Entergy Arkansas, Inc.
Integrated Resource Plan
Stakeholder Committee Meeting

July 31, 2012

Today's Agenda

Agenda Item	Presenter	Time
Introduction and Meeting Objectives	Kurt Castleberry	8:30 – 9:00
EAI Resource Planning History	Kurt Castleberry	9:00 – 9:30
EAI Current Capacity Position	Matt Wolf	9:30 -10:00
Break		10:00 – 10:15
EAI's Role in Transmission Planning	Kurt Castleberry	10:15 – 10:30
Overview of Environmental Issues	Myra Glover	10:30 – 11:15
Demand Side Management and Energy Efficiency	Richard Smith	11:15 – 12:00
Lunch		12:00 – 1:00

Today’s Agenda (Cont’d)

Agenda Item	Presenter	Time
Generation Technology Assessment & Production Cost Analysis	Charles DeGeorge	1:00 – 2:00
Preliminary Resource Plans	Matt Wolf	2:00 – 2:45
Break		2:45 – 3:00
Stakeholder Committee Formation	Stakeholders	3:00 – 4:00
EAI Respond to Written Stakeholder Questions	EAI	4:00 – 4:45
Wrap-up and Adjourn	Kurt Castleberry	4:45 – 5:00

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

EAI Statistics

Peak Load (2011)	5,178 MW
Retail Sales (2011)	21,583,567 MWh
# Retail Customers (2011 year-end)	695,397
# Active Electric Generating Units	26
# Power Plant Sites	13
Generating Capacity (Summer 2012 Ratings)	
- Nuclear	2,285 MW
- Coal	1,209 MW
- Gas / Oil	1,528 MW
- Hydro	94 MW
Total Capacity (Retail and Wholesale)	5,116 MW
Transmission Lines (miles)	4,744
Distribution Lines (miles)	37,455

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

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 2012 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

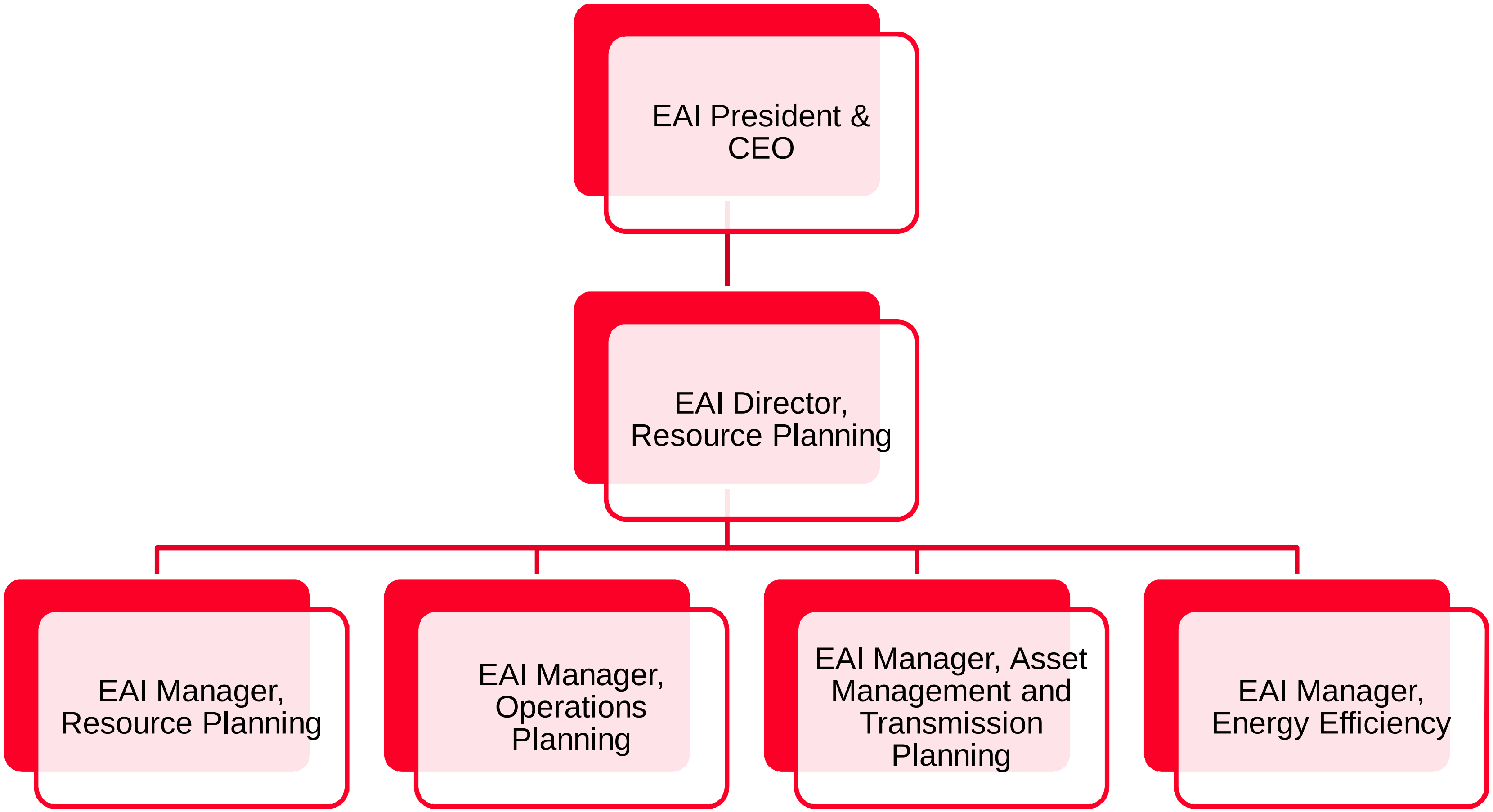
ACTIVITY	DATE
Stakeholder meeting	July 31
Stakeholder / EAI interaction (as needed)	August 1 – September 30
Stakeholders finalize Stakeholder Report and provide to EAI	October 1 – 30
EAI finalizes IRP and files it with the APSC including Stakeholder Report	October 1 - October 31

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 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

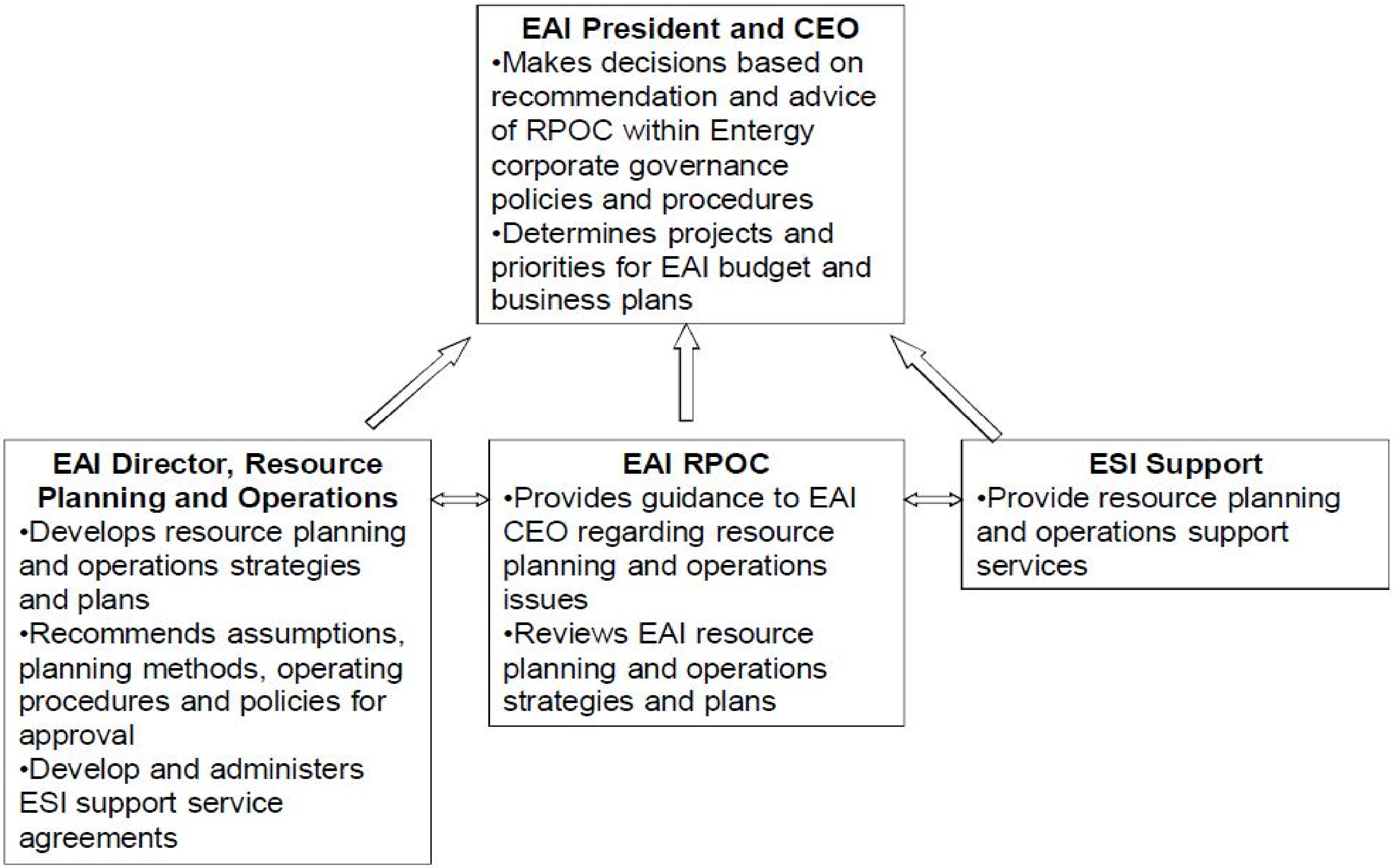


EAI Resource Planning and Operations Committee (RPOC)

Chair
EAI Director, Resource Planning and Operations

- EAI Vice President Regulatory Affairs (Vice Chair)
- EAI Legal Counsel (Secretary)
- ESI Director - EAI Jurisdictional Finance
- ESI Vice President - System Planning and Operations
- ESI Director – Fossil Operation NW Region
- ESI Vice President - Nuclear Operations
- EAI Manager, Resource Planning
- EAI Manager, Operations Planning

EAI Resource Planning and Operations Governance



EAI / ESI Support Services Agreement

Services that EAI may continue to utilize from the System Planning and Operations organization may include, but are not limited to:

1. **Performing load forecasting and technical support for integrated resource planning and operations**
2. **Providing technical support for EAI's transmission service arrangements and evaluation of potential economic transmission upgrades**
3. **Arranging for non-nuclear fuel supplies**
4. **Providing technical support for generation resource procurement**
5. **Performing real-time operations for EAI's generation fleet, and operating plans, including planned and maintenance outages for EAI's generation fleet**
6. **Buying and selling capacity and energy on behalf of EAI, including providing administration services for contractual arrangements, and power supply accounting and settlements for power and energy**
7. **Representing EAI in industry and stakeholder committees**

EAI Resource Planning Objectives

EAI Resource Planning Objectives

EAI has adopted the following resource planning objectives to guide EAI's Integrated Resource Plan (IRP) and to meet requirements of the APSC Resource Planning Guidelines for Electric Utilities:

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.**

EAI Resource Planning Objectives

3. **<u>Planning for Uncertainty</u> – 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. **<u>Reliability</u> – The IRP should provide adequate resources to meet EAI's customer demands and expected contingency events in keeping with established reliability standards.**

5. **<u>Baseload Production Costs</u> – The IRP should provide baseload resources that provide stable long-term production costs and low operating costs to serve baseload energy requirements.**

EAI Resource Planning Objectives

6. <u>Operational Flexibility for Load Following</u> – 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. <u>Generation Portfolio Enhancement</u> – 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. <u>Price Stability Risk Mitigation</u> – 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.

EAI Resource Planning Objectives

9. <u>Supply Diversity and Supply Risk Mitigation</u> – 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. <u>Locational Considerations</u> – 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 power to EAI's customers.

11. <u>Reliance on Long-Term Resources</u> – 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.

EAI Resource Planning Objectives

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

Questions / Comments

Entergy Arkansas Integrated Resource Planning History - Overview

July 31, 2012

Entergy

Objective

- Review resource planning activities since EAI gave notice that it would exit the Entergy System Agreement

Significant Resource Planning Events

2005
EAI gives notice to exit the Entergy System Agreement

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2006
Energy Efficiency Docket Opened

→

2008
Ouachita Power Plant Purchase completed

→

2009
White Bluff Environmental Controls Analysis completed for CAVR

↓

2009
EAI IRP filed with APSC

→

2009
EAI Stand-Alone Plan filed with APSC

→

2011
Hot Springs KGen acquisition announced

→

2011
MISO Announcement

↓

2011
RFP Issued for up to 750 MW

→

2012
Deactivation Analysis Completed

Negotiating with two bidders from 2011 RFP

→

2012
Application made to add certain wholesale base load resources to serve EAI's retail load

→

2012
IRP Development

2005 – “Notice”

- The Entergy Operating Companies have operated as a pool utilizing some form of a system agreement since 1951

- Due to the outcome of litigation at the FERC regarding the current System Agreement, EAI gave its 96-month notice to withdraw from the System Agreement on December 19, 2005

- Departure Day (D-Day) is December 19, 2013

- EAI must have in place systems to operate an electric system and sufficient capacity and reserves to serve its customers

2006 – Energy Efficiency

- In 2006, the APSC opened the energy efficiency and conservation docket (06-004-R)
- In 2007, EAI filed its first application for approval of energy efficiency programs and energy cost rate rider
- (More details to follow in Richard Smith's presentation)

2008 – Closed Ouachita Acquisition

- RFP issued in 2006
- A purchase agreement was executed by EAI in 2007 to buy the Ouachita Power facility from Cogentrix Energy, Inc.:
  - 789 MW nominal
  - Combined Cycle
- Transaction was completed in September 2008.
  - EAI owns two of the three trains in the plant
  - Entergy Gulf States Louisiana, LLC owns one train

2009 – Stand-Alone Plan

- In 2008 EAI began developing preliminary estimates of the cost and structure needed for EAI to plan and operate outside the Entergy System Agreement
- EAI filed these cost estimates with the APSC in 2009
- Technical conferences were held in 2010 regarding this option

2009 – White Bluff Environmental Controls

- EAI requested a Declaratory Order from the Commission finding that the addition of a Flue Gas Desulfurization system and Low Nitrogen Oxide Burners and Separated Overfire Air at White Bluff for compliance with the Clean Air Visibility Rule ("CAVR") is in the public interest (APSC Docket 09-024-U)

- A petition for a variance from the October 15, 2013 compliance deadline for the CAVR was granted by the Arkansas Pollution Control and Ecology Commission in 2010

- EAI withdrew its Declaratory Order request in May 2010

- Myra Glover's Presentation will provide more details on the current status

2011 – KGen Hot Spring Plant

- RFP issued in 2009
- EAI announces plan to purchase the Hot Spring Plant in July 2011
  - 620 MW
  - Combined Cycle
- APSC approved the acquisition on July 11, 2012
- Awaiting clearance under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (the ‘‘HSR Act’’)

2011 – MISO Announcement

- Entergy Operating Companies announced on April 25, 2011 that they intended to join MISO as a fully integrated transmission owning member
- What is MISO?
  - A Regional Transmission Organization
    - Maintains reliability of the transmission system
    - Administers a regional transmission tariff
    - Facilitates a transmission expansion planning process
    - Manages an energy market
    - Ensures that adequate resources are available to serve load

2011 – MISO (Continued)

- EAI is working towards integrating into MISO when EAI exits the Entergy System Agreement (December 19, 2013)

- EAI will continue to be responsible for planning the resources needed to meet its customer's demand

2011 – RFP Issued

- EAI issued an RFP for up to 750 MW limited term resources
- In November 2011, EAI selected two proposals for additional negotiations
- In February 2012, EAI executed letters of intent with both counterparties
- In June 2012, EAI made an application with the APSC for approval of a capacity cost recovery rider
- EAI expects to finalize definitive purchase power agreements with both counterparties in the near future

2012 Wholesale Base Load Capacity

- A portion of the generation capacity that EAI owns is not currently in retail rates

- In June 2012, EAI made an application to the APSC seeking to return a portion of this capacity to retail rates (APSC Docket No. 12-038-U):

2013:	100 MW
2014 and beyond:	186 MW
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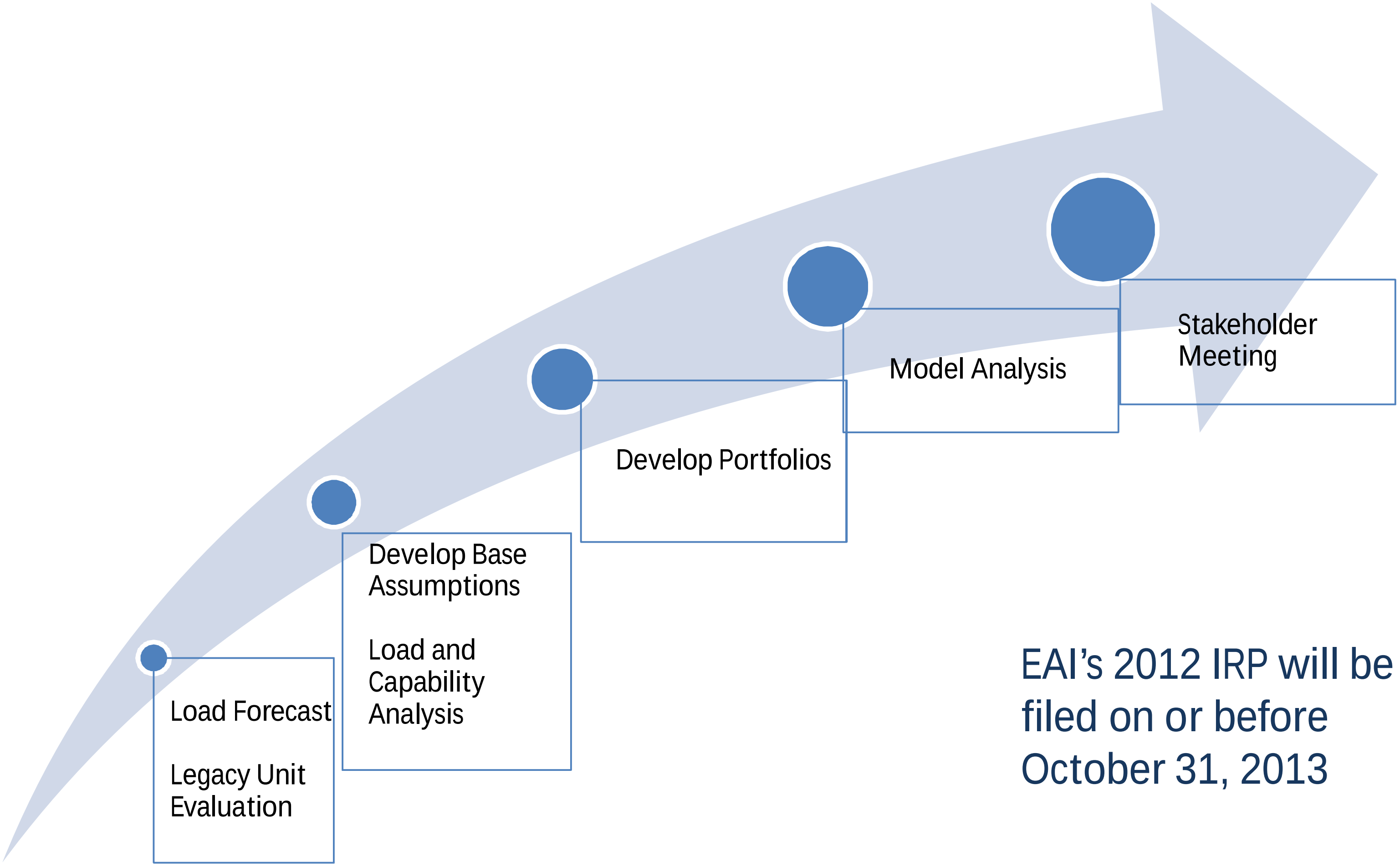
Total	286 MW

- The capacity is fueled by nuclear and coal
  - 184 MW nuclear
  - 102 MW coal

2012 IRP Development



EAI's 2012 IRP will be filed on or before October 31, 2013

Questions / Comments

Entergy Arkansas Integrated Resource Plan General Review

- Load and Capability
- Assumptions
- Stakeholder Input from 2009

July 31, 2012

Entergy

Purpose

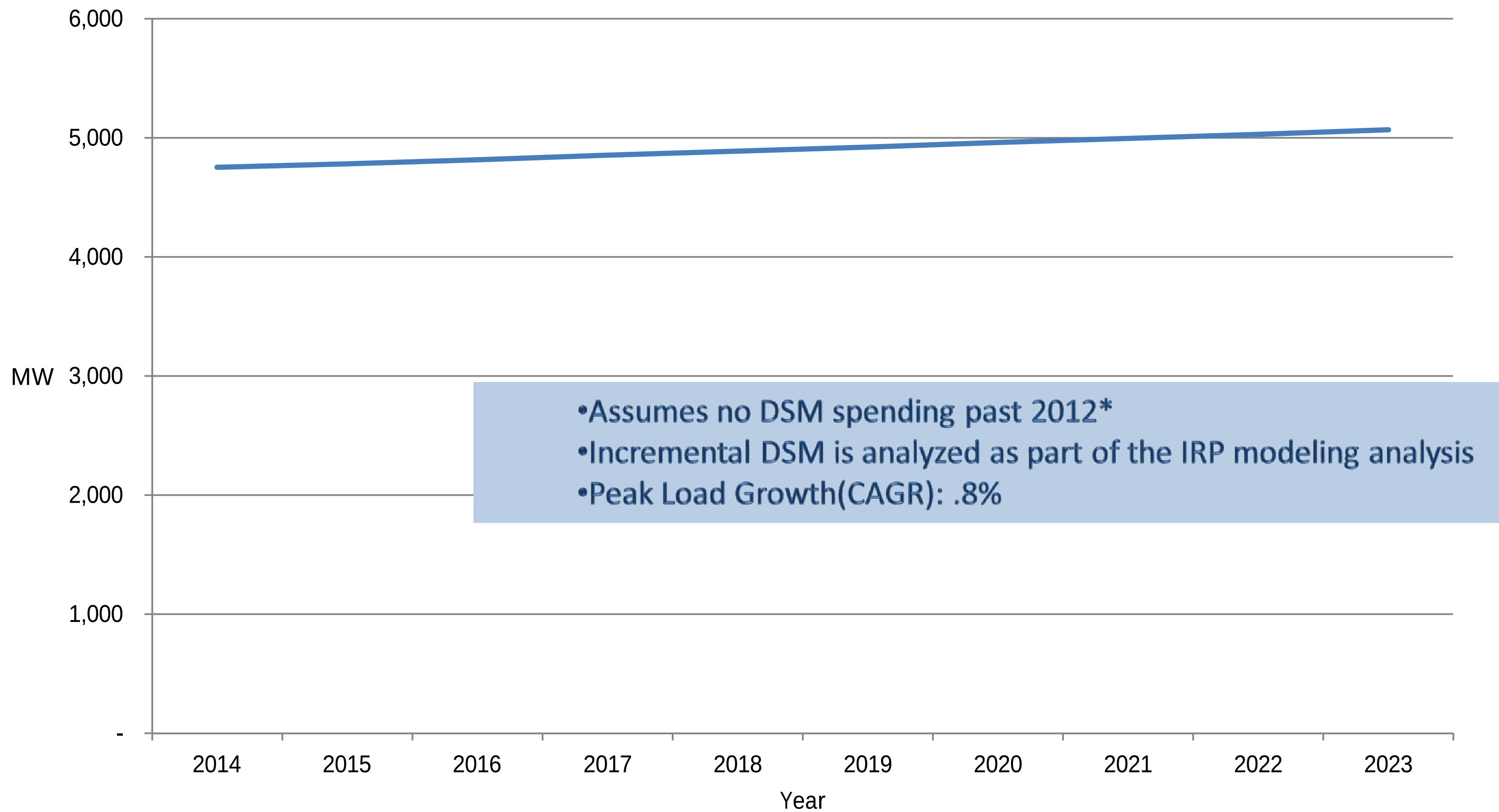
- Give an overview of EAI's current capacity position
  - Load Forecast
  - Existing Generation Capability
- Describe the base assumptions and the focus of the IRP model analysis
- Review the stakeholder committee input from 2009, and how EAI sees IRP addressing that input

IRP Study Period

- The study period for the 2012 IRP is 10 years (2014 – 2023)
- Reasons:
  - Significant changes to EAI's planning and operations framework supports a more concentrated focus on the near-term issues:
    - MISO Transition
    - Post-Entergy System Agreement Transition
    - The uncertainties surrounding these issues and their influences on EAI's capacity needs and options render longer term (i.e., > 10 years) too speculative
  - Adequate generation capacity in the region for the next several years

Load and Capability

EAI Retail Load Forecast (Includes existing DSM)
Base Case (Scenario 1)



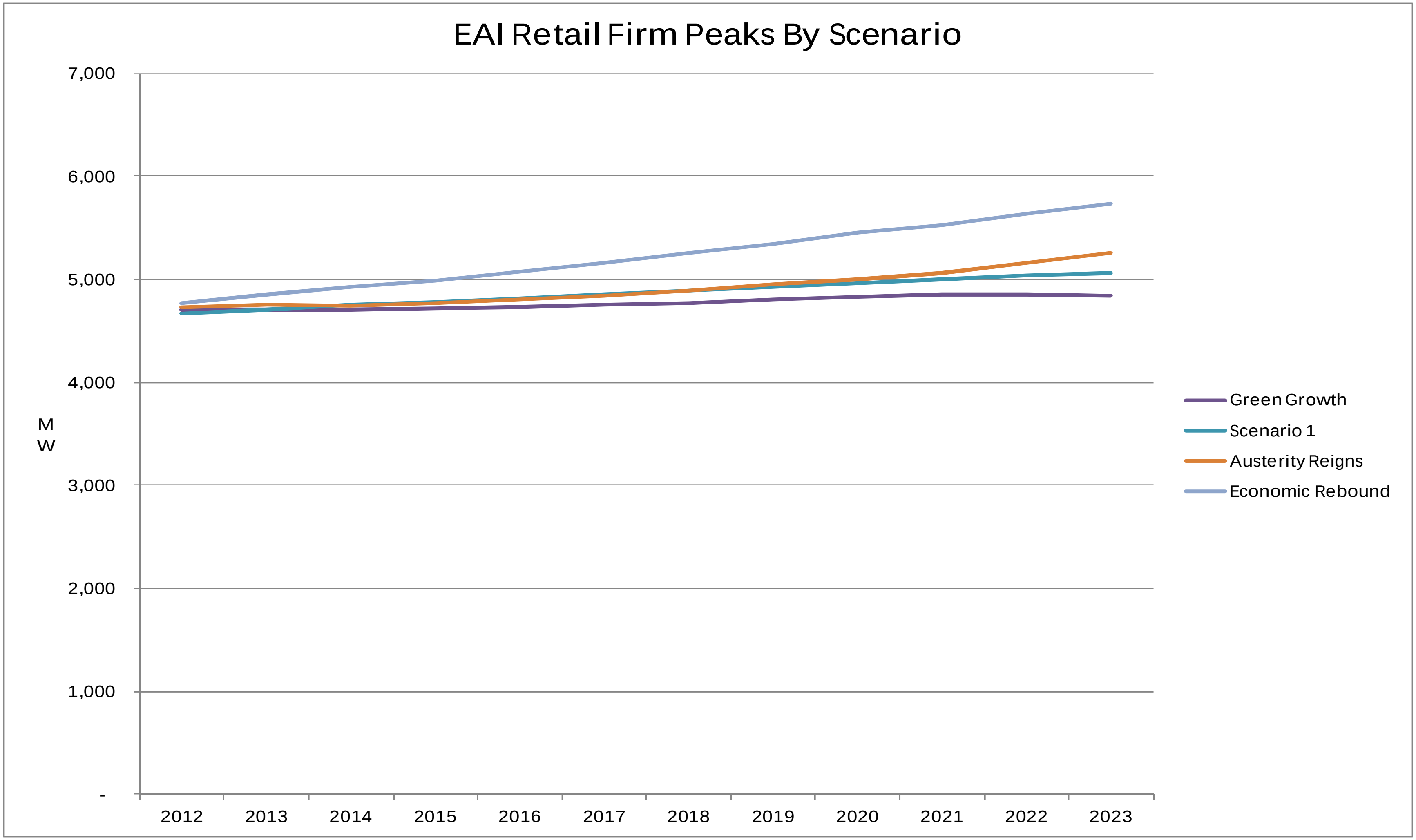
*Note that EAI's Three-Year Plan projects demand reductions of about 50 MW, which was not included in EAI's load and capability

EAI's Planning Scenarios

- IRP analytics will rely on four scenarios to assess alternative portfolio strategies under varying market conditions. Additional information regarding the scope of and assumptions used in the market modeling are provided in other slides. The four scenarios are:
  - Scenario 1 (Assumes Reference Load, Reference Gas, and no CO_2 cost)
  - Scenario 2 (Economic Rebound)
  - Scenario 3 (Green Growth)
  - Scenario 4 (Austerity Reigns)

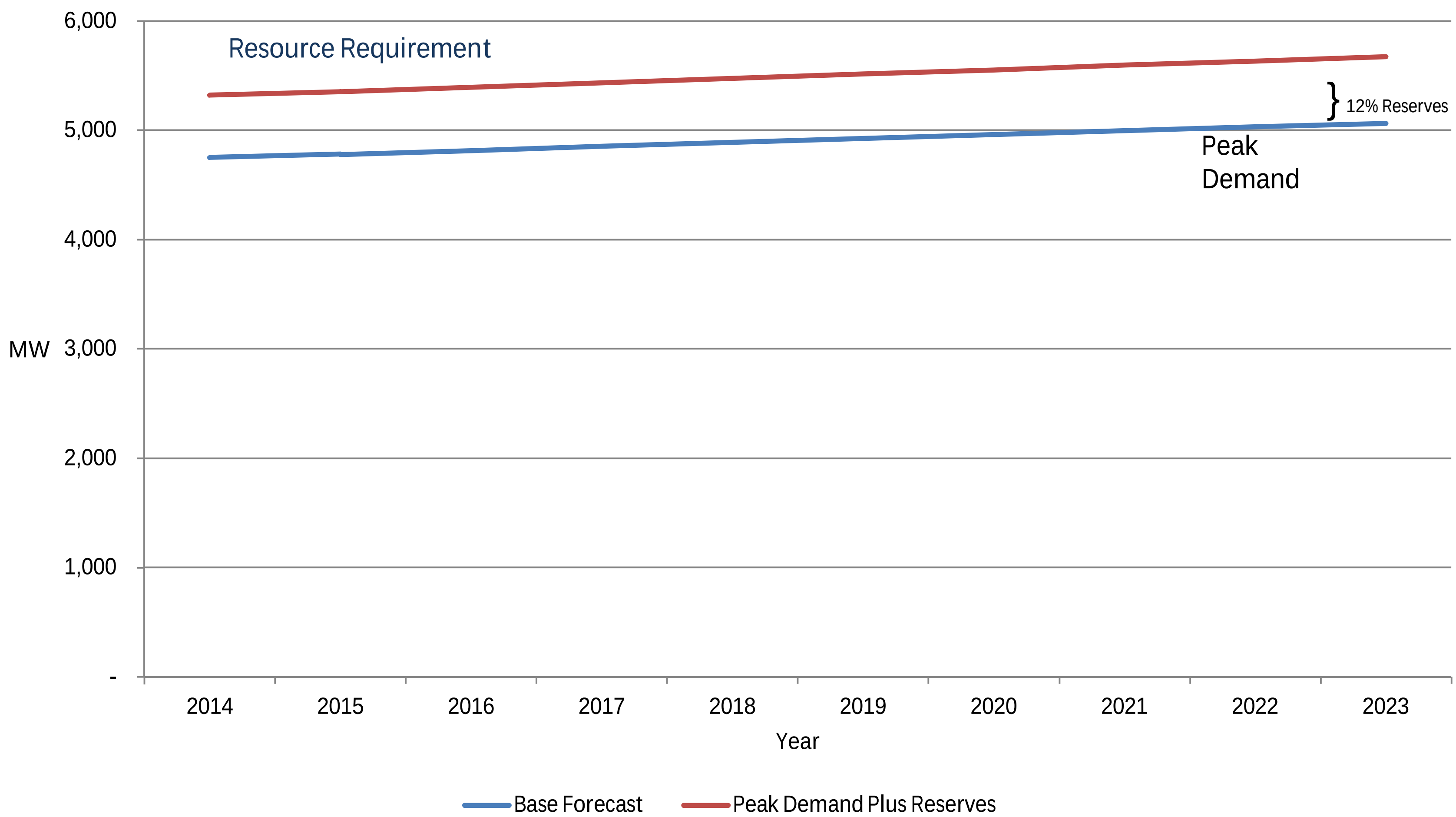
- More information on scenarios is provided in the modeling analysis presentation

Forecast Scenarios
(Used in Modeling Analysis)



Resource Requirements

(Assumes a Planning Reserve Requirement equal to 12% of EAI's Peak Load)



Current Active Capability

- Total Active Generation: 5,116 MW

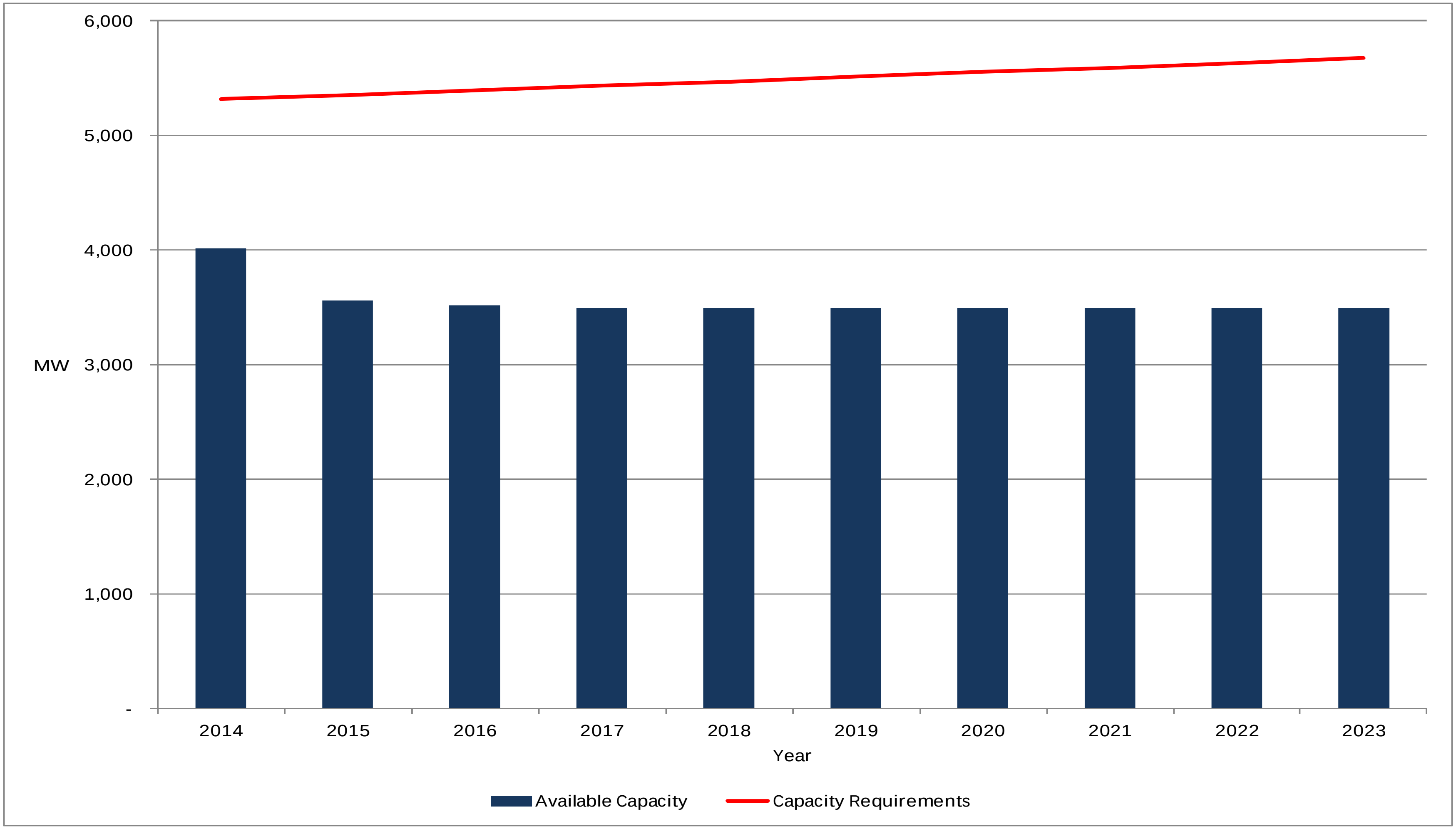
Wholesale Capacity:	726 MW
Retail Capacity:	4,390 MW
Total	5,116 MW

- Wholesale capacity is not in rate base.

