# INDIANA INTEGRATED RESOURCE PLANNING REPORT

to the:

Indiana Utility Regulatory Commission

Appendix – Volume 4

Submitted Pursuant to:

Commission Rule 170 IAC 4-7

March 28, 2025

# Appendix Volume 4

<u>Public Advisory Process</u>

Exhibit A: Workshop #1 June 27, 2024

- Meeting Presentation
- Meeting Minutes

Exhibit B: Workshop #2 September 24, 2024

- Meeting Presentation
- Meeting Minutes

Exhibit C: Workshop #3a December 18, 2024

- Meeting Presentation
- Meeting Minutes

Exhibit D: Workshop 3b January 27, 2025

- Meeting Presentation
- Meeting Minutes

Exhibit E: Workshop #4 March 5, 2025

- Meeting Presentation
- Meeting Minutes

Exhibit F: Public Advisory Comments

Appendix 4, Exhibit A: Workshop #1 June 27, 2024

Meeting Presentation

Meeting Minutes

Indiana Michigan Power Company

# 2024 INDIANA IRP STAKEHOLDER MEETING 1

June 27, 2024

# Welcome & Introductions

## I&M Leadership Team

David Lucas | Vice President, Regulatory and Finance

Andrew Williamson | Director, Regulatory Services

Stacie Gruca | Manager, Regulatory Services

Austin DeNeff | Regulatory Consultant Senior

Tammara Avant | Senior Counsel

## 1898 Leadership Team

Brian Despard | Senior Project Manager

## I&M IRP Planning Team

Kelly Pearce | Managing Director, Resource Planning & Strategy

Mark Becker | Managing Director, Resource Planning & Grid Solutions

Mohamed Abukaram | Manager, Resource Planning

Greg Soller | Manager, Resource Planning

Dylan Drugan | Manager, Resource Planning

Mark O'Brien | Director, Generation & Market Simulation

Joshua Burkholder | Managing Director, RTO Strategy & Policy

David Canter | Manager, RTO Regulatory PJM

# Agenda

| Time (EST) | Agenda Topic | Presenter |
|---|---|---|
| *1:00 – 1:25 PM* | Welcome & Introductions<br>• Stakeholder Meeting Objectives<br>• Introduction of 1898 & Co.<br>• Company Overview & Updates | Brian Despard (1898 & Co.)<br>Andrew Williamson |
| *1:25 – 1:40 PM* | IRP Process & Stakeholder Engagement<br>IRP Requirements | Greg Soller |
| *1:40 – 1:50 PM* | 2024 IRP Highlights<br>• Indiana specific IRP<br>• Cook and Hydro Relicensing | Andrew Williamson |
| *1:50 – 2:00 PM* | Q&A | |
| *2:00 – 2:30 PM* | IURC Pillars and 2024 IRP Objectives & Metrics<br>• Reliability, Affordability, Stability, Resiliency, Sustainability<br>PJM Update<br>Capacity and Energy Needs Review (Going-In Position) | Greg Soller<br><br>Joshua Burkholder/David Canter<br>Greg Soller |
| *2:30 – 2:45 PM* | Q&A and Break | |
| *2:45 – 3:30 PM* | Fundamentals and Scenario Analysis<br>Technology Alternatives and Strategies<br>IRP Proposed Cases and Sensitivities | Mark O'Brien<br>Greg Soller |
| *3:30 – 3:40 PM* | Q&A | |
| *3:40 – 4:15 PM* | Proposed Portfolio Performance Metrics | Greg Soller |
| *4:15 – 4:30 PM* | Final Questions, Discussion, Action Items, and Adjourn | Brian Despard (1898 & Co.) |

# Participation

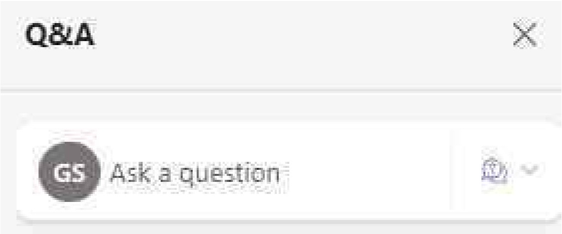
Participants joining today's meeting will be in a "listen-only" mode. Please use the "Raise" function to be recognized and unmuted.

During the presentation, please enter questions at any time into the Teams Q&A feature. Questions will be addressed after each section. At the end of the presentation, we will open up the floor for additional questions, thoughts,  ideas, and suggestions.

All questions and answers will be logged and provided on the IRP website.  Any questions not answered during the meeting will be answered after the meeting and provided in the Q&A log posted to the IRP website.

Questions, thoughts, ideas, and suggestion related to Stakeholder Meeting 1 can be provided to I&MIRP@aep.com following this meeting.


Click the Q&A feature at the top of the Teams screen



# Guidelines

- Please focus questions, thoughts, ideas, and suggestions to the IRP process and the content being discussed in this meeting. Time will be taken during this meeting to respond to questions.
- Please respect other participants and their views by not addressing other participants directly and not commenting on the views expressed by others.
- This meeting will not be recorded or transcribed.
- Any further questions or comments can be provided to I&MIRP@aep.com.

