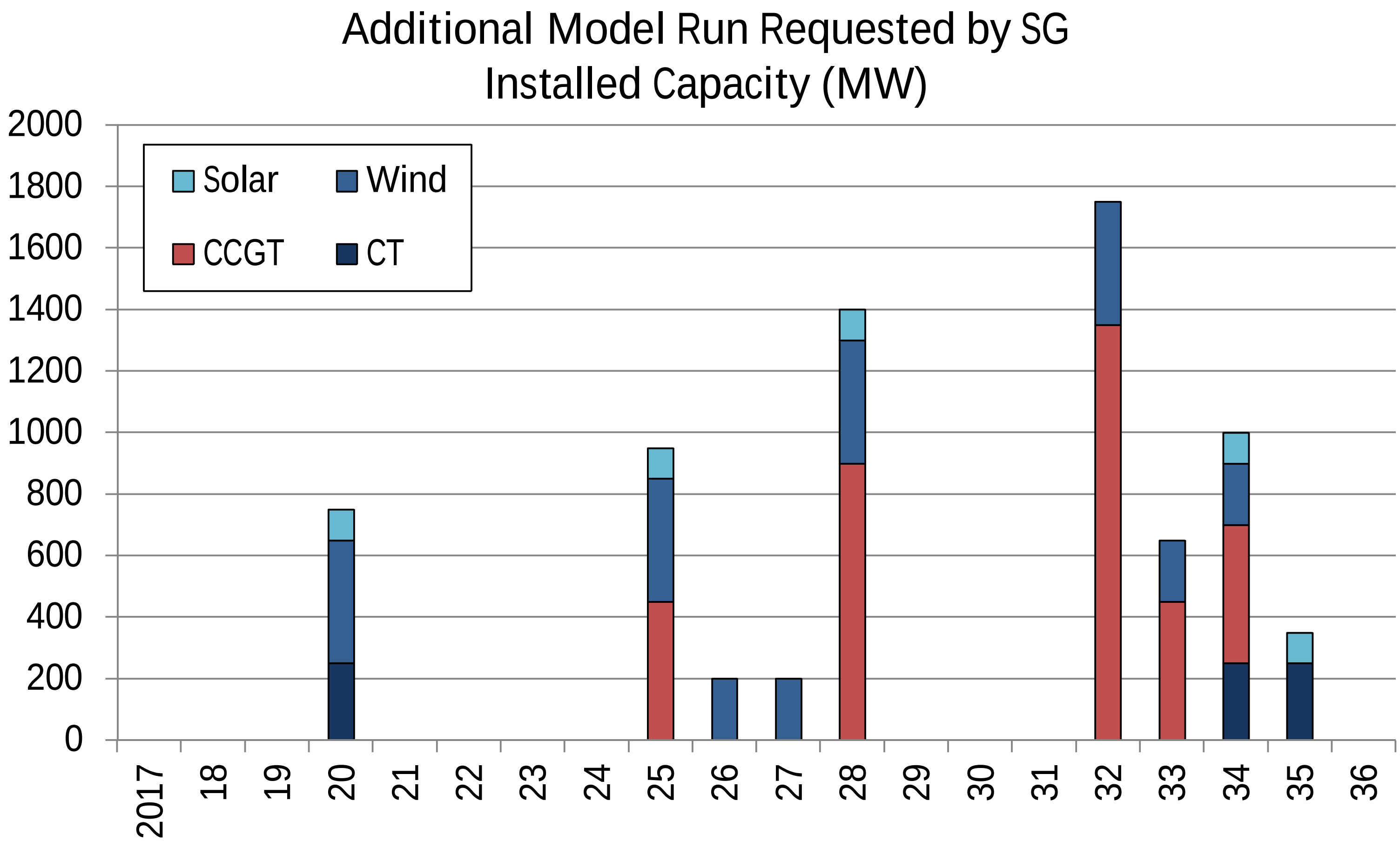
Per SG request, an additional AURORA Portfolio Optimization model run was completed, which is similar to the Alternate Future provided to the SG on 9/3/2015, with one change.

In response to feedback from the SG, an additional pricing option for wind resources is being made available in the model to meet EAI's future supply needs.

The resulting supply additions are shown on the following slide.

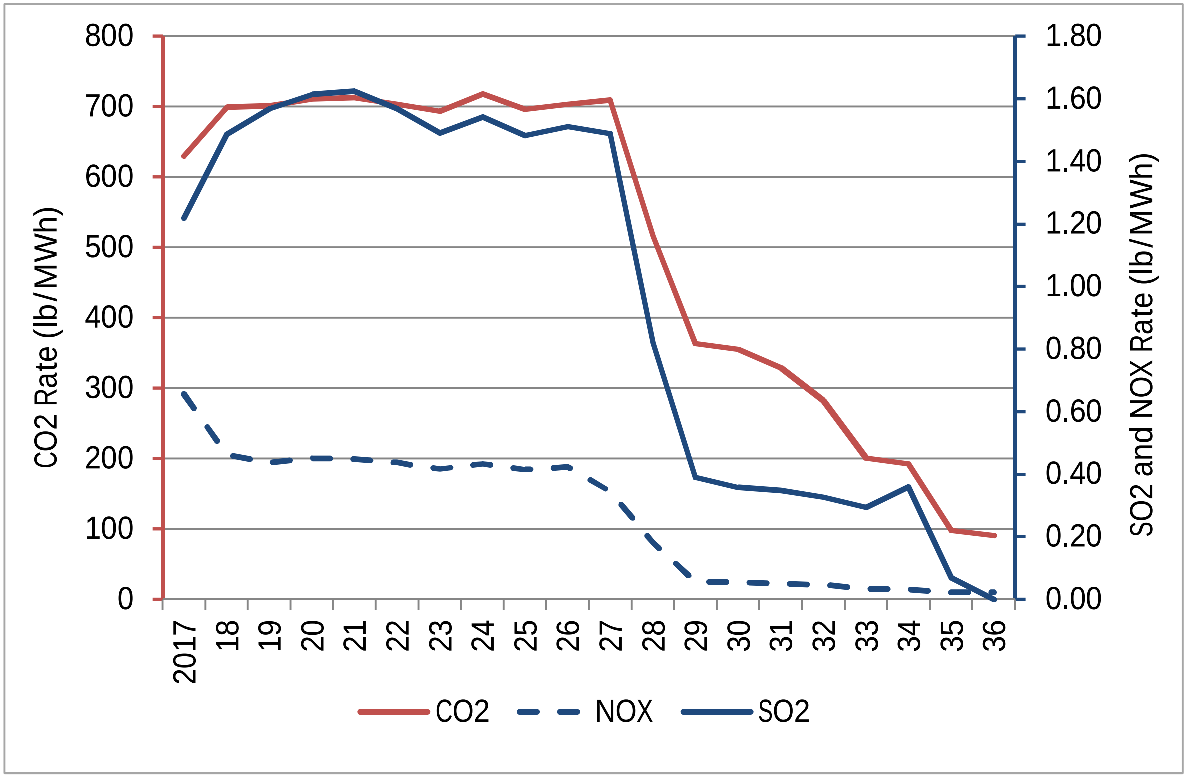
	Alternate Future
Existing Resource Portfolio	
Cease to Use Coal at White Bluff	2028
Cease to Use Coal at Independence	2035
EAI Existing CCGTs	30 years
Solar Technology Cost	$1,400/kW
Wind Technology Cost	$1,800/kW and $2,050/kW
Customer Electricity Requirements	
Energy sales and Load	Reference
Commodity Price Forecasts	
Fuel Prices	Reference
Environmental Allowances	Reference

Additional Analysis - Results



Additional Analysis - Emissions

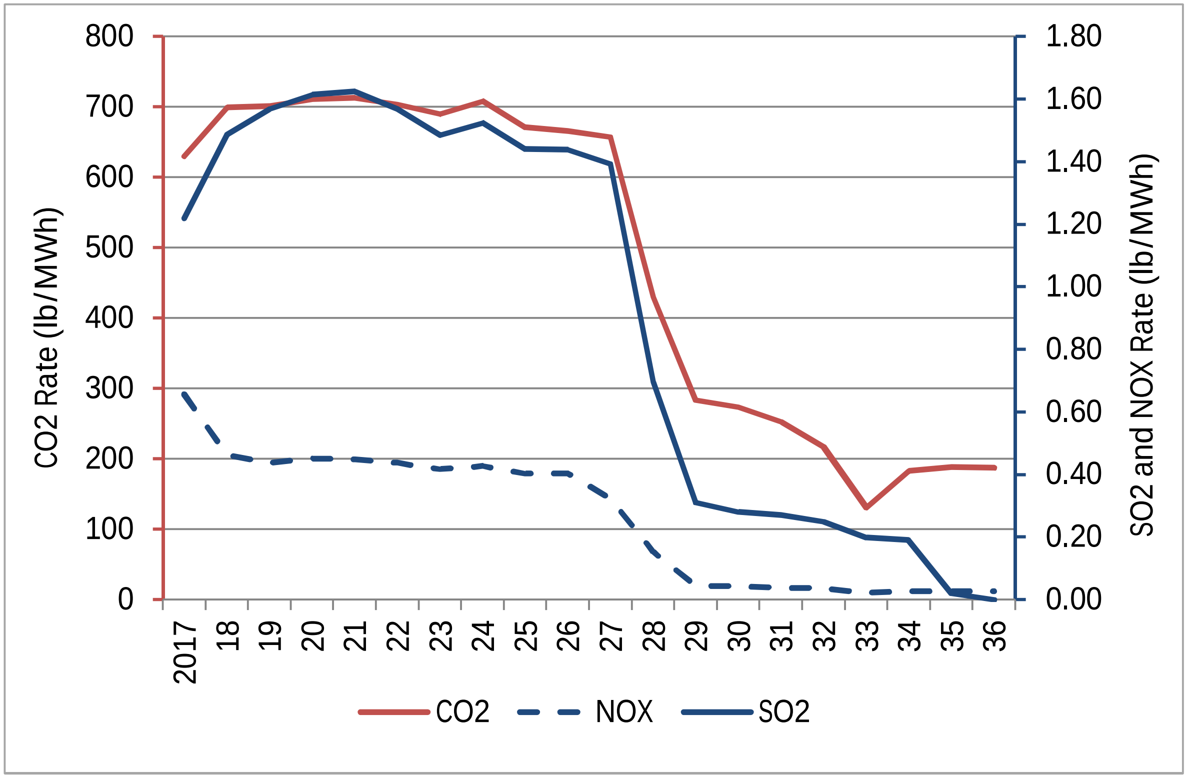
The emissions rates shown below correspond to the first model run completed in response to the SG's request, which is described on slide 153.