Unit Deactivation Assumption

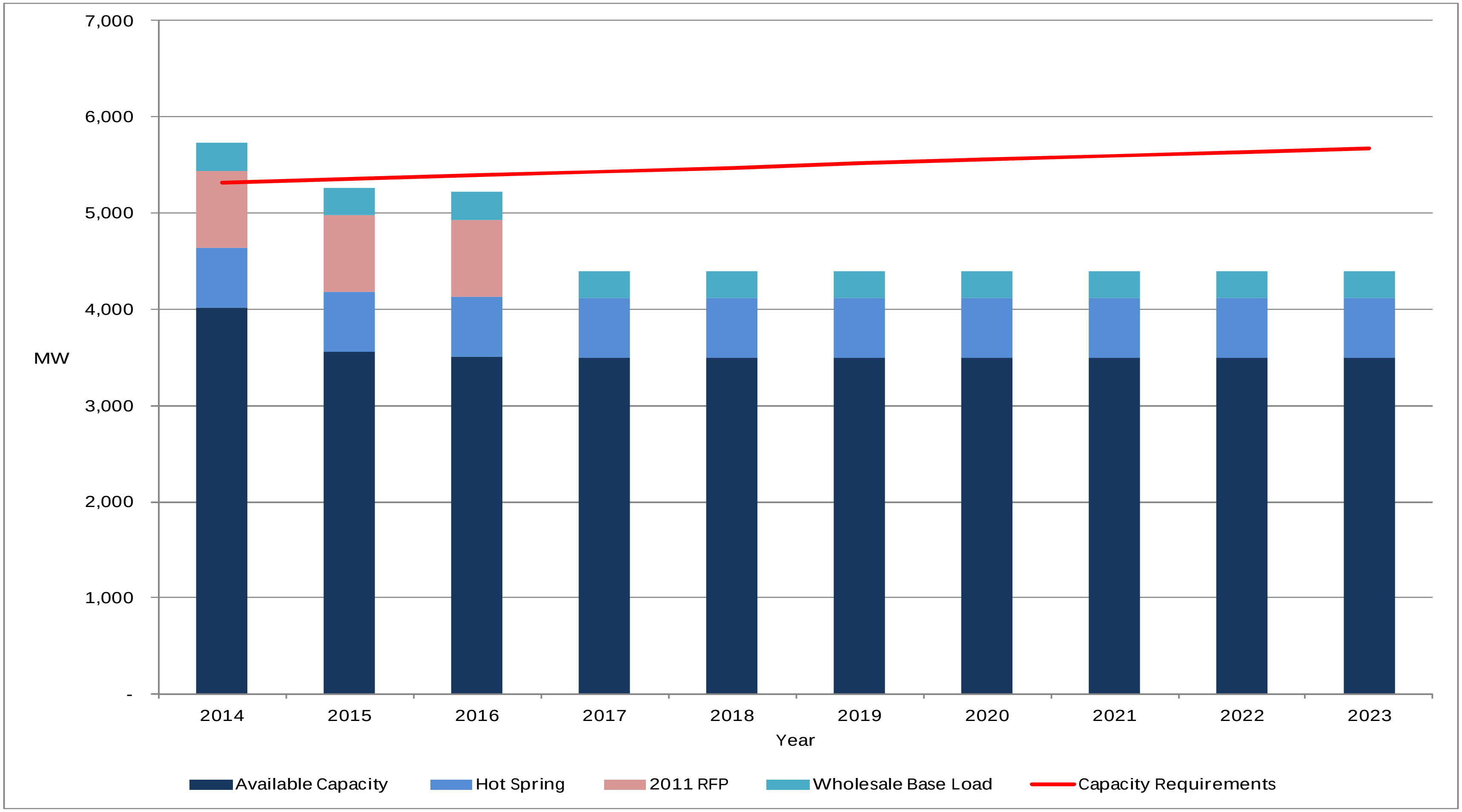
- EAI has approximately 1,000 MW of active gas/oil/diesel fired units which are all at least 40 years old
- EAI completed an assessment of this capacity on May 18, 2012 and filed that assessment with the APSC on May 21, 2012 in Docket No. 11-069-U
- For the 2012 IRP base case (Scenario 1), EAI is assuming that all the legacy gas generation will be deactivated before the 2016 summer peak, although actual decisions to deactivate units will be made on a unit-by-unit basis based upon the needs of customers and the economics of the units relative to available options at the time of the decision
- The continued operation of Lake Catherine 4 is being evaluated as part of the 2012 IRP

Capacity Position – Current Active Retail Capacity

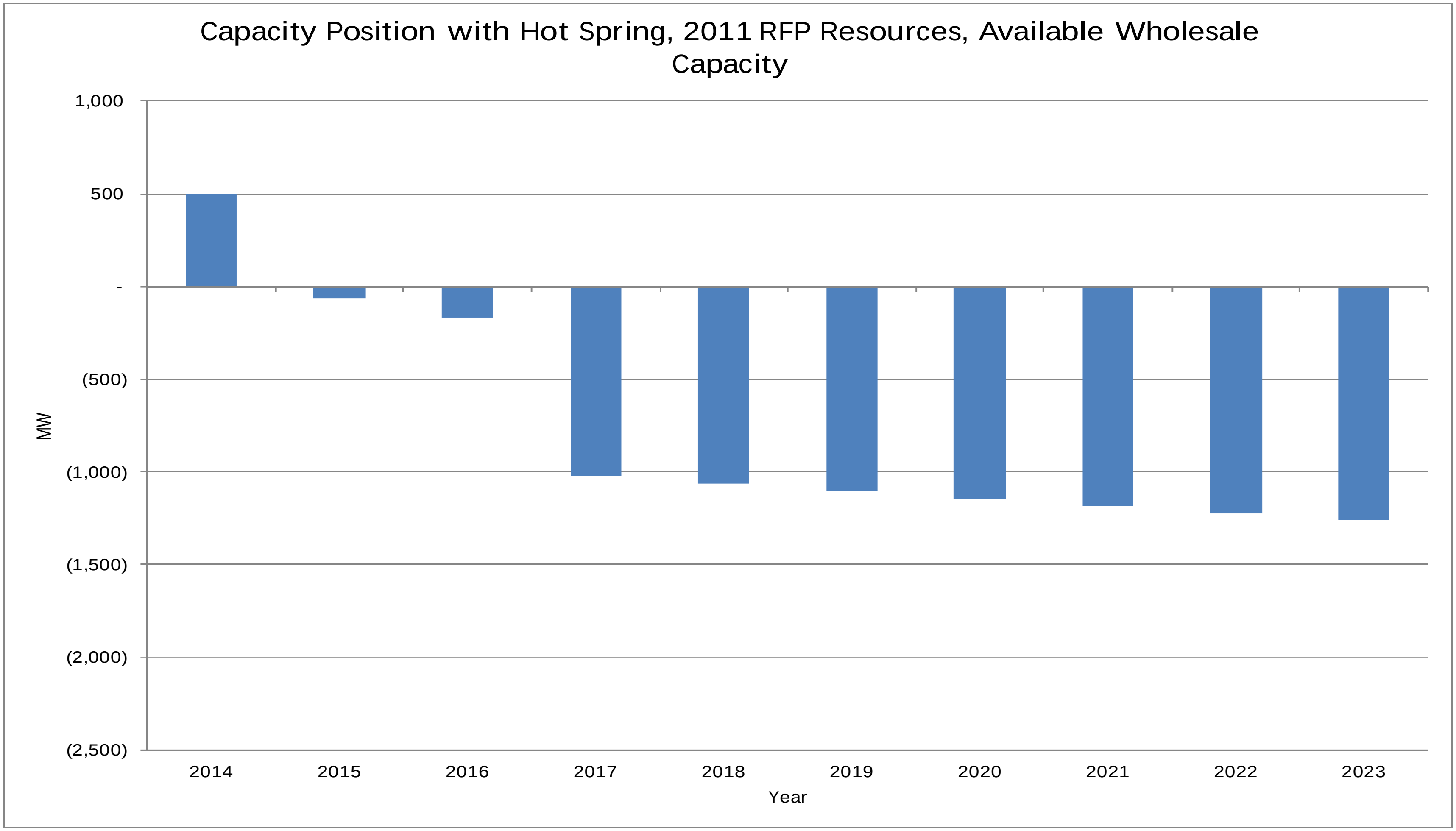


Planned Resources Added

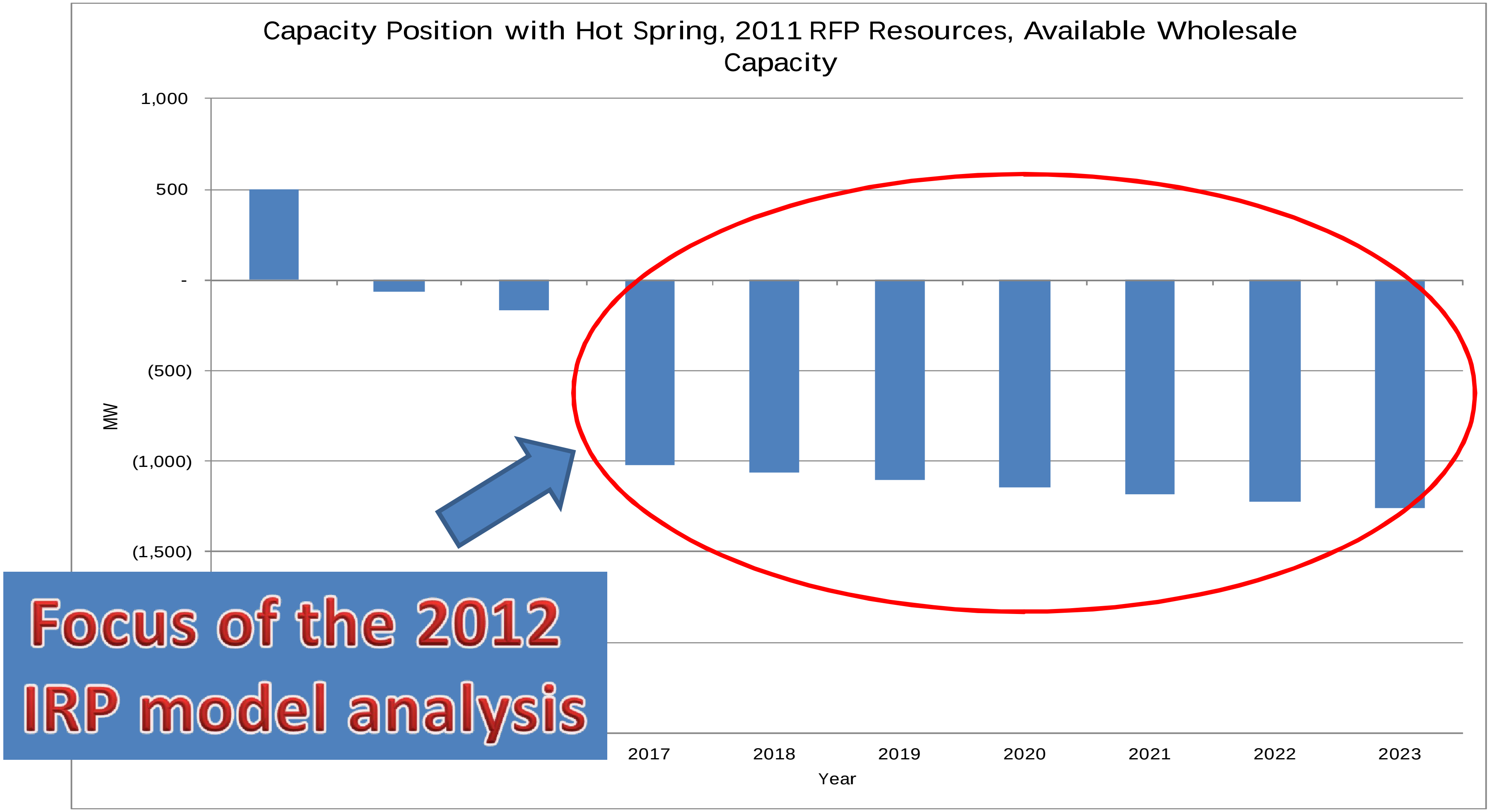
(Hot Spring Power Plant, 2011 RFP Transactions, Wholesale Base Load Capacity)



Net Capacity Position



Net Capacity Position



Options Evaluated

- Five different portfolios were designed for the model evaluation
- Each portfolio included limited or short-term market purchases up to 20% of EAI's needs
- Each portfolio was evaluated under the four different scenarios described earlier
- Again, more details will be provided in the modeling analysis presentation

Portfolio Design for Model Runs

Portfolio	New Combustion Turbine Capacity	New Combined Cycle Generation Capacity	Extend the life of Lake Catherine #4	1000 MW of Wind Generation	Demand Side Management	Limited Term Market Purchases
Portfolio 1	X					X
Portfolio 2		X				X
Portfolio 3	X		X			X
Portfolio 4	X			X		X
Portfolio 5					X	X

Stakeholder Input From 2009 IRP

Stakeholder Input Overview

- In preparing scenarios and portfolios for review, EAI reviewed stakeholder concerns that were provided in the stakeholder process conducted for EAI's IRP filed October 31, 2009

2009 Stakeholder Concerns

A. *EAI must plan to acquire the lowest cost reliable resources that are reasonably possible*
B. *Consideration of non-mandated, non-monetized social and environmental factors in its IRP analysis.*
C. *EAI should provide additional information on its need for automatic generation control for load following generation owned by third parties*
D. *EAI should work to reduce TLRs on its system*
E. *EAI should provide additional information to the Commission and its Stakeholders.*
F. *If EAI is short capacity resources in a given planning scenario, how is that deficiency met in the plan? Will EAI conduct an RFP to meet those needs?*
G. *Demand Side Management*
H. *Distributed Generation and CHP*
I. *Renewable Generation*
J. *Reliability*
K. *Quantifying rate impact on different customer classes.*
L. *Advanced metering technology for residential and commercial customers*

Questions / Comments

BREAK

Post-ESA Transmission Infrastructure Planning

EAI IRP Stakeholder Meeting

July 31, 2012

Transmission Planning Process

- When EAI exits the Entergy System Agreement, EAI will:
  - Become a transmission customer under a FERC-approved OATT
    - MISO Tariff, if EAI is a member of MISO
    - Entergy OATT, if EAI operates on a stand-alone basis
  - Take network service for its retail load

Transmission Planning Process

- EAI will participate in the transmission planning process under the applicable tariff
  - The transmission planning process may impact the deliverability of generation supply that must be considered in the development and implementation of EAI's resource plan
  - Participation is required to support certain functions associated with the planning, construction and operation of EAI's transmission facilities
  - EAI Resource Planning and Operations Staff will be active participants in the transmission planning processes

Transmission Planning Process

- EAI Staff will conduct the generation resource planning for EAI's customer
  - Separately from the generation resource planning conducted on behalf of the other Operating Companies
  - Will include the consideration of potential economic transmission projects to reduce production costs for EAI's customers

Transmission Planning Process

- FERC has required transmission owners that are part of a holding company system to provide transmission services, including planning their transmission facilities, on a system-wide, integrated basis

Transfer Control to MISO (I)

- In the event EAI obtains the requisite approvals to transfer functional control of its transmission facilities to MISO
  - MISO Tariff requires EAI, as a Transmission Owner, to support certain transmission planning functions
- Upon MISO integration, EAI will be participating in the MISO bottom-up MISO Transmission Expansion Planning process that MISO conducts
- EAI will participate as a member of any MISO committee that is allowed under MISO governance and tariff provisions

Transfer Control to MISO (II)

- Under Attachment B to the Transmission Owners Agreement, "[t]o fulfill their roles in the collaborative process for the development of the Midwest ISO Plan, the Owners shall develop expansion plans for their transmission facilities while taking into consideration the needs of
  - connected loads, including load growth,
  - new customers and new generation sources within the Owner's system, and
  - known transmission service requests

Transfer Control to MISO (III)

- Under NERC Standard TPL-001-2, “[e]ach Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request.”
  - Given these requirements, at a minimum EAI will have to coordinate with the other Operating Companies when engaging in transmission planning even if EAI is the only Operating Company that integrates into MISO

MISO Transmission Expansion Planning Process (MTEP)

- EAI’s participation in MISO transmission planning processes would include participation in MISO MTEP process information exchange events
  - Regional Planning meeting including participation of all sub-regions
  - Sub-regional planning meetings
  - Sub-regional Technical Study Task Force meeting

Questions / Comments

Environmental Regulatory Update

Entergy Arkansas, Inc.
Integrated Resource Plan
Stakeholder Committee Meeting

Myra Glover, Entergy Services Inc.

July 31, 2012

I. EAI's Environmental Stewardship

II. Overview of EPA rules –status and next steps

- Cross-State Air Pollution Rule
- Mercury and Air Toxics Standards
- Regional Haze
- NAAQS
- 316(b)
- Coal ash
- GHGs

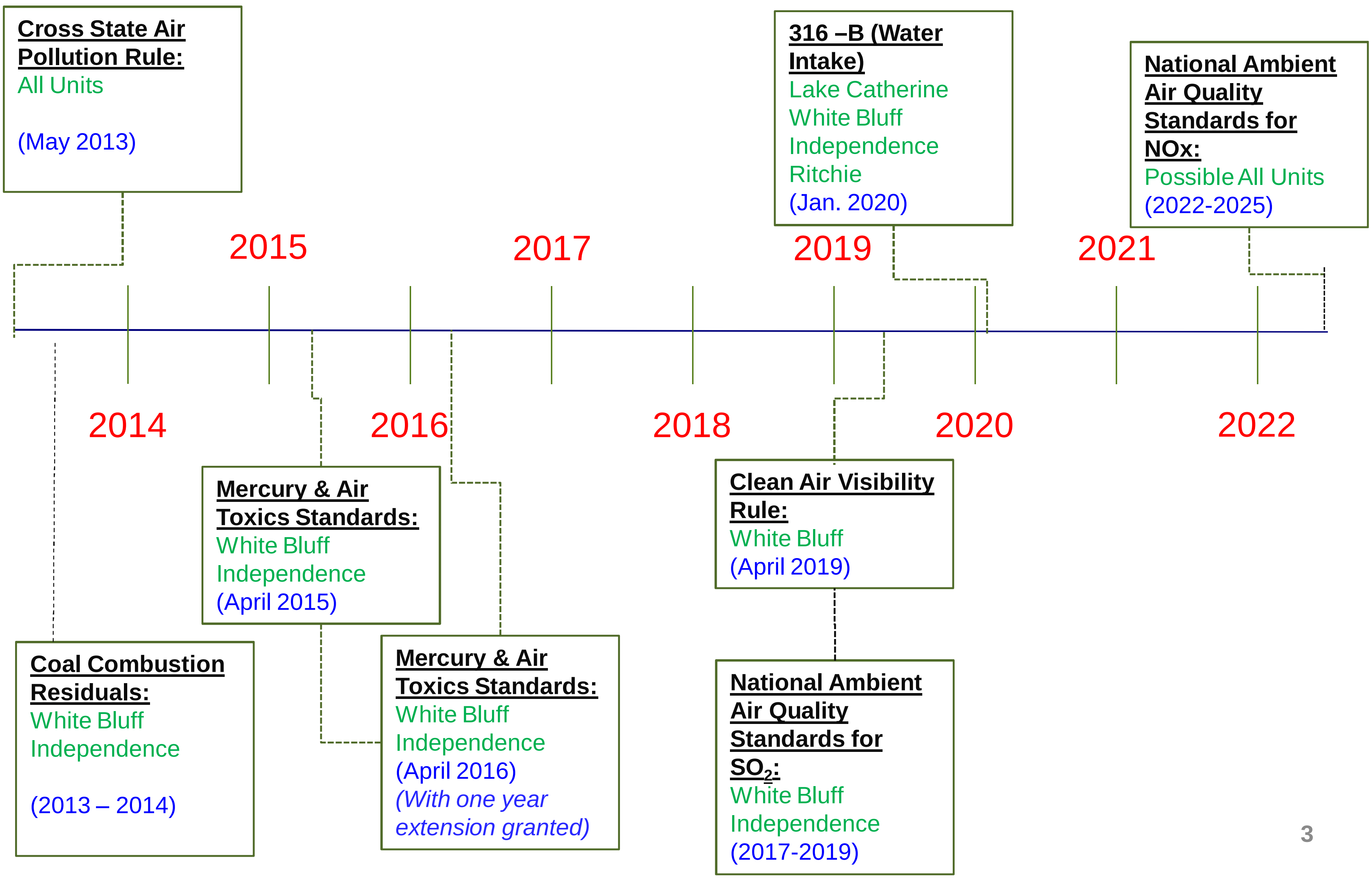
III. Implications

EAI's Environmental Stewardship

- For the 10th straight year, Entergy Corporation has been recognized as a leader in sustainability by the Dow Jones Sustainability Index (DJSI). DJSI North America evaluates the largest North American companies based on long-term economic, environmental and social criteria. Entergy Corporation was one of only 13 U.S. utilities included on that list.

- Entergy Corporation's environmental strategy includes our third voluntary greenhouse gas commitment through 2020, which represents 20 years of continuous greenhouse gas emission stabilization.

Anticipated Timeline for Compliance with Environmental Regulations



Cross-State Air Pollution Rule (CSAPR)

- This final rule was published in August 8, 2011 to replace the 2005 Clean Air Interstate Rule (CAIR).
- The Cross State Air Pollution Rule requires 28 states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ozone and PM non-attainment.
  - Scheduled to go into effect January 1, 2012.
  - Established state emission budgets for NOx and/or SO_2
  - The rule allows sources to trade emission allowances with other sources within the same program. Trading is limited by "assurance provisions" or state emission ceilings.

Reaction to Final CSAPR

- 45 entities filed petitions for reconsideration with EPA.
- Numerous negotiations with EPA resulted in proposed modification to final rule in October 2011.
- 19 Parties petitioned for a stay of the rule on October 26, 2011.
- The court stayed CSAPR on December 30, 2011.
- EPA required to reinstate CAIR pending resolution of CSAPR litigation.
- Court activities/litigation
  - Parties submitted legal briefs to the court by January 17, 2012.
  - Oral arguments held April 2012.
  - Expecting a court decision soon.

EPA Remains Committed to CSAPR

- February 7, 2012, EPA revised 2012 and 2014 State emission budgets and delayed until 2014 implementation of CSAPR's assurance penalty provisions (limited trading)

- May 30, 2012, EPA issued a Final Rule that finds that participation in CSAPR satisfies regional haze requirements (RHR).
  - SIPs implementing CSAPR can be used as a substitute for source-specific BART.
  - SIPs relying on CAIR were disapproved.

- June 12, 2012, EPA published in the Federal Register another final rule, again adjusting CSAPR emission budgets.

- The final rule is effective on August 13, 2012.

Mercury and Air Toxics Standard (MATS)

- February 16, 2012, EPA finalized the Mercury and Air Toxics Standards (MATS) for power plants.

- This final rule established national emissions standards for hazardous air pollutants for existing coal- and oil-fired power plants and new source performance standards for EGUs.

- Affects approximately 1,350 EGUs at 525 facilities
  - Approximately 1,200 coal-fired boilers at approximately 450 facilities
  - Approximately 150 oil-fired boilers at approximately 75 facilities

- Compliance with MATS requirements starts April 16, 2015, with two possible one year extensions

MATS Compliance Requirements

Implementation

- 3 years to comply, with possible one year extension granted by permitting authority (State);
- 4th year extension applies to staggering of controls for reliability, permitting, labor or resource availability constraints; may apply to construction of replacement generation
- 5th year extension may be granted through administrative orders if necessary for a specific documented reliability concern

Coal Unit Standards High Rank Coal

- Mercury; 1.2 lb/Tbtu or 0.013 lb/GWh
- Non-mercury metallic emissions; 0.030 lbs/MMBtu or 0.30 lb/MWh (filterable PM)
- Acid gases; 0.0020 lb/MMBtu or 0.02 lb/MWh HCl
- Organic HAPs; work practice standards

Oil-fired Unit Standards

- Created limited use category for oil fired units with an annual CF < 8% on oil over each two year period after the compliance date
- Standards for HAPs metals, acid gases (HCl and HF) and Organic HAPs

MATS Impacts on Unscrubbed Coal Units

Mercury Controls

- Install Activated carbon injection
- Install mercury CEMs or sorbent trap

Acid Gases Controls

- Possible installation of Dry Sorbent Injection or Scrubber
- Install HCl CEMs or conduct quarterly stack tests

Non-mercury Metallic HAPS (PM standards)

- Possible Installation of fabric filter bag houses or possible ESP upgrades
- Install PM CEMs or conduct quarterly stack tests

Organic HAPS

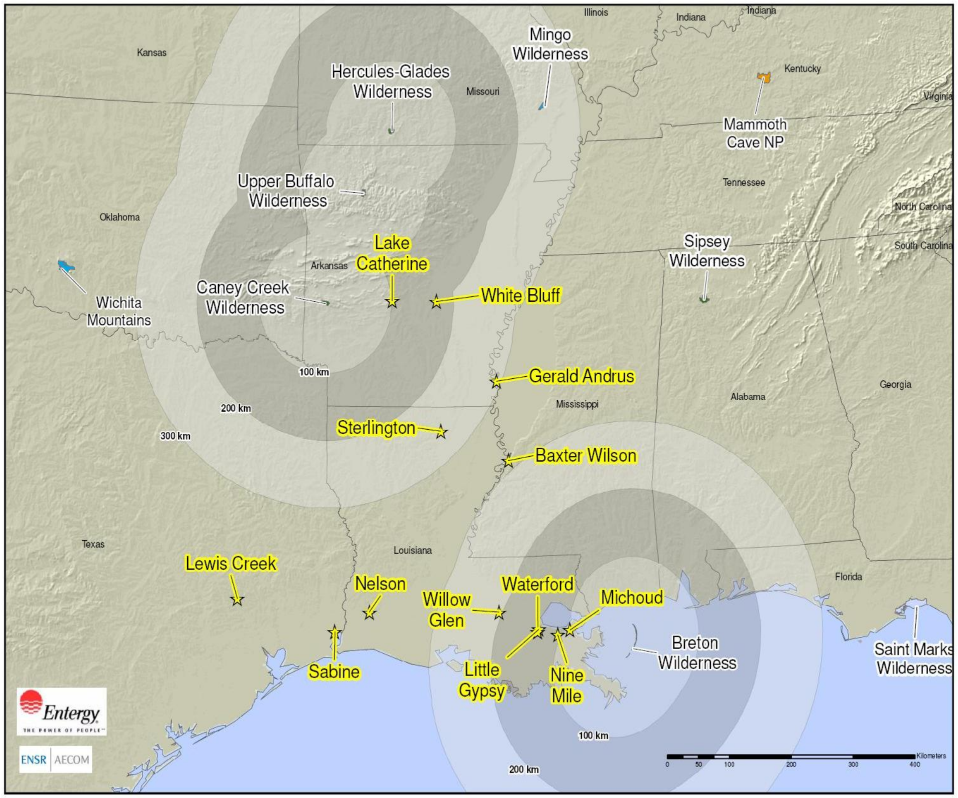
- Perform efficiency tune up of combustion unit

Regional Haze Rule

The Regional Haze Rule require eligible units that contribute to the visibility degradation of a Class I area (national park or national scenic area) to install controls to reduce emissions of NOx, SO_2, and particulate matter.

Eligible units are those that were built between 1962 and 1977 and have the potential to emit more than 250 tons a year of visibility impairing pollution.

Four Class 1 areas within 150km of EAI BART eligible facilities: Caney Creek, Upper Buffalo, Hercules Glade, and Mingo Wilderness.



Best Available Retrofit Technology (BART) is described in the Regional Haze Rule for Affected Units.

Arkansas Dept. of Environmental Quality developed State Implementation Plan to reduce SO_2 and NOx at affected facilities.

Adopted into State Regulation 19 on September 28, 2007.

Regional Haze Rule
Arkansas

- March 12, 2012, EPA published in the Federal Register its final rule disapproving most of the emission limits in the Arkansas Regional Haze State Implementation Plan (SIP).
  - Within 24 months following the final disapproval, EPA must either approve an ADEQ submitted SIP or promulgate a Federal Implementation Plan (FIP).
  - EPA expressed a preference for a SIP if the ADEQ submits a revised plan that EPA can approve before the expiration of the mandatory FIP clock for the portions of the SIP that were disapproved in the final rulemaking.
  - Stakeholders are working with ADEQ to conduct Best Available Retrofit Analyses which will address the disapproved portions of the Arkansas Regional Haze SIP.

Regional Haze Rule

- June 7, 2012, EPA published in the Federal Register its final rule finding that state participation in Cross-State Air Pollution Rule (CSAPR) programs satisfy regional haze requirements.
- States can substitute participation in CSAPR for source-specific Best Available Retrofit Technology (BART) for sulfur dioxide and/or nitrogen oxides emissions from power plants that are subject to the regional haze rule.
  - EPA determined that participation by power plants in CSAPR's trading programs results in greater visibility improvements than source specific BART.
  - CSAPR = BART for NOx and SO2 in annual programs.
  - CSAPR = BART for NOx in seasonal program.
- The rule disapproves state implementation plans that rely on the Clean Air Interstate Rule (CAIR).
- The rule finalized federal implementation plans that replace reliance on CAIR with reliance on CSAPR.