# Stakeholder Meeting Objectives

Objectives for meeting include:

- ❑ **Transparency:** Share 2024 IRP Objectives and Assumptions at the beginning of our process
- ❑ **Gather Feedback:** Provide a forum for productive stakeholder feedback

I&M welcomes stakeholder comments and input on any aspect of the IRP process, including:

- ❑ Requirements & Objectives
- ❑ Key IRP Topics
- ❑ PJM and Market Conditions
- ❑ Capacity Needs
- ❑ Fundamentals Pricing Assumptions
- ❑ IRP Cases/Sensitivities
- ❑ Proposed Portfolio Performance Metrics

# About Indiana Michigan Power Company (I&M)

- Indiana Michigan Power Company (I&M) headquartered in Fort Wayne, IN
- More than 614,000 retail customers in Indiana and Michigan.
  - ~482,000 customers - IN
  - ~133,000 customers - MI
- I&M also serves wholesale customers which represents 12.6% of its load
- I&M participates in the PJM Regional Transmission Organization which establishes system reliability criteria


*I&M is a unit of American Electric Power (NYSE: AEP), which is one of the largest electric utilities in the United States, delivering electricity to more than 5 million customers in 11 states.*

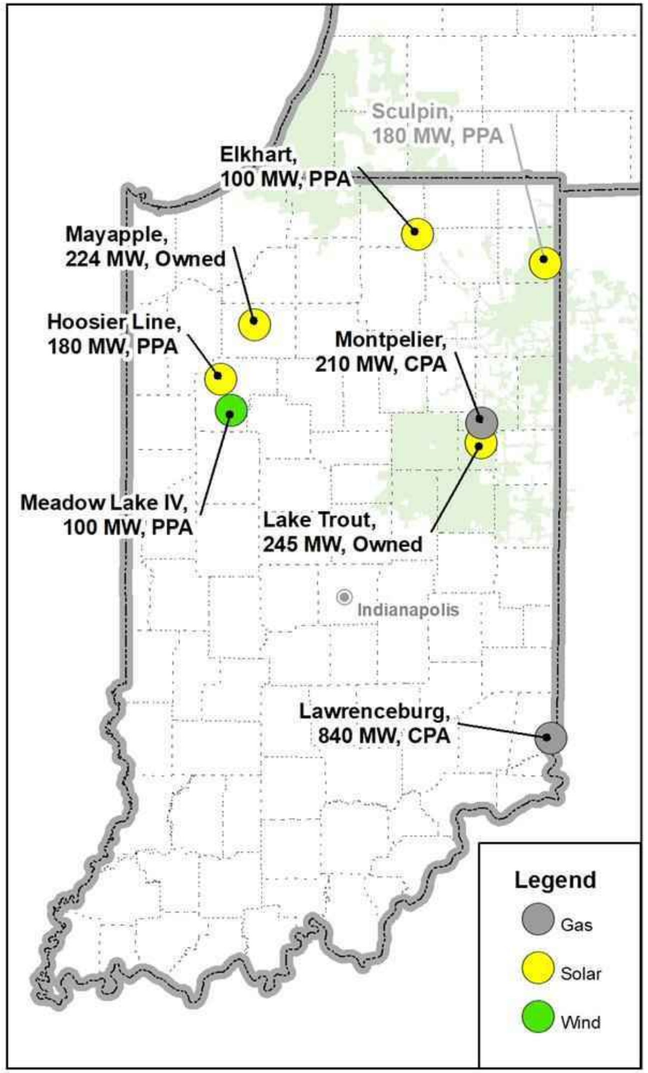
# New Generation Resource Overview

| Facility Name | Agreement Type | COD/Term Start | Nameplate (MW) |
|---|---|---|---|
| **Solar** | | | |
| Lake Trout | PSA | 2027 | 245 |
| Mayapple | PSA | 2027 | 224 |
| Hoosier Line | PPA | 2027 | 180 |
| Elkhart County | PPA | 2026 | 100 |
| ~~Sculpin~~ | ~~PPA~~ | ~~2025~~ | ~~180~~ |
| Total Solar | | | 749 |

| | | | |
|---|---|---|---|
| **Wind** | | | |
| Meadow Lake IV | PPA | 2025* | 100 |

| | | | |
|---|---|---|---|
| **Natural Gas** | | | |
| Montpelier | Capacity-Only Purchase (7 yr) | 2027 | 210 |
| Lawrenceburg | Capacity-Only Purchase (6 yr) | 2028 | 840 |
| Total Natural Gas | | | 1,050 |

* Repower of existing facility



# 2024 IRP Highlights

- Relicense Evaluation for Cook Nuclear Plant and Certain Hydroelectric Assets
- Transition to State-Specific Planning Model
- Major Load Growth Underway
- Dynamic Market Conditions Impacting New Generation Resources