Included in this calculation are existing EAI-owned generation, including hydro and nuclear generation, located in AR, MS and LA, as well as future generation as optimized by AURORA.

Additional Analysis - Emissions

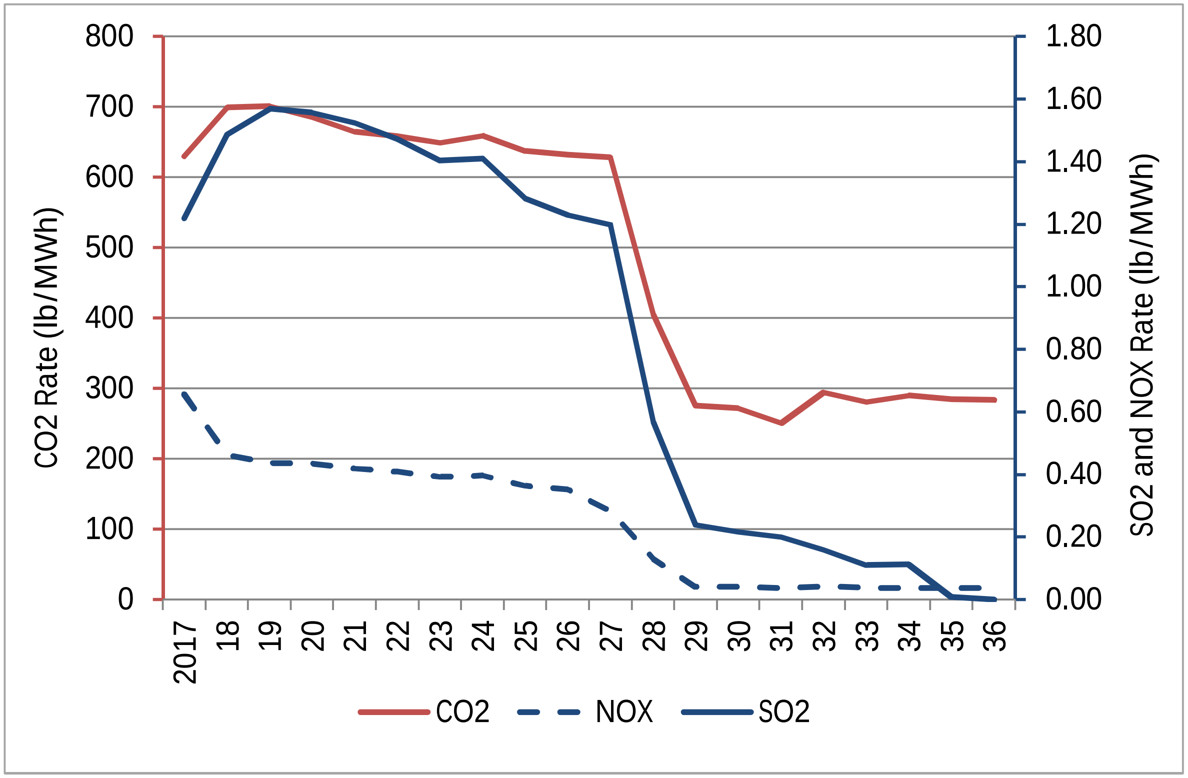
The emissions rates shown below correspond to the second model run completed in response to the SG's request, which is described on slide 155.



Included in this calculation are existing EAI-owned generation, including hydro and nuclear generation, located in AR, MS and LA, as well as future generation as optimized by AURORA.

Additional Analysis - Emissions

The emissions rates shown below correspond to the third model run completed in response to the SG's request, which is described on slide 175.



Included in this calculation are existing EAI-owned generation, including hydro and nuclear generation, located in AR, MS and LA, as well as future generation as optimized by AURORA.

STAKEHOLDER COMMENTS REGARDING ENTERGY ARKANSAS'S 2015 INTEGRATED RESOURCE PLAN

INTRODUCTION

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 also recognize the difficulty it is for an electric power company to forecast future generation and transmission scenarios in light of the Federal Implementation Plan of the Regional Haze Regulation, the August 3rd release of the final Clean Power Plan, the fluctuating costs of fuels and construction of generation and transmission infrastructure, and the rapid advancements in utility- and distributed-scale generation technologies.

The stakeholders that attended and participated in EAI's 2015 IRP process reflect different experiences and perspectives determined largely by whom they represent and the entities that employ them. In spite of those differences it is safe to say that the stakeholders support a diversity of generation resources and support energy efficiency as a cost-effective resource that should be considered equally with generation resources. All of the stakeholders embrace grid reliability and improving the transmission and distribution network. However, not all stakeholders are in agreement on environmental regulations and retirement of older fossil fueled power plants. A majority of stakeholders encourage EAI to move forward with Clean Power Plan compliance and other environmental regulations; a few prefer a wait and see approach pending review and decision of the CPP and MATS by the federal courts. A few stakeholders want EAI to stay with its existing fossil fueled generation fleet as long as possible. Others embrace the retirement of the coal burning plants sooner than later and bringing on line replacement renewable and natural gas energy resources. 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 2015 IRP, the stakeholders recommend to EAI that it should consider and respond to each issue and recommendation as presented in the comments. The primary authors of the attached comments are:

Gary Moody	Energy Efficiency
Jordan Tinsley	Coal and Environmental Regulations
Ken Smith	Clean Power Plan
Ken Smith	Combined Heat and Power
Scott Thomasson	Solar Energy
Simon Mahan	Wind Energy

COMBINED HEAT AND POWER
Ken Smith, AAEA

<u>Summary of Combined Heat Power Technology</u>

With their ability to provide power generation and thermal energy, Combined Heat and Power (CHP) and Waste Heat Recovery (WHR) systems are more efficient than conventional power generation. Policies to encourage CHP must recognize the diversity of technologies, sizes, and ownership structures that exist. To be viable economically, CHP systems must be able to connect to the electric grid, sell excess electricity and purchase backup power and to do so in a consistent, unbiased manner. According to the Oak Ridge National Laboratory[1], CHP could supply 20 percent of US electric capacity by 2030, electric power on the order of 200,000 Megawatts (MW), equivalent to 400 conventional power plants.

In August 2012, President Obama signed an Executive Order directing the Departments of Energy, Commerce, and Agriculture, and the Environmental Protection Agency (EPA), in coordination with White House Councils, and the Office of Science and Technology to encourage investment in industrial efficiency. The primary goal of the order was to achieve a national target of 40 Gigawatts of new industrial CHP by the end of 2020 with the federal agencies providing technical assistance and financial incentives.

Current CHP capacity in Arkansas is about 497 MWs at 16 sites.[2] The largest projects are found in Pine Bluff and Ashdown. The Pine Bluff Energy Center is a 215-MW CHP system that includes an electricity-generation turbine with a WHR system. The center sells electricity while providing steam to its host facility, a paper mill owned by Evergreen Packaging, a subsidiary of International Paper Company. There are 35 major-source, biomass-fired boilers in Arkansas. [3] If these boilers were converted to CHP, it would generate 617 MWs of new electric capacity. Five oil-fired boilers would produce an additional 154 MWs.

Based on raw data compiled by EPA and the Department of Energy, there are 19 dry bio-mass boilers within EAI's service territory for a potential CHP total of

[1] Oak Ridge National Laboratory, Dec. 1, 2008, *Combined Heat and Power. Effective Energy Solutions for a Sustainable Future,* at (http://www1.eere.energy.gov/industry/distributedenergy/pdfs/chp_report_12-08.pdf).
[2] Dep't of Energy, ICF, "Combined Heat and Power Units Located in Arkansas" (http://www.eea-inc.com/chpdata/States/AR.html).
[3] EPA, Emissions Database for Boilers and Process Heaters (2008 & 2011 update) (http://www.epa.gov/ttn/atw/boiler/boilerpg.html)

284 MWs. The average capacity factor or annual load factor of these boilers is 65%. Each one of these boilers is part of a wood or paper manufacturing plant.

Recommendation

The stakeholders encourage EAI to deploy a full array of renewable energy in the company's generation portfolio. The fact that most if not all of the 19 biomass boilers in EAI's territory are not used for CHP leaves a significant amount of renewable energy generation on the table. The new power purchase agreement legislation, Act 1088 of 2015, provides EAI and its customers an opportunity to enter into long-term power purchase agreements (PPA); to supplement or to replace existing generation sources; and the opportunity to request an additional sum from the APSC over the costs of the PPA should the APSC finds that the additional sum is in the public interest.

Other advantages of CHP are that it is electricity generated within the state from existing manufacturing plants. With the use of dry biomass as the fuel source, the raw energy source is local as well -- the residual from manufactured wood or paper products. CHP is strongly touted as a cost-effective energy source for environmental compliance under a number of state and federal regulations. Under the Clean Power Plan, unaffected CHP and waste-to-heat recovery qualify for Emission Rate Credits.

CLEAN POWER PLAN STAKEHOLDER COMMENTS
Ken Smith, AAEA

EPA set Arkansas's final carbon emissions target at 1130 lbs/MWH or a 36% reduction from the 2012 historic CO2 rate. The final rule set emission guidelines for fossil steam and NGCC units, and it made electric generating units (EGUs) the only entities with enforceable requirements. The start of the compliance period in the final rule also was extended two more years from 2020 to 2022. The state of Arkansas is required to submit an initial compliance plan in September 2016, and a final plan is due in September 2018 if the state is granted an extension.

EAI's Independence, White Bluff, Hot Spring, Cecil Lynch, Lake Catherine, and Mabelvale EGUs are subject to the new emission reductions under the CPP. The Hamilton Moses, Harvey Couch, and the Robert E. Ritchie EGUs were retired in 2013. And in August 2015, EAI announced its plan to shut down coal operations at the White Bluff plant in 2028, though leaving open the possibility that White Bluff could be converted to natural gas. Additionally, EAI has before the APSC the purchase of one of the four CCGT units (495 MWs) at the Union Power Station and a PPA for 81 MWs of solar power with an affiliate of NextEra Energy Resources LLC.