National Ambient Air Quality Standards (NAAQS)

- NAAQS continually ratcheted down over time.
  - Ozone – 1997, 2008, 2011
  - PM 2.5 – 1997, 2006, 2012
  - “Transport Rule” developed to address 1997 and 2006 standards.

- EPA implementing 2008 ozone standard.
  - On April 30, 2012 final rule released designating the non-attainment areas for Ozone.
  - Attainment dates set for each non-attainment category.

- New 1-hour NO_2 and SO_2 standards issued in 2010.
  - On July 17, 2012, the U.S. Court of Appeals for the D.C. Circuit issued a decision upholding the 1-hour NO_2 National Ambient Air Quality Standard.

- State Implementation Plans
  - Establishes requirements for in-state sources.

- On June 15, 2012 EPA announced the reduction of the PM 2.5 standard for ambient air. The final standard to be issued by December 14, 2012

Cooling Water Intake Structure 316(b)

- Rule proposal published in Federal Register April 20, 2011.
  - EPA Published a Notice of Data Availability on June 12, 2012
  - Final Rule was due July 27, 2012 (Court ordered deadline)
  - On July 18, 2012 deadline extended one year.
  - Implementation expected 2018 – 2020.
- Affects all facilities with design intake capacity greater than 2 million gallons per day that use more than 25% of water withdrawal for cooling purposes
  - Approximately 890 steam electric generating units likely to require modifications
- More prescriptive than remanded rule
  - Fine mesh screens with fish handling systems designated as BTA for impingement standards.
  - State agencies will select site-specific requirements for entrainment standards.
  - Cooling towers not selected as BTA for either at national level.

Cooling Water Intake Structure 316(b) Implications

- Facilities with intake flow greater than 2 MGD must demonstrate compliance with impingement standards
  - Intake flow velocity less than 0.5 ft/sec

    \- OR -
  - Annual average impingement mortality less than 12% with monthly average impingement mortality less than 31%

- Facilities with intake flow greater than 125 MGD must also demonstrate compliance with entrainment standards regardless of the source water body type
  - Will require a number of peer reviewed studies
  - Site-specific requirements determined by state permitting authority
  - Timeline for implementation and compliance is negotiated with the permitting agency
- Rule also includes entrapment standards

Coal Combustion Residuals

- EPA proposed 2 options in June 2010:
  - Subtitle C, “Special” hazardous waste listing.
    - Beneficial use exempt from regulation.
  - Subtitle D (non-hazardous waste) regulations.

- Final Rule expected in late 2012 or first quarter 2013.
  - If regulated under Subtitle C, each state has to adopt the listing in the hazardous waste regulations before requirements are effective (2+ years).
  - If regulated under Subtitle D, rule goes into effect within 6 months after rule finalized.

EPA's GHG Regulations Upheld

On June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld EPA's greenhouse gas ("GHG") regulations**:**

- The GHG Endangerment Finding - the foundation for EPA's regulation of GHGs under the Clean Air Act.

- Tailpipe Rule – made GHGs subject to regulation under the CAA, triggering the applicability of PSD and Title V permitting programs.

- Tailoring Rule – temporarily raises the statutory thresholds for PSD and Title V permitting requirements to avoid an overwhelming number of newly regulated sources.

GHG Rules Focus on Largest Emitters

- New facilities with GHG emissions of at least 100,000 tons per year (tpy) carbon dioxide equivalent (CO_2e) will be required to obtain Prevention of Significant Deterioration (PSD) permits

- Existing facilities that emit 100,000 tpy of CO_2e and make changes (Modified Sources) increasing the GHG emissions by at least 75,000 tpy of CO_2e, must also obtain PSD permits

Applicability of the GHG New Source Performance Standards (NSPS)

- This new rule is based on the assumption that Natural Gas Combined Cycle technology constitutes the best system of emissions reductions.

- Applies only to new fossil-fuel-fired electric utility generating units (EGUs)
    - EGUs include:
        - fossil-fuel-fired boilers,
        - integrated gasification combined cycle (IGCC) units
        - stationary combined cycle turbines

- The rule is an output-based emission standard of 1,000 pounds of CO_2e per MWh

Applicability of GHG NSPS

Sources are grouped into one New Source Performance Standard source category:

- Gas
- Oil
- Coal refuse
- Coal
- Pet coke-fired EGUs

Exempt Sources include:

- Transitional Sources
- Simple Cycle Turbines
- Peaking Units

Implications

Potential Impacts

- **The challenge utilities face is unprecedented in terms of:**
  - **The number of rules coming due simultaneously.**
  - **The compressed timeframe for compliance with the near-term rules.**
  - **The continuing ratcheting down of compliance obligations.**
- **Approximately 34 GW of coal-fired generation retirements have been announced already.**
- **Will require significant amount of investment.**
- **Key factors and uncertainties:**
  - **What will final rules look like**
  - **Litigation**
  - **Congressional activity**
  - **Impact of 2012 elections**
  - **Will there be extensions?**

Industry’s Predicament

- And still no long-term carbon policy exists
  - Without a long term carbon policy, industry faces the possibility of uneconomic investments.
  - Industry needs satisfactory resolution of both the current regulatory challenges and a long-term legislative solution on carbon to allow for the most efficient transition to a cleaner generation fleet.

EAI Power Plants

- EAI continues to evaluate options for environmental compliance for the EAI coal units.
- EAI has not determined what compliance technology may be required and when.
- Work is on-going.

Questions / Comments

Meet Future Energy Needs Through Cost Effective Demand Side Management

Entergy®

July 31, 2012

Demand Side Management's Role in Resource Planning

Presentation Objective:

Review / Discuss the process for integrating DSM into the overall resource planning process

What This Presentation Includes:

- Changes in Regulatory Framework Since the last IRP
- EAI's achievement of Energy Efficiency activities to date
- Benefit Cost Analysis Changes
- The process used to identify the cost effective DSM opportunity for the Entergy Arkansas, Inc. (EAI) service area
- High level results of DSM potential study
- The role DSM can play in meeting future resource needs for Entergy Arkansas
- Next steps and framework needed to move forward

Demand Side Management's Role in Resource Planning

Presentation Objective Continued:

What This Presentation Doesn't Include:

- Detailed DSM program design

What is Demand Side Management (DSM)

Demand Side Management (DSM) is a set of actions, activities or measures that impacts energy use, energy use patterns or customer behavior as it relates to energy consumption. DSM includes:

- ***Conservation***: Activities / actions that reduce energy use through changes in life style and the reduction in energy consumption through activities such as increasing thermostat settings on air conditioning equipment in the summer, lower thermostat settings on water heaters, turning off lights when not in use, etc. Conservation activities typically require little to no investment by the customer to reduce energy usage.

- ***Energy Efficiency***: Activities / actions that typically require an investment to achieve lower energy usage, such as, improving insulation levels, sealing heating and cooling ducts, weather stripping, caulking, the purchase of more efficient appliances etc.

- ***Demand Response***: Activities or actions that result in changes to energy use patterns that may or may not reduce overall energy usage. Demand response programs are utilized to lessen customer usage / demand during peak periods or those times when the cost to supply energy is more expensive. Programs in this area include Time of Use (TOU) rates, load control programs such as AC or pool pump switches, etc.

Regulatory Framework

Arkansas' Regulatory Framework has Improved Significantly Since the last IRP.

EAI is allowed to recover

- Program cost concurrently with true up after each year is completed
- Lost contribution to fixed costs (LCFC) concurrently with true up each year of program completion and adjusted for independent evaluation.
- Performance incentives based upon completed year and with independent evaluated results

EAI has Regulatory Guidance for

- Program/ Portfolio comprehensiveness, including a portfolio comprehensiveness Checklist and targets[1]
- Benefits and Objectives within the Rules for Conservation and Energy Efficiency Programs, and
- All energy savings and demand reduction results are adjusted based upon an independent and robust Evaluation Measurement & Verfication ("EM&V")

The Regulatory Framework has Implemented and Approved:

- Self- Direct Options for Customers
- A Technical Resource Manual ("TRM") and updating process
- Conservation and Energy Efficiency Rules ("CEE")
- Collaboratives for ongoing energy efficiency development

1) Subject to adjustments associated with Large Commercial and Industrial Customer Self-Directed Option.

Regulatory Framework

- Annual Commission Mandated Annual Targets, as a percent of 2010 Weather Adjusted MWh Sales
  - 2011: 0.25% = 52,706 MWh
  - 2012: 0.50% = 105,413 MWh
  - 2013: 0.75% = 158,119 MWh

- Adjustments to Annual Targets Associated with Commercial and Industrial Self – Direct Option

	2012	2013
Impact to Overall 2012 and 2013 Targets	8.3%	10.2%
Impact to Commercial and Industrial Customer Classes	12.2%	15.3%

- Commission has ordered an 80% Net-To-Gross ("NTG") Multiplier[2] for all programs but CFL and those are now at 63% NTG. The gross energy savings EAI is estimating on a portfolio basis to meet the Commission targets are as follows:

  - The gross goals in 2011 is 65,883 MWh
  - The gross goals for 2012 is 147,292 MWh
  - The gross goals for 2013 is 215,554 MWH
  - The three year gross goal of program plans are 428,729 MWh or 2% of 2010 weather adjusted sales.

2) 80% NTG was limited to 2011 plan. In 2011 a settlement was approved that reduced the CFL lighting NTG from 0.8 to 0.63. In 2012, all program NTGS are to be evaluated based upon Arkansas achievements and through an independent EM&V Consultant. The EM&V Consultant's work is reviewed by Independent Evaluator Monitor reporting to the General Staff of the APSC

Regulatory Framework

Seven criteria (Check-List) were established in the Comprehensiveness Order on December 10, 2010 (Docket No. 08-144-U, Order No. 17). The Check List is to help the commission decide whether annual EE programs are comprehensive. The seven additional criteria are as follows:

- Provide, either directly or through identification and coordination the education, training, marketing, or outreach needed to address market barriers;
- Include adequate budgetary, management, and program delivery resources to plan, design, implement, oversee and evaluate EE programs;
- Reasonably address all major end-uses;
- Address to the maximum extent reasonable the needs of customers at one time, in order to avoid cream-skimming and lost opportunities;
- Take advantage of opportunities to address the needs of targeted customer sectors (schools, large retail stores, agricultural users, or restaurants) or to leverage non-utility program resources such as state or federal tax incentives, rebates, or lending programs;
- Enable the delivery of all achievable, cost-effective EE within a reasonable period and maximize net benefits to customers and the utility; and
- Have adequate EM&V procedures to support program management and improvement, calculation of energy, demand and revenue impacts, and resource planning decisions

Regulatory Framework

The Commission also established both formal and informal collaboratives

- Self Direct Collaborative was completed in 2011 with rules for commercial and industrial customers the provision to apply for a self direct certificate and opt out of utility programs and cost recovery riders.
- EM&V Collaborative in 2011 was instrumental in obtaining Commission approval for rules for independent Evaluation, Measurement and Verification ("EM&V"), established a Technical Resource Manual ("TRM"), identified an Independent Evaluation Monitor ("IEM") that reports to the APSC General Staff and is responsible for managing the TRM, Filing summary reports of the independent EM&V consultants and assisting with continued decision masking of the continuing EM&V Collaborative.
- More informally directed the utilities to work to identify ways to modify programs to deliver inter-utility and inter fuel programs to customers and report on results.

EAI Energy Efficiency Achievements

- Existing Approved Programs
  - EAI filed a new Program plan in March of 2011 in to meet the Commission mandated targets and check list.
  - On June 30, 2011 the APSC approved 16 programs through the end of 2013.
  - For the reminder of 2011 EAI was busy identifying implementing consultants, database providers, EM&V consultants, negotiating contracts for new programs and expanding EAI staff to manage these expanded programs.

EAI Energy Efficiency Achievements
Evolution from Quick Start to Comprehensive Programs

RESIDENTIAL PROGRAMS

2010
$3.9 Million

2013
$19 Million

Quick Start Program	Target Market		Corresponding Comprehensive Program & New Programs	Target Market
Residential Energy Solutions	Single family homes	→	Home Energy Solutions	Single family homes
CFL	All residential	→	Lighting & Appliances	All residential
AC Tune-Up	All homes with Central AC	→	Residential Cooling Solutions	All homes with Central AC
AR Weatherization	Low Income	→	AR Weatherization	Low Income
			ENERGY STAR New Homes	New construction
			Multifamily & Mobile Home Energy Solutions	Multifamily & mobile homes
			Benchmarking	All residential
			Direct Load Control	All homes with Central AC

C&I PROGRAMS

2010
$6.9 Million

2013
$33 Million

Quick Start Program	Target Market		Corresponding Comprehensive Program & New Programs	Target Market
Large C&I Energy Solutions	100 kW or larger facilities	→	C&I Prescriptive	100 kW or larger facilities
Large C&I Standard Offer	100 kW or larger facilities	→	C&I Custom	100 kW or larger facilities
Small Commercial Energy Solutions	<100 kW facilities	→	Small Commercial Direct Install	<100 kW facilities
AC Tune-Up	<100 kW facilities	→	Small Commercial Cooling Solutions	<100 kW facilities
CitySmart	City government	→	CitySmart	City government
Irrigation Pump Load Control	Agriculture	→	Irrigation Pump Load Control	Agriculture
			Agriculture Energy Solutions	Farms & Agribusiness

EAI Energy Efficiency Achievements

- Budgets and First Year Basis cost of existing program plans.
  - 2010 actual spending[3] was $10,713,000 or $0.24/kWh on First Year Basis without NTG
  - 2011 budgeted spending is $18,685,000 or $0.28/kWh on First Year Basis without NTG, $0.35/kWh on First Year Basis with 0.8 NTG adjustment included.
  - 2012 budgeted spending is $ 39,109,000 or $27/kWh on First Year Basis without NTG, $0.34/kWh on First Year Basis with 0.8 NTG adjustment included
  - 2013 budgeting spending is $ 52,566,000 or $0.24/kWh on First Year Basis without NTG, $0.30/kWh on First Year Basis with 0.8 NTG adjustment included
- Program Costs are Competitive Nationally
- Programs are expanding with decreasing the cost per kWh

3) 2010 values do not include a 5% budget for independent EM&V nor cost of database (Around $4 Million dollars for the three year period).

EAI Energy Efficiency Achievements
Program Cost are Competitive Nationally

EAI's proposed programs are also very cost-effective vis-a-vis EAI's peers; as is EAI's financial commitment.

Investor Owned Utility Administered Program Spending, 2009

Investor Owned Utility State	Program Cost ($Million)	Program Cost as % Revenue	$/kWh
Pacific Gas & Electric Co CA	$523.1	4.7%	$0.99
Interstate Power and Light Co IA	$60.0	4.5%	$1.40
Massachusetts Electric Co MA	$90.2	4.3%	$0.76
Southern California Edison Co CA	$404.9	3.4%	$0.57
United Illuminating Co CT	$29.9	3.3%	$1.65
Idaho Power Co ID	$34.8	3.3%	$0.88
Entergy Arkansas Inc. (2013) AR	$52.6	3.2%	$0.32
Puget Sound Energy Inc. WA	$70.7	3.2%	$0.37
Baltimore Gas & Electric Co MD	$87.6	3.1%	$1.21
Western Massachusetts Elec Co MA	$12.4	3.1%	$0.99
The Narragansett Electric Co RI	$27.1	3.0%	$0.87
Northern States Power Co - Minnesota MN	$75.8	2.2%	$1.66
Nevada Power Co NV	$50.0	2.0%	$0.33
PacifiCorp OR	$80.8	1.9%	$0.52
Avista Corp WA	$17.6	1.8%	$0.51
MidAmerican Energy Co IA	$42.4	1.7%	$0.89
Florida Power & Light Co FL	$186.1	1.6%	$2.08
Public Service Co of Colorado CO	$43.9	1.6%	$9.71
Connecticut Light & Power Co CT	$53.3	1.6%	$0.86
Progress Energy Florida Inc FL	$80.3	1.5%	$2.02
Tampa Electric Co FL	$32.2	1.5%	$2.55
Kansas City Power & Light Co MO	$18.8	1.4%	$1.68
Public Service Co of NH NH	$15.5	1.4%	$0.86
Public Service Co of NM NM	$12.1	1.2%	$0.50
Alabama Power Co AL	$56.3	1.0%	$3.90
Arizona Public Service Co AZ	$25.6	0.8%	$0.24
Consumers Energy Co MI	$22.2	0.6%	$0.41
Duke Energy Ohio Inc OH	$13.3	0.5%	$0.59
Union Electric Co MO	$13.7	0.5%	$1.30
Progress Energy Carolinas Inc NC	$21.0	0.5%	$3.99
Consolidated Edison Co-NY Inc NY	$31.4	0.4%	$1.92
Georgia Power Co GA	$28.7	0.4%	$1.30

Notes:

Source: U.S. EIA Form 861 Data, 2009

$/kWh is on a "first year" basis. That is, annual program spend divided by incremental savings achieved in the same year. Average=$1.50/kWh and Median=$0.94/kWh.

Average program cost as % revenue=2.04% and median=1.68%

Results of EAI Energy Efficiency Efforts

- 2011 reported evaluated savings energy savings was 41,958 MWH or 79.6% of APSC target.
- Sum of evaluated energy reductions since 2009 energy efficiency programs have delivered 134,277 MWh of sales reduction or 0.64% of 2010 sales.
- Demand Reduction is 58 MWs. 9.4 MWs of demand reduction is due to demand response programs and 48.6 is due to energy efficiency programs.
- The amount of incremental cost associated with energy efficiency since 2009 is $ 29.4 Million and $0.22 per kWh on a First Year Cost basis.

Benefit Cost Changes
Portfolio Benefit Cost Analysis of Three Year Plan

Benefit Cost Analysis Result For Comprehensive Portfolio Filed in March of 2011

Test	Results	
Participant Cost	NPV (all participants)	$ 104,913,427
	Benefit-cost ratio	1.93
	NPV (average participant)	$39
Ratepayer Impact Measure (RIM)	NPV	$ 45,064,288
	Benefit-cost ratio	1.20
	Lifecycle revenue impact per kWh	-$0.000166
	2011 revenue impact per kWh	$0.000920
	2012 revenue impact per kWh	$0.000922
	2013 revenue impact per kWh	$0.000835
Total Resource Cost (TRC)	NPV	$ 125,137,685
	Benefit-cost ratio	1.89
	Levelized cost per kWh	$0.076
Program Administrator Cost (PAC)	NPV	$ 174,516,441
	Benefit-cost ratio	2.89
	Levelized cost per kWh	$0.049

Benefit Cost Changes
Updated Portfolio Benefit Cost Analysis

2012 Updated Benefit cost analysis of Programs filed in March 2011.

- Updates include of 2011 achieved results
- updated avoided capacity and energy cost, and
- more discrete application of avoided cost based upon time of day avoided cost.

Test	Results	
Participant Test (PC)	NPV	115,214
	Benefit Cost Ratio	2.05
	Levelized $ per kWH	0.09
Ratepayer Impact Test (RIM)	NPV	72,894
	Benefit Cost Ratio	1.50
	Levelized $ per kWH	0.09
Total Resource Cost Test (TRC)	NPV	52,083
	Benefit Cost Ratio	1.31
	Levelized $ per kWH	0.09
Program Administrator Test (PAC)	NPV	129,927
	Benefit Cost Ratio	2.45
	Levelized $ per kWH	0.09

Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Objectives & Deliverables

- In June 2012 (final report pending), ICF completed an updated DSM Potential Study for the period 2012-2031 assessing the potential for EAI. The results of which provide a basis for long-term planning. The ICF Study considered a Low, Reference and High Level of spending on a full range of potential Arkansas DSM programs and associated DSM peak load and energy reduction.

- Study objective: Develop high level, long-run achievable DSM program potential estimates suitable for inclusion in Entergy's IRP analysis.
  - *Achievable program potential* is the level of savings assumed to be reasonably achievable in the course of the planning horizon, given market barriers that may impede customer participation in utility programs. Achievable potential varies depending on program incentive structure, marketing efforts, energy costs, and other market factors, as well the regulatory treatment of the utility's programs
  - 3 scenarios: Low, Reference & High

- EAI Contracted with ICF International to Provide the Following Deliverables
  - Program loadshapes
  - Program cost estimates
  - Study report

Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Interpreting the estimates

- The purpose of the study was to provide to EAI loadshapes and costs representing a reasonable set of long-run assumptions about achievable DSM program potential.

- The long-run nature of the study means the estimates are not designed to be used for:

  - Program planning, or
  - Utility goal setting

Some key differences between long-run potential study & short-run DSM program plan

Study Activity/ Characteristic	Long-Run (IRP, 10-20 years)	Short-Run (Program Plan, 1-3 years)
Measure Review	Expansive/broad	Less expansive/more specific than in long-run study
Measure Analysis	Analyze universe of representative measures that could be implemented over long run.	Analyze currently offered measures, plus changes/additions per codes & standards, emerging technologies, and EM&V results.
Goal of Final Measure List	Groups of measures included should be reasonably representative of savings and costs within end-uses, over the long-run.	Measures should generally have well-understood performance in the short-run (exceptions for items like emerging technologies/pilots).
Program Review	Broad and representative	More likely to include currently offered programs with limited expansions, or contractions.
Program Design	Very high level/representative	Very specific
Program Costs	Estimated long-run average costs. Broad cost categories (incentive & non-incentive). Long-run average costs tend to be lower than short-run planning costs, especially for studies covering immature markets.	Based on current program costs. More specific cost categories (incentive, admin, marketing, training, EM&V, etc.).
Participation Model	Based more on measure and market economics, taking into account recent program performance (if available).	Based more on current program performance, or recent performance of similar programs in comparable jurisdictions, taking into account measure and market economics.
Uncertainty of Estimates	High, especially in territories with immature programs.	Low to medium depending on program maturity.

Process to Identify Cost Effective Achievable DSM At Entergy Arkansas – Potential Study ICF Overview

- **ICF International**
  - A global consultancy based in the Washington area with offices around the U.S., Canada, U.K., Belgium, Brazil, China, India, Russia
  - 4500 professionals, about 1700 of whom work on energy and environment, 350 full time energy-efficiency professionals
  - More than 20 years of public/private energy efficiency experience
  - One of the leading U.S. energy efficiency delivery companies:
    - Currently implement about 130 state/utility EE programs around the U.S.
    - Supported Federal programs including, ENERGY STAR® for over 10 years
    - Performed over 30 potential studies and program plans for utilities and state agencies

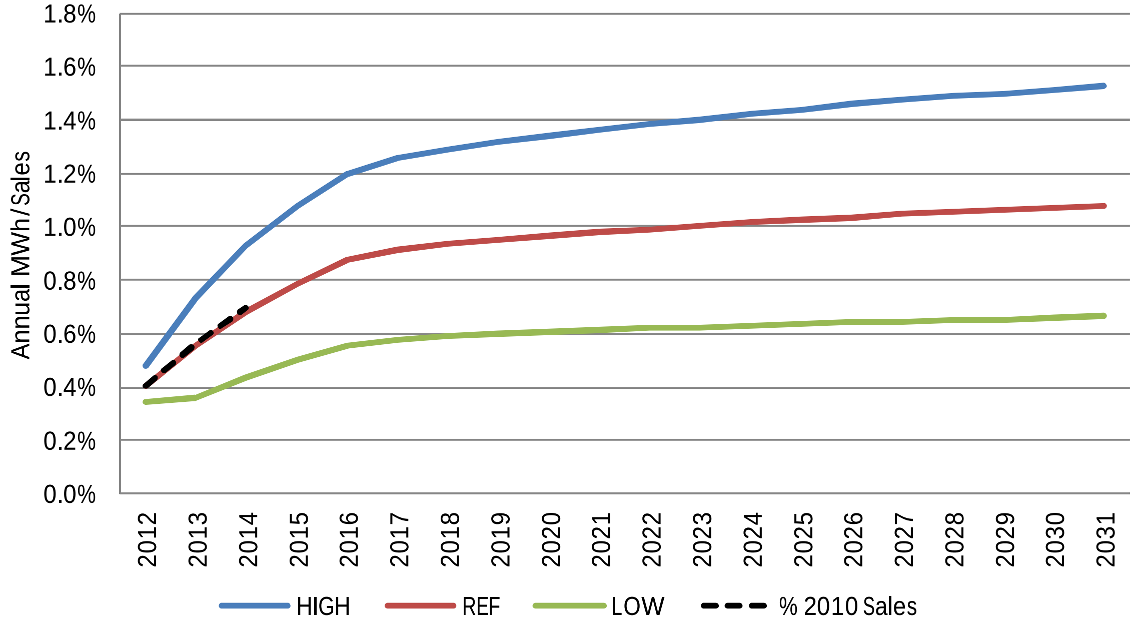
Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Interpreting the estimates – uncertainty

- All long-run economic forecasts are subject to high levels of uncertainty.
- Medium to high uncertainty for energy efficiency estimates, especially given evolving nature of fuel costs and the economy.
- Very high uncertainty for demand response estimates given uncertainty about AMI deployment.
- Used best data available at the time of the analysis.
- Assumes EAI continues receiving favorable regulatory treatment for programs (cost recovery, LCFCs, shareholder incentive).

Bottom-up study approach

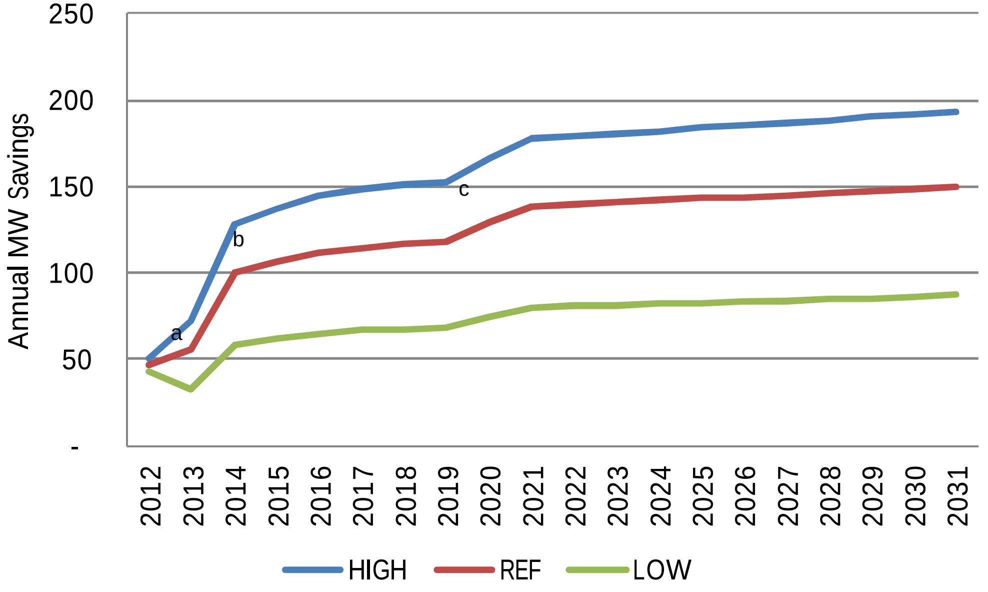
1. **Data collection**. Utility data, baseline customer and building data, measure data and program data. Development and sourcing of non-deemed measure savings estimates and characteristics.
2. **Baseline characterization**. Electricity use by sector by building type and end-use. Utility sales forecast.
3. **Measure analysis**. Measure cost-effectiveness testing. Consideration of non-cost-effective measures for inclusion.
4. **Program analysis.** Grouping measures into programs. Program cost and participation estimation. Calculation of reference case achievable potential estimates.
5. **Scenario analysis.** Development of high and low achievable potential estimates.
6. **Benchmarking.** Comparison of estimates from this study to those from other recent Southern studies.

Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Annual net MWh savings estimates as % sales



INC. SAVINGS/SALES	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2031
HIGH	0.5%	0.7%	0.9%	1.1%	1.2%	1.3%	1.3%	1.3%	1.3%	1.4%	1.5%
REF	0.4%	0.6%	0.7%	0.8%	0.9%	0.9%	0.9%	1.0%	1.0%	1.0%	1.1%
LOW	0.3%	0.4%	0.4%	0.5%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.7%
% 2010 Sales	0.4%	0.6%	0.7%								

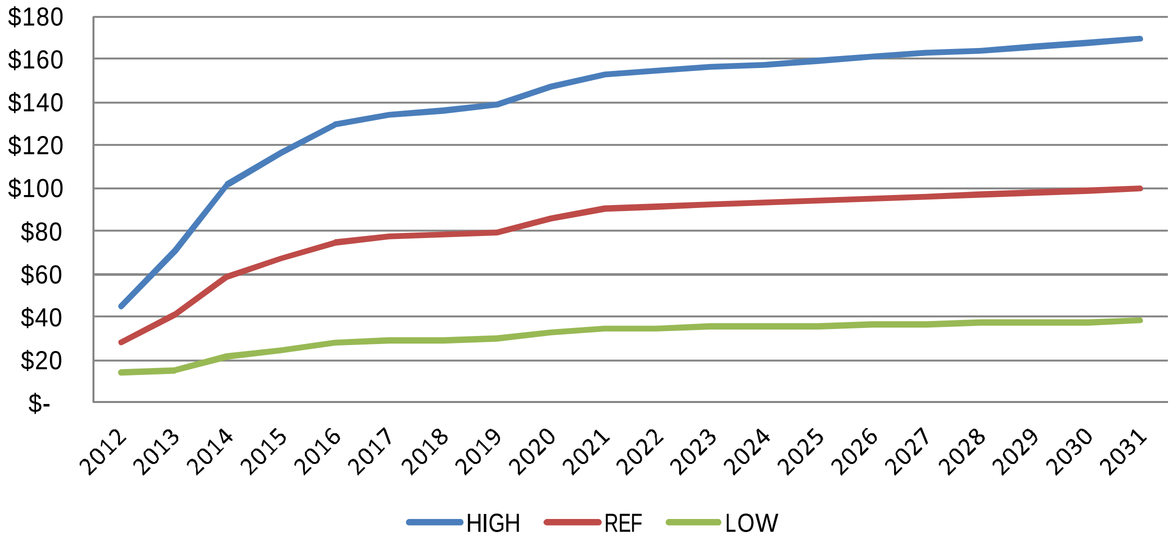
Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Annual net MW savings estimates



ANN. MW Savings	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2031
HIGH	51	72	129	138	145	148	151	153	167	178	193
REF	46	55	100	107	112	115	117	118	129	138	150
LOW	42	33	58	62	65	66	68	68	75	80	87

a. Leveling-off of new Agricultural Irrigation Load Control enrollments
b. Programs *not* included in current EAI portfolio added (except per below)
c. Commercial dynamic rates added (consistent with AMI schedule)

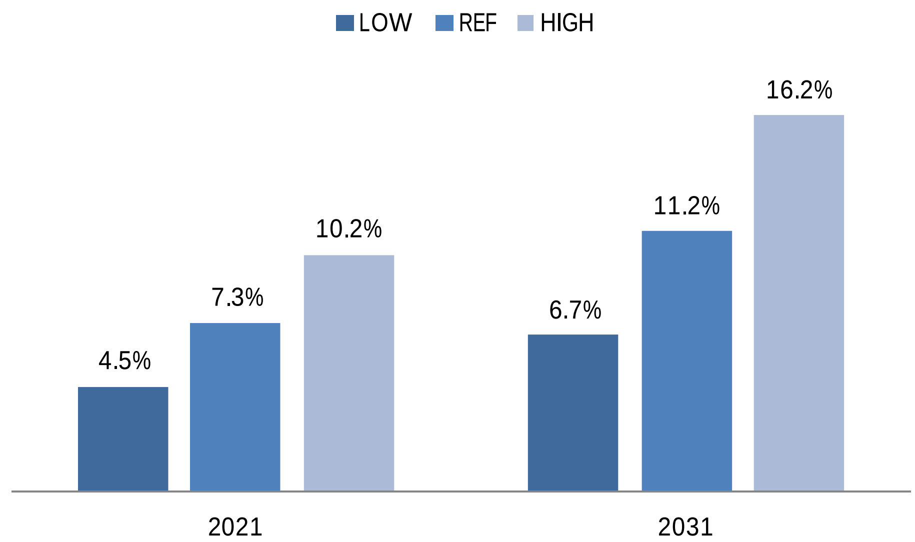
Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Program cost estimates (Real 2011$)



Portfolio cost-effectiveness test result estimates

- Total Resource Cost (TRC) Test = 2.2
- Program Administrator Cost (PAC) Test = 2.9
- Participant Cost Test (PCT) = 3.9
- Ratepayer Impact Measure(RIM) Test = 0.9

Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Cumulative net MWh savings estimates as % of sales (10 & 20 year estimates)



Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Benchmarking– comparison of this study's estimates to those studies from other recent Southern studies

Study	Primary Author	Study Comm-issioned or Sponsored by	Year Released	Study Time Horizon	Method-ology	Type of Achievable Potential	10 Year Savings Estimate	20 Year Savings Estimate
Entergy Arkansas (this study)	ICF International	Entergy, Corp.	2012	20 Year	Bottom-up	Achievable Low	4.5%	6.7%
						Achievable Reference	7.3%	11.2%
						Achievable High	10.2%	16.2%
Tennessee Valley Authority	Global Energy Partners	TVA	2011	20 Year	Bottom-up	Achievable Low	5.1%	10.6%
						Achievable High	9.8%	19.8%
Missouri Statewide	KEMA	MO PSC	2011	10 Year	Bottom-up	Three Year Payback Achievable Net	3%	N/A
						One Year Payback Achievable Net	7%	N/A
Missouri Statewide	ACEEE	ACEEE	2011	10 Year	Top-Down	Achievable program	6.4%	N/A
Arkansas Statewide	ACEEE	ACEEE	2011		Top-Down	"Medium" Case Achievable	9.8% by 2025	
U.S. National Study, Southern Region	Electric Power Research Institute	EPRI	2009	20 Year	Bottom-up	Maximum Achievable	10.0%	11.1%
						Realistic Achievable	4.4%	8.1%
Review of Southern EE Studies	Georgia Tech	Georgia Tech	2009	N/A	Meta-Study	Maximum Achievable	1.2% per year	
						Realistic Achievable	0.9% per year	

*Savings estimates are cumulative unless otherwise noted. Some studies did not develop 10 and 20 year savings estimates, rather estimates were developed that are one or two years shorter or longer in time frame. For the above table approximations were made for the purposes of benchmarking. All studies shown are long-term in nature and therefore subject to high levels of uncertainty.