# 2024 IRP Process

## Overview of 2024 IRP Process

Set Objectives & Performance Criteria

Provide Load and RFP based Supply-side assumptions

Provide Demand-side Assumptions

Develop Supply-side Assumptions

Model Market Scenarios

Develop Optimal Resource Portfolios

Populate Scorecard

Evaluate Optimal Resource Portfolios

Identify Preferred Portfolio for 2024 IRP

Develop Short-term Action Plan

IRP Stakeholders

Provide Feedback on IRP Inputs & Planning

## 2024 IRP Analysis Steps

1. Define IRP Objectives Aligned to Customer Needs
2. Forecast Multiple Market Scenarios of Fundamental PJM Energy, Capacity, and Commodity Prices
3. Optimize I&M Resource Portfolios under multiple market scenarios, load, and technology cost cases and sensitivities
4. Perform Scenario-Based Risk Analysis on I&M Resource Plans
5. Compare Results & Identify the Preferred Portfolio

# 2024 I&M Indiana IRP Stakeholder Engagement Timeline

June | July | Aug | Sept | Oct | Nov | Dec | Jan | Feb | Mar

**I&M IRP Planning Technical Conference***

Technical Conference(s) held with key stakeholders with IRP Plexos licenses for modeling application.

**Stakeholder Meeting 1**

IRP Objectives
Assumptions
Estimated Resource Needs
Scenarios
Proposed Portfolio Metrics

**Stakeholder Meeting 2**

Discuss IRP assumptions and modeling inputs

**Stakeholder Meeting 3**

Discuss IRP Draft Modeling Results, Portfolio Metrics

**Stakeholder Meeting 4**

Review IRP
Preferred Portfolio
Risk Analysis

**I&M submits 2024 Indiana IRP**

May

***Draft timeline is provided for preliminary planning purposes.***

***All dates and activities are subject to change by I&M as new information becomes available.***

***Additional technical information will be shared and technical conferences held as appropriate.***

****The Company's Market Potential Study (MPS) is complete and IRP Technical Sessions have been held on EE Bundling.***

# IRP Requirements

- Indiana regulations require the Company to submit Integrated Resource Plans (IRPs) every three years according to Indiana Code § 8-1-8.5-3(e)(2).
- The IRPs are subject to a rigorous stakeholder process.
- IRPs describe how the utility plans to deliver safe, reliable, and efficient electricity at just and reasonable rates.
- Further, these plans must be in the public interest and consistent with state energy and environmental policies.
- Each utility's IRP explains how it will use existing and future resources to meet customer demand.
- When selecting these resources, the utility must consider a broad range of potential future conditions and variables and select a combination that would provide reliable service in an efficient and cost-effective manner.
- The IRP will also address how the Company's Preferred Plan will align to the recently enacted HEA 1007, codified at Ind. Code § 8-1-2-0.6, that set forth five attributes (also referred to as "pillars").
- The five pillars are **reliability, affordability, resiliency, stability and environmental sustainability**.

# 2021 IRP Action Plan

1. Continue the planning and regulatory actions necessary to implement additional economic DSM programs in Indiana and Michigan.
2. Obtain the short-term capacity needed for the 2024/2025 and subsequent PJM Planning Years.
3. Issue All-Source RFPs in 2022 and 2023 to target the generation resources identified in I&M's Preferred Portfolio that are necessary to meet the capacity and energy needs of I&M's customers as Rockport is retired by the end of 2028.
4. Initiate efforts to evaluate Cook relicensing costs
5. Be in a position to adjust this action plan and future IRPs to reflect changing circumstances.

# I&M Commitments Related to the 2024 IRP

- Rockport Unit 2 Declination of Jurisdiction Settlement in CN 45546:
  - Model Rockport Unit 1 retirement in 2025
  - Model Rockport Unit 1 retirement in 2026
  - Model exiting the OVEC ICPA in 2030
  - Adjust the load forecast methodology to be consistent with the use of a Net-To-Gross methodology associated with Energy Efficiency.
- 2024 Test Year Base Case Settlement in CN 45933:
  - IRP Modeling Licenses: Provide up to three executable modeling licenses for IURC, OUCC and CAC.
  - Schedule of data releases
  - Energy Efficiency: work with CAC and interested stakeholders to construct IRP bundles.
  - Storage Resources: model longer duration (8-10 hour lithium ion) and potentially multiday storage in the 2024 IRP (and solicit input on cost and performance in SH process prior to modeling)

# Cook Nuclear Plant Overview

- 2,200+ MWs of carbon-free generation, producing on average 16 - 18 million MWhs of generation annually
- Highest capacity, reliability and availability of all generation sources
- Highest Institute of Nuclear Power Operations (INPO) rating
- Provides lowest cost fuel resource within AEP's regulated fleet and has supported fuel cost stability during periods of volatility
- Provides sustainable generation to customers
- I&M invested more than $1 billion between 2012 and 2022 completing the Life Cycle Management project which has uniquely positioned Cook to operate beyond its current license dates