With the closing of White Bluff, the addition of CCGT and solar, and the earlier retirements in 2013, it is apparent to the stakeholders that EAI is on a path that will reduce carbon emissions. On page 146 of the IRP slide deck, EAI projected pollutant emissions for SOX, NOX, and CO2 for each of one of the three futures. The stakeholders request EAI to project annual projected emissions for each of the two alternative futures described on pages 152 and 153.

EPA is allowing states to consider a number of technologies for compliance in addition to the BSER technologies used to set the state targets. The stakeholders call attention to CHP, WHR, Cogeneration, Distributed Generation, Demand Response, and end-use Energy Efficiency as compliance technologies that are readily available to EAI. Early investments in renewable energy, particularly wind and solar, and energy efficiency in the years 2020 and 2012 (prior to the start of compliance in 2022) can qualify for incentives in the form of "allowances" and "Emission Rate Credits" or ERCs. EPA will provide additional incentives for investment in low-income communities. These investments will contribute to air quality reductions and enhance local job and economic development but will vary from state to state as to the degree states and their utilities choose to subscribe to the CPP's Clean Energy Incentive Program. **The stakeholders encourage EAI to take full advantage of the new incentive program.** EPA's new 81-MW Stuttgart Solar Project is commendable but it is only a small step forward in its generation portfolio as compared to utilities such as AEP-SWEPCO or Georgia Power.

While energy efficiency (EE) was not included in the target-setting calculations by EPA, it remains a strong technology for compliance. Should Arkansas pursue a mass-based plan, it will have unlimited flexibility to leverage those investments to meet the state target and the interim steps. EE programs do not need to be approved as part of a mass-based plan, and EMV is not required because measuring carbon emissions at the power plant shows compliance. Arkansas could even use EE in a mass-based trading program. Under a rate-based plan, Arkansas could incorporate EE in a rate-based trading program. EE may be the only commodity the state has for trading due to lack of renewable energy investments to date. It is clear in the CPP that states like Arkansas with pre-existing oversight of EE programs through the public service commissions will be able to rely on them for CPP compliance. **Finally, the stakeholders encourage EAI to**

accelerate its industrial EE programs due to its cost-effective role to reduce pollutants including carbon. The industrial sector offers the most cost-effective energy savings. Industrial efficiency projects like insulation and lighting lower electricity demand. CHP and WHP displace the need for central power generation. These projects avoid the need to build new power plants at the ratepayer's expense, extend the life of existing utility generation, distribution resources, and lower the cost of electricity for all ratepayers. The earlier comments about rate- and mass-based plans apply here as well. Industrial EE can be credited with ERCs and allowances can be traded or set-aside for industrial energy projects such as CHP or WHP systems. **The stakeholders encourage EAI to incorporate industrial EE into its compliance plan.**

ENERGY EFFICIENCY STAKEHOLDER COMMENTS
Gary Moody, Audubon Arkansas

<u>Background of Energy Efficiency in Arkansas</u>

To implement the Energy Conservation Endorsement Act (ECEA) passed by the Arkansas General Assembly in 1977, the Arkansas Public Service Commission launched a rulemaking on energy efficiency and conservation in January 2006. After a year of meetings, workshops, comments, and briefs, the PSC finalized the C&EE Rules in mid-2007 and utility programs began that fall. The initial years of the program consisted of a quick-start phase to get the programs up and running.
In 2009 and 2010 the Commission conducted proceedings to implement "comprehensive" programs. The Commission defined a comprehensive EE effort as one "capturing the greatest amount of cost-effective potential that can effectively be

delivered," and required comprehensive program implementation beginning in 2011. Docket No. 08-144-U, Order No. 17 at 33-34.

In Docket No. 08-137-U, Order No. 14 the Commission further stipulated that utilities should meet specific performance energy savings goals or targets that significantly change the outlook for utility resource planning. The targets were established as a percentage of 2010 baseline energy sales. They started low and have ramped up: Electric Utility Targets were set at 0.25% for 2011, 0.50% for 2012, 0.75% for 2013 and 2014, and 0.9% for 2015 and 2016. (Note: Targets beyond 2016 have not yet been set by the APSC.) These policies have elevated Arkansas as a regional leader in Energy Efficiency.

EAI deployment of EE in the Comprehensive Era

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 a leader among their peers in achieving capacity savings. During 2012-2014, EAI added 135 MW of capacity savings and over 515,000 MWh of energy efficiency through their EE Portfolio. (www.entergy-arkansas.com/content/transition_plan/IRP_Materials_Compiled.pdf, slide 7) In EAI's current portfolio EE programs contribute 36 MW of peak capacity, which represents an impressive 1.14% of total sales – the most among Arkansas Investor Owned Utilities.

Treatment of EE in 2015 EAI IRP

The 2015 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 both existing and Incremental Utility-Sponsored DSM as modifiers to their Retail Sales Forecast, while only Interruptible Loads/DR are modeled as a supply side resource. For the sake of these comments, when the Stakeholders refer to EE or EE programs we mean both the Existing and Incremental Utility-Sponsored DSM.

EE programs were assumed to continue flat at 0.9% of sales for the duration of the IRP period with costs adjusted for inflation.

Stakeholder Concerns

The Stakeholder group has the following concerns of EAI's treatment of EE in the IRP draft:

1. Planning estimate for EE is too conservative

With little explanation EAI chose to use 0.9% of retail sales as the DSM proxy within the Sales and Load forecasts, despite higher planned savings for 2015-2018 programs. Planning on 0.9% of sales despite actually achieving 1.14% savings in 2014, planned savings of 1.15% for 2015, and planned savings of 1.27% per year for 2016-2018 drastically underestimate the impact of EE. For just the years of 2015-2018, this leaves 122,205,027 KWh of projected cost-effective EE savings out of the IRP planning process. This is particularly troublesome considering the APSC's charge that utilities should capture "the greatest amount of cost-effective potential that can effectively be delivered."

Stakeholders also note this is a step backwards from EAI's 2012 IRP where EE was projected to ramp to 1.0% of sales for the duration of the study period. Nothing in the history of the last few years of EE policy in Arkansas justifies a decreased focus on EE.

2. Underestimating EE prevents EAI from acquiring the lowest cost reliable resources that are reasonably available

The Commission established formal Resource Planning Guidelines for Arkansas's electric public utilities in Docket 06-028-R. These guidelines "create a regulatory framework that requires electric utilities in the state to plan for and meet their service obligations in the most prudent, reliable, and cost-effective manner possible." APSC Docket 06-028-R, Order No. 6 at 1. Further, utilities have an obligation under Arkansas law to provide to consumers the lowest cost reliable energy supplies that are reasonably possible, per Arkansas Code Annotated Section 23-4-103. Meaning if EE savings are the lowest cost reliable resource available to serve the EAI's customers, they have a legal obligation to produce or acquire it. EE is often the least cost resource available. Data taken from EAI's historical EE portfolio performance show an EE savings acquisition cost of roughly $32 per MWh for 2013 and $29 per MWh for 2014 using EAI's estimate of an average 10-year measure life. Even using the older, higher figure, EE savings are by far the most cost effective resource available to EAI for planning purposes, coming in at 40% less costly than the lowest-cost resource modeled. While these are very simple figures and certainly do not include all needed adjustments (e.g. inflation, potential, cost adjustments for harder-to-reach savings), they are certainly compelling enough to warrant more in-depth analysis.

3. Significant lack of EE analysis

The Stakeholder's appreciate the detailed look at Entergy's past performance in regards to DSM contained in the draft IRP. However, we find the analysis used to determine the appropriate amount of future EE deployment to be inadequate. APSC's Resource Planning Guidelines direct utilities as follows: "Utility efforts to encourage energy efficiency, conservation, demand-side management, interruptible load, and price responsive demand should be identified. Identified resources should be investigated to determine costs, effectiveness, and other attributes such as potential future emission control or allowance costs to the extent they are monetizeable. Non-monetizable costs and benefits should be recognized."

While EAI did a good job of identifying EE resources, it merely assumed that the size of the EE portfolio would remain steady at 2013 levels without any further analysis of whether more or less EE than 0.9% of retail sales is cost effectively feasible and if its procurement would be more or less beneficial for customers.

There was no analysis of EE's comparative cost effectiveness with other available resources, EE's comparable risk factors, EE's potential future emission control benefits, EE's reliability assessment compared with other resources, or the availability of future EE potential.

4. EE Treatment as load reduction

Perhaps the most concerning issue for Stakeholders in regards to treatment of EE in the IRP is its treatment as a modification to load growth rather than being modeled as a resource. This is a departure from EAI's 2012 IRP, which stated, "EAI's planners determined the best approach was to assess this DSM assumption as a resource option to be specifically evaluated." Entergy Arkansas, Inc. 2012 Integrated Resource Plan p. 7-8

As discussed in the next section of these comments there are several known benefits to modeling EE as a supply-side resource over treating it as a demand-side adjustment.

Recommendations

1. EAI should model all Utility-Sponsored EE as a resource

The Stakeholders recommend EAI treat Utility-sponsored EE as a supply-side resource, and allow it to compete dynamically in the model for future utility investment against other capacity resources. We recommend the assumed future APSC EE targets be set as a minimum and the model be allowed to select as much additional EE as is feasible and cost competitive. This process, if done correctly, would alleviate the concern of under-deployment of EE as a portfolio resource.

Treating EE as a resource is quickly becoming a best practice in resource planning. This year both SWEPCO and TVA implemented a supply-side treatment for EE into their respective IRPs. EAI treated EE as a resource in their 2012 IRP filing, and correctly modeled the DR/Interruptible load portion of DSM in the 2015 draft. In fact EAI, recently helped sponsor the ACEEE Energy Efficiency as a Resource national conference in Little Rock, where 400 industry experts gathered to discuss this very topic.

2. EAI should conduct additional analysis on EE as a resource

The Stakeholders are aware that successfully modeling EE as a supply resource will require additional research and analysis by EAI. We recommend that EAI review the procedures used by TVA, SWEPCO, and any other utilities they see fit, to develop a modeling approach for EE.

Stakeholders further recommend that as a part of this analysis EAI should determine a methodology to credit EE in the model for the benefits it would bring to EAI's portfolio. EAI's IRP presentation identified cost, risk, reliability, and sustainability as the four key planning objectives. While the issue of cost will be handled directly in the modeling, EE provides benefits of increased reliability, decreased risk, and increased sustainability.