Estimates from this study are most comparable to those from the other bottom-up studies (EPRI, TVA, KEMA). Estimates from this study are similar, if somewhat higher, than estimates from these studies.

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Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Measures

- Key sources
  - AR deemed savings
  - ICF building simulations
  - FERC (some Demand Response measures)
- Many non-deemed measures added. Key additions include:
  - Retrocommissioning
  - Advanced new buildings
  - Lighting measures, particularly LEDs
  - Mini-split ACs
  - Industrial

Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Measure Types Analyzed & Included

Measure Type

	New Construction		Retrofit		Replace-on-Burnout		Totals	
	Analyzed	Included	Analyzed	Included	Analyzed	Included	Analyzed	Included
Non-Residential Measures	96	36	777	182	76	38	949	256
% Sector Total	10%	14%	82%	71%	8%	15%		27%
Residential Measures	164	34	378	213	216	130	758	377
% Sector Total	22%	9%	50%	56%	28%	34%		50%
Grand Total	260	70	1155	395	292	168	1707	633
% Grand Total	15%	11%	68%	62%	17%	27%		37%

Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Measure Analysis

Measure Included?	Measure TRC>=1?		Total
	No	Yes	
No	934	140	1075
Yes	58	575	633
Grand Total	992	715	1707

Measure TRC test = PV(avoided costs over measure life) ÷ PV(measure incremental costs)

Passing TRC test value =1.0

Measures passing TRC but not included (140)

- Majority of measure applications not cost-effective (cool roofs)
- Duplicative measures (2” v. 3” hot water heater wrap)
- Measures targeting converted residences

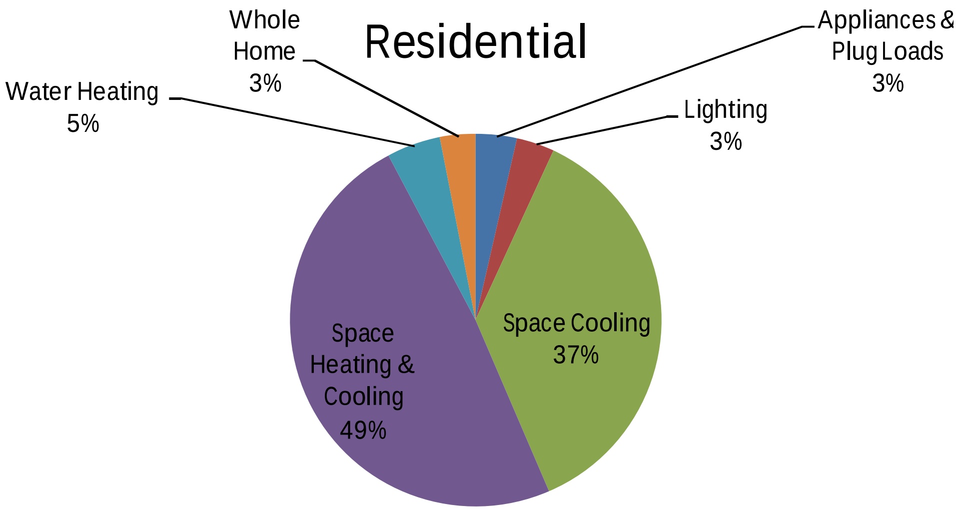
Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Measure Analysis – cont.

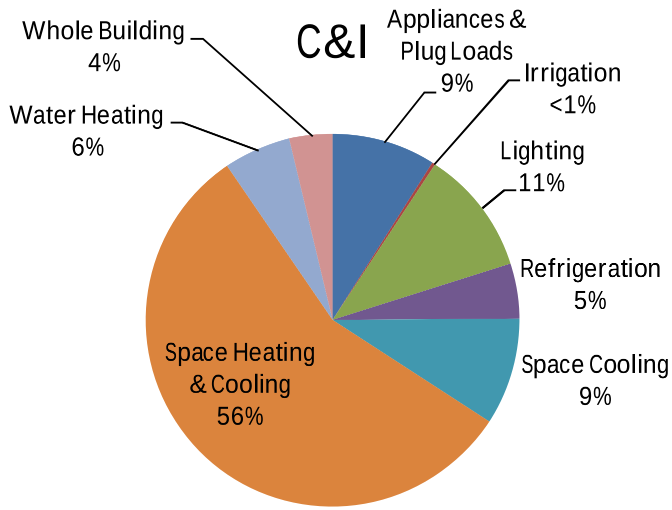
Measure Included?	Measure TRC>=1?		Total
	No	Yes	
No	934	140	1075
Yes	58	575	633
Grand Total	992	715	1707

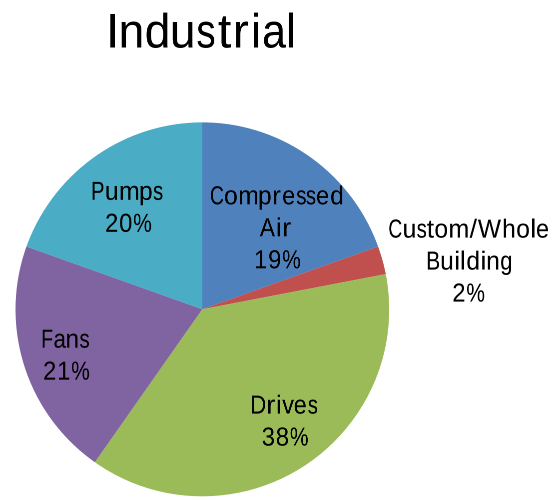
Measures not passing TRC but included (58)

- Majority of measure applications cost-effective (attic knee wall insulation)
- Policy measures (weatherization)
- Declining costs (LEDs)

Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Distribution of Measure Types Analyzed, by Sector & End Use







Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Programs modeled

ICF then bundled the measures into programs that resemble the EAI's comprehensive programs.

Those that were not similar to EAI's Comprehensive Programs were bundled separately.

	Modeled Program Name	Relevant Sector(s)	Type	EAI Compre-hensive Program?
1	Residential Lighting and Appliances	Residential	EE	Yes
2	Residential Cooling Solutions	Residential	EE	Yes
3	Home Energy Solutions	Residential	EE	Yes
4	Energy Efficiency Arkansas	Residential	EE	Yes
5	AR Weatherization	Residential	EE	Yes
6	Benchmarking	Residential	EE	Yes
7	ENERGY STAR Homes	Residential	EE	Yes
8	Mobile Homes	Residential	EE	Yes
9	Multifamily	Residential	EE	Yes
10	C&I Prescriptive	C&I	EE	Yes
11	City Smart	Government	EE	Yes
12	Commercial Custom	C&I	EE	Yes
13	Small Commercial	Small Commercial	EE	Yes
14	Agricultural Energy Solutions	Agricultural	EE	Yes
15	Direct Load Control	Residential	DR	Yes
16	Agricultural Irrigation Load Control	Agricultural	DR	Yes
17	Commercial New Construction	Commercial	EE	No
18	Retrocommissioning	Commercial	EE	No
19	Industrial	Industrial	EE	No
20	Interruptible Rate	Large C&I	DR	No
21	Enabled Pricing (Non-Res)	Commercial	DR	No
22	Non-Enabled Pricing (Non-Res)	Commercial	DR	No
23	Enabled Pricing (Res)	Residential	DR	No
24	Non-Enabled Pricing (Res)	Residential	DR	No

Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Estimating Participation – Two Approaches

- Market Adoption Curve Approach (Approach A)
  - Combines research on customers' financial motives with research on the diffusion of innovative technologies in the marketplace.
  - Usually applied to programs where payback acceptance is important to customer decision making, e.g.,
    - Mass Market programs (e.g., Residential Lighting)
    - Replace-on-burnout measures
    - Small to mid sized retrofit
- Program Experience Approach (Approach B)
  - Usually applied programs where payback acceptance is not as important to customer decision making, or where ICF program data or experience is more accurate than the market adoption curve approach.
    - Large retrofit/whole building (e.g., Residential Solutions, Retrocommissioning)
    - New home construction
    - Custom

Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Participation approach by program

	Modeled Program Name	Relevant Sector(s)	Type	EAI Compre-hensive Program?	Participation Approach
1	Residential Lighting and Appliances	Residential	EE	Yes	A
2	Residential Cooling Solutions	Residential	EE	Yes	A
3	Home Energy Solutions	Residential	EE	Yes	B
4	Energy Efficiency Arkansas	Residential	EE	Yes	B
5	AR Weatherization	Residential	EE	Yes	B
6	Benchmarking	Residential	EE	Yes	B
7	ENERGY STAR Homes	Residential	EE	Yes	B
8	Mobile Homes	Residential	EE	Yes	A
9	Multifamily	Residential	EE	Yes	A
10	C&I Prescriptive	C&I	EE	Yes	A
11	City Smart	Government	EE	Yes	B
12	Commercial Custom	C&I	EE	Yes	B
13	Small Commercial	Small Commercial	EE	Yes	A
14	Agricultural Energy Solutions	Agricultural	EE	Yes	A
15	Direct Load Control	Residential	DR	Yes	B
16	Agricultural Irrigation Load Control	Agricultural	DR	Yes	B
17	Commercial New Construction	Commercial	EE	No	A
18	Retrocommissioning	Commercial	EE	No	B
19	Industrial	Industrial	EE	No	A
20	Interruptible Rate	Large C&I	DR	No	B
21	Enabled Pricing (Non-Res)	Commercial	DR	No	B
22	Non-Enabled Pricing (Non-Res)	Commercial	DR	No	B
23	Enabled Pricing (Res)	Residential	DR	No	B
24	Non-Enabled Pricing (Res)	Residential	DR	No	B

Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Scenarios

	Scenario		
Variable	Low	Reference	High
Incentive Simple Payback Target (Years)	3	2	1
Incentive Min. (% Incremental Cost)	10%	25%	50%
Incentive Max. (% Incremental Cost)	50%	75%	100%

Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Other program inputs

- Costs
  - Long-run
  - EAI filed programs
  - ICF program experience
- Net-To-Gross
  - 0.80 for each program, per APSC order

Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Utility assumptions

- Average avoided energy and capacity costs and discount rate provided by Entergy SPO.
- EAI 2011 retail rates escalated at same rate as avoided costs.
- Gas savings included for electric measures, where applicable. No “gas” measures included.
- Advanced meter deployment schedule.
- MISO benefits were included in the Potential Study. The Benefit Cost Analysis was adjusted to reflect a cost reduction in the Reserve Capacity cost.

Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Treatment of codes & standards

Residential

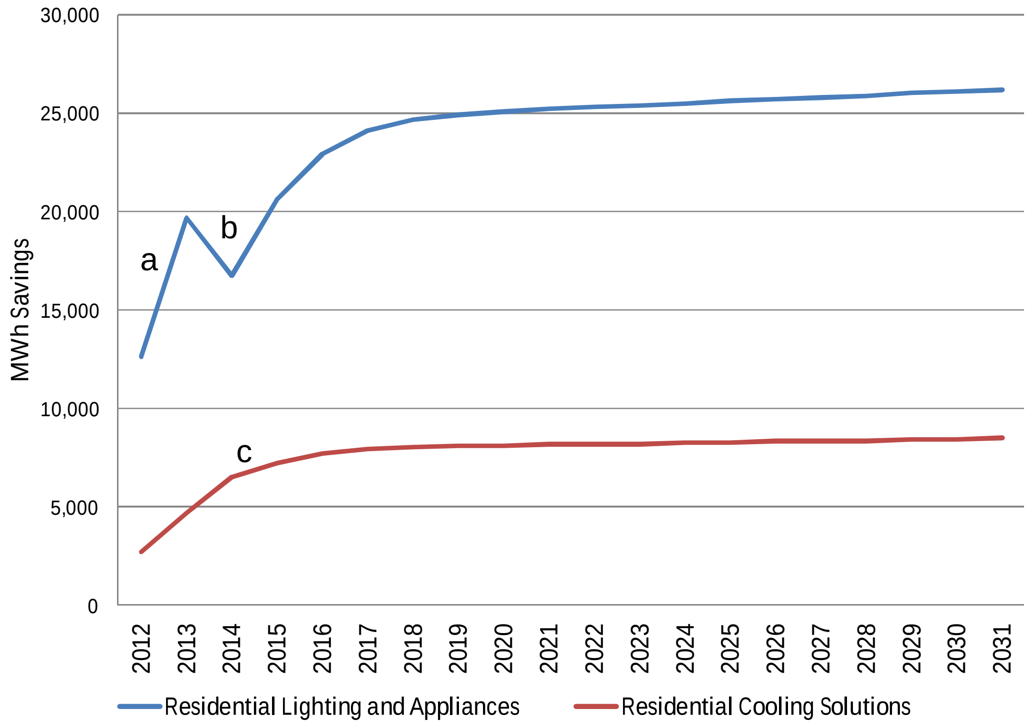
- Deemed savings
- IECC 2003* for non-deemed retrofit & new construction measures
- EISA 2007
  - Lighting: Changed CFL and lighting baselines according to EISA/DOE schedule (2012, 2013 or 2014 depending on bulb wattage)
  - CACs & HPs: Changed baseline from SEER 13 to SEER 14 in 2015

Commercial

- Deemed savings (assumes ASHRAE 90.1-2001*)
- ASHRAE 90.10-2010 for non-deemed retrofit & new construction measures

*Adopted AR building energy code at time of study

Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Treatment of codes & standards – cont.

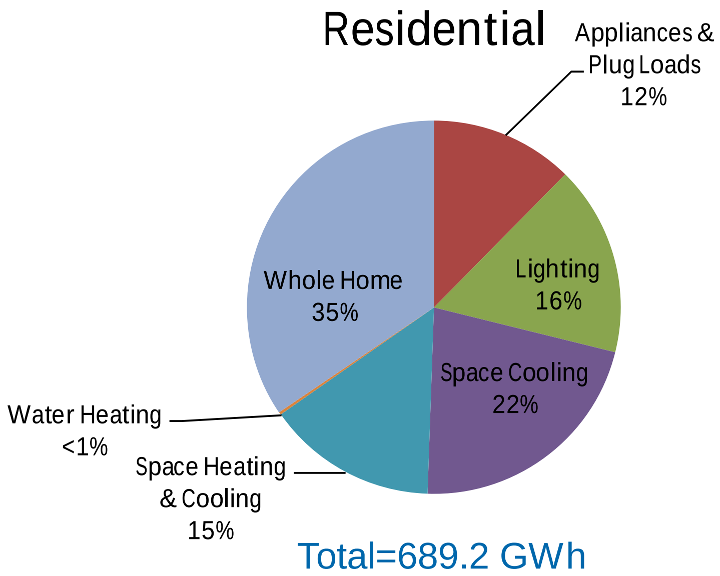


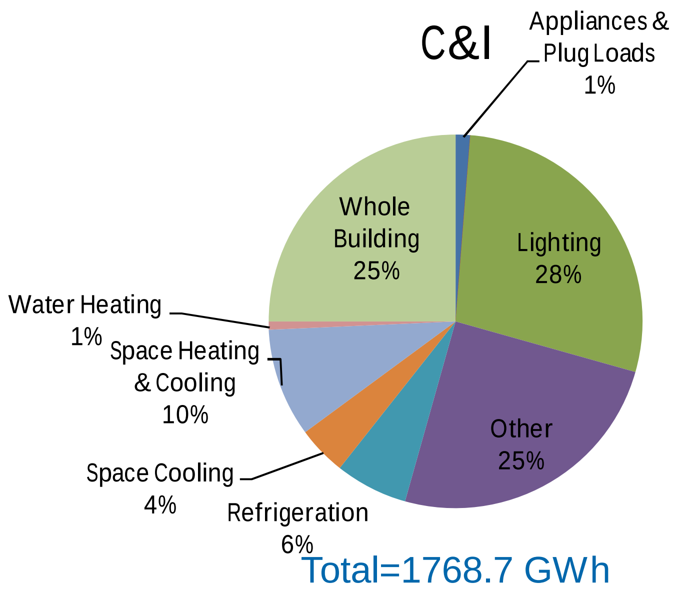
a. 27W CFL with 100W Florescent baseline phased-out
23W CFL with 75W Florescent baseline phased-out

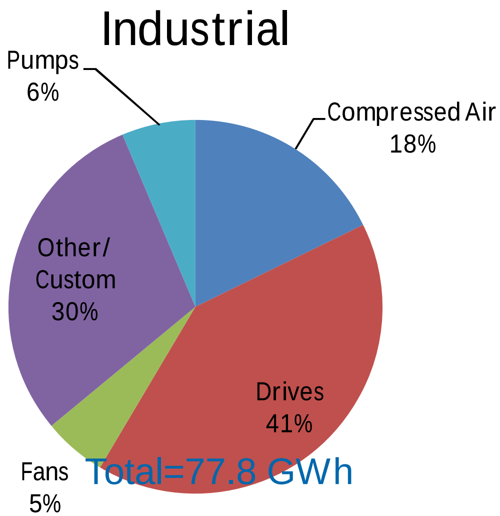
b. 11W CFL with 40W Florescent baseline phased-out
15W CFL with 60W Florescent baseline phased-out
Program continues with CFLs and LEDs with EISA compliant Halogen baselines

c. Shift from SEER 13 to SEER 14 baseline for residential ACs and heat pumps has a comparatively smaller impact on program trajectory

Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Distribution of net 2031 cumulative electric savings, by sector & end use, reference case







Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Annual Net MWh savings estimates by program, Reference Case

			Incremental Electricity Savings - MWh										
Type	Sector	Program Name	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2031
EE	Residential	Residential Lighting and Appliances	12,588	19,691	16,771	20,621	22,931	24,098	24,642	24,912	25,073	25,194	26,185
EE	Residential	Residential Cooling Solutions	2,728	4,732	6,489	7,249	7,719	7,925	8,023	8,079	8,119	8,153	8,471
EE	Residential	Home Energy Solutions	2,863	3,832	4,809	6,372	9,691	9,728	9,765	9,802	9,839	9,877	10,259
EE	Residential	Energy Efficiency Arkansas	-	-	-	-	-	-	-	-	-	-	-
EE	Residential	AR Weatherization	2,832	2,843	2,854	2,864	2,875	2,886	2,897	2,908	2,919	2,930	3,044
EE	Residential	Benchmarking	15,030	7,543	7,572	7,601	7,630	7,659	7,688	7,717	7,747	7,776	8,078
EE	Residential	ENERGY STAR Homes	1,376	1,658	2,219	3,675	5,589	5,610	5,632	5,653	5,675	5,696	5,917
EE	Residential	Mobile Homes	493	856	1,173	1,361	1,449	1,488	1,506	1,516	1,524	1,530	1,590
EE	Residential	Multifamily	963	1,671	2,291	2,658	2,830	2,905	2,941	2,962	2,976	2,989	3,105
EE	Non-Residential	C&I Prescriptive	20,385	35,823	49,757	58,469	63,071	65,609	67,296	68,664	69,927	71,166	84,776
EE	Non-Residential	City Smart	6,256	8,519	10,877	11,109	11,347	11,589	11,837	12,090	12,348	12,612	15,581
EE	Non-Residential	Commercial Custom	14,747	22,593	30,768	31,425	32,096	32,782	33,482	34,198	34,928	35,675	44,073
EE	Non-Residential	Small Commercial	1,814	3,138	4,292	4,965	5,272	5,398	5,449	5,472	5,484	5,493	5,553
EE	Non-Residential	Agricultural Energy Solutions	498	879	1,226	1,447	1,568	1,638	1,687	1,729	1,768	1,806	2,232
EE	Residential	Commercial New Construction	-	-	-	1,967	3,463	4,820	5,676	6,136	6,395	6,573	7,999
EE	Non-Residential	Retrocommissioning	-	-	-	1,907	3,893	5,962	6,087	6,214	6,344	6,477	7,972
EE	Non-Residential	Industrial	2,203	3,811	5,212	6,029	6,402	6,555	6,618	6,646	6,661	6,671	6,744
DR	Residential	Direct Load Control	-	-	-	-	-	-	-	-	-	-	-
DR	Non-Residential	Agricultural Irrigation Load Control	-	-	-	-	-	-	-	-	-	-	-
DR	Non-Residential	Interruptible Rate	-	-	-	-	-	-	-	-	-	-	-
DR	Non-Residential	Enabled Pricing (Non-Res)	-	-	-	-	-	-	-	-	-	-	-
DR	Residential	Enabled Pricing (Res)	-	-	-	-	-	-	-	-	-	-	-
DR	Residential	Non-Enabled Pricing (Res)	-	-	-	-	-	-	-	-	-	-	-
DR	Non-Residential	Non-Enabled Pricing (Non-Res)	-	-	-	-	-	-	-	-	-	-	-
		Total Portfolio	84,776	117,590	146,308	169,718	187,825	196,654	201,227	204,698	207,728	210,617	241,580

Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Annual Net MW savings estimates by program, Reference Case

	Incremental Electricity Savings - MW										
Program Name	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2031
Residential Lighting and Appliances	3.0	5.1	5.8	6.9	7.4	7.7	7.8	7.9	7.9	8.0	8.3
Residential Cooling Solutions	1.0	1.8	2.5	2.8	2.9	3.0	3.0	3.1	3.1	3.1	3.2
Home Energy Solutions	1.3	1.7	2.1	2.8	4.2	4.3	4.3	4.3	4.3	4.3	4.5
Energy Efficiency Arkansas	-	-	-	-	-	-	-	-	-	-	-
AR Weatherization	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9
Benchmarking	5.2	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.7	2.7	2.8
ENERGY STAR Homes	0.4	0.5	0.7	1.1	1.7	1.7	1.7	1.7	1.7	1.7	1.8
Mobile Homes	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Multifamily	0.1	0.2	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4
C&I Prescriptive	4.7	8.3	11.5	13.4	14.4	15.0	15.3	15.5	15.8	16.0	18.4
City Smart	0.8	1.1	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.7	2.1
Commercial Custom	2.7	4.1	5.6	5.7	5.8	6.0	6.1	6.2	6.4	6.5	8.0
Small Commercial	0.7	1.2	1.6	1.8	1.9	2.0	2.0	2.0	2.0	2.0	2.0
Agricultural Energy Solutions	0.1	0.3	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.7
Commercial New Construction	-	-	-	0.4	0.6	0.9	1.1	1.1	1.2	1.2	1.5
Retrocommissioning	-	-	-	0.3	0.7	1.1	1.1	1.1	1.1	1.2	1.4
Industrial	0.3	0.5	0.7	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9
Direct Load Control	11.3	18.1	27.2	27.3	27.5	27.6	27.7	27.8	27.9	28.0	29.1
Agricultural Irrigation Load Control	13.5	9.0	9.2	9.4	9.6	9.8	10.0	10.2	10.4	10.6	13.1
Interruptible Rate	-	-	24.7	24.7	24.7	24.7	24.8	24.8	24.8	24.9	25.1
Enabled Pricing (Non-Res)	-	-	-	-	-	-	-	-	-	4.5	5.5
Enabled Pricing (Res)	-	-	0.2	0.4	0.7	0.9	1.3	1.5	8.8	11.0	11.5
Non-Enabled Pricing (Res)	-	-	0.1	0.2	0.3	0.4	0.6	0.7	4.0	5.0	5.2
Non-Enabled Pricing (Non-Res)	-	-	2.6	2.7	2.7	2.8	2.9	2.9	3.0	3.1	3.8
Total Portfolio	46.0	55.3	100.1	106.6	112.1	114.6	116.5	117.9	129.5	138.2	150.3

Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Program costs, Reference Case

			Annual Program Cost Estimates ($Millions)										
Type	Sector	Program Name	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2031
EE	Residential	Residential Lighting and Appliances	$3.3	$5.7	$7.4	$8.6	$9.2	$9.4	$9.6	$9.6	$9.7	$9.7	$10.1
EE	Residential	Residential Cooling Solutions	$1.5	$2.6	$3.5	$4.0	$4.2	$4.4	$4.4	$4.4	$4.5	$4.5	$4.7
EE	Residential	Home Energy Solutions	$3.1	$4.1	$5.1	$6.8	$10.4	$10.4	$10.4	$10.5	$10.5	$10.6	$11.0
EE	Residential	Energy Efficiency Arkansas	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
EE	Residential	AR Weatherization	$1.8	$1.8	$1.8	$1.8	$1.8	$1.8	$1.8	$1.8	$1.8	$1.8	$1.9
EE	Residential	Benchmarking	$1.1	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.6	$0.6	$0.6
EE	Residential	ENERGY STAR Homes	$0.6	$0.8	$1.0	$1.7	$2.6	$2.6	$2.6	$2.7	$2.7	$2.7	$2.8
EE	Residential	Mobile Homes	$0.2	$0.3	$0.4	$0.4	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
EE	Residential	Multifamily	$0.4	$0.7	$0.9	$1.1	$1.2	$1.2	$1.2	$1.2	$1.2	$1.2	$1.3
EE	Non-Residential	C&I Prescriptive	$5.6	$9.8	$13.6	$15.9	$17.1	$17.7	$18.1	$18.4	$18.7	$19.0	$21.9
EE	Non-Residential	City Smart	$1.6	$2.2	$2.9	$2.9	$3.0	$3.0	$3.1	$3.2	$3.2	$3.3	$4.1
EE	Non-Residential	Commercial Custom	$3.8	$5.9	$8.0	$8.1	$8.3	$8.5	$8.7	$8.9	$9.1	$9.2	$11.4
EE	Non-Residential	Small Commercial	$0.9	$1.6	$2.2	$2.6	$2.8	$2.8	$2.8	$2.9	$2.9	$2.9	$2.9
EE	Non-Residential	Agricultural Energy Solutions	$0.2	$0.4	$0.6	$0.7	$0.7	$0.8	$0.8	$0.8	$0.8	$0.8	$1.0
EE	Residential	Commercial New Construction	$0.0	$0.0	$0.0	$0.5	$0.8	$1.1	$1.3	$1.4	$1.5	$1.5	$1.8
EE	Non-Residential	Retrocommissioning	$0.0	$0.0	$0.0	$0.2	$0.4	$0.6	$0.6	$0.6	$0.6	$0.6	$0.8
EE	Non-Residential	Industrial	$0.7	$1.3	$1.7	$2.0	$2.1	$2.2	$2.2	$2.2	$2.2	$2.2	$2.2
DR	Residential	Direct Load Control	$1.1	$1.7	$2.6	$2.6	$2.6	$2.6	$2.6	$2.6	$2.6	$2.6	$2.7
DR	Non-Residential	Agricultural Irrigation Load Control	$2.2	$1.5	$1.5	$1.5	$1.6	$1.6	$1.6	$1.7	$1.7	$1.7	$2.1
DR	Non-Residential	Interruptible Rate	$0.0	$0.0	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.9
DR	Non-Residential	Enabled Pricing (Non-Res)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$2.3	$2.8
DR	Residential	Enabled Pricing (Res)	$0.0	$0.0	$0.1	$0.2	$0.3	$0.4	$0.6	$0.8	$4.3	$5.4	$5.6
DR	Residential	Non-Enabled Pricing (Res)	$0.0	$0.0	$0.0	$0.1	$0.1	$0.2	$0.3	$0.3	$1.9	$2.4	$2.5
DR	Non-Residential	Non-Enabled Pricing (Non-Res)	$0.0	$0.0	$0.8	$0.8	$0.8	$0.8	$0.8	$0.9	$0.9	$0.9	$1.1
		Total Portfolio	$28.1	$40.8	$58.4	$66.8	$74.8	$77.0	$78.6	$79.7	$85.6	$90.3	$99.7

*Real 2011 $

Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Cost-effectiveness estimates, Reference Case

Type	Program Name	TRC Test	PAC Test	RIM Test	PCT Test
EE	Residential Lighting and Appliances	1.8	2.4	0.7	4.2
EE	Residential Cooling Solutions	1.1	1.2	0.6	3.0
EE	Home Energy Solutions	1.0	1.5	0.6	2.5
EE	Energy Efficiency Arkansas				
EE	AR Weatherization	1.3	1.3	0.5	4.6
EE	Benchmarking	1.6	1.6	0.6	4.3
EE	ENERGY STAR Homes	1.4	3.5	0.7	3.0
EE	Mobile Homes	1.2	1.4	0.5	3.9
EE	Multifamily	1.2	1.4	0.5	3.6
EE	C&I Prescriptive	2.4	3.0	0.9	4.5
EE	City Smart	1.6	2.4	0.8	2.9
EE	Commercial Custom	1.9	3.1	0.9	3.2
EE	Small Commercial	1.6	1.9	0.7	3.0
EE	Agricultural Energy Solutions	1.3	1.8	0.7	2.6
EE	Commercial New Construction	3.9	5.3	1.0	7.2
EE	Retrocommissioning	4.4	6.2	1.0	7.6
EE	Industrial	1.7	2.1	0.8	3.3
DR	Direct Load Control	6.5	7.4	7.4	0.8
DR	Agricultural Irrigation Load Control	4.9	4.3	1.0	N/A*
DR	Interruptible Rate	27.5	7.7	1.2	N/A*
DR	Enabled Pricing (Non-Res)	1.6	2.3	0.9	2.5
DR	Enabled Pricing (Res)	2.6	2.4	2.4	1.1
DR	Non-Enabled Pricing (Res)	1.9	2.5	2.5	N/A*
DR	Non-Enabled Pricing (Non-Res)	4.5	4.0	1.0	N/A*
	Total Portfolio	2.2	2.9	0.9	3.9

*Assumed participant costs are zero.

Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Demand Response Programs

		Sectors Modeled/Covered				
DR Measure/Program Type	Existing Program	Resi-dential	Small Comm-ercial	Large Comm-ercial	Industrial	Agri-cultural
Agricultural Irrigation Load Control	X					X
Direct Load Control	X	X				
Dynamic Pricing without Enabling Technology		X	X	X		
Dynamic Pricing with Enabling Technology		X	X	X		
Interruptible Rate				X	X	

- Existing DR program savings and participation informed by EAI Comprehensive Plan
- Other DR program assumptions informed by 2009 FERC National DR Study
- All DR programs assumed to be “opt-in”
- DR analysis did include reduced reserve margins associated with MISO benefits

Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: AMI Schedule

Total cumulative meter deployments

	Existing 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
EAI	800	3,703	6,606	11,392	21,165	35,824	55,370	74,916	89,575	479,214	753,023	757,495

Yellow shading indicates the years in which each OpCo engaged in full deployment of AMI
Full Deployment: includes all customer classes except the top 150 Industrials and Cogens
Years before full deployment include targeted deployments primarily to the Residential Customer class (for simplifying purposes use the residential class only)

Subject to very high uncertainty

- Smart meters are another tool in a utility's continuing effort to reduce costs to customers and to improve service reliability
- Entergy is not planning widespread deploying of smart meters
- Pilot tests to validate technologies and economics
  - Pilot demand response programs
    - Arkansas - irrigation load control pilot for farmers
  - Beginning very limited, targeted deployments (0-5%)
    - Hard to read, frequent disconnection/reconnection
    - Considering further tests on voltage control
    - Considering developing and offering a pre-pay program
  - Voluntary option for customers to assist with monthly budgeting
  - Eliminates security deposits and late fees

EAI 2012 IRP Development
DSM Assumptions

- The Potential Study began in October of 2011.

- Best available information was used to value the energy efficiency potential
  - 2010 cost of capital information.
  - 2011 load forecast

- All the energy efficiency savings beginning in 2007 and concluding in 2011are included in the base case and projected energy savings based upon Commission approved programs through 2012 are included in the base case.
  - 2012 Energy savings – 128,055 MWH
  - 2012 Demand reductions – 50.7 MW

- Evaluation of DSM in the 2012 EAI IRP
  The DSM assumption will be modeled as one of five potential portfolios; the other four portfolios assume supply side resource additions. Each portfolio will be evaluated within each of the four IRP scenarios and the total cost of service for each portfolio will be compared to find the lowest cost portfolio option. This methodology allows for demand side resources to be compared alongside supply side resources for long-term planning of EAI's portfolio mix.