For example, EAI identified a number of environmental regulatory issues at the federal level that have or will impact EAI's operations during the planning period. These are likely to impose emissions limits or scrubber requirements on existing fossil generating units. These regulations and the uncertainty associated with their application were among the greatest risks discussed in the presentation as they could impose significant costs on EAI and its customers. An increased role for EE in the portfolio would serve to mitigate these risks. TVA found that "even after accounting for the planning factor uncertainty, EE blocks have a significantly lower range of uncertainty than a comparable combined cycle plant…"

3. EAI should vigorously pursue acquisition of least cost resources

These comments have earlier noted EAI's responsibilities in cost of resource acquisition. The Stakeholders contend that these responsibilities can only be best met when all available resources are placed on level footing and allowed to compete for future utility investment.

4. EAI should maximize stakeholder involvement

Finally, we recommend that EAI continue to engage with Stakeholders as this process develops. Lack of sufficient stakeholder involvement was emphasized in the 2012 Stakeholder's report on EAI's IRP, and the engagement timeline for 2015 has been even shorter. By engaging stakeholders earlier and in a more meaningful way, issues like those mentioned above could have been mitigated or avoided all together. We believe that EAI should follow the Louisiana model and begin stakeholder involvement at least one year prior to IRP submission to allow for increased engagement and process transparency, which in the end will benefit both EAI and its customers.

Conclusion

To fully meet EAI's planning objectives the IRP process should put all options on the table, evaluate them equally, and choose a portfolio of resources that best meets those objectives. EE is an important resource, often the lowest cost resource available to planners; it mitigates a variety of risks such as the risk of future carbon costs and other environmental regulations for air and water quality. EE brings multiple benefits in addition to offsetting energy consumption, such as relieving stress on and deferring required investments into transmission and distribution systems. Further, EE can be modeled as the addition of a supply-side resource and should be thought of as selectable EE power plants.

This comprehensive, analytic, and transparent process to assess all utility resource choices is in the best interest of consumers. EE as a power system resource among other supply resources appears under-used with its current treatment compared with its value to customers and society.

Therefore, the Stakeholder group feels that the above listed concerns merit the APSC's consideration of invoking their authority under Section 4.8 of the Resource Planning Guidelines for Electric Utilities as approved in docket 06-028-R, which states, "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."

COAL AND ENVIRONMENTAL REGULATIONS
Jordan Tinsley, AEEC

Although the promulgation of certain federal environmental regulations, including the Regional Haze Rule ("RHR") and the Clean Power Plan ("CPP"), has apparently caused EAI to question its ability to operate its coal-fired power plants for the remainder of their useful lives,[4] the recent Supreme Court decision regarding the MATS rule[5] demonstrates that EAI should closely monitor ongoing challenges and litigation concerning these environmental regulations while it attempts to identify the lowest cost option for complying with said regulations. Although EAI has already spent vast sums of money to comply with the MATS rule, for which it

4 EAI has indicated that the coal plants at issue have a useful life of sixty years.
5 Michigan v. EPA, 576 U.S. ___ (2015).

currently seeks recovery from Arkansas ratepayers in APSC Docket No. 15-015-U, in Michigan v. EPA, the United States Supreme Court took issue with the MATS rule, holding that the US EPA abused its administrative authority when it failed to consider the costs of compliance when promulgating the MATS rule.[6] The Court stated: "We hold that EPA interpreted § 7412(n)(1)(A) unreasonably when it deemed cost irrelevant to the decision to regulate power plants."[7]

This development regarding the MATS rule[8] should prove instructive to EAI as it considers the RHR and the CPP. Since the EPA's authority to promulgate a federal implementation plan ("FIP") for Arkansas under the RHR has been challenged by various parties, including Nucor, Arkansas Electric Energy Consumers, Inc. ("AEEC"), the Arkansas Department of Environmental Quality ("ADEQ"), and others, and the legality of the CPP has been and will be challenged vociferously by a number of states and other organizations,[9] EAI should not foreclose the possibility that it can operate its coal-fired power plants for the remainder of their useful lives by bowing to federal environmental regulations that rest upon uncertain legal footing. EAI's decision to agree to prematurely retire its White Bluff plant due to the RHR FIP[10] demonstrates an ill-advised rush to comply with an environmental regulation that may fail to survive litigation, which will further waste the money and resources of Arkansas ratepayers.

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[6] Id. at 15.

[7] Id.

[8] Although the future of the MATS rule is far from settled, Michigan v. EPA makes it clear that the MATS rule cannot survive in its current form, insofar as the costs of compliance outweigh the benefits, according to the Court.

[9] http://www.eenews.net/interactive/clean_power_plan/fact_sheets/legal.

[10] http://talkbusiness.net/2015/08/entergy-arkansas-proposes-to-cease-operations-at-white-bluff-power-plant-by-2028/.

Further, rushing to comply with potentially unlawful federal regulations by prematurely retiring coal-fired plants may violate EAI's fiduciary obligations toward Arkansas ratepayers. It is well established under Arkansas law that a public utility holds its assets and resources in trust for its ratepayers.[11] In Acme Brick, the Arkansas Supreme Court stated the following:

> [I]t has been traditional heretofore to limit the net earnings of a utility company to a percent of its invested capital or some other indication of the extent of its capital assets. In Arkansas the rate base is the prudent investment value of the property of the utility, as defined by the Commission and this Court, and about which definition there is no dispute. It is upon this method of rate fixing that the relationship between the utility, on the one hand, and the public, on the other, has been established. Upon this basis the public grants the utility a monopoly [or a virtual monopoly] to do business and guarantees the right to charge a price that will produce a fair and reasonable return to the stockholders on all the capital invested by them. In return for the public's concessions, the utility is obligated [under the statutes of this state, and under the rate base method] to render services at the lowest possible prices commensurate with a fair and reasonable return on its prudently invested capital. To the above end, the utility holds and must manage its property in the nature of a trusteeship. In the case of City of Ft. Smith v. Southwestern Bell Tel. Co., 220 Ark. 70, at page 85, 247 S.W.2d 474, at page 483, we said: 'The utility must use all its receipts as though they were a public trust.'[12]

In El Dorado, the Arkansas Supreme Court described the following as one of "the well established fundamental rules…by which [it] must be guided:"

> It is the duty of the Company to operate in such manner as to give to the consumers the most favorable rate reasonably possible. This stems from the fact that the State has given the Company the exclusive right to sell and distribute gas to its customers. Consequently the Company bears a trust relationship to its customers and must conduct

[11] *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).

[12] Acme Brick, *supra*, at 441, 211 (emphasis added).

> its operations on that basis and not as if it were engaged in a private business with no restrictions as to the income it could earn.[13]

As recently as 2012, the Arkansas Court of Appeals acknowledged that Acme Brick remains good law[14] and, therefore, Arkansas utilities still hold their assets in trust for the public. Indeed, Arkansas ratepayers have been paying for the White Bluff plant since its construction; thus, EAI should not capitulate to federal environmental regulations that have the effect of divesting its ratepayers of cheap electric generating units for which they have already paid and which have been well maintained throughout their lives through the use of ratepayer monies.

As EAI considers whether to prematurely retire any of its coal-fired power plants in response to potentially unlawful federal environmental regulations, it must acknowledge that its existing coal-fired power plants, many of which still have decades of useful life remaining, can produce electricity at a cost substantially lower than the cost of any newly constructed plant, regardless of the fuel source utilized at the new plant.[15] Given EAI's undeniable obligation under Arkansas law to "render services at the lowest possible prices" and "give to [its] consumers the most favorable rate reasonably possible," EAI should refuse to drive up its rates[16] by prematurely retiring old, cheap plants and building new, expensive plants until it

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[13] City of El Dorado, *supra*, at 816, 684 (emphasis added).

[14] Ark. Elec. Energy Consumers, Inc. v. Ark. Pub. Serv. Comm'n, 2012 Ark. App. 264, 410 S.W.3d 47, 53 (2012).

[15] *See* Thomas F. Stacy and George S. Taylor, *The Levelized Cost of Electricity from Existing Generation Resources*, at 4 (http://instituteforenergyresearch.org/wp-content/uploads/2015/06/ier_lcoe_2015.pdf).

[16] AECC's analysis of the costs of compliance with the CPP reveals that the plant retirements required by the CPP will raise electricity and natural gas rates substantially, wreaking economic havoc on the state (https://www.adeq.state.ar.us/air/planning/cpp/pdfs/adeq_apsc_111d_stakeholder_mtg_aug_28_14_aecc_v2.pdf).

can reasonably determine that the federal environmental regulations with which it believes it must eventually comply will survive contentious litigation and challenge.

Further, Arkansas law mandates that the state's compliance with the CPP cannot result in "a significant rate increase annually for any rate class of the total delivered electricity cost per kilowatt hour."[17] Since the Arkansas General Assembly has decreed that the state's compliance with the CPP cannot result in a significant rate increase, EAI should not unilaterally submit to federal environmental regulations in a manner that will undoubtedly result in "a significant rate increase."[18] This deference to questionably legal federal environmental regulations abdicates EAI's fiduciary obligations to its ratepayers and directly contravenes Arkansas law as established by the General Assembly in Act 382 of 2015.

The mandate established by the General Assembly in Act 382 of 2015 stems from legitimate concerns regarding the economic havoc that significant increases in the price of electricity will undoubtedly wreak upon Arkansas's economy. Recent research by the Center for Business and Economic Research at the University of Arkansas suggests that rates of manufacturing employment in Arkansas are negatively correlated in a statistically significant manner with the price of electricity.[19] This finding is consistent with other academic literature discussing the effect of electricity prices on industrial investment and job growth.[20] Further, the National Rural Electric Cooperative Association (NRECA) recently released a new

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[17] *See* Act 382 of 2015, now codified at Ark. Code Ann. § 8-3-206(a)(1).

[18] Retiring low cost resources and replacing them with high cost resources will necessarily raise electricity rates.

[19] *See* Direct Testimony and Exhibit of Katherine A. Deck, APSC Docket No. 15-015-U.

[20] Id.

economic study detailing a devastating relationship between higher electricity prices and job losses.[21] The study, which is titled *Affordable Electricity: Rural America's Economic Lifeline*, measures the impact of electricity price increases on jobs and gross domestic product (GDP) from 2020 to 2040. According to the study, a ten percent increase in electricity prices results in 1.2 million jobs lost in 2021. In terms of national GDP from 2020 to 2040, a ten percent increase results in a cumulative loss of almost three trillion dollars.[22] Given these findings, EAI should recognize that rushing to prematurely retire coal-fired power plants in the face of federal environmental regulations that lack solid legal footing abdicates its fiduciary responsibility to the public, insofar as premature retirement of cheap, coal-fired power plants and replacement of those cheap plants with expensive new plants will likely devastate the state's economy and drive many of EAI's residential ratepayers to financial ruin.[23] Further, said retirement decisions constitute a violation of EAI's fiduciary obligations to its ratepayers, which stem from the fundamental regulatory bargain that underlies EAI's ability to operate without competition.

RECOMMENDATIONS

- Consistent with its fiduciary obligations toward Arkansas ratepayers, EAI must identify and pursue the lowest cost strategy for complying with recent federal environmental regulations, including the RHR FIP and the CPP.

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[21] http://www.nreca.coop/wp-content/uploads/2015/07/Affordable-Electricity-Rural-Americas-Economic-Lifeline.pdf.

[22] Id.

[23] http://americaspower.org/sites/default/files/ARKANSAS-Energy-Cost-Analysis-315R.pdf.

- EAI should closely monitor ongoing challenges and litigation concerning these environmental regulations while it attempts to identify the lowest cost option for complying with said regulations, insofar as these challenges may ultimately nullify EAI's obligation to comply with the regulations.
- EAI should recognize that Arkansas law forbids compliance with the CPP in a manner that will result in "a significant rate increase annually for any rate class of the total delivered electricity cost per kilowatt hour;" therefore, EAI must find a strategy for complying with the CPP that preserves its ability to operate its cheap, depreciated coal-fired power plants for as long as possible.
- EAI should recognize that Arkansas law forbids certain strategies for complying with the CPP due to legitimate concerns, which the General Assembly has appropriately recognized by enacting Act 382 of 2015, regarding the economic havoc that the CPP could wreak upon the State of Arkansas and its citizens.

SOLAR ENERGY STAKEHOLDER COMMENTS
Scott Thomasson, Vote Solar

Stakeholder comments about EAI's modeling of solar as a capacity resource focused on the accuracy of EAI's cost assumptions, which stakeholders believed were unreasonably high and inconsistent with recent market evidence from the Southeast and from EAI's executed Stuttgart PPA. At stakeholders' request, EAI ran its planning models using a lower cost assumption for solar. As a result, EAI's models selected more solar resources than they did with the higher cost figures used in EAI's 2015 IRP documents. The sensitivity of EAI's planning models to solar costs suggests that the Commission should carefully scrutinize EAI's 2015 IRP assumptions, in public hearings if necessary. Stakeholders also recommend that the Commission and EAI consider near-term opportunities for adding more utility-scale and distributed solar as energy resources in the 2015 IRP, including comparing market costs for solar to EAI's long-term avoided cost of energy, independent of the capacity needs identified in its models.

EAI Assumed Cost of Solar in 2015 IRP

EAI includes two forms of utility-scale solar in its IRP modeling: fixed-tilt and single-axis tracking. EAI evaluates both technologies as capacity resources for purposes of meeting its projected need during the 20-year study period. This analysis does not reflect other benefits for which additional solar energy may be needed, independent of EAI's capacity need. As the PSC found in its recent order approving EAI's 20-year solar PPA with Stuttgart Solar, LLC ("Stuttgart PPA"), the need for solar energy does not necessarily depend on capacity needs, and solar energy may be prudently procured to bring cost savings and portfolio diversification benefits for EAI's customers.[24] It is likely that EAI could identify additional savings opportunities for its customers by including an evaluation of these non-capacity benefits achieved by adding new solar resources, as it did with the Stuttgart PPA.

With regard to EAI's modeling of solar as a capacity resource, stakeholder comments focused on the accuracy of EAI's cost assumptions for solar, which stakeholders believed were unreasonably high and inconsistent with current

[24] Order No. 5, Docket No. 15-014-U, issued September 24, 2015, at p. 22. ("While the PPA is not a significant source of capacity within EAI's portfolio, the need for the PPA does not depend on capacity needs, although capacity benefits are still a factor in EAI's cost benefit analysis.")

market data. Vote Solar and Scenic Hill Solar pointed out that the EAI's assumed installed cost of $2,300/kW for fixed-tilt solar systems was at least 40 to 50 percent higher than published averages for 2015 solar projects, and even higher compared to more recent costs reported by solar developers. For example, EAI's cost assumption is 54 percent higher than the average U.S. installed cost of $1,490/kW in the second quarter of 2015, as reported by GTM Research and SEIA.[25]

In response to stakeholder requests, EAI clarified that its capital cost assumptions for fixed-tilt solar are equivalent to a levelized cost of $75/MWh over a 25-year period. This levelized cost is significantly higher than recent market prices for PPAs executed in the Southeast in 2014 and 2015, including EAI's Stuttgart PPA. In 2014, Georgia Power Company reported a weighted average of $65/MWh for 76 MW of executed PPAs following its RFP for smaller utility-scale projects (20 MW or less). TVA executed a 20-year PPA with NextEra in 2015 for an 80 MW Alabama project at $61/MWh. Austin Energy's 2015 RFP attracted bids offering over 1,200 MW of long-term PPAs priced below $45/MWh. And while the price paid by EAI under the Stuttgart PPA has not been publicly disclosed, statements made in hearings suggest the price is slightly above $50/MWh, and that the price is below EAI's avoided costs for energy over the term of the PPA. These prices show that the Southeast market has quickly caught up with the Southwest and is capable of offering competitive prices in line with national trends, and consistently cheaper than EAI's cost projection of $75/MWh.

[25] *U.S. Solar Market Insight Report, Q2 2015*, published by GTM Research and the Solar Energy Industries Association.

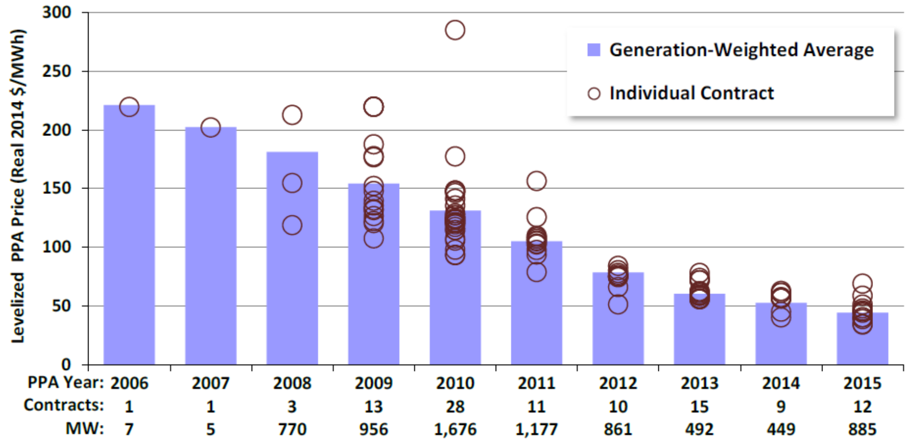


Figure 19. Levelized PV PPA Prices by Contract Vintage

Source: Lawrence Berkeley National Laboratory, "Utility-Scale Solar 2014," published September 2015

Stakeholders Proposed Solar Cost Assumptions

Given the wide discrepancy between EAI's cost assumptions and recent market evidence from the Southeast and from EAI's Stuttgart PPA, stakeholders believe there is a clear and compelling case for EAI to use more accurate solar costs in its 2015 IRP modeling. At stakeholders' request, EAI ran its planning models using a lower cost assumption for solar. As a result, EAI's models selected more solar resources than they did with the higher cost figures used in EAI's 2015 IRP documents.

Stakeholders requested that EAI adjust its cost estimates downward for fixed-tilt solar systems in its planning models, to assume a 2015 installed cost of $1,400/kW. Stakeholders believe this assumption is reasonable and may in fact understate the rapid cost declines occurring for utility-scale solar installations. Between the first and second quarters of 2015, the average installed cost for fixed-tilt solar dropped nearly 6 percent, from $1,580/kW to $1,490. Stakeholder's recommended cost assumption of $1,400/kW reasonably anticipates another 6 percent drop over the remaining two quarters of 2015, which developers are anecdotally reporting has already been exceeded for new projects.

Using EAI's assumptions and calculations, the $1,400 capital cost is equivalent to a levelized energy price of $49/MWh over a 25-year term. Given the 2015 market evidence for long-term PPA prices in Arkansas, Texas, and the Southeast, stakeholders believe this levelized price is also conservative, in that it is reflective of reported prices for executed PPAs but not as low as costs developers are reporting for new projects.

Figure 2.6 Modeled Utility Turnkey Fixed-Tilt PV System Pricing With Cost Breakdown, Q1 2014-Q2 2015

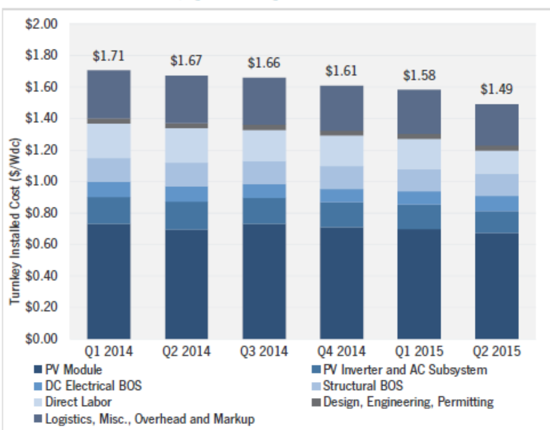
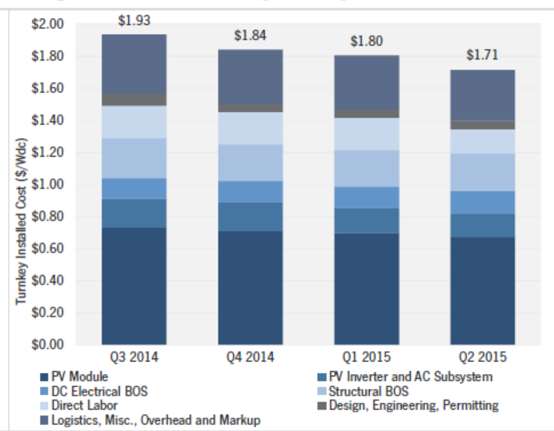


Figure 2.7 Modeled Utility Turnkey One-Axis Tracking PV System Pricing With Cost Breakdown, Q3 2014-Q2 2015



Note: Assumes a 10 MW_{dc} fixed-tilt or horizontal single-axis ground-mount system with standard crystalline silicon. All datapoints available in the Full Report.