EAI 2012 IRP Development
DSM Assumptions

- Proposed Assumptions for 2012 EAI IRP
  For EAI, which has on-going DSM efforts, the assumptions for long-term planning (IRP) are consistent with programs in EAI's current DSM portfolio assuming a Reference Level of potential as contemplated in the ICF Study.

- The following charts show the underlying DSM assumptions and provide an annual view of DSM Potential and cost for EAI. Note that 2012 DSM Potential is shown at zero because that potential has already been reflected in the four load forecasts developed for the EAI IRP.

EAI 2012 IRP Development : DSM Programs

ICF Potential Study – Six Bundled Loadshapes

Bundle	Type	Programs
1	DR	Interruptible Rate Direct Load Control Agricultural Irrigation Load Control
2	EE	Retrocommissioning Commercial New Construction Energy Star Homes Commercial Custom C&I Prescriptive
3	DR	Non-enabled Dynamic Pricing Enabled Dynamic Pricing
4	EE	City Smart Residential Lighting and Appliances Industrial
5	EE	Small Commercial Agricultural Energy Solutions Benchmarking Home Energy Solutions
6	EE	Mobile Homes Multifamily Arkansas Weatherization Residential Cooling Solutions

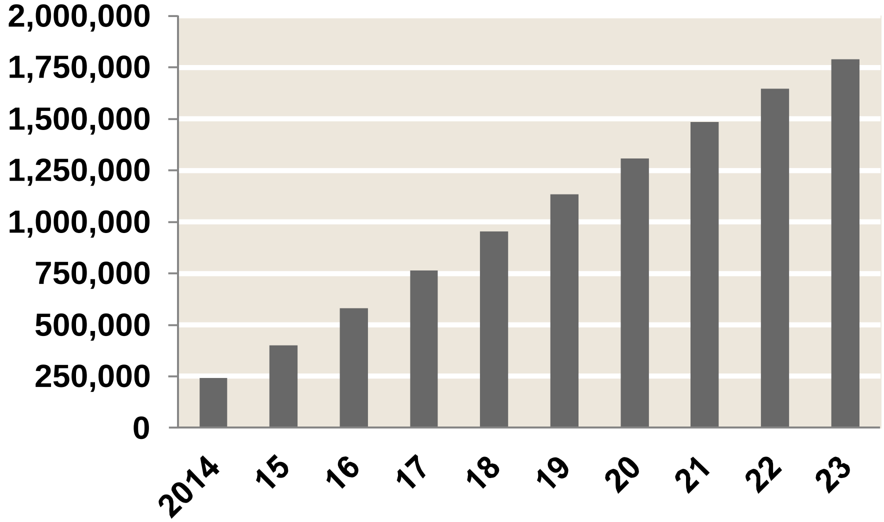
IRP DSM Portfolio – Single Aggregated Loadshape

Type	Programs
DR	~~Interruptible Rate~~ Direct Load Control Agricultural Irrigation Load Control ~~Non-enabled Dynamic Pricing~~ ~~Enabled Dynamic Pricing~~
EE	Retrocommissioning Commercial New Construction Energy Star Homes Commercial Custom C&I PrescriptiveCity Smart Residential Lighting and Appliances Industrial Small Commercial Agricultural Energy Solutions Benchmarking Home Energy Solutions Mobile Homes Multifamily Arkansas Weatherization Residential Cooling Solutions

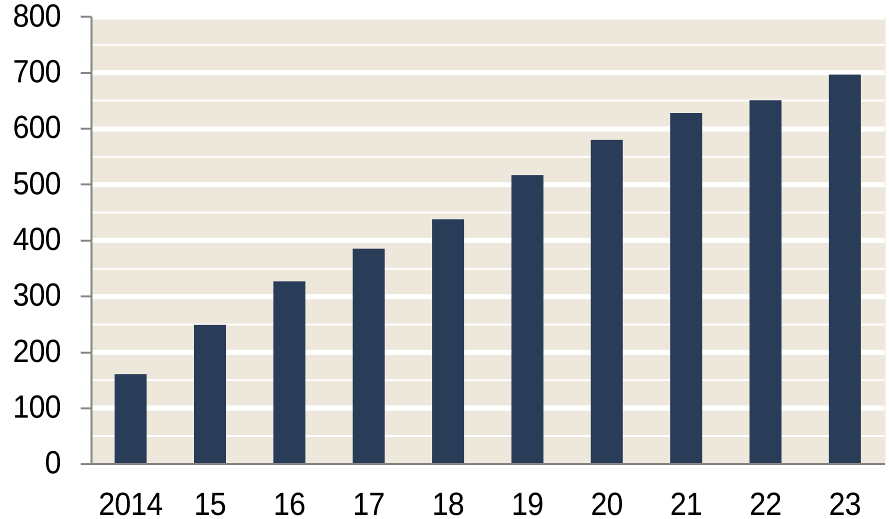
Hourly DSM impacts in 2012 of the ICF Potential Study are substracted from the hourly DSM impacts in all subsequent years of the EAI IRP DSM load shape.

EAI 2012 IRP Development : Incremental Utility-Sponsored DSM Potential Forecast

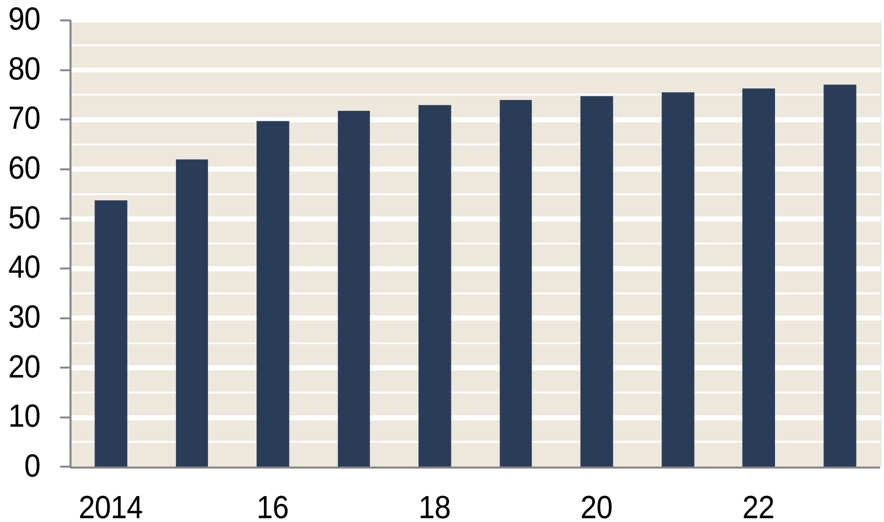
*Annual Energy Savings (MWh)**



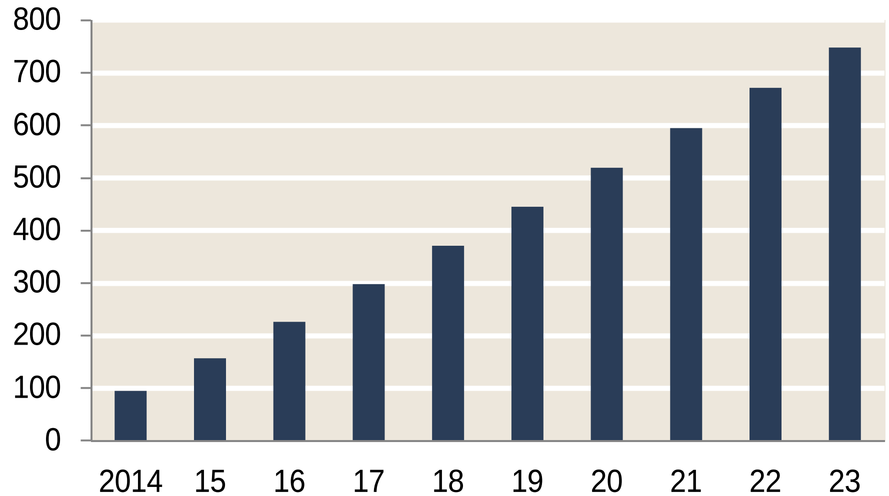
Peak Reduction (MW)*



Annual DSM Program Cost ($M)



Cumulative Program Cost ($M)



*In order to obtain specified benefit in a given year spending from 2012 through that year is required.

EAI 2012 IRP Development : Miscellaneous

- The remaining driver in the achievement of the energy efficiency potential is tariff driven savings that must have new technology installed to communicate such energy cost with customers and measure the results of customer usage.
- Presently Entergy Arkansas is thinking AMI technology is the preferred technology, and Entergy Arkansas has matured in our thinking of the roll out of AMI technology to a more measured point of view to ensure the technology can be proven to deliver promised results.
- None of the energy efficiency potential study demand reduction associated with the AMI technology was included in the IRP.

Energy Efficiency and the Future at EAI

- ASPC Targets have not been established beyond 2013. Based upon Commission orders EAI anticipates annual Energy Efficiency targets to be at least 0.75% of annual sales post NTG adjustments.

- Avoided cost have decreased significantly resulting in several of the existing programs to become non-cost effective, though the portfolio of programs continue to be cost effective.

- EAI is anticipating to file a portfolio of programs for 2014 through 2016 sometime in 2013. EAI is awaiting EM&V results to inform next portfolio filing; however, with information known today, EAI would plan to file the same programs with some modifications for measure changes and more coordination with over lapping gas utilities, minor adjustments in marketing and increased budgets to meet the potential 0.75% per year reduction targets.

NEXT STEPS

- Continue with EAI Suite of comprehensive programs, have independent Evaluation, Measurement and Verification completed and capture lessons learned to improve next phase of DSM implementation for 2014 through 2016.
- Continue to move forward with the development and implementation of enabling technologies (AMI / Smart Grid) at a measured pace to ensure technology can deliver energy efficiency results.

APPENDIX

Participation Approach A – illustrative example

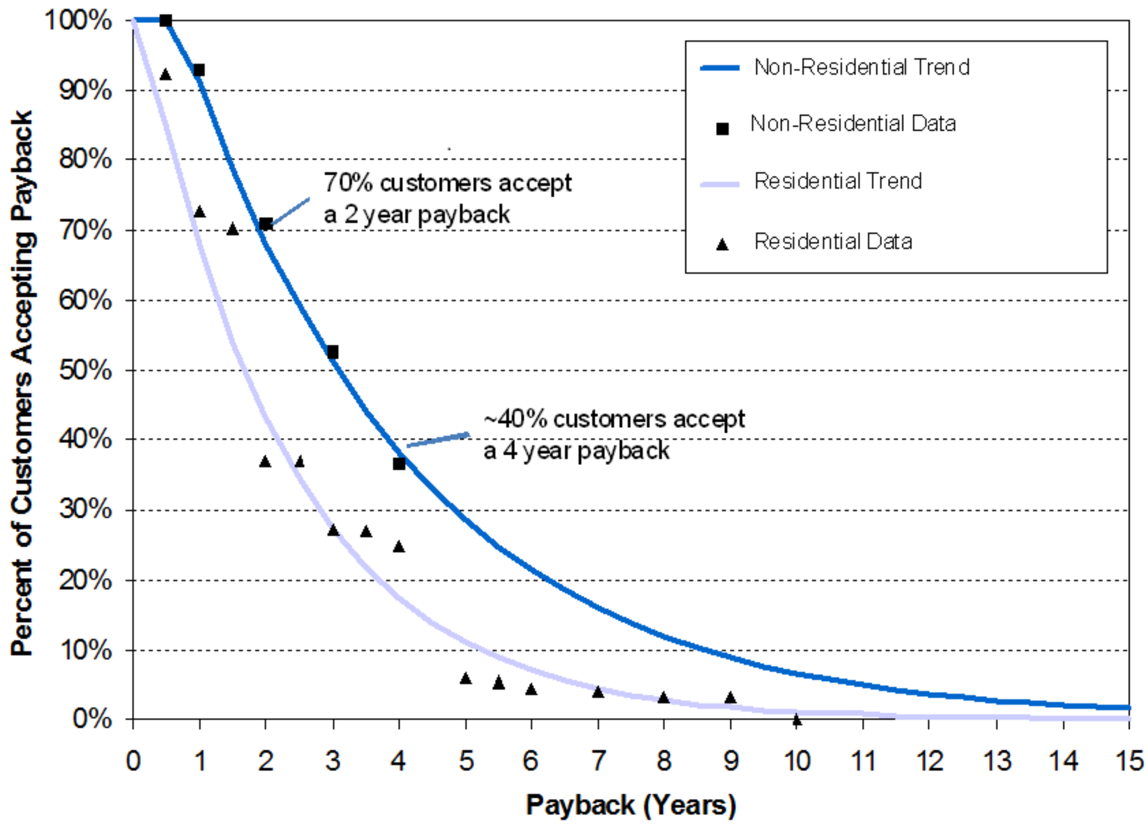
Measure Information

Program Name	ENERGY STAR Air Conditioning
Measure ID	16
Sector	Residential
Sub-Sector	SingleFamily&Duplex
End Use	HVAC
Technology Type	AC/Gas Heat
Efficient Measure	Central AC Replacement
Efficient Measure Definition	SEER 15
Base Measure Definition	SEER 13
Unit Name	ton

Incentive Calculations	Value	Source/Calculation
Residential retail electricity rate-kWh	$0.09	Utility
Residential retail capacity charge-kW	$0.00	Utility
Residential retail gas rate-therm	$0.85	Utility
Base Measure Life	15	Deemed Savings
Total Incremental Cost	$238.00	Deemed Savings
Annual kWh Savings	417.33	Deemed Savings
Annual kW Summer-Peak Savings	0.12	Deemed Savings
Annual Gas Savings	0	Deemed Savings
Annual Bill Savings	$37.91	Annual Energy Savings by Participant
Pre-rebate payback	6.3	Total Incremental Cost/Annual Bill Savings
Incentive Assumptions		
Minimum Incentive Level	25%	Reference case assumption
Maximum Incentive Level	75%	Reference case assumption
Post-rebate Payback Target	2	Reference case assumption
Incentive as % of Incremental Cost	68%	MAX(MIN(Minimum Incentive Level,1-Post-rebate Payback Target /Pre-rebate payback))
Incentive	$162.18	Incentive as % of Incremental Cost X Total Incremental Cost
Post-rebate payback	2	(Total Incremental Cost-Incentive)/Annual Bill Savings

Participation Approach A - cont.

Payback Acceptance Curves



Participation Approach A - cont.

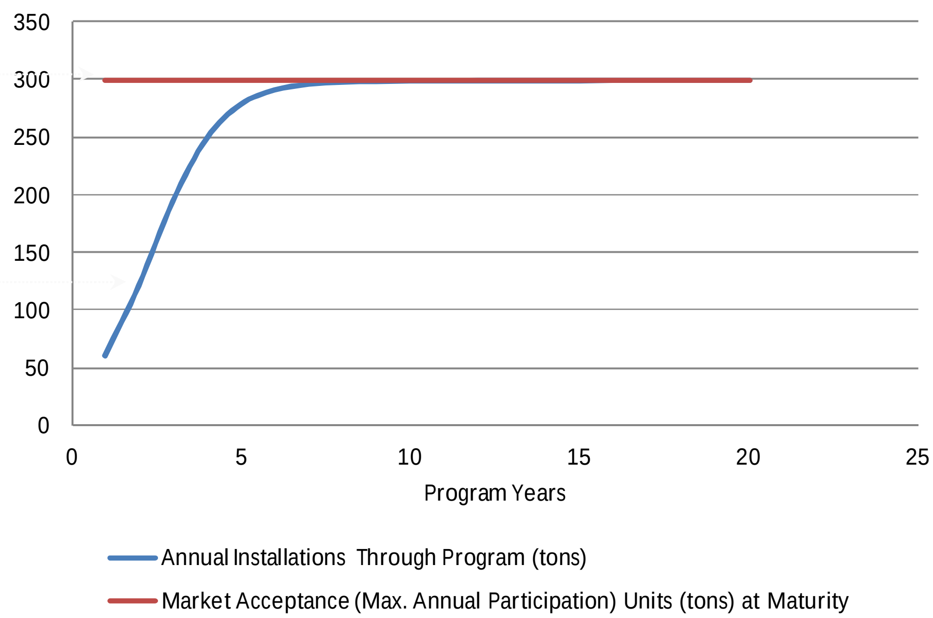
Applicability Factors	Value	Source/Calculation
Share of SingleFamily&Duplex Dwellings	87%	Utility
Measure Units per Sub-Sector Unit	3	Average size of unit (3 tons)
Applicability	32%	Percent of homes with AC/Gas Heat
Feasibility/Distribution	18%	ICF
Not Yet Adopted	100%	For ROB=100% For Retrofit=(1-Saturation of Efficiency Technology)
Annual Replacement Eligibility	7%	For ROB=1/Measure Life For Retrofit=100%

Program Assumptions	Value	Source/Calculation
Payback acceptance formula coefficient "a"	1.22	ICF market research
Payback acceptance formula coefficient "b"	-0.29	ICF market research
Customer stated payback acceptance	68%	Payback acceptance = 1.22 Years*exp(post rebate payback*b)
Program Market Acceptance Rate	30%	ICF program assumption
Ramp-up Rate	5	ICF program assumption
Ramp-up Shape	100%	ICF program assumption
Program Start Year	2012	
Program Implementation Period (Years)	20	
First Year Participation Estimates		
Maximum Annual Market Share (Smax)	20.4%	Program Market Acceptance Rate X Customer stated payback acceptance
First Year Share of Installations (So)	4.1%	Maximum Annual Market Share (Smax)/Ramp-up Rate

Participation Approach A-cont.

Maximum estimated annual installations

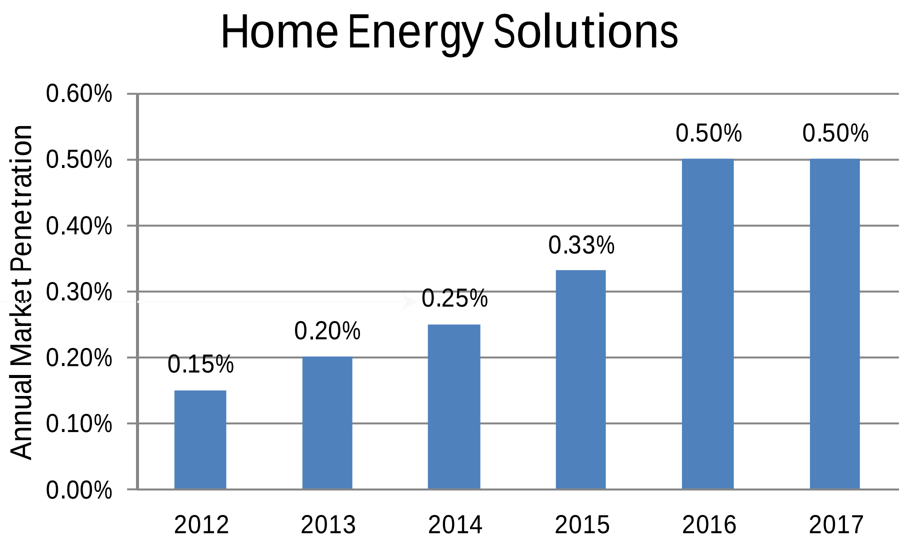
"S-curve" – participation ramps up to maximum annual installations



Participation Projections	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2031
Number of Residential Customer	141,609	144,537	145,094	145,309	145,352	145,323	145,276	145,230	145,170	145,111	145,060	144,952
Average Annual Residential Growth Rate (2012 to 2031)	*0.0143%*											
Single Family & Duplex Customers	123,766	126,326	126,344	126,362	126,380	126,398	126,416	126,434	126,452	126,471	126,489	126,670
Customers with A/C and Gas Heat	39,732	40,554	40,560	40,565	40,571	40,577	40,583	40,589	40,594	40,600	40,606	40,664
Not Yet Adopted Efficient Measure	39,732	40,554	40,560	40,565	40,571	40,577	40,583	40,589	40,594	40,600	40,606	40,664
Total Measure Units (tons)	119,196	121,661	121,679	121,696	121,714	121,731	121,748	121,766	121,783	121,801	121,818	121,993
Feasibility (tons)	21,455	21,899	21,902	21,905	21,908	21,912	21,915	21,918	21,921	21,924	21,927	21,959
Failing Feasible Units, Units Eligible for Replacement (tons)	1,430	1,460	1,460	1,460	1,461	1,461	1,461	1,461	1,461	1,462	1,462	1,464
Units reporting acceptable payback		994	995	995	995	995	995	995	995	996	996	997
Market Acceptance Units at Maturity		*298*	*298*	*298*	*298*	*299*	*299*	*299*	*299*	*299*	*299*	*299*
Annual Participation (%)		4.1%	8.3%	13.3%	17.0%	19.0%	19.9%	20.2%	20.4%	20.4%	20.4%	20.4%
Annual Installations (tons)		60	121	194	249	278	291	296	298	298	299	299
Cumulative Installations (tons)		60	180	374	623	901	1192	1487	1785	2083	2382	4470

Participation Approach B – illustrative example

Annual market penetration estimates manually entered



Based on

- Current Entergy program performance
- The EAI Comprehensive Program Plan
- ICF program experience

Participation approach by program

	Modeled Program Name	Relevant Sector(s)	Type	EAI Compre-hensive Program?	Participation Approach
1	Residential Lighting and Appliances	Residential	EE	Yes	A
2	Residential Cooling Solutions	Residential	EE	Yes	A
3	Home Energy Solutions	Residential	EE	Yes	B
4	Energy Efficiency Arkansas	Residential	EE	Yes	B
5	AR Weatherization	Residential	EE	Yes	B
6	Benchmarking	Residential	EE	Yes	B
7	ENERGY STAR Homes	Residential	EE	Yes	B
8	Mobile Homes	Residential	EE	Yes	A
9	Multifamily	Residential	EE	Yes	A
10	C&I Prescriptive	C&I	EE	Yes	A
11	City Smart	Government	EE	Yes	B
12	Commercial Custom	C&I	EE	Yes	B
13	Small Commercial	Small Commercial	EE	Yes	A
14	Agricultural Energy Solutions	Agricultural	EE	Yes	A
15	Direct Load Control	Residential	DR	Yes	B
16	Agricultural Irrigation Load Control	Agricultural	DR	Yes	B
17	Commercial New Construction	Commercial	EE	No	A
18	Retrocommissioning	Commercial	EE	No	B
19	Industrial	Industrial	EE	No	A
20	Interruptible Rate	Large C&I	DR	No	B
21	Enabled Pricing (Non-Res)	Commercial	DR	No	B
22	Non-Enabled Pricing (Non-Res)	Commercial	DR	No	B
23	Enabled Pricing (Res)	Residential	DR	No	B
24	Non-Enabled Pricing (Res)	Residential	DR	No	B

LUNCH

SPO Planning Analysis

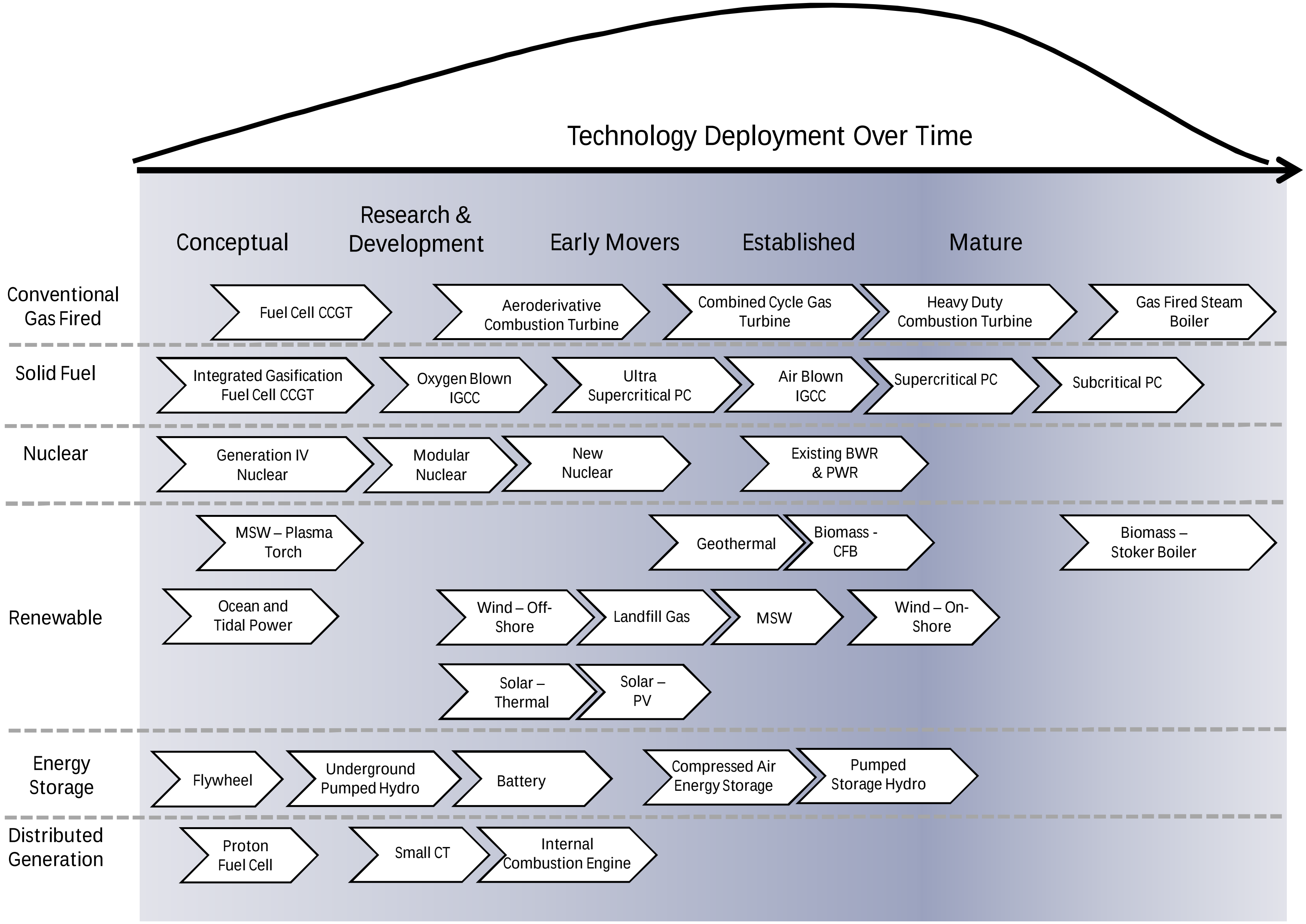
Generation Technology Assessment & Production Cost Analysis

EAI Stakeholder Meeting

July 31, 2012

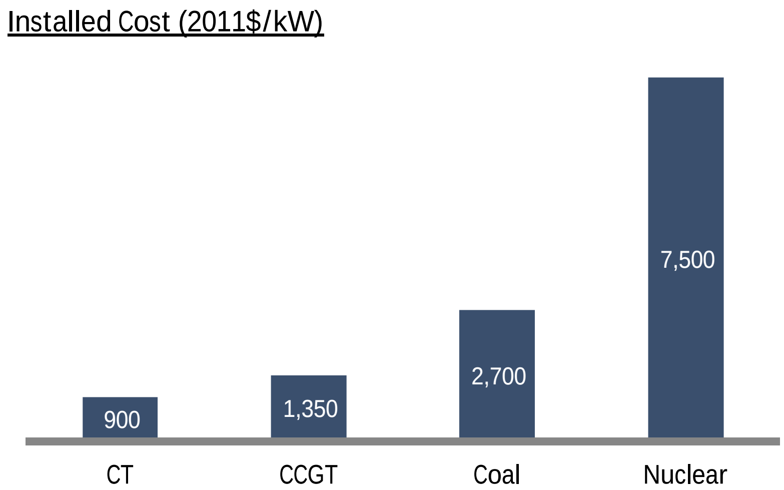
Entergy®

Technology Life Cycle

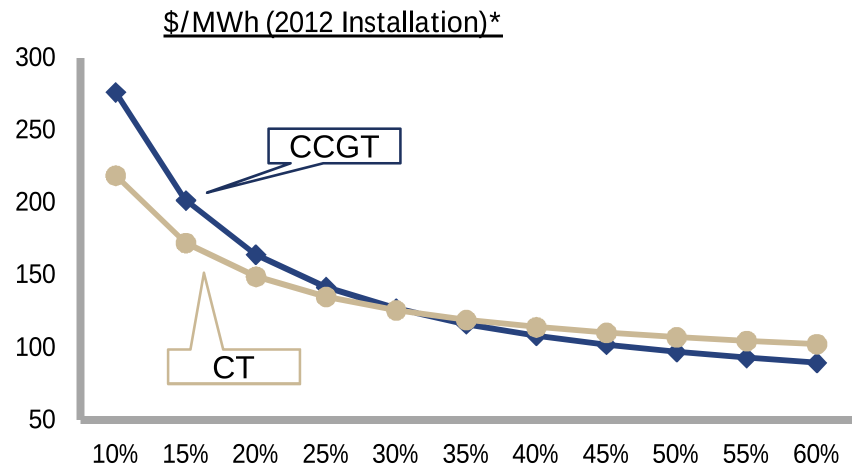


Conventional Alternatives

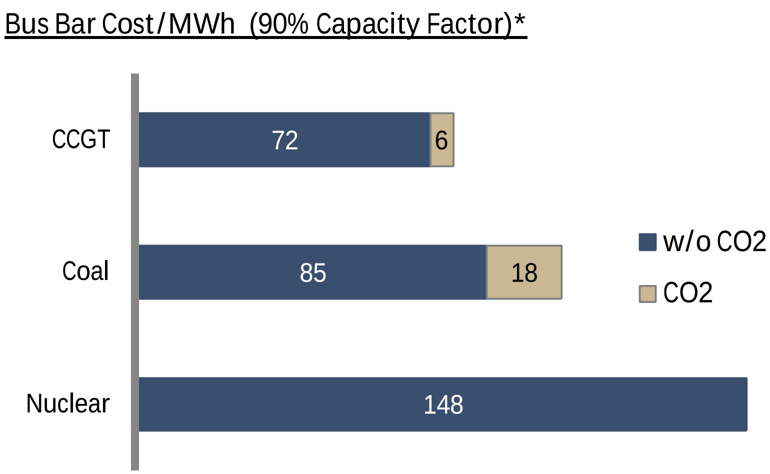
Gas Fired CT / CCGT offers Lowest Capital Cost



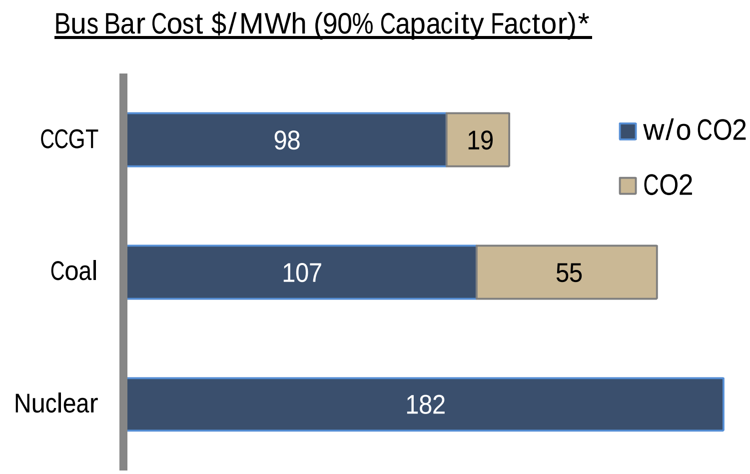
CT is preferred over CCGT below about 30% Capacity Factor



For base load CCGT is low cost alternative in 2012 . . .