Source: GTM/SEAI U.S. Solar Market Insight Report, Q2 2015.

Stakeholders' modeling requests were specific to fixed-tilt solar costs, but as single-axis tracking is gaining market share to become the more cost-effective technology, the same concerns about using accurate cost assumption data apply to both categories of utility-scale solar. As the chart above shows, single-axis system costs are also rapidly declining, with an average installed cost of $1,710/kW in Q2 2015,[26] well below EAI's cost assumption of $2,550/kW.

Stakeholders recommend that EAI also update its capital cost assumptions for single-axis tracking systems to $1,600/kW. This estimate is a reasonable projection of further cost declines through the end if end of 2015, consistent with

[26] See GTM/SEIA *U.S. Solar Market Insight Report, Q2 2015.*

current trends for single-axis systems and with stakeholders' projections for declines in 2015 fixed-tilt capital costs. And because single-axis tracking is proving in the market that it can deliver higher capacity factors and deliver more high-value energy during peak load hours, EAI should take care to evaluate this technology in its IRP modeling, separate and distinct from fixed-tilt solar.

Similarly, EAI's capital cost projections for solar over the 20-year study period appear to be unreasonably conservative with regard to downward price trends for installed solar. EAI does not break out the year-by-year cost projections represented in its line chart comparing future resource costs, but the cost declines for solar appear to be much more modest than consensus projections by independent analysts, even after adjusting its chart to use stakeholders' $1,400/kW capital cost as the starting data point.

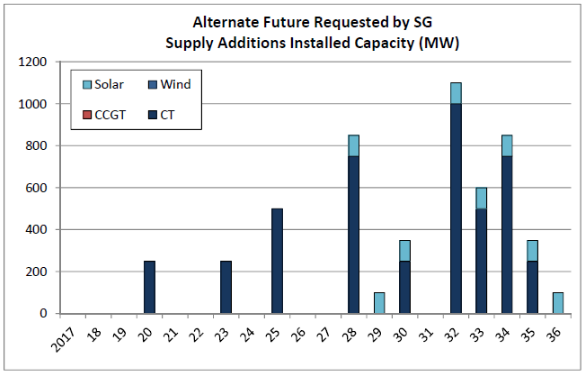
Modeling Results of Stakeholder Recommendation

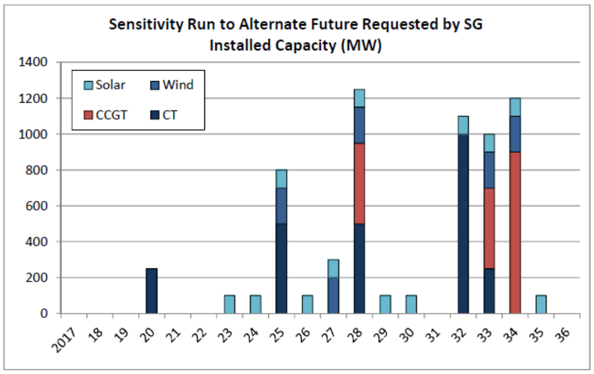
In response to stakeholder concerns, EAI ran new models using a lower cost assumption of $1,400/kW for fixed-tilt systems. Those model runs result in higher additions of solar capacity to meet EAI's needs, relative to other capacity options. These results clearly indicate that solar is competitive as a least-cost capacity resource, and that its selection is sensitive to the capital cost assumptions EAI chooses to include as inputs to its planning models. Because the accuracy of EAI's solar costs have such a significant impact on its selection of planned capacity resources, it is critically important that the cost assumptions are accurate to ensure EAI's customers benefit from the most cost-effective resource options available in the market.

	Future 1	Future 2	Future 3	SG 1*	SG 2*
Installed Cost $/kW	$2,300	$2,300	$2,300	$1,400	$1,400
Solar MW added	500 MW	0	400 MW	800 MW	1200 MW
% of new capacity					
First year added	2023	N/A	2020	2028	2023

- September 3 EAI responses to Stakeholder Group. SG1 includes assumptions that White Bluff and Independence cease to use coal in 2028 and 2035. SG2 includes EAI sensitivity analysis forcing 4 additional solar resources (400 MW).

EAI also provided a sensitivity run in which it "forced" the model to select four additional 100 MW solar resources. This approach is particularly interesting for EAI and the Commission to consider for further analysis of the benefits adding low-cost solar as an energy resource, and for better integrated planning of customer-sited solar and net metering tariffs. As the Commission concluded in approving the Stuttgart PPA, EAI may choose to add new solar resources for other needs such as cost savings and portfolio diversification, independent of its capacity need. So what EAI describes as "forced" solar resources in its models could represent cost-effective solar additions that are beneficial for customers in their own right, but are procured outside of the confines of EAI's capacity planning process.





Importantly, the additional solar resources in EAI's sensitivity case shifts the model results to a much more diverse optimized portfolio, with additional wind and CCGT resources not selected in the absence of the forced solar. The domino effect of extra generation diversity represents real benefits and economic value to customers, but EAI states that between the two model runs, "the total effective capacity and costs are very close."

Adding Solar as an Energy Resource

The portfolio benefits of solar in the sensitivity case argue for more rigorous planning for solar as an energy resource, to evaluate the potential benefits for EAI's future capacity options when it adds solar energy resources like the Stuttgart PPA. EIA should model scenarios for aggressive near-term procurement of solar energy resources, in amounts similar to its "forced" 400 MW and front-loaded in the first years of its study period, beginning as early as 2016-2017. The Stuttgart PPA shows that such opportunities are available in the market now at prices that result in cost savings to customers.

Other utilities have proven that large amounts of solar can be added without a capacity need and without upward pressure on rates. Georgia Power Company's Advanced Solar Initiative (ASI) is the most notable example in the Southeast. Georgia Power's 2013 IRP proceeding resulted in the utility agreeing to add 525 MW of solar as energy resources over 3 years under ASI, despite having no identified capacity need. The Georgia Public Service Commission required Georgia Power to compare market prices for new solar resources to its projected avoided energy costs over terms as long as 30 years, rather than planning for solar only as a capacity resource. The Commission capped the price for solar energy purchases at levelized avoided costs to ensure cost savings for customers and prevent upward pressure on rates. The ASI expansion also included 100 MW of distributed solar resources (up to 3 MW), further diversifying the utility's energy mix and adding benefits from avoided transmission and distribution costs.

The Alabama PSC recently approved a voluntary proposal by Alabama Power Company to plan for 500 MW of renewable energy procurement over a 6-year period. Like Georgia Power's ASI, Alabama Power's projects must avoid upward rate pressure by being below avoided cost or otherwise providing a net benefit to customers.

Modeling an EAI solar program similar to Georgia Power's ASI could identify new benefits for EAI's planned generation mix, in addition to the other program benefits of avoided cost savings and opportunities for local installers to help retail customers go solar.

Stakeholder Recommendations

1. Cost Assumptions: Stakeholders recommend that the Commission closely examine EAI's cost and technology assumptions for solar resources and reject any proposed 2015 IRP that does not use assumptions that accurately reflect current market data.
    a. Assumed capital costs for fixed-tilt, utility-scale solar resources should be at or below $1,400/kW.
    b. Assumed capital costs for single-axis tracking, utility-scale solar resources should be at or below $1,600/kW.
    c. Assumptions for capacity factors and hourly production estimates should be modeled separately for fixed-tilt and single-axis resources, and EAI should cite recent and widely-accepted sources for these technical assumptions.
    d. Projections of future capital costs for solar resources should cite recent and widely accepted sources to support EAI's assumptions.
    e. EAI should include analysis of longer useful-life assumptions beyond 25 years, to reflect growing market confidence in both PPAs and manufacturer performance guarantees with terms of 30 years or more.
2. Commission Hearings: Because EAI's cost assumptions for solar depart so dramatically from current market realities, EAI's customers would benefit from a more formal examination of the current cost trends for solar technologies, to ensure EAI is making well informed decisions about additional opportunities to

save money for its customers and economically diversify its generation portfolio. Solar costs have fallen precipitously over the last 5 years, but EAI's cost assumptions have not been updated to reflect those declines, even after EAI has seen them first-hand when it executed the Stuttgart PPA. The IRP stakeholder process does not provide an adequate venue for this type of examination, so the Commission may want to consider options for receiving independent perspectives on the potential economic and customer benefits of adding solar energy and capacity resources in Arkansas. Public hearings may be needed for the Commission to determine questions of fact about whether EAI is using accurate cost assumptions for solar resources.

3. Near-Term Solar Opportunities: In light of the Commission's findings in approving EAI's Stuttgart solar PPA, the Commission should consider holding hearings to determine how EAI can take advantage of near-term market opportunities to add new utility-scale and distributed solar energy resources to achieve cost savings and portfolio diversity benefits for its customers, independent of capacity needs identified in the 2015 IRP.
4. Integrating Distributed Solar: Given the market growth of customer-sited solar and the increased attention to net metering policies and tariffs, EAI should provide analysis of distributed energy resources, including customer-sited solar, in its integrated resource planning.

WIND ENERGY STAKEHOLDER COMMENTS
Simon Mahan, Southern Alliance For Clean Energy

The United States has over 67,870 megawatts (MW) of wind power capacity installed with another 13,600 MW under construction. Wind turbine technology has advanced significantly, even over the past five years. With taller turbines and longer blades, wind energy prices have declined and further technological improvements are expected.

As of 2014, seven states have more than 15% of their in-state generation as wind energy. In three of those states, wind energy provides more than 20% of the state's generation.[i] The fact that so many states are capable of handling significant quantities of variable generation resources strongly suggests that even a modest increase in variable generation in Arkansas may not be difficult.

A variety of wind energy resources are available to Entergy Arkansas, Inc. (EAI), each with its own unique price points, performance levels and other attributes. Utilities from around the region are purchasing wind energy resources, particularly from within the Southwest Power Pool (SPP). SPP wind energy resources, even with transmission requirements, tend to be extremely cost competitive with exceptionally high capacity factors. Proposed new-build High Voltage Direct Current (HVDC) transmission lines, built to enable direct transmission of high-quality wind energy resources, are another cost competitive wind energy option for direct delivery into the Midcontinent Independent System Operator (MISO) and high capacity values. Finally, local wind energy resources could also be available, albeit with relatively higher cost than with imported wind and lower capacity factors, but with fewer transmission considerations.

<u>Figure 1. Recommended Wind Energy Model Inputs for EAI's IRP</u>

	SPP Wind Imports	HVDC Wind	Local Wind
LCOE 2014$/MWh w/PTC (busbar)	$23.43	$23.43	$58
w/o PTC (adds $15/MWh)	$38.43	$38.43	$73
Transmission ($/MWh)	$15-$19	$15-$19	$0
Delivered Cost w/o PTC	$53.43-$57.43	$53.43-$57.43	$73
Installed Cost 2014$/kW (all-in)	$1,638	$1,638	$1,877
in 2020	$1,568	$1,568	$1,856
in 2030	$1,515	$1,515	$1,840
2014 Capacity Factor	51%	51%	38%
in 2020	54%	54%	41%
in 2030	57%	57%	44%
Capacity Value	15%	28%	15%

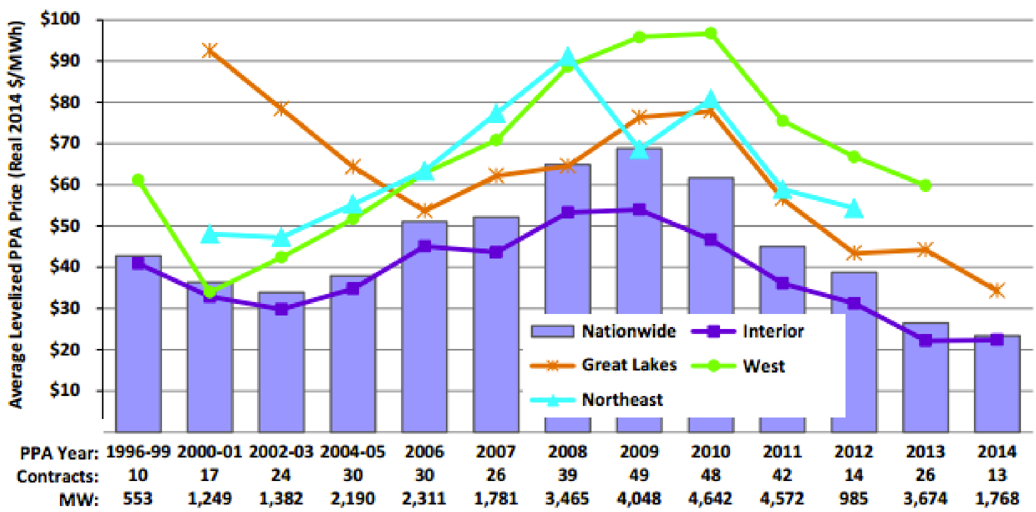
SPP/HVDC wind energy resource LCOE and Installed costs for 2014 are based on Lawrence Berkeley National Laboratory's *2014 Wind Technologies Market Report*[ii]. The PTC cost savings of $15/MWh is also reported by LBNL. All costs (excluding the PTC) and learning curves for Local wind energy resources are based off the Department of Energy's *Wind Vision* report Table H–3 and Table H–4 for Land4/TRG4 resources.[iii] All net capacity factors and learning curves are based off DOE's Table H-4 for TRG1 and TRG4 resources. HVDC's wind energy resource capacity values are based on analysis performed for the Tennessee Valley Authority.[iv]

When evaluating wind energy opportunities, utilities can access those resources through a variety of contractual options to enable transmission. A wind developer, or a utility could pay transmission costs. Transmission could be based on a firm point-to-point delivery or a non-firm delivery could be available. After the level of "firmness" is selected, energy could either be block-scheduled or as-generated by a wind project. These are just a few options available in developing transmission costs and assumptions. Another contract type can avoid issues associated with point-to-point transmission requirements. Virtual PPA's avoid point-to-point transmission impacts; however, wind energy is not physically delivered to the purchasing utility.[v]

Wind Energy Resources Are Low Cost

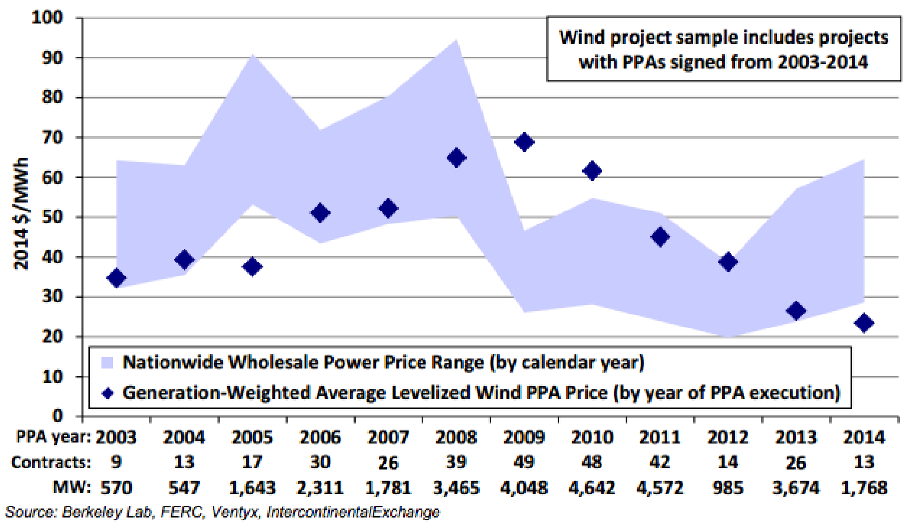
Wind energy resources are one of the lowest cost energy resources available to utilities. Recent announcements of power purchase agreements ("PPAs") and the results of other IRP processes highlight the cost benefit of incorporating additional wind energy resources. New analysis from Lawrence Berkeley National Laboratory (LBNL) shows that the national average of wind energy power purchase agreements from 2014 has reached record lows. Average PPA prices in the mid-$20/megawatt hour (MWh) range were achieved in the country's Interior region in 2014. Average PPA prices are competitive with wholesale electric costs across the country.[vi]

Figure 2. Generation-weighted average levelized wind PPA prices by PPA execution date and region



Source: LBNL 2015[vii]

<u>Figure 3. Average levelized long-term wind PPA prices and yearly wholesale electricity prices over time</u>



Source: LBNL 2015[viii]

The nationwide capacity-weighted average installed project cost in 2014 was $1,710/kW. Installed project costs in the interior region of the country (including Texas, Oklahoma and Kansas), reached $1,638/kW in 2014.[ix] The capacity-weighted average installed project cost represents an all-in cost, thus no additional fixed-rate charge or financing interest rates should be added in addition to the installed costs provided here. Additionally, LBNL notes that the federal Production Tax Credit (PTC) does not affect the installed cost directly.[x]

LBNL found that the average power purchase agreement (PPA) for wind energy contracts in 2014 reached an all-time low price of $23.43 per megawatt hour (MWh), including the PTC.[xi] For comparison, Arkansas Electric Cooperative Corporation (AECC) has taken advantage of these low-cost wind energy resources. Specifically, AECC has entered into a PPA with the Origin wind farm in south-central Oklahoma. News reports state that the recently completed Origin wind farm represents a nameplate capacity of 150 MW at a total cost of $250 million, or an installed project cost of roughly $1,667/kW.[xii] According to a recent Electronic Quarterly Report (EQR) filing with the Federal Energy Regulatory Commission (FERC), Origin Wind Energy LLC transmitted 156,459 MWh of energy to AECC at a rate of $25.6/MWh, during the second quarter of 2015.[xiii]

Wind Energy Prices and Performance Factors Are Expected to Continue to Improve

As shown by the LBNL market report, wind energy PPA's have consistently declined since 2008 (See Figure 2).[xiv] Price declines are a factor of both improved performance as well as reduced all-in installed costs and highlight a need to apply a learning curve to wind energy resources, similar to solar energy resources. As part of the DOE *Wind Vision* report, the National Renewable Energy Laboratory (NREL) conducted an extensive literature review to deduce future cost reduction potential, as well as capacity factor improvements. The DOE noted that, "…the High Cost case represents no future cost reduction or performance improvement through 2050 for land-based wind, and the Low Cost case represents a land-based wind LCOE reduction of 37% by 2050."[xv] In its "mid-cost" learning curves, the DOE reduced the 2014 installed capital cost assumptions between 1.1% to 4.3% by 2020, and a full 1.9% to 7.5% by 2030 (over 2014 cost assumptions). These figures varied depending on wind resource quality, with the lower cost reductions (1.1% by 2020 and 1.9% by 2030 over 2014 cost estimates) occurring in lower quality wind resource areas and the higher cost reductions (4.3% by 2020 and 7.5% by 2030 over 2014 cost estimates) in higher quality wind resource areas.

In addition to a reduction in installed costs, the DOE assigned performance improvements to turbine capacity factors. In its "mid-cost" learning curves, the DOE increased 2014 estimated capacity factors by 4.3% to 9.4% by 2020 and 10.6% to 15.8% by 2030. These figures varied depending on wind resource quality, with the lower capacity factor improvements (4.3% by 2020 and 10.6% by 2030 over 2014 capacity factors) occurring in higher quality wind resource areas and the higher capacity factor improvements (9.4% by 2020 and 15.8% by 2030 over 2014 cost estimates) in lower quality wind resource areas.

Many Southern Utilities are Purchasing Wind Energy Resources

Purchasing wind energy from out-of-state is not only feasible, such purchases are commonplace throughout the south. Some existing out-of-region wind energy purchases include Arkansas Electric Cooperative (309 MW)[xvi], Alabama Power (404 MW)[xvii], Georgia Power (250 MW)[xviii], Gulf Power (178 MW)[xix], SWEPCO (469 MW)[xx] and the Tennessee Valley Authority (1,515 MW).[xxi] Many of the purchases of out-of-region wind energy are voluntary, underscoring wind energy's current cost competitiveness.