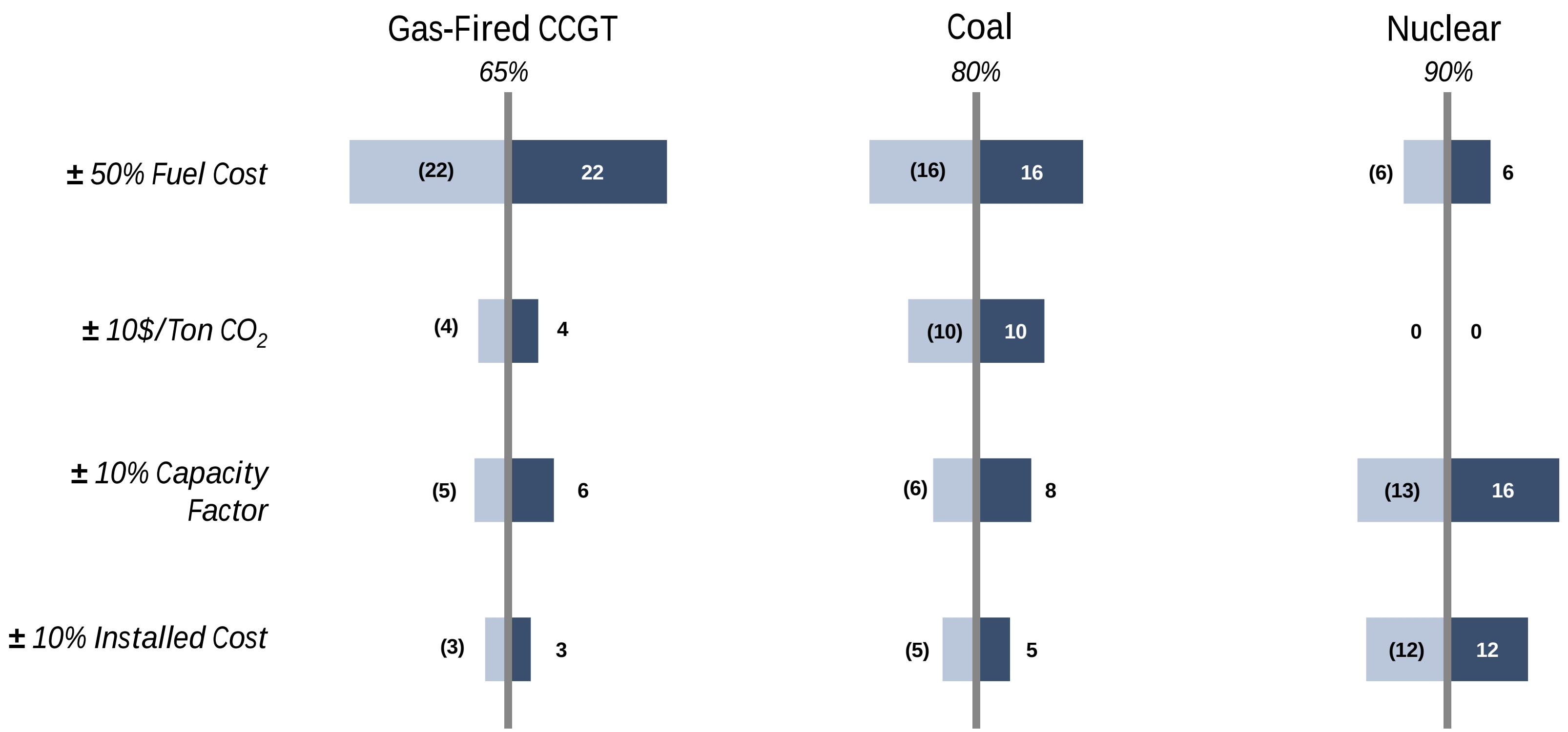
And in 2022



*Bus bar cost levelized in nominal $/MWh over expected life of resource (30 years CCGT & CT, 40 years coal and nuclear). CO_2 compliance cost begins in 2023 and escalates over time.

Sensitivities

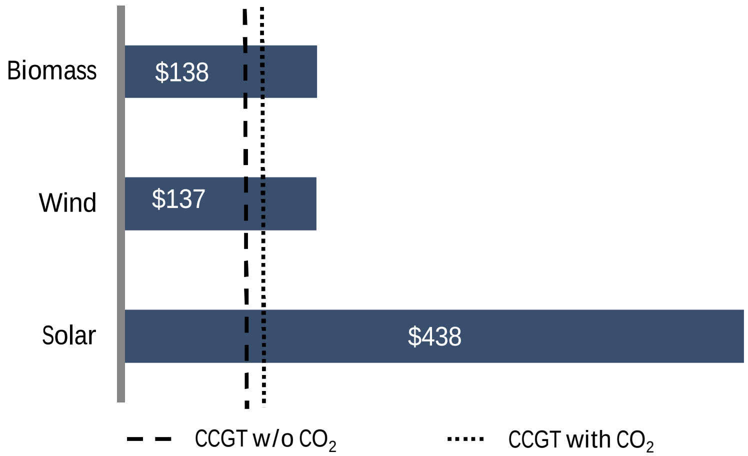
*Gas-fired CCGT economics remain favorable across range of assumptions**



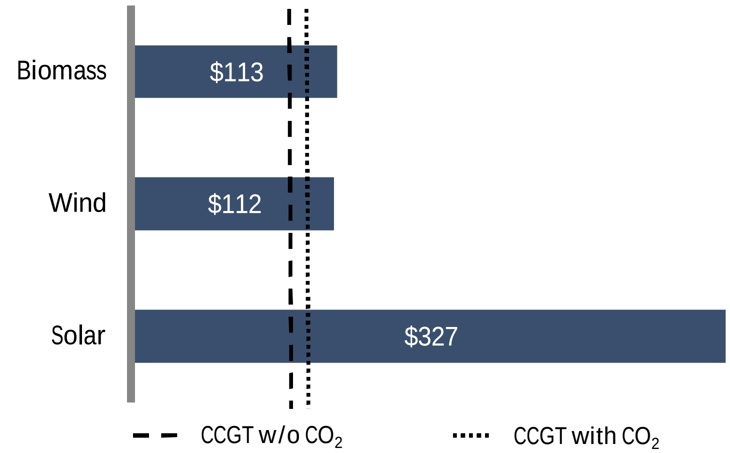
*Bus bar cost levelized in nominal $/MWh over expected life of resource (30 years CCGT & CT, 40 years coal and nuclear). CO_2 compliance cost begins in 2023 at $24.12/U.S. and escalates over time at about 7% per year. Cost based on 2012 COD.

Renewable Alternatives

$/MWh Without Incentives*

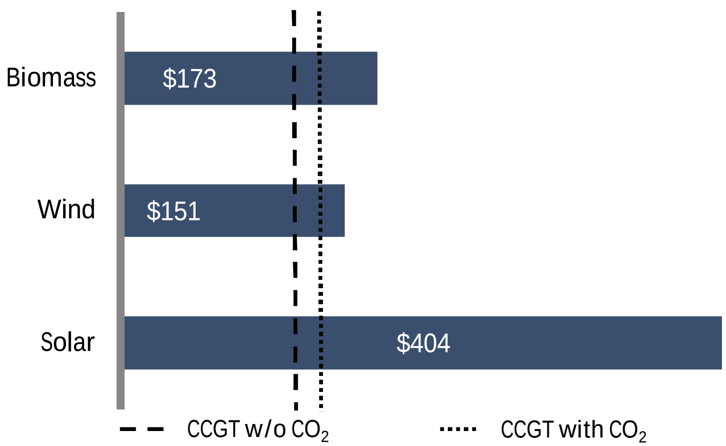


$/MWh With Incentives*

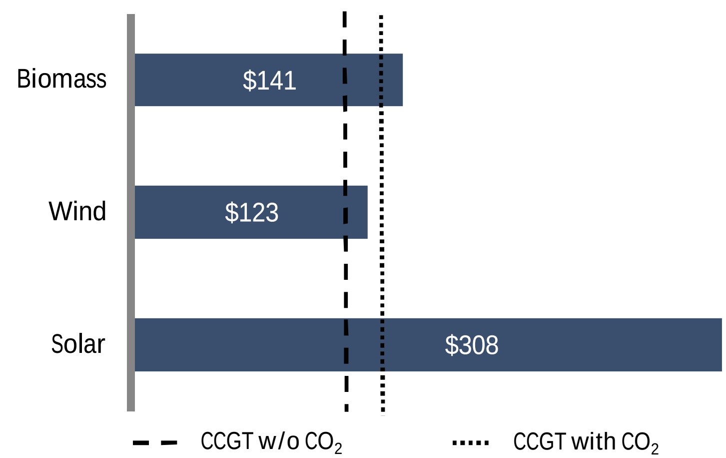


2022 In Service Date

$/MWh Without Incentives*



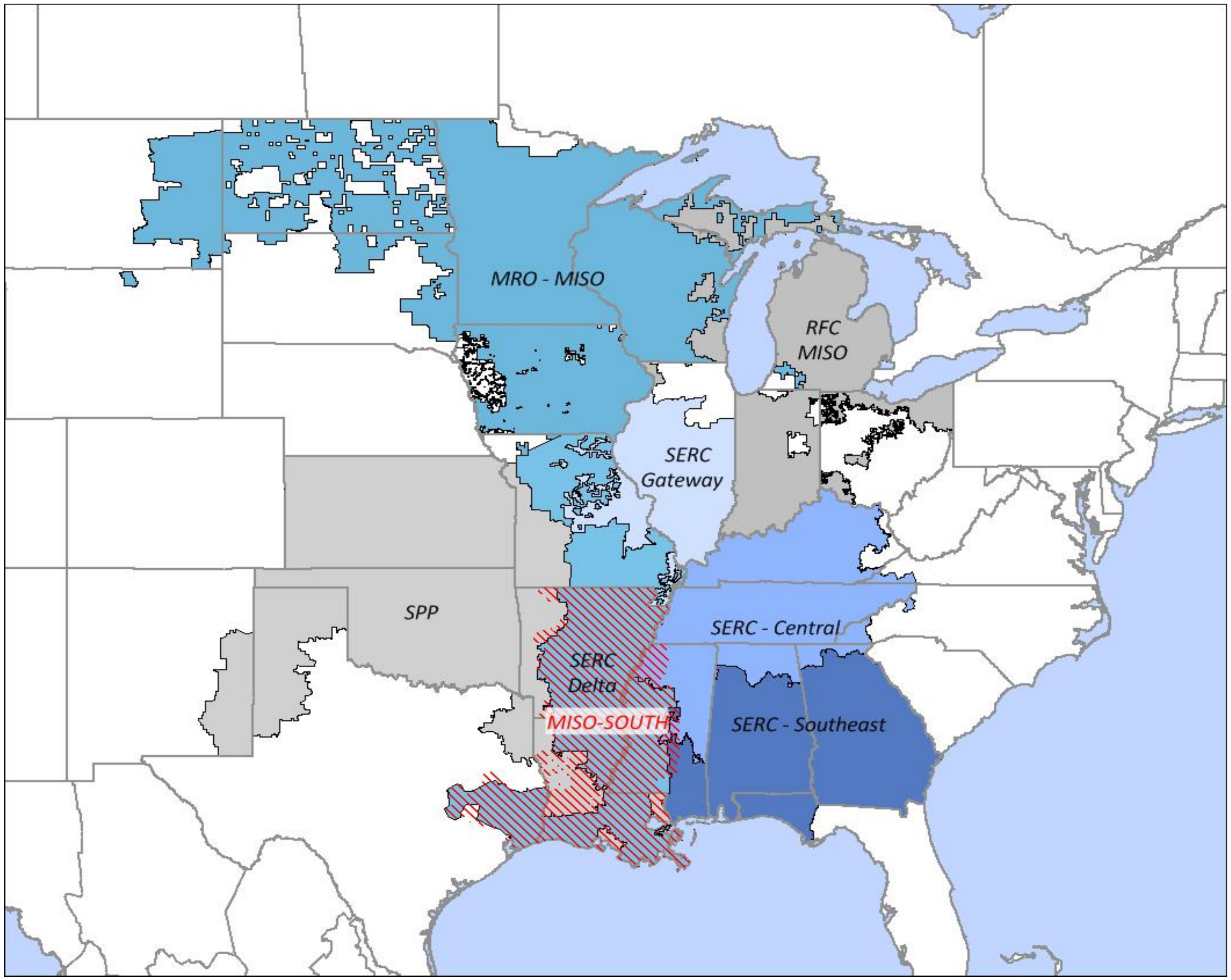
$/MWh With Incentives*



*Bus bar cost levelized in nominal $/MWh over expected life of resource (30 years CCGT & CT, 40 years coal and nuclear). CO_2 compliance cost begins in 2023 and escalates over time.

Scope of Aurora Market Modeling For IRP

Entergy Region and surrounding regions were modeled . . .



Supply Cost Assessment Overview

Aurora Production Cost Model

AURORA is used to simulate the hourly operation of the MISO and 1st tier power markets over the study period 2014 – 2023.

Includes a zonal representation that reflects transmission transfer capability limitations.

Includes a load forecast for each modeled entity and each generating unit is modeled individually.

Additional constraints are modeled to reflect operational limitations and requirements, including:

- Balancing Authority reserve requirements;
- Zonal reserve requirements;
- Generating unit forced outage rates; and
- Generator unit maintenance

All of the generators are committed and dispatched to serve the combined load at the lowest variable cost subject to the constraints.

Results in hourly power prices that are representative of the Locational Marginal Prices (LMP) for each zone.

Supply Cost Assessment

Variable production cost is measured as:

Cost of Service = Load Payment
+ Generation Cost
– Generation Revenue

To assess the total supply cost of each portfolio of resources, the incremental fixed cost of the resources that comprise the portfolio is added to the variable production cost of service.

Market Modeling Overview

IRP analytics will rely on four scenarios to assess alternative portfolio strategies under varying market conditions. Additional information regarding the scope of and assumptions used in the market modeling are provided in other slides. The four scenarios are:

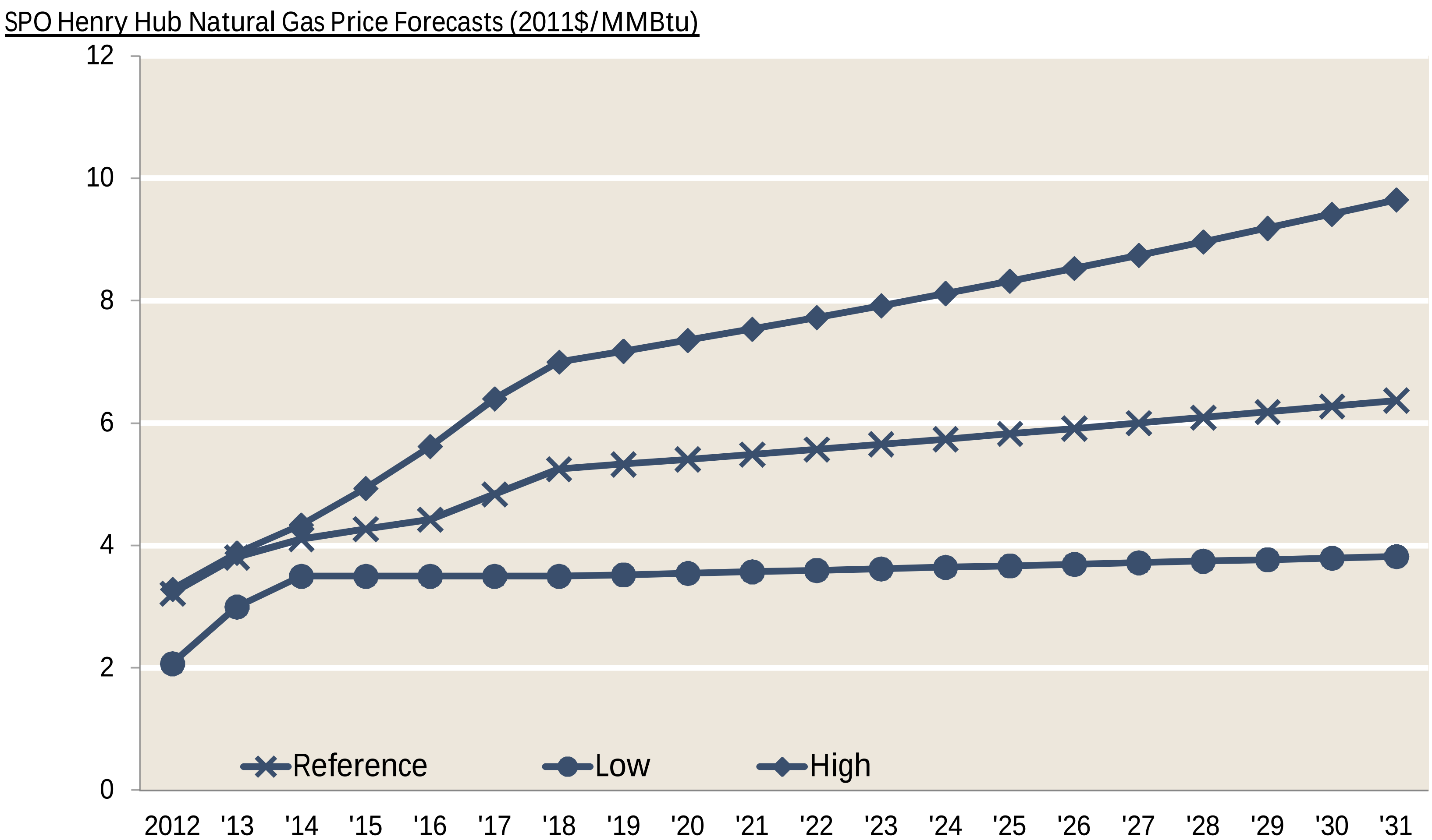
- Scenario 1 (Assumes Reference Load, Reference Gas, and no CO_2 cost)
- Scenario 2 (Economic Rebound)
- Scenario 3 (Green Growth)
- Scenario 4 (Austerity Reigns)

- More information of Scenarios 2-4 are found on the following page.

Scenario Storylines

	Scenario 2 Economic Rebound	Scenario 3 Green Growth	Scenario 4 Austerity Reigns
General Themes	• U.S. economy recovers and resumes expansion at relatively high rates. Improved domestic energy supply and productivity improvements keep current manufacturing/industrial base competitive.	• Government policy and public interest drive a "green agenda" marked by government subsidies for renewable generation; regulatory support for energy efficiency; and consumer acceptance of higher cost for "green." • Overall economic conditions are good with moderate GDP growth which enables investment in energy infrastructure.	• Sustained poor economic conditions in U.S. – low GDP. • Economic issues trump environmental concerns in public policy and consumer attitude.
Power Sales	• Economic growth and new uses for electric power drive power sales. New power uses more than offset energy efficiency gains. Technology improvements drive electric demand and vehicles grow at a steady pace. EVs are about an 12% of the light duty fleet by 2031.	• Moderate economic growth stimulates power demand. • However, decline in electricity intensity resulting from energy efficiency measures provides a countervailing force. • Consistent with green agenda, electric vehicles represent about a quarter of the light vehicle fleet by 2031, slightly muting de-electrification.	• Poor economic conditions result in low growth in demand for power. Electric vehicles don't catch on. Due to low power prices, relaxation of some efficiency standards and consumer's unwillingness to invest in energy efficiency, electricity intensity and therefore KWh sales growth and peak demand is higher than expected.
Climate Policy	• Carbon capture & storage required when commercially available for all new power generation. • Mild cap and trade for power in 2023.	• Cap & trade for carbon (power sector only) starting in 2018. • New coal must have CCS.	• Neither Congress nor EPA regulate CO_2. (no carbon cost).
Energy Policy	• Primarily market solutions. Slow but steady move toward a cleaner environment driven by innovation.	• Clean energy standard enacted. • Government subsidies for renewable generation , new nuclear & EVs.	• Renewable subsidies end. Government has little appetite for new policy. No new state RPSs.
Fuels	• Although demand is strong, technology allows supply to keep pace. Fuel prices stay in reasonable check.	• Natural gas prices are driven higher by EPA regulation of fracking & local opposition. Coal and oil prices also high.	• Low fuel prices, but natural gas and coal still plentiful as E&P cost are also lower.

Henry Hub Natural Gas Forecast



Natural Gas Assumptions

System Planning & Analysis has produced three gas price curves which are proposed for use in the development of the 2012 IRP. The curves are summarized in the following tables.

2012- 2031 Nominal $ per MMBtu			
	Low	Reference	High
Levelized*	$3.97	$5.79	$7.58
Average	$4.38	$6.66	$9.15
19 Yr. CAGR	5.37%	5.75%	7.96%

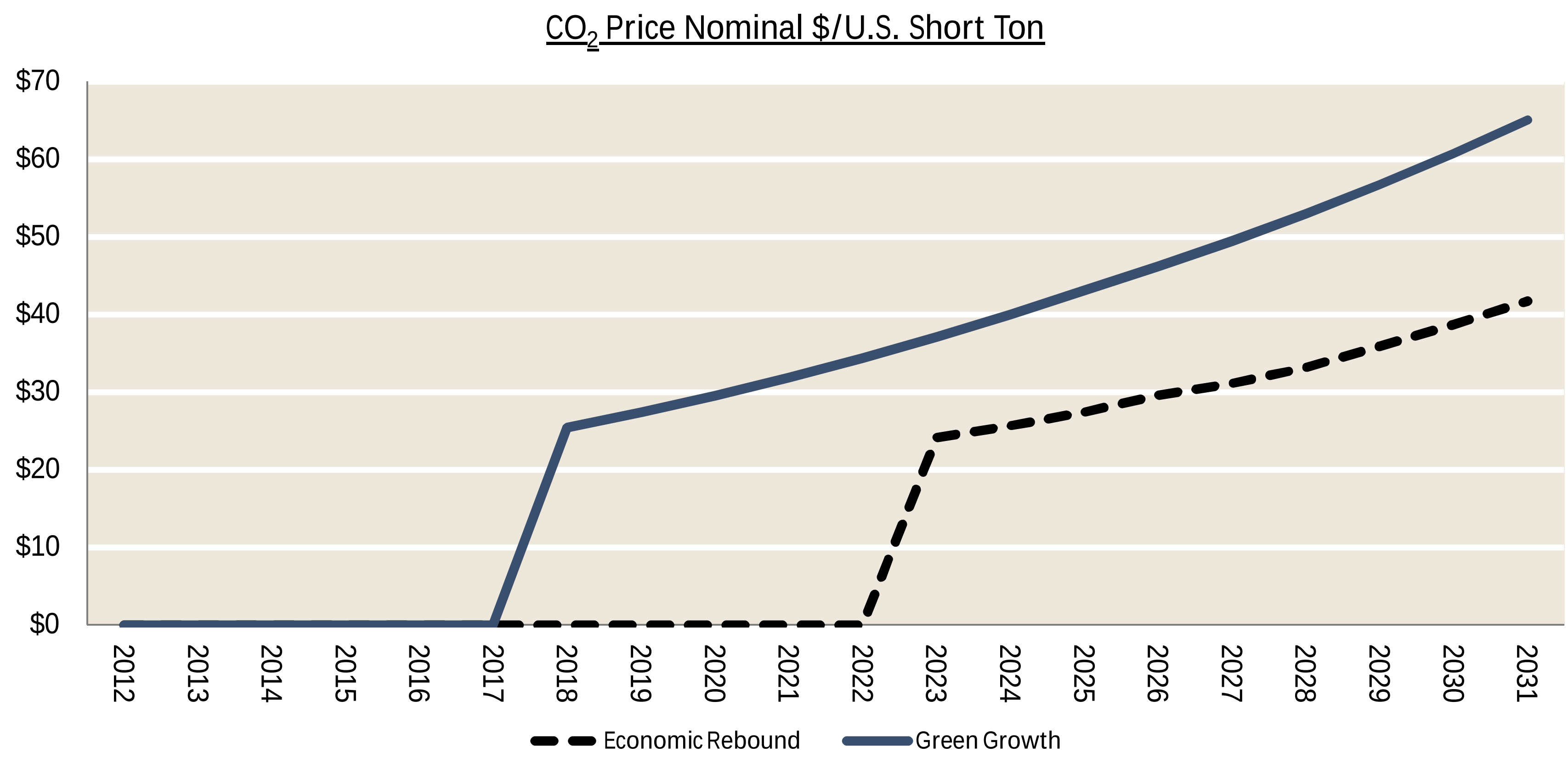
2012- 2031 Real 2011$ per MMBtu			
	Low	Reference	High
Levelized*	$3.41	$4.95	$6.47
Average	$3.51	$5.29	$7.20
19 Yr. CAGR	3.29%	3.67%	5.84%

**Real prices levelized at 7.25% discount rate*

Forecast based on January 13 Market Close.

2012 IRP Carbon Assumptions

Reference Case and Austerity Reigns scenarios assume no direct CO_2 regulation. The Economic Rebound and Green Growth Scenarios assume cap and trade programs beginning in 2023 and 2018, respectively.



Market Model Inputs (2012-2031)

	Scenario 1	Economic Rebound	Green Growth	Austerity Reigns
Electricity CAGR (Energy GWh)	~0.8%	~1.5%	~0.3%	~1.1%
Energy CAGR (w/o Elec. Vehicles)	Not materially different	~1.4%	~0.1%	Not materially different
Peak Load Growth CAGR	~0.8%	~1.4%	~0.2%	~1.1%
Henry Hub Natural Gas Prices ($/MMBtu)	$4.96 levelized 2011$	Same as Reference $4.96 levelized 2011$	High Case ($6.48 levelized 2011S	Low Case ($3.40 levelized 200x)
WTI Crude Oil ($/Barrel)	$93 levelized 2011$	$127 levelized 2011$	High Case $209 levelized 2011$	Low Case $53 levelized 2011$
CO_2 ($/short ton)	None	Cap and trade starts in 2023 $6.56 levelized 2011$	Cap and trade starts in 2018 $16.65 levelized 2011$	None
Conventional Emissions Allowance Markets	CAIR	CSAPR starts 2013	CSAPR starts 2013	CAIR
Delivered Coal Prices – Entergy Owned Plants (Plant Specific Includes Current Contracts) $/MMBtu	Reference Case (Vol. Weighted Avg. $2.66 levelized 2011$)	Same as Reference Case (Vol. Weighted Avg. $3.40 levelized 2011$)	High Case (Vol. Weighted Avg. $3.40 levelized 2011$)	Low Case (Vol. Weighted Avg. $2.27 levelized 2011$)
Delivered Coal Prices – Non Entergy Plants In Entergy Region	Mapped to similar Entergy Plant	Mapped to Similar Entergy Plant	Mapped to Similar Entergy Plant	Mapped to Similar Entergy Plant
Delivered Coal Prices – Non Entergy Regions	Reference Case - Varies By Region	Same as Reference Case - Varies By Region	High Case – Varies By Region	Low Case – Varies By Region
Coal Retirements Capacity (GW)*	54 GW	54 GW	115 GW	25 GW
New Nuclear Capacity (GW)*	7 GW	8 GW	25 GW	2 GW
New Biomass (GW)*	0.1 GW	0.1 GW	7 GW	0.1 GW
New Wind Capacity (GW)*	57 GW	68 GW	80 GW	22 GW
New Solar Capacity (GW)*	0.9 GW	1 .0 GW	2 GWs	0.3 GW

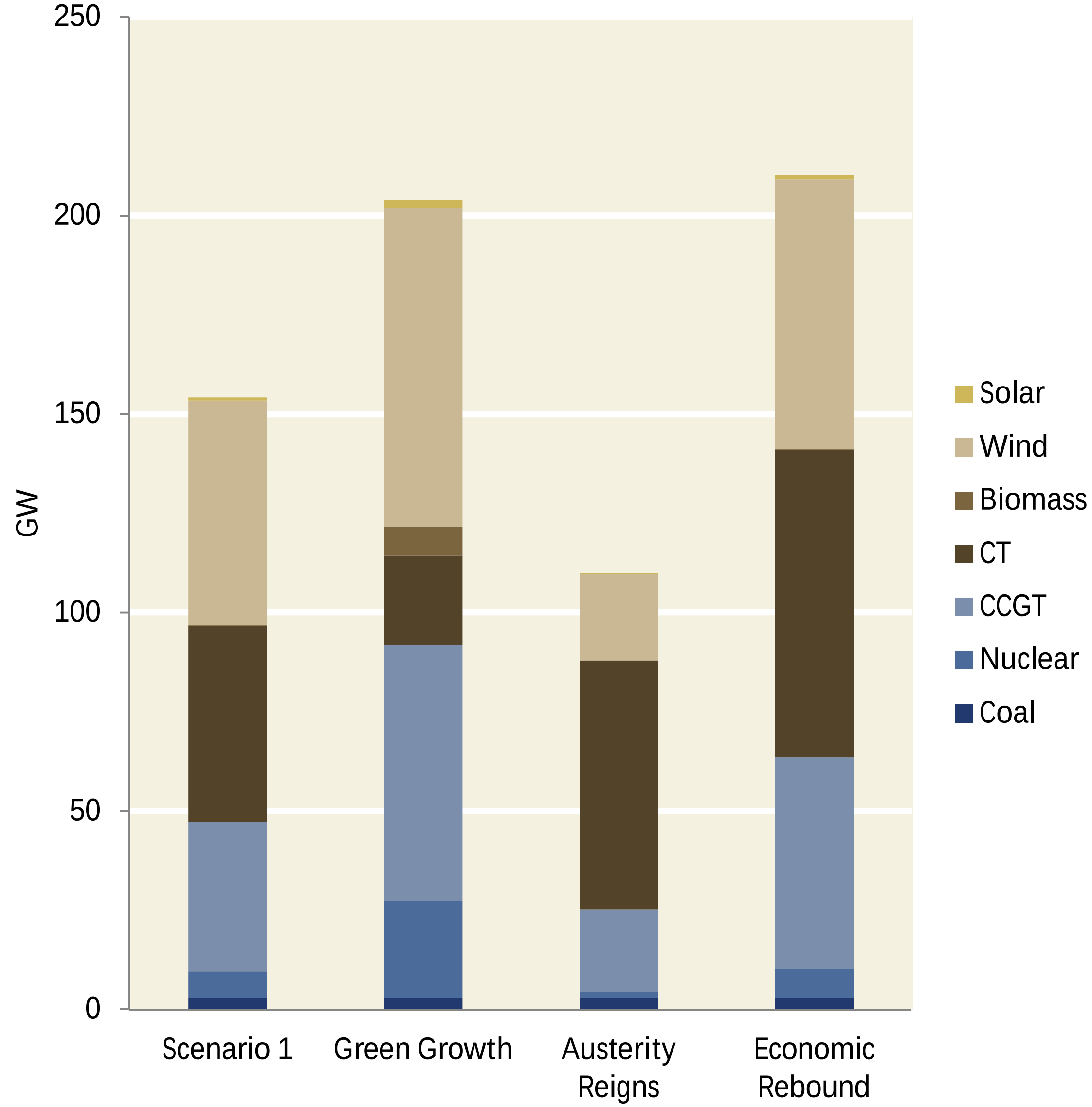
*Figures shown are for the period 2012-2031 covering a sub-set of the Eastern Interconnect which is approximately 34% of total U.S. 2011 TWh electricity sales. Gas and Coal additions other than 5 GW currently under construction handled through the Aurora capacity expansion algorithm. Non coal retirements are assumed to occur when resource reaches 60 years old unless an earlier retirement date has been announced. Entergy regulated plant assumed deactivations based on internal forecasts and do not change by scenario.

Note: Levelized prices refer to the price in 2011 dollars where the NPV of that price grown with inflation over the 2012-2031 period would equal the NPV of levelized nominal prices over the 2012-2031 period when the discount rate is 9.25%.

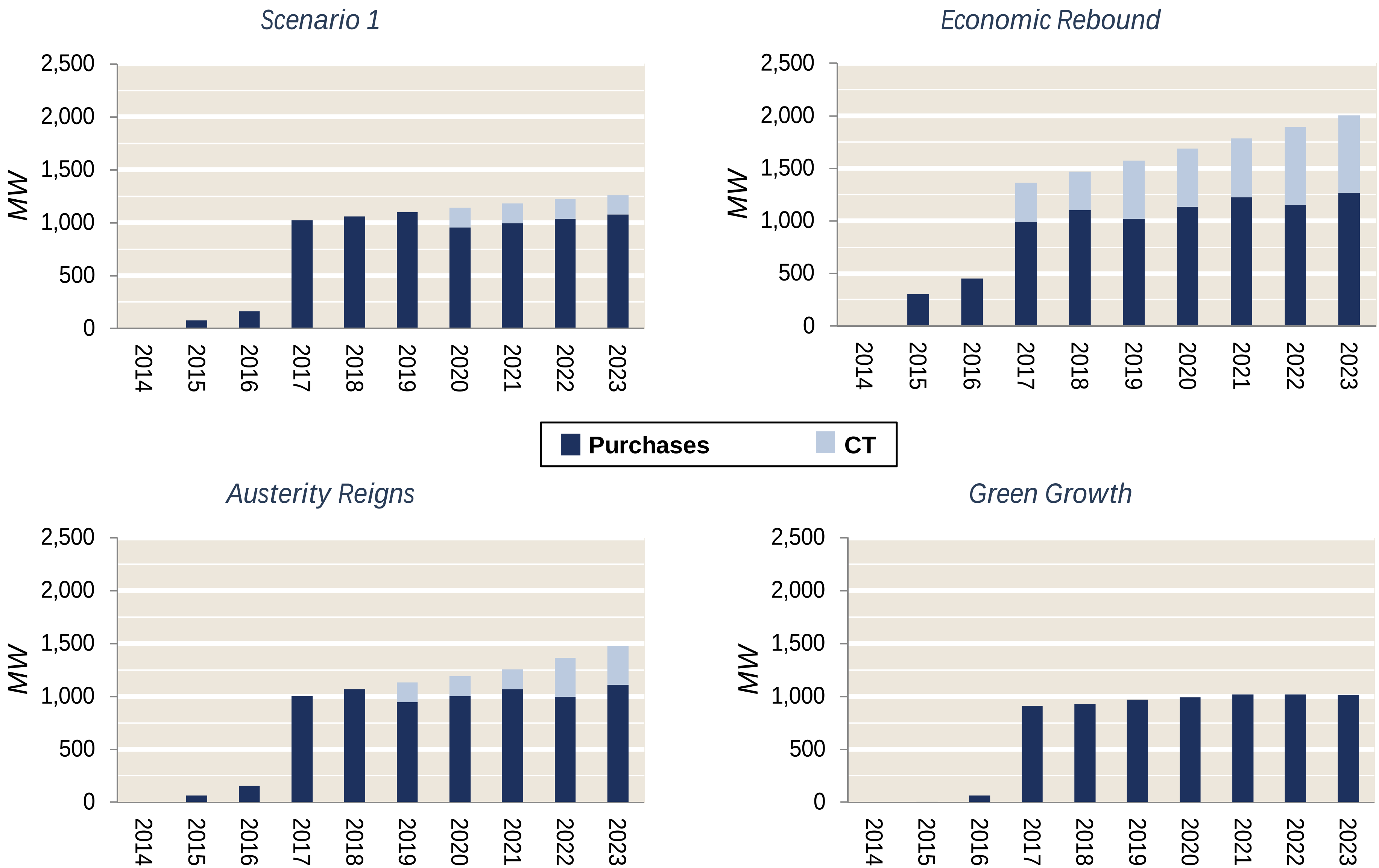
Capacity Additions In Modeled Market 2012-2031

Capacity Expansion

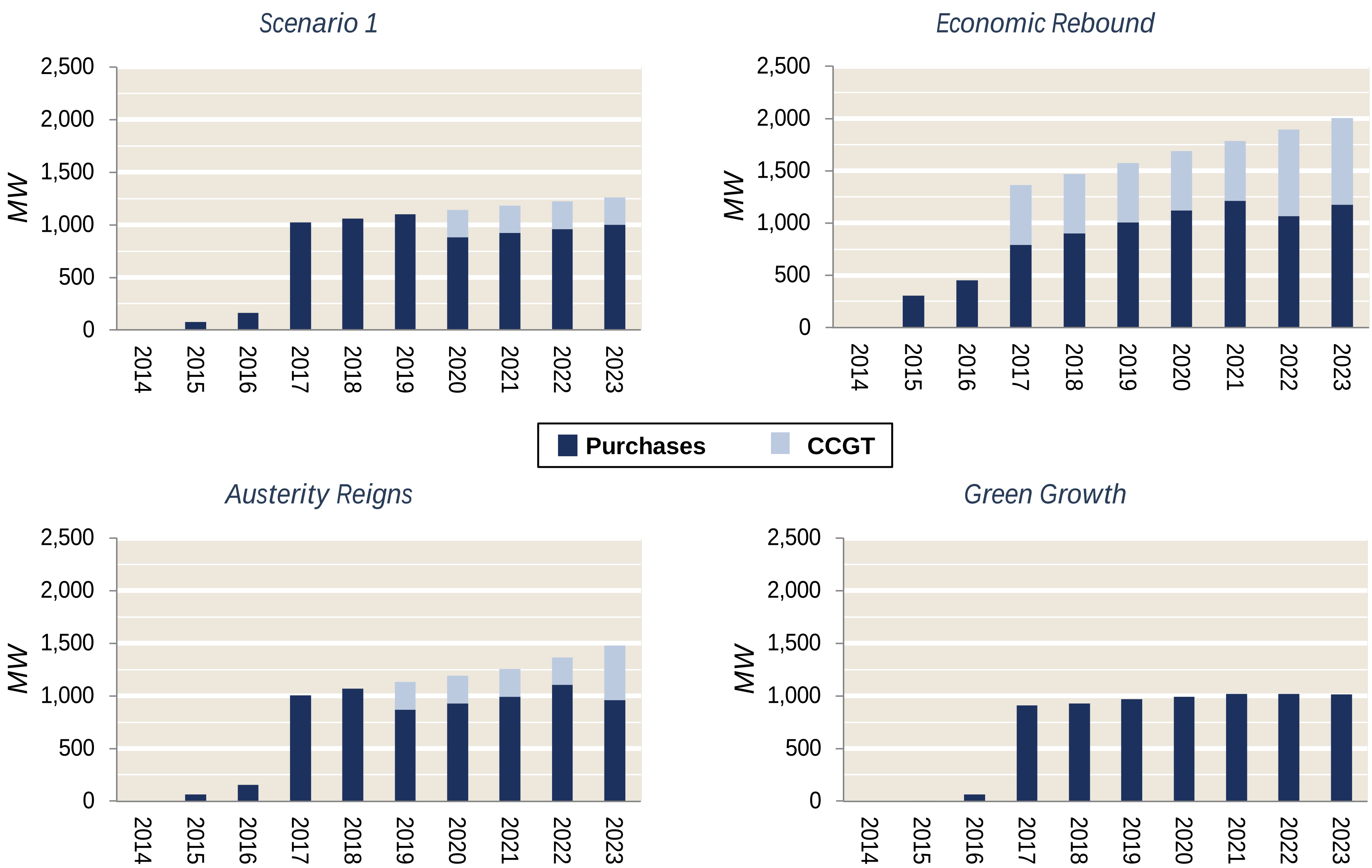
The scenarios differ in regards to the amount and type of capacity added in the market over the planning horizon. The differences reflect specific input assumptions for some technologies (nuclear, biomass, wind, solar) and automatic capacity expansion results, i.e., model-selected additions for others (coal, CCGT and CT). Capacity expansion results shown to the right relate to the overall modeled market (not Entergy Operating Companies specific). The "market" had about one third of U.S. energy sales in 2011.



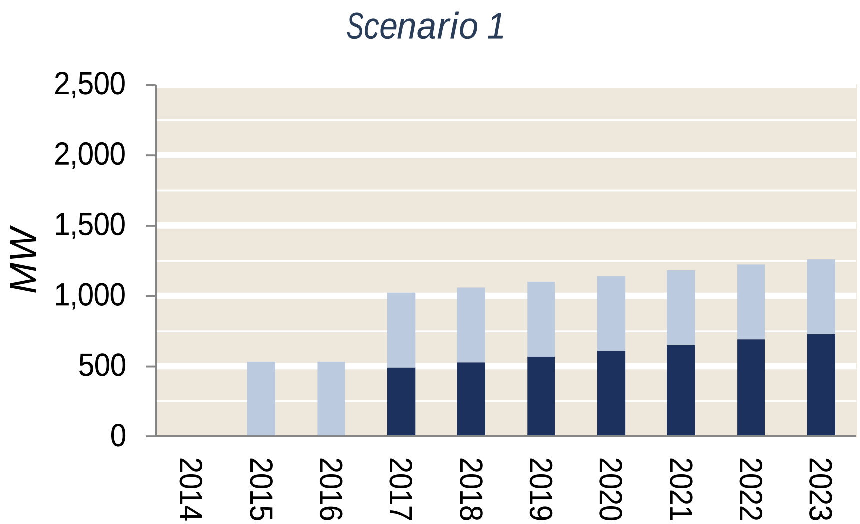
EAI Portfolio 1 – Resource Additions by Scenario

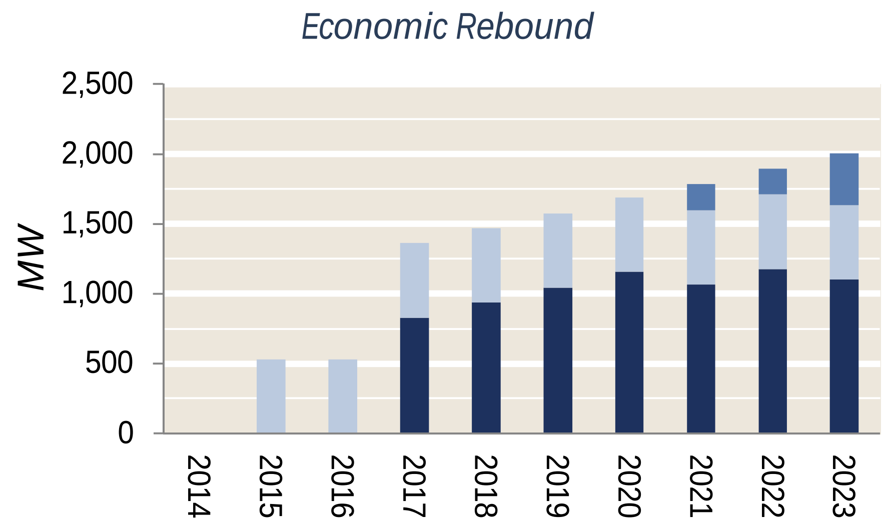


EAI Portfolio 2 – Resource Additions by Scenario

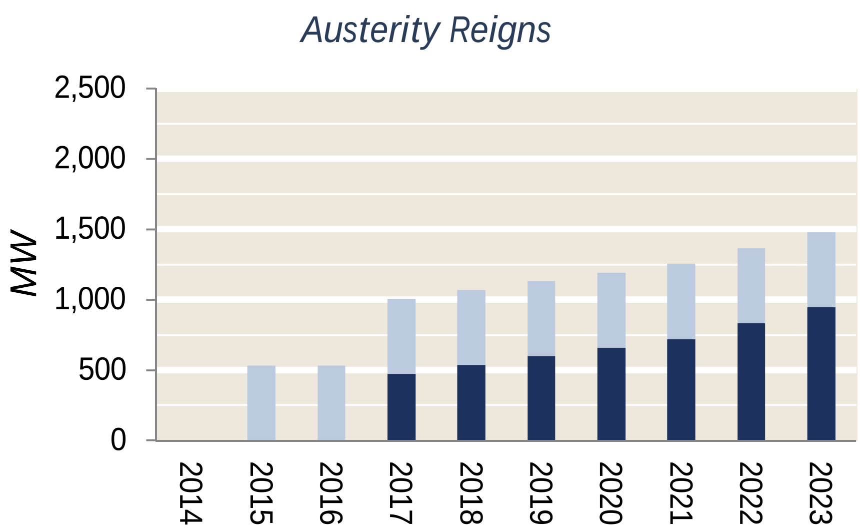


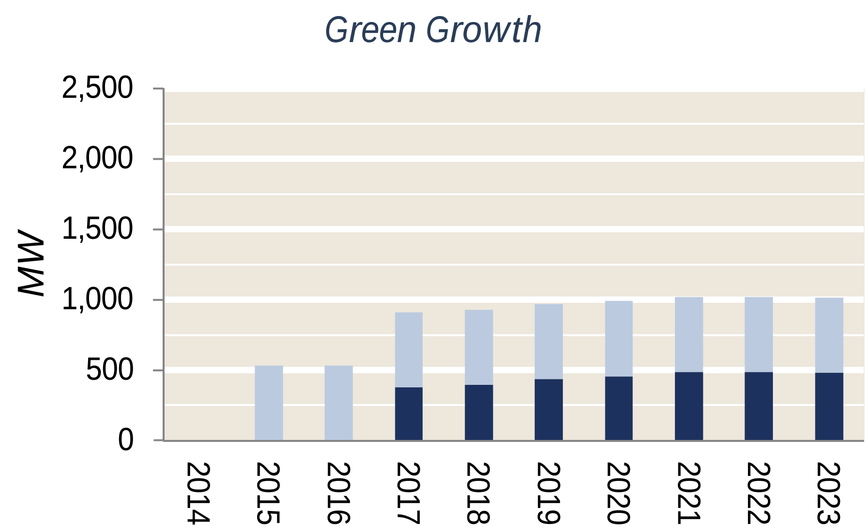
EAI Portfolio 3 – Resource Additions by Scenario



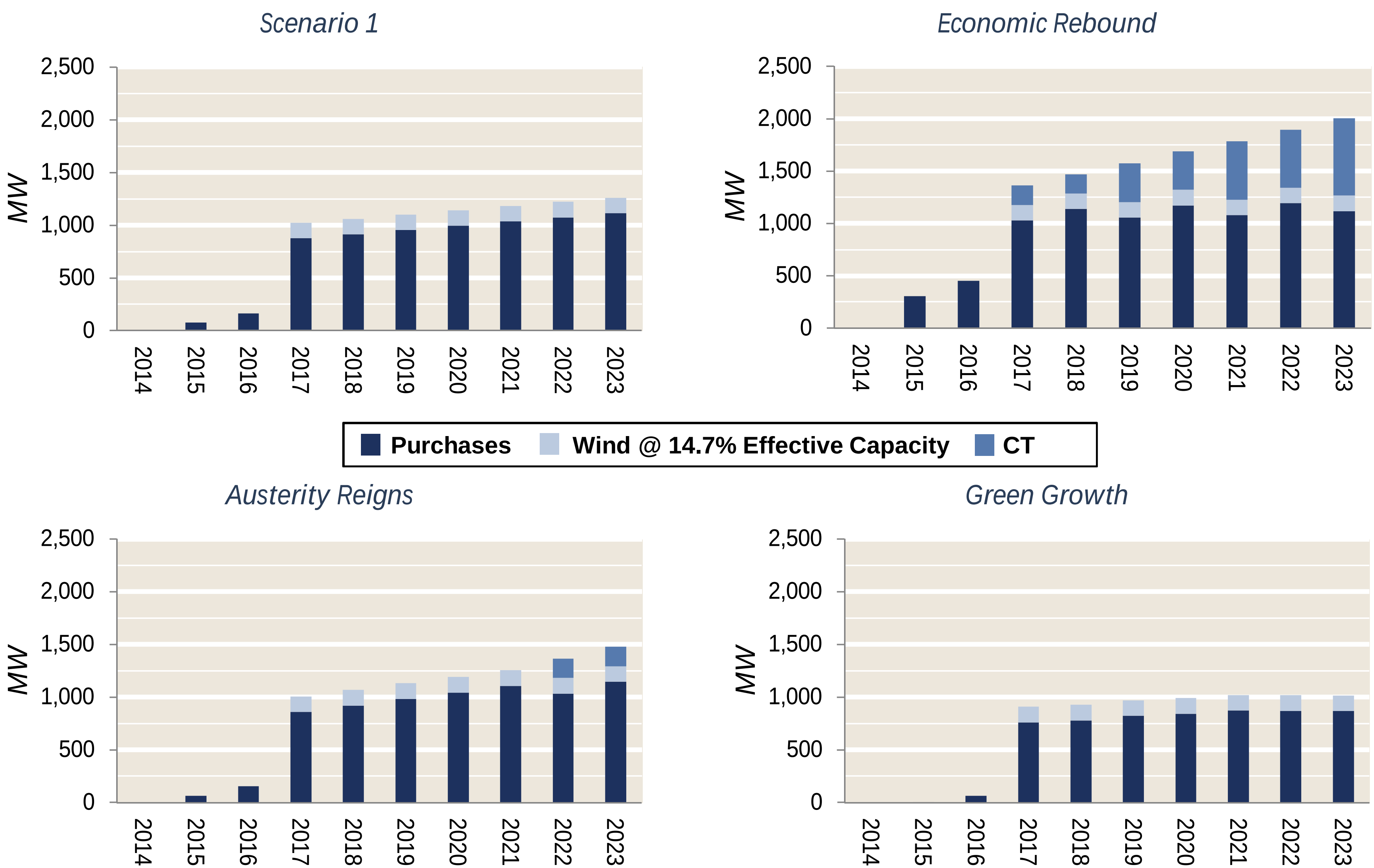


Purchases Lake Catherine 4 CT

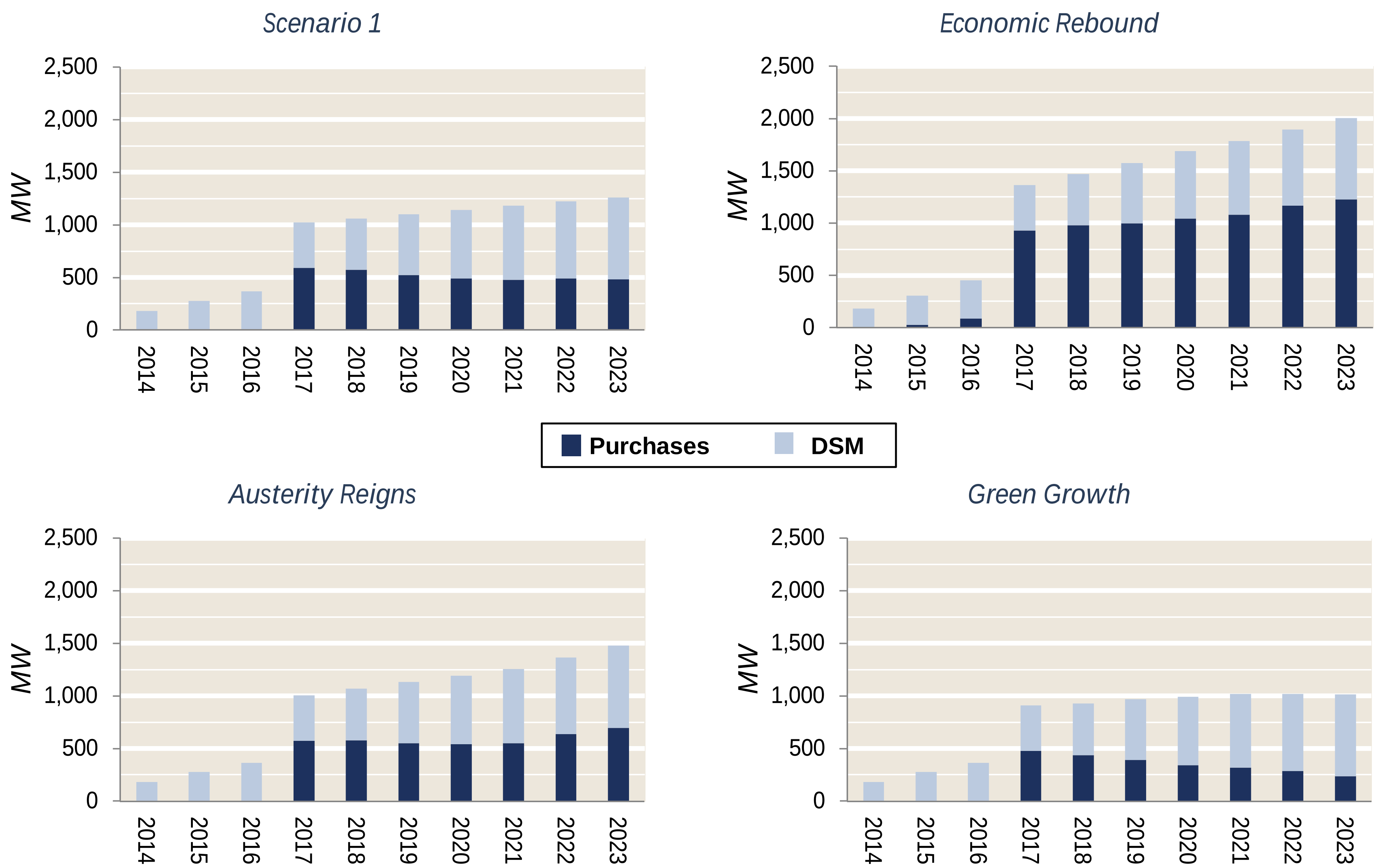




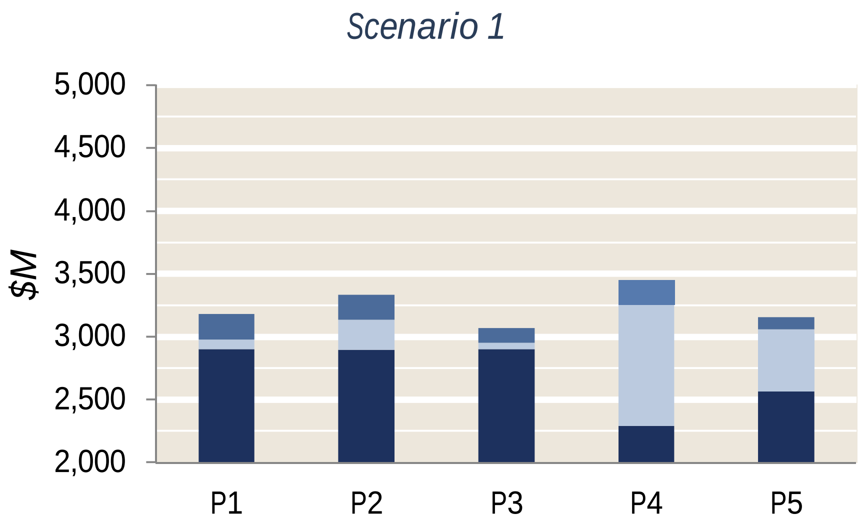
EAI Portfolio 4 – Resource Additions by Scenario

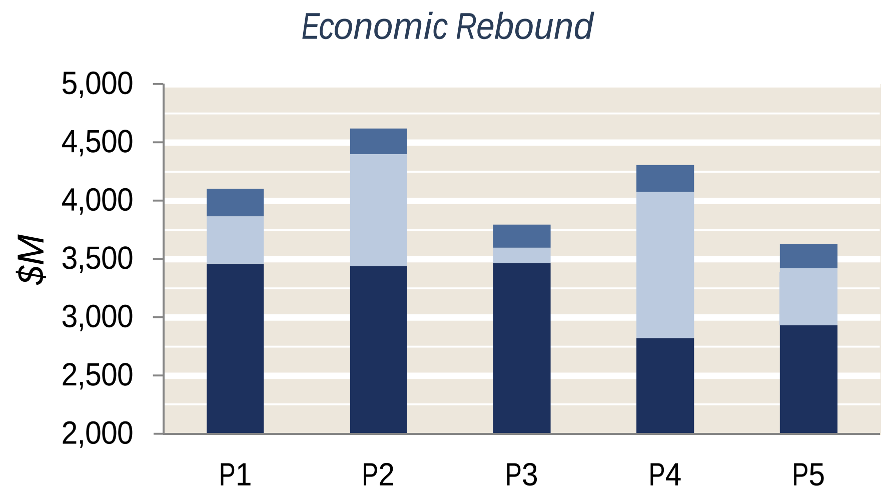


EAI Portfolio 5 – Resource Additions by Scenario

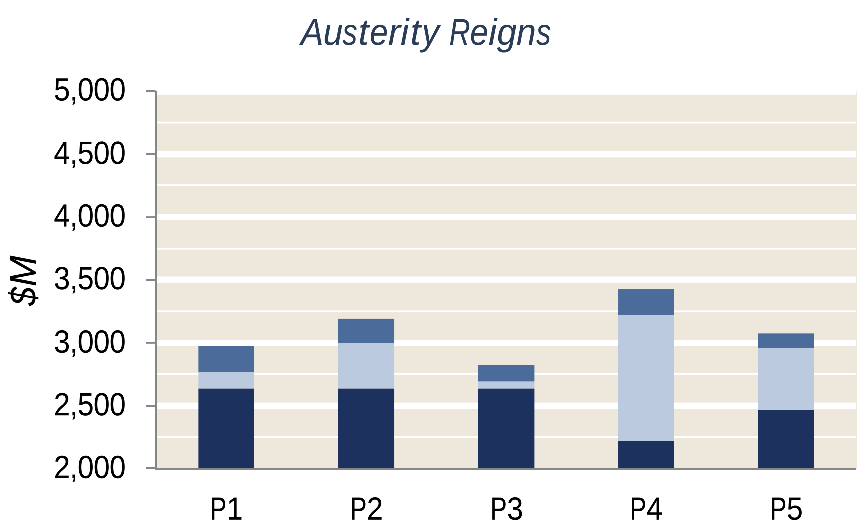


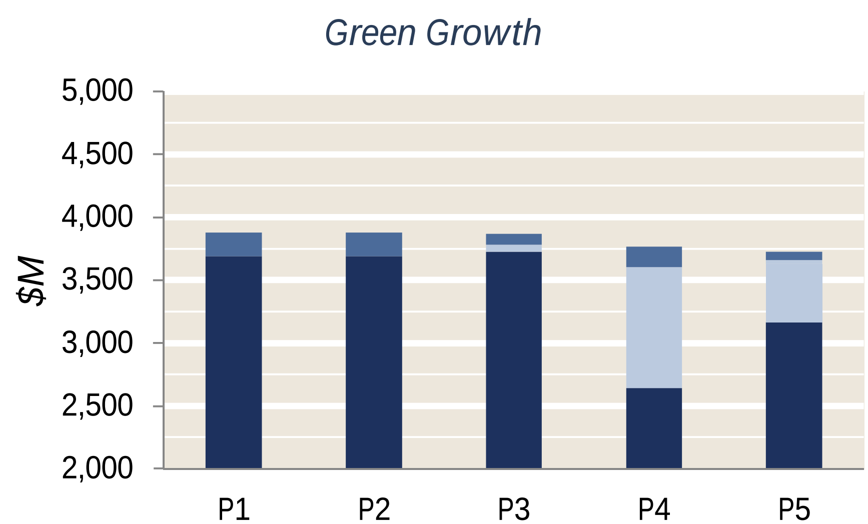
Total Supply Cost 2014 – 2023 (NPV 2012 $M)*





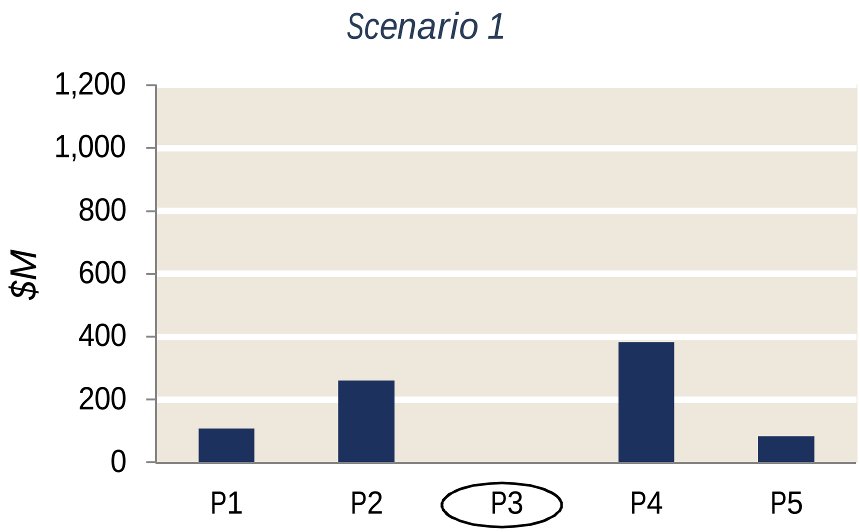
Variable Cost Fixed Cost Purchases

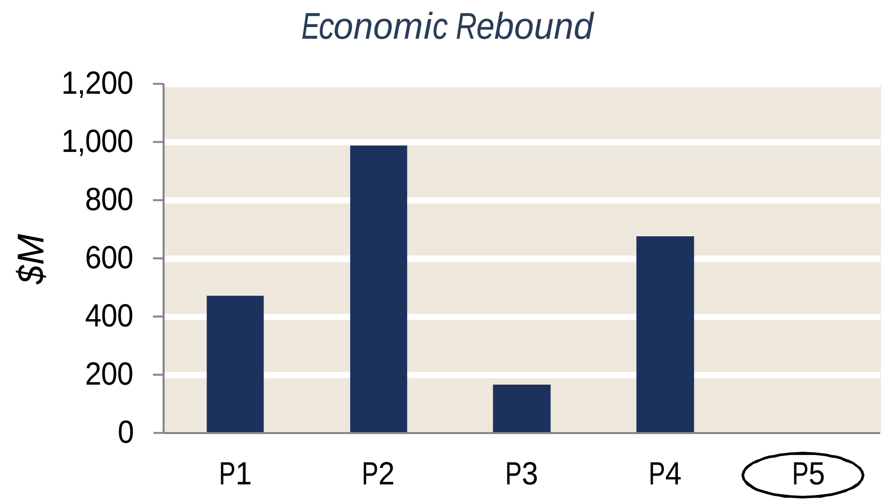




Variable cost refers to total EAI cost of service as modeled in Aurora, fixed cost is incremental resources only

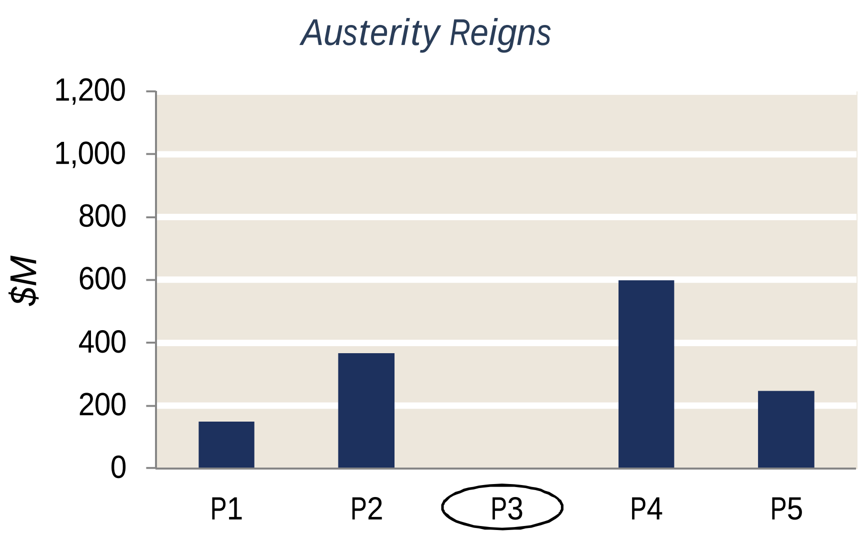
Relative Portfolio Ranking Total Supply Cost

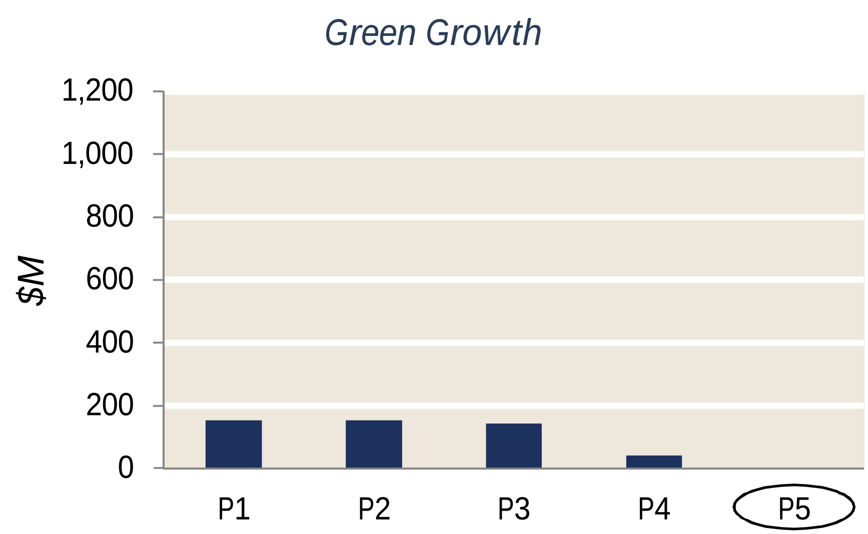




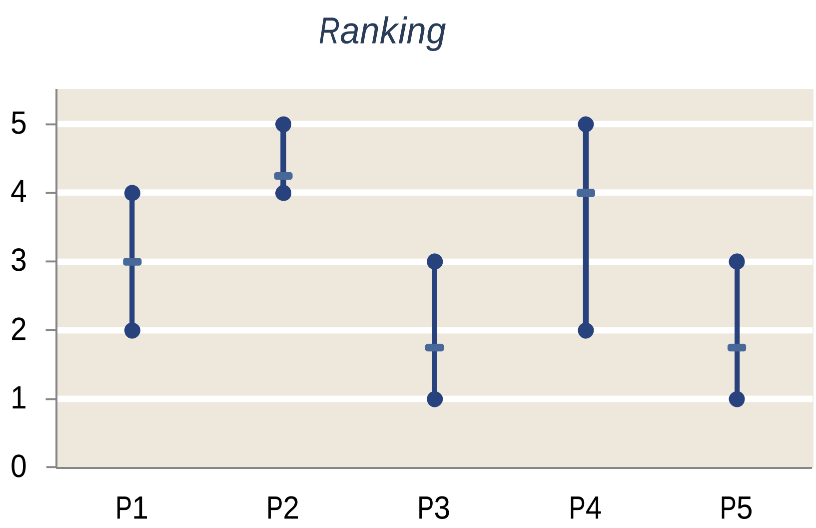
Low Cost Portfolio

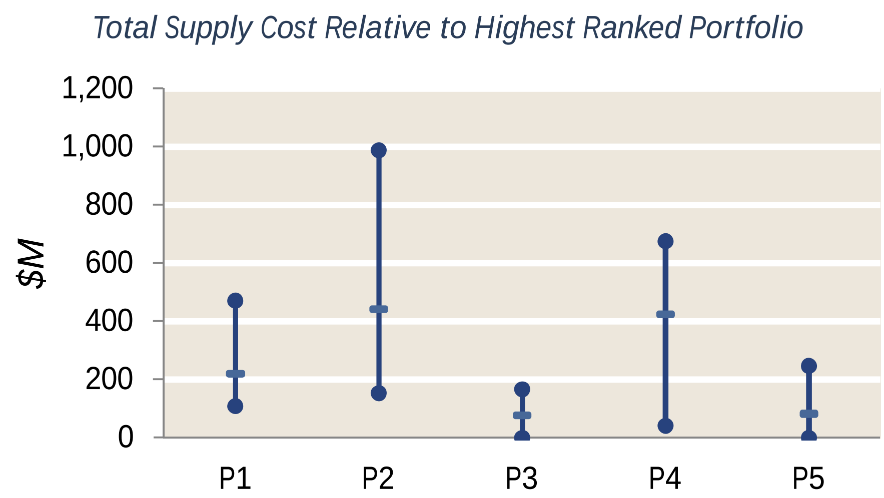
Total Supply Cost Relative to Highest Ranked Portfolio 2014 – 2023 (NPV 2012 $M)

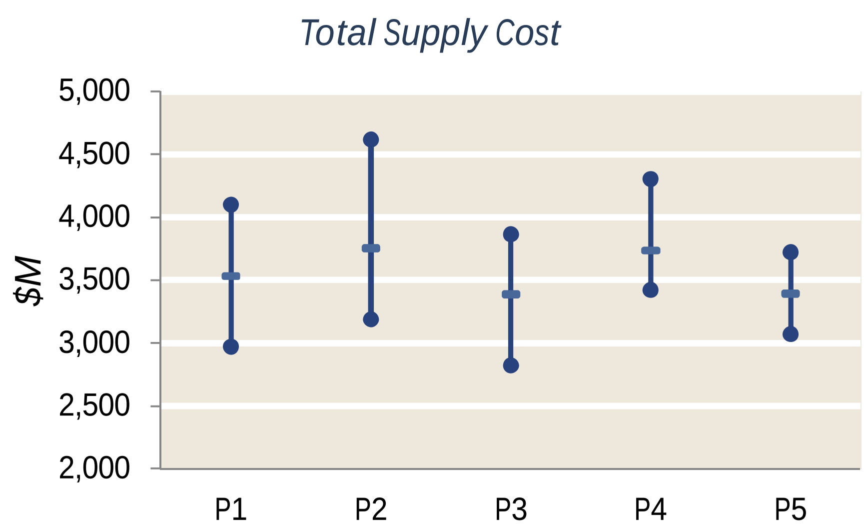




Portfolio Ranking







Preliminary 2012 EAI Integrated Resource Plan (IRP) Action Plan

EAI Stakeholder Meeting

July 31, 2012

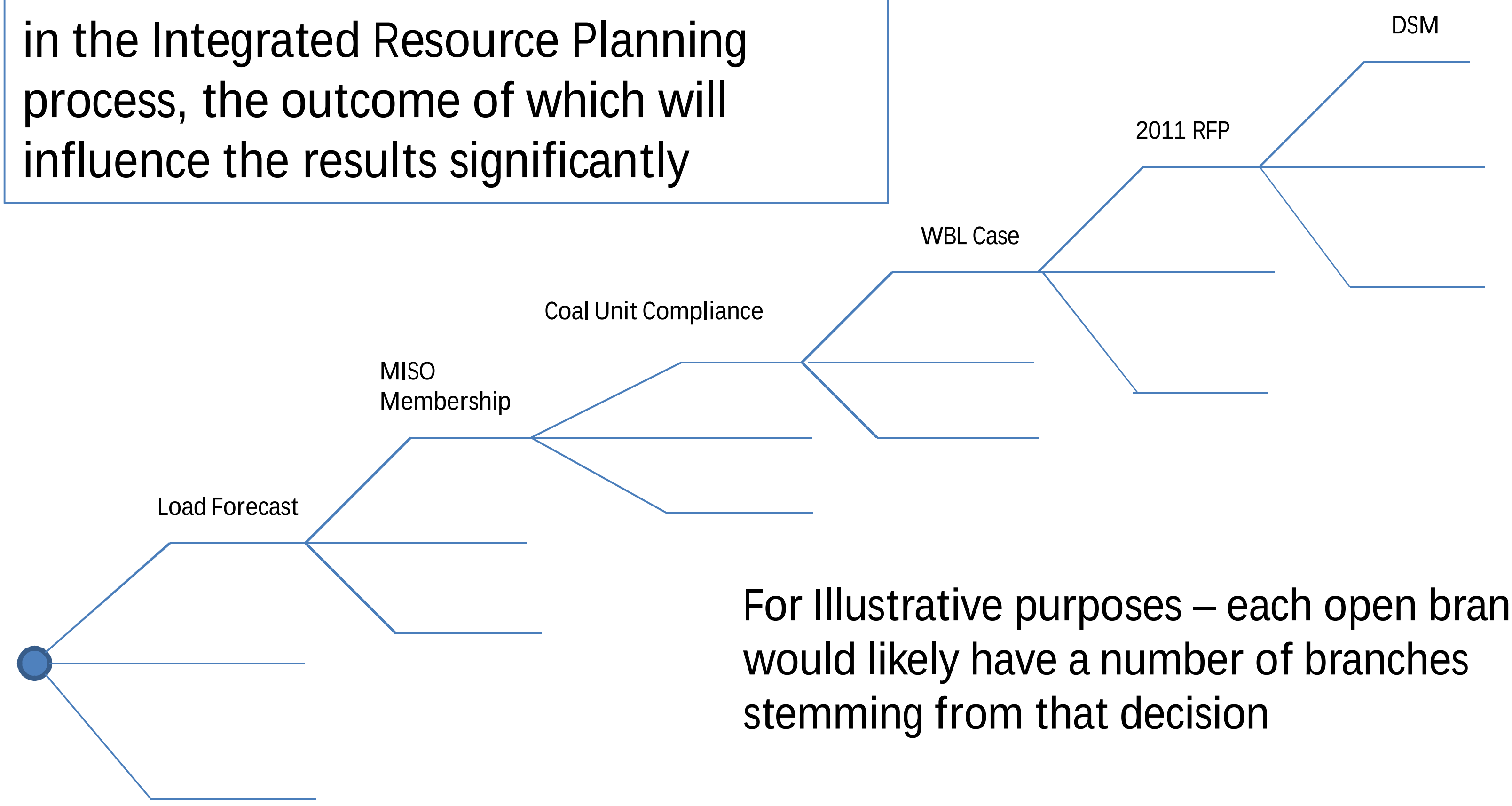
EAI IRP - Action Plan

- EAI has developed a preliminary action plan for stakeholder review.

- The action plan is subject to change prior to EAI filing the 2012 IRP.

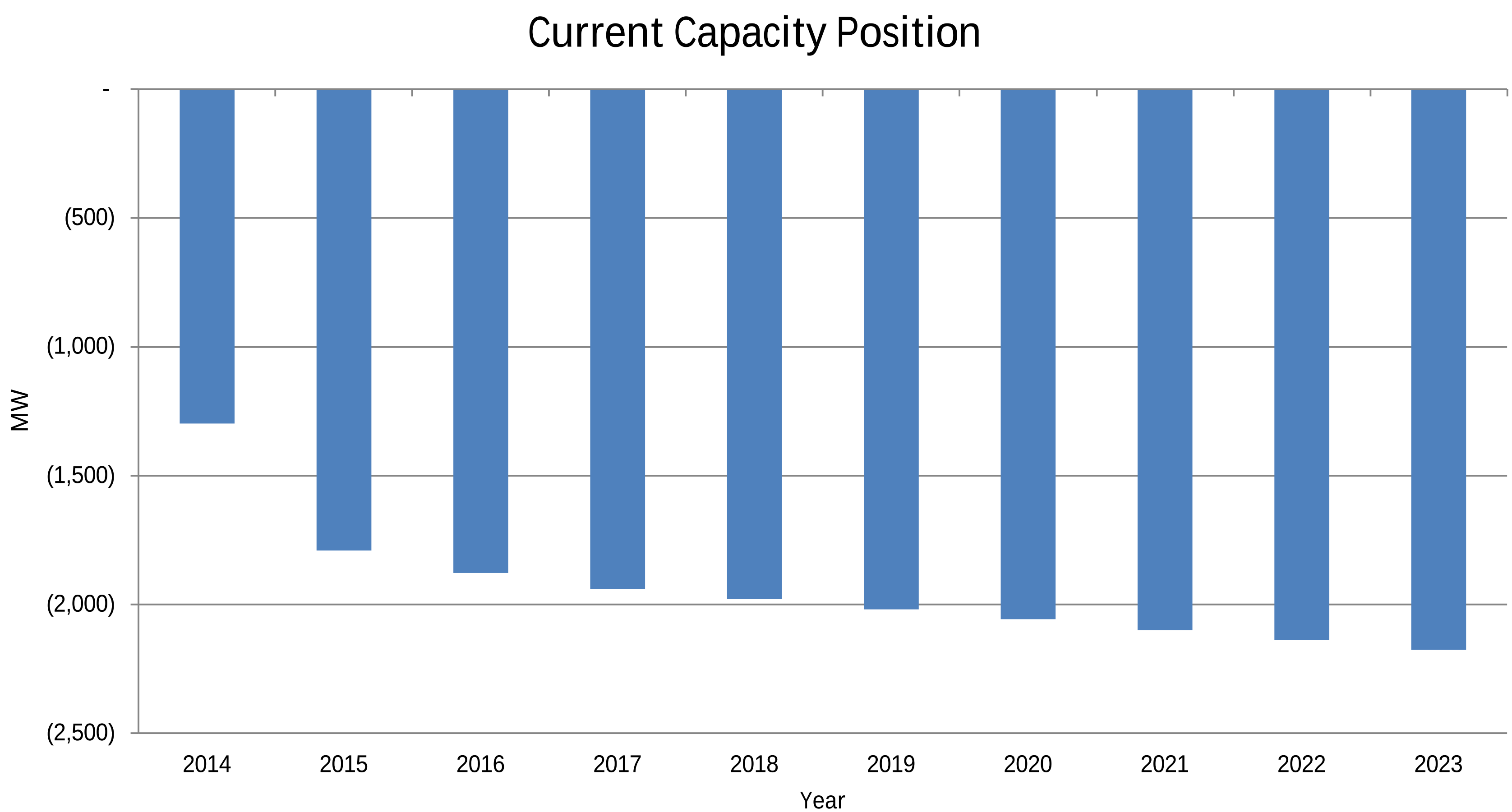
Action Plan – Managing Risk

The action plan recognizes that there are numerous uncertainties to be considered in the Integrated Resource Planning process, the outcome of which will influence the results significantly



For Illustrative purposes – each open branch would likely have a number of branches stemming from that decision

Current Capacity Position



IRP Action Plan - Overview

1. MISO Transition
2. Coal Unit Environmental Compliance
3. Hot Spring Power Plant Acquisition
4. 2011 RFP Transactions
5. Available Wholesale Base Load Capacity to Retail
6. Wholesale Peaking Capacity to Retail
7. DSM and Energy Efficiency Expansion
   (2012 In Progress, 2013 and beyond is planned)
8. Lake Catherine 4 reliability / sustainability
9. Legacy Unit Deactivation Decisions
10. Renewable Energy Assessment
11. Short-Term RFPs

In Progress

Planned

On-going

#1 - MISO Transition

A. Transition to the MISO Resource Adequacy Construct (RAC) as EAI integrates into MISO
   - Develop a fixed resource adequacy plan and participate in MISO LOLE study
   - Modify planning processes as needed for the MISO RAC
     - Coincident Peak Forecasting
     - UCAP verses ICAP

B. Participate in the MISO Transmission Expansion Process (MTEP)

#2 - Coal Unit Environmental Compliance

A. Monitor changes in environmental law at state and federal levels

B. Monitor the progression of the Flint Creek case at the APSC and permitting at ADEQ

C. Evaluate options for environmental compliance (e.g. MATS, Regional Haze, etc.)

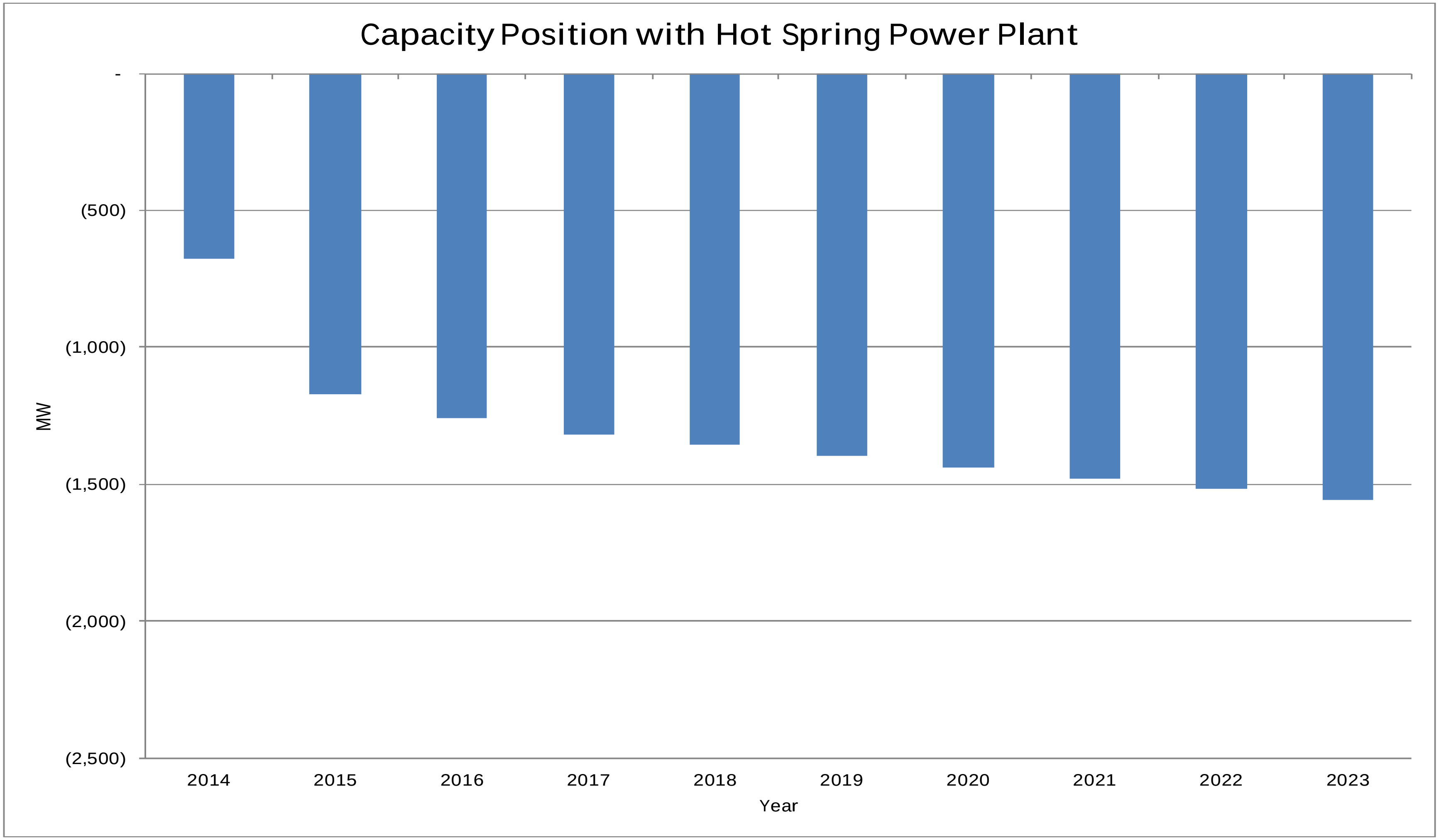
D. Work with co-owners to keep them advised of compliance planning progress

#3 - Hot Spring Power Plant Acquisition

A. Complete Hot Spring Power Plant acquisition pursuant to the July 11, 2012 APSC order in Docket No. 11-069-U

B. Adds approximately 620 MW of CCGT capacity to the EAI fleet

Hot Spring Power Plant Acquisition



#4 - 2011 RFP Transactions

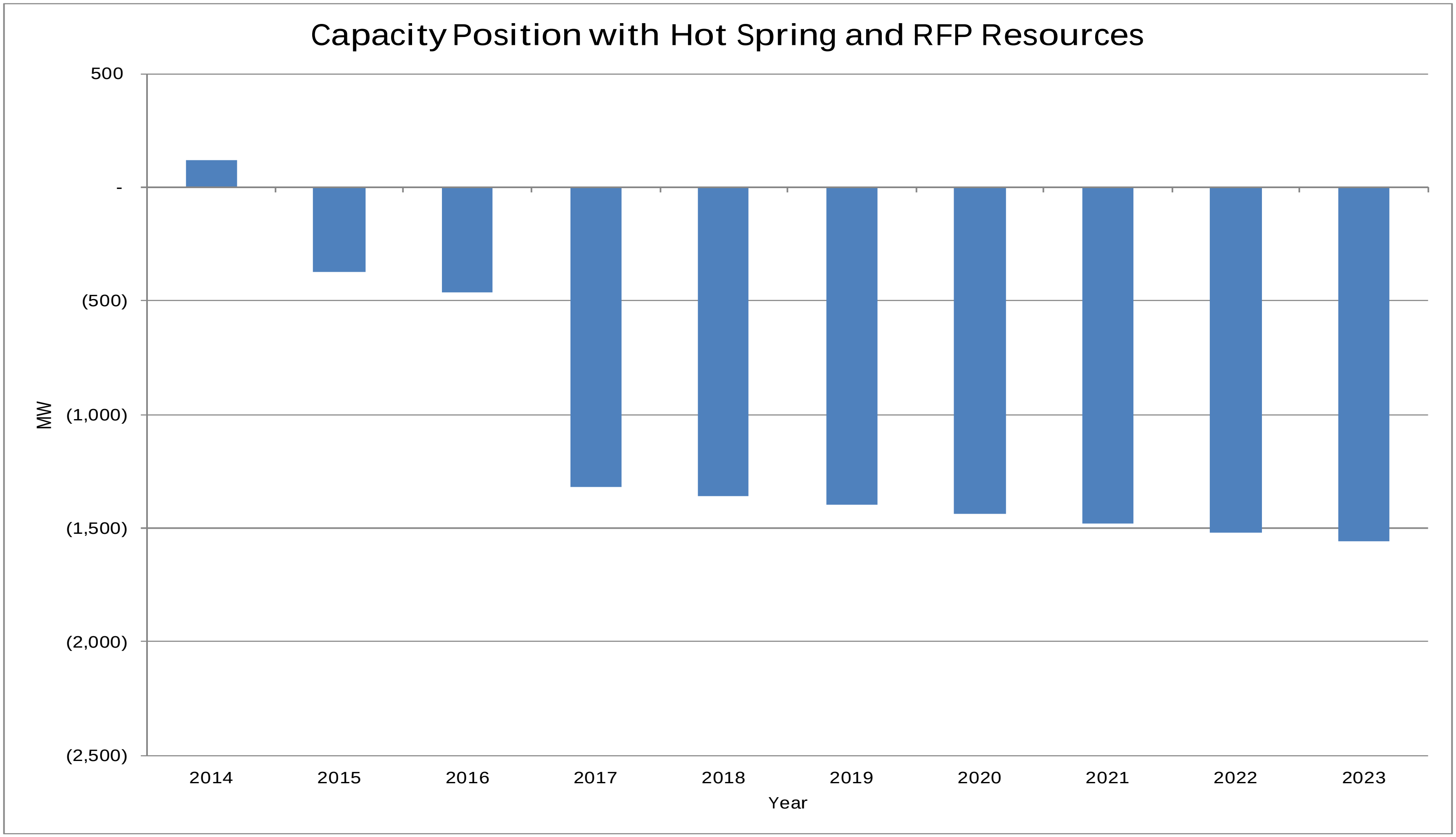
A. Complete negotiations on resources from the 2011 RFP

B. Continue to pursue approval of a capacity cost recovery rider in Docket No. 12-038-U

C. Secure transmission service for both transactions no later than June 30, 2013

D. Adds approximately 795 MW from December 2013 through May 2017

Hot Spring and RFP Resources Added



#5 – Available Wholesale Base Load (WBL) Capacity to Retail

A. Continue to pursue APSC approval to return the WBL capacity to retail rate base in Docket No. 12-038-U

B. Provides approximately 286 MW of additional resources:
   - 184 MW Nuclear Capacity
   - 102 MW Coal Capacity

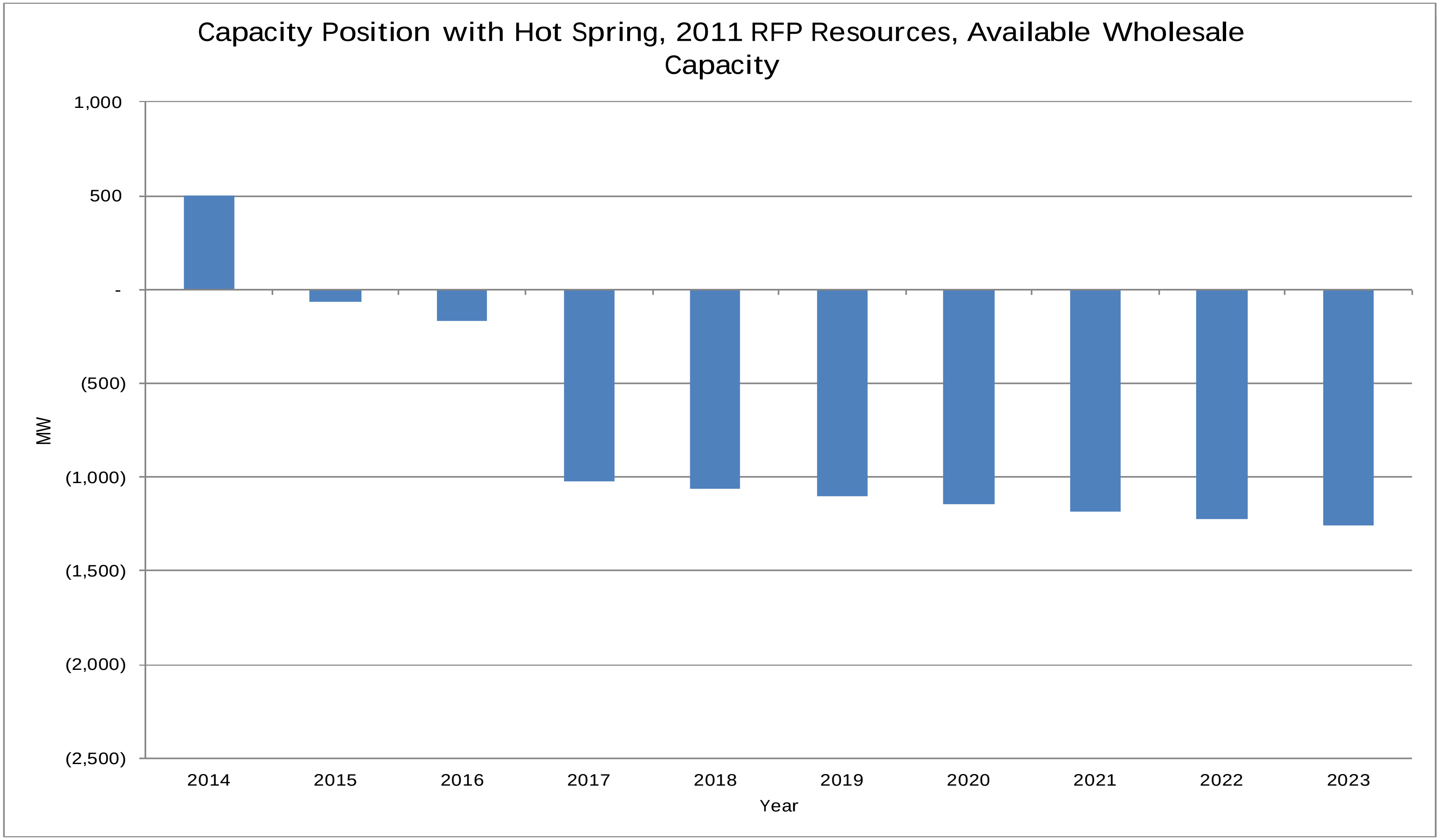
#6 - Wholesale Peaking Capacity to Retail

A. Pursue APSC approval to return the Wholesale peaking capacity to retail rate base in the 2013 general rate case

B. Results in the following capacity additions:

2014:	95 MW
2015:	21 MW
2016:	13 MW
2017 – Forward	10 MW

With Hot Spring, 2011 RFP Resources and Available Wholesale Capacity



#7 - Demand Side Management and Energy Efficiency Expansion (2012 In Progress / 2013 and Beyond Planned)

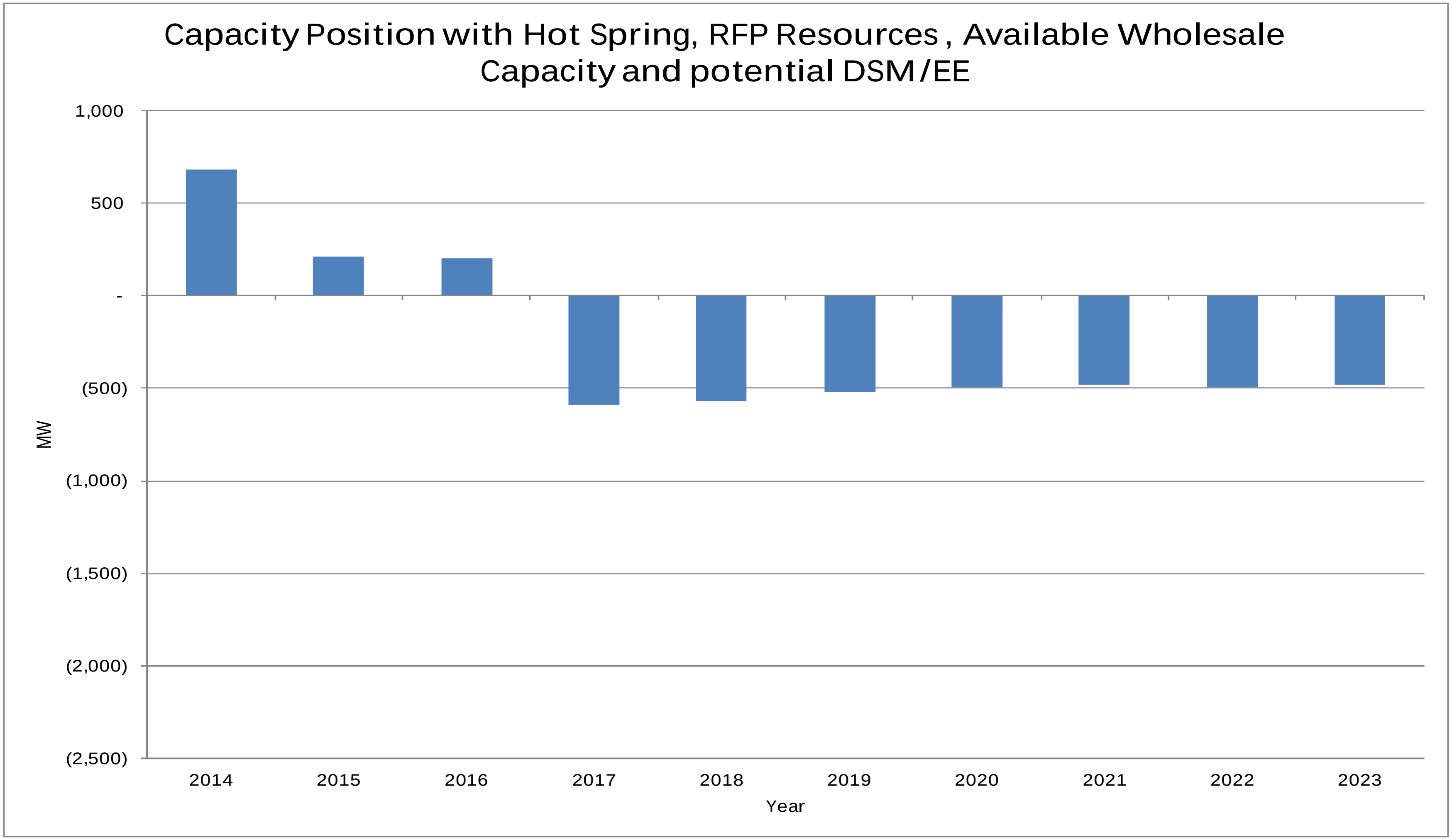
A. Continue with suite of comprehensive programs, including ongoing independent Evaluation, Measurement and Verification, capturing any lessons learned to improve next phase of implementation

B. Continue to move forward with the development and implementation of enabling technologies (AMI / Smart Grid) at a measured pace to ensure technology can deliver results

C. Monitor results and adjust load forecast and resource plans as warranted

D. Continue to research options for DSM in the MISO market

Demand Side Management and Energy Efficiency Added

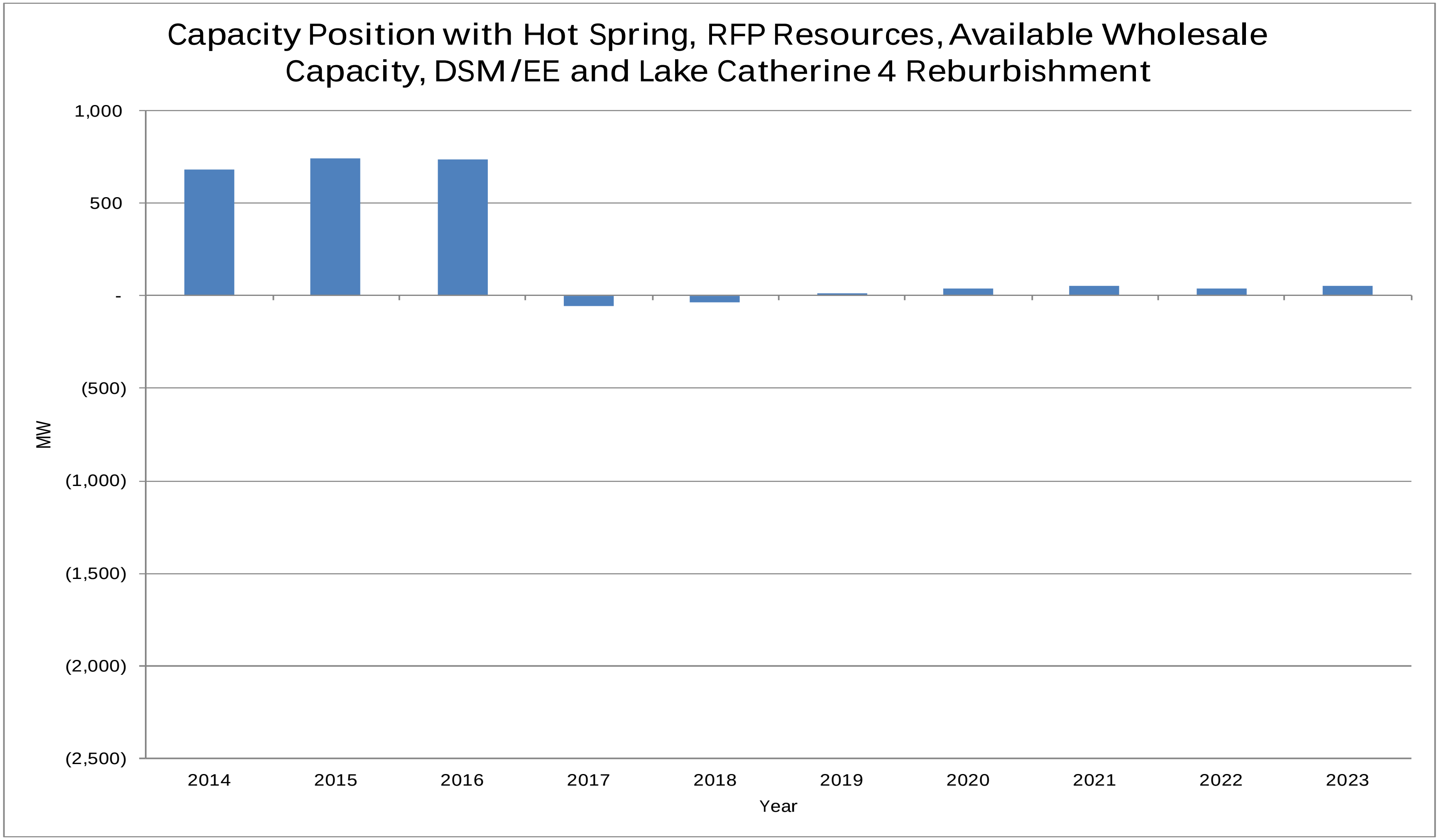


#8 – Lake Catherine 4 Reliability / Sustainability Program

A. Update project cost estimates in 2012

B. Develop a detailed project schedule and budget to complete reliability / sustainability program

Lake Catherine Unit 4 Refurbishment



#9 – Legacy Deactivation Decisions

A. The current long-term planning assumption is that approximately 422 MW (363 MW retail) of legacy generation will be deactivated by the beginning of 2014

B. A follow-up review of this generation will be conducted over the remainder of 2012 and 2013 to determine tactical plans for this capacity

C. Actual decisions to deactivate generation will be made on a unit-by-unit basis based upon the needs of customers and the economics of the units relative to available options at the time of the decision

#10 - Renewable Energy Assessment

A. Continue to monitor:
   - technology developments in renewable energy
   - public policy developments

B. Consider economically attractive renewable generation, taking into account evolving mandates and an on-going assessment of cost and availability

#11 – Short-Term RFPs

A. Continuously monitor progress on IRP Action Plans

B. Issue short-term (1 year) RFPs for additional capacity if needed to maintain reserve margins

Questions / Comments

BREAK

Stakeholder Session