In February 2015, Gulf Power announced plans to procure 178 megawatts of wind energy resources from Oklahoma. In its petition for approval to the Florida Public Service Commission, Gulf Power stated that the "Net present value benefits to Gulf's customers under the 2015 energy budget evaluation total approximately $11 million 2016 dollars. The primary driver of the differences between 2014 and 2015 evaluations is a lower fuel cost projection..."[xxii]

Several Southern Utilities are Projecting Wind Energy Resource's Low Costs and Planning Procurement

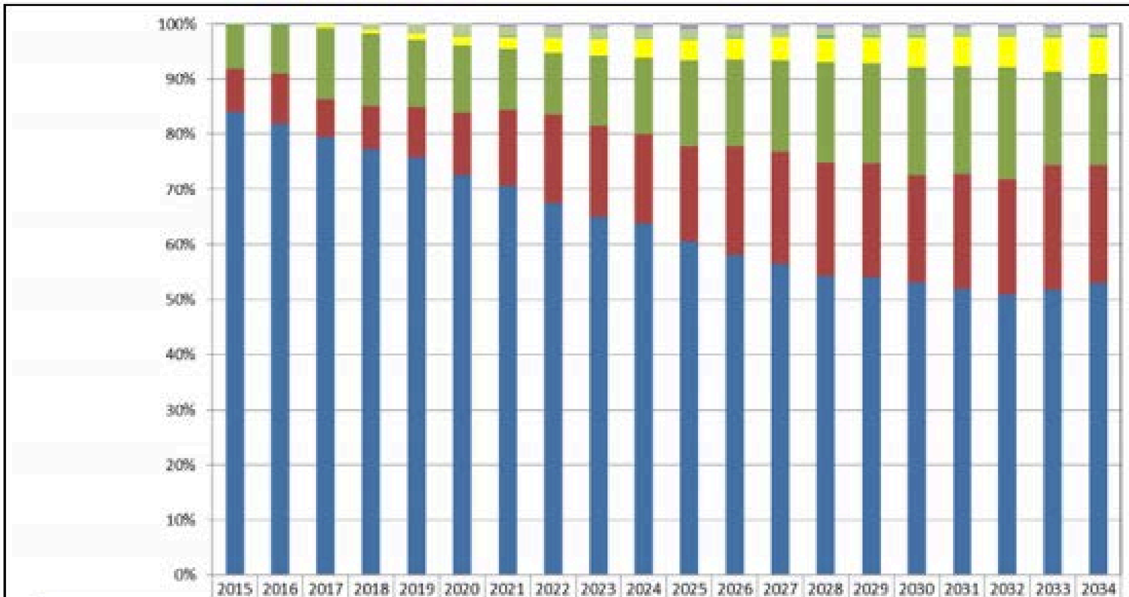
The Southwestern Electric Power Company (SWEPCO), with a service territory in parts of Arkansas, Louisiana and Texas, recently filed its 2015 Final IRP with the Louisiana Public Service Commission.[xxiii] In direct response to comments filed by the Southern Wind Energy Association, SWEPCO developed its wind energy modeling assumptions. Specifically, SWEPCO undertook the following methodology:

> "For modeling purposes, wind was considered under various 'blocks' or 'tranches' for each year. There are three tranches of wind with different pricing. The first

tranche of wind resources, Tranche A was modeled as a 100MW block with a Levelized Cost Of Energy (LCOE) with the Production Tax Credit (PTC) of $24/MWh in 2015 and a 55% capacity factor load shape. In 2017, after the expiration of the PTC, the LCOE of Tranche A increases to $47/MWh in nominal dollars with prices increasing 0.5%/year through 2035. Tranche A resources were assigned a capacity value of 20% of nameplate rating. The second tranche of wind resources, Tranche B, was modeled as a 100MW block with a LCOE with the PTC of $28/MWh in 2015$ and a 50% capacity factor load shape. In 2017, after the assumed expiration of the PTC, the LCOE of Tranche B increases to $51/MWh in nominal dollars with prices increasing 2%/year through 2035. Tranche B resources were assigned a capacity value of 10% of nameplate rating. The third tranche of wind resources, Tranche C, was modeled as a 100MW block with a LCOE with the PTC of $37/MWh in 2015$ and a 45% capacity factor load shape. In 2017, after the assumed expiration of the PTC, the LCOE of Tranche C increases to $60/MWh in nominal dollars with prices increasing 2%/year through 2035. Tranche C resources were assigned a capacity value of 5% of nameplate rating. Wind prices were developed based on the U.S. DOE's Wind Vision Report." [xxiv]

SWEPCO's Final IRP preferred plan calls for up to 1,200 MW of new wind energy resources, plus additional solar energy resources, and would move the utility from a 2015 generation mix including 7.5% renewable energy to a 2035 generation mix including 34.8% renewable energy.

Figure 4. SWEPCO Final IRP Annual Energy Production Position throughout Planning Period (2015-2034)



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Volt-Var Optimization	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Energy Efficiency	0%	0%	0%	1%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	1%	1%	1%	1%
Distributed Solar	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Utility-Scale Solar	0%	0%	1%	1%	1%	2%	2%	3%	3%	3%	4%	4%	4%	5%	5%	5%	5%	6%	6%	7%
Wind	8%	9%	13%	13%	12%	12%	11%	11%	13%	14%	16%	16%	17%	18%	18%	20%	20%	20%	17%	17%
Natural Gas	8%	9%	7%	8%	9%	11%	14%	16%	16%	16%	17%	20%	20%	21%	21%	19%	21%	21%	23%	21%
Coal	84%	82%	79%	77%	76%	73%	71%	67%	65%	64%	60%	58%	56%	54%	54%	53%	52%	51%	52%	53%

Source: SWEPCO 2015[xxv]

In its Final 2015 IRP, the Tennessee Valley Authority (TVA) evaluated wind energy resources from within the TVA service territory (In-Valley), the Southwest Power Pool (SPP), the Mid-Continent Independent System Operator (MISO), as well as wind energy imports from two proposed High Voltage Direct Current (HVDC) transmission projects designed to deliver substantial quantities of low-cost, high-performance wind energy resources. TVA evaluated the various wind energy resources with varying installed capital costs as well as different capacity factors. Despite some of TVA's high cost and low performance assumptions, its Final IRP models called for between 500-1,750 MW of wind energy resources.[xxvi] With more accurate cost and performance assumptions, more wind energy resources may be warranted.

The recent Georgia Power Company (GPC) Request for Information (RFI) for wind energy corroborates industry data provided by LBNL.[xxvii] GPC received information from 14 different companies, with 40 different projects representing 21 different locations. Information was provided on wind energy resources from the Interior region (Texas, Oklahoma, Kansas and Iowa), Great Lakes region (Illinois and Indiana), and Southern region (Alabama, North Carolina and Tennessee). In a memorandum to the PSC regarding the results from the RFI, La Capra Associates noted, "Of the 37 project configurations analyzed, 30 project configurations had positive net benefits, with the majority of these having significant net benefits."[xxviii] La Capra Associates noted that net benefits could be larger, if GPC evaluated "non-firm imports" into the SBA. GPC is expected to use these cost figures in its upcoming IRP process, set to begin in January 2016. Shown in Figure 5 are the pricing data points provided through the RFI process to GPC.

Figure 5. Wind energy pricing by delivery method provided via GPC RFI process ($/MWh)

Source: Georgia Power Company 2015[xxix]

The Federal Production Tax Credit (PTC) Creates Near-Term Opportunities

The federal Production Tax Credit (PTC) is the primary federal incentive for wind energy resources. The PTC is benchmarked as a tax credit of $23/MWh for wind energy generated, and is available for the first ten years of a wind project. LBNL notes that the cost savings of the PTC is likely about $15/MWh.[xxx] Wind farms completed by the end of 2016 may still qualify for the PTC, despite the incentive's lapse in late 2014. The PTC has been extended numerous times with broad bipartisan support in the past and in July 2015, a key senate committee approved a bill that could extend the PTC to the end of 2016.[xxxi] If Internal Revenue Service (IRS) guidelines remain similar, wind farm developments could qualify if development begins prior to the end of 2016 with operations beginning as late as 2018. Of course, at that time the PTC may be extended again. Entergy is more likely to be able to capture the value of the PTC if they add wind resources to their mix sooner rather than later. As part of its Final IRP, SWEPCO took the PTC into account and plans to issue a Request for Proposals (RFP) for up to 200 MW of PTC/ITC eligible wind energy resources for electricity delivery by December 31, 2016.[xxxii]

2015 Integrated Resource Plan Analysis

Wind energy resources are evaluated in the 2015 IRP. However, only one form of wind energy resource is evaluated, specifically, imported wind energy from the SPP footprint. Evaluating imported wind energy resources is an important factor for IRP modeling, but additional wind energy resources should be modeled as a way to differentiate between these resources, evaluate various costs and benefits and provide a diversified portfolio.

In most model scenarios evaluated, substantial quantities of wind energy resources are selected as a low-cost energy resource. A key variable in the various model scenarios is the cost of wind energy resources. Given the substantial quantities of low-cost wind energy purchases from utilities across the south, ground-truthing wind energy pricing is vitally important to resource planning exercises. While most of the scenarios evaluating wind energy rely on a price of $54/MWh, one additional model run with wind energy costs of $47/MWh highlights the importance of accurate wind energy pricing. In the "Additional Model Run" requested by the stakeholder group, wind energy with a price of $47/MWh resulted in the model selecting 2,400 MW of wind energy resources, or twice as much wind energy capacity as any of the other model results. Corroborating these model inputs and results, the Southwestern Electric Power Company (SWEPCO) evaluated wind energy resource prices at $47/MWh, $51/MWh and $60/MWh in its Final 2015 IRP. SWEPCO's model results show a need for approximately 1,200 MW of new wind energy capacity.[xxxiii]

Figure 6. Entergy Arkansas, Inc. Draft 2015 Integrated Resource Plan Model Results for Wind Energy Resources

IRP Preliminary Model Results			Stakeholder Model Results		
Future 1	Future 2	Future 3	Alt. Future	Alt. Future, Sensitivity	Additional Model Run
800 MW	0 MW	1,200 MW	0 MW	1,000 MW	2,400 MW

Source: Entergy Arkansas, Inc. 2015[xxxiv]

Recommendations for the Final IRP

Wind power represents a large scale, low cost energy resource for Arkansas. Entergy Arkansas, Inc.'s Draft IRP has taken some positive steps towards evaluating wind power. With this in mind, the stakeholders group would like to provide the following recommendations for the Final IRP:

- Include feasible wind energy options, including out-of-state wind energy from a new HVDC transmission project, SPP and local wind energy resources and adjust cost and performance accordingly.
- Use the data submissions provided for the IRP inputs, including installed costs, capacity factors, levelized cost of energy as well as cost and performance improvements over the IRP study timeframe.
- Apply cost reductions and performance improvements for wind energy resources; a methodology already applied to solar energy resources within the IRP.
- Incorporate the PTC for wind energy resources through December 31, 2020.
- Allow multiple wind energy resources to be added each year, if model results recommend doing so.

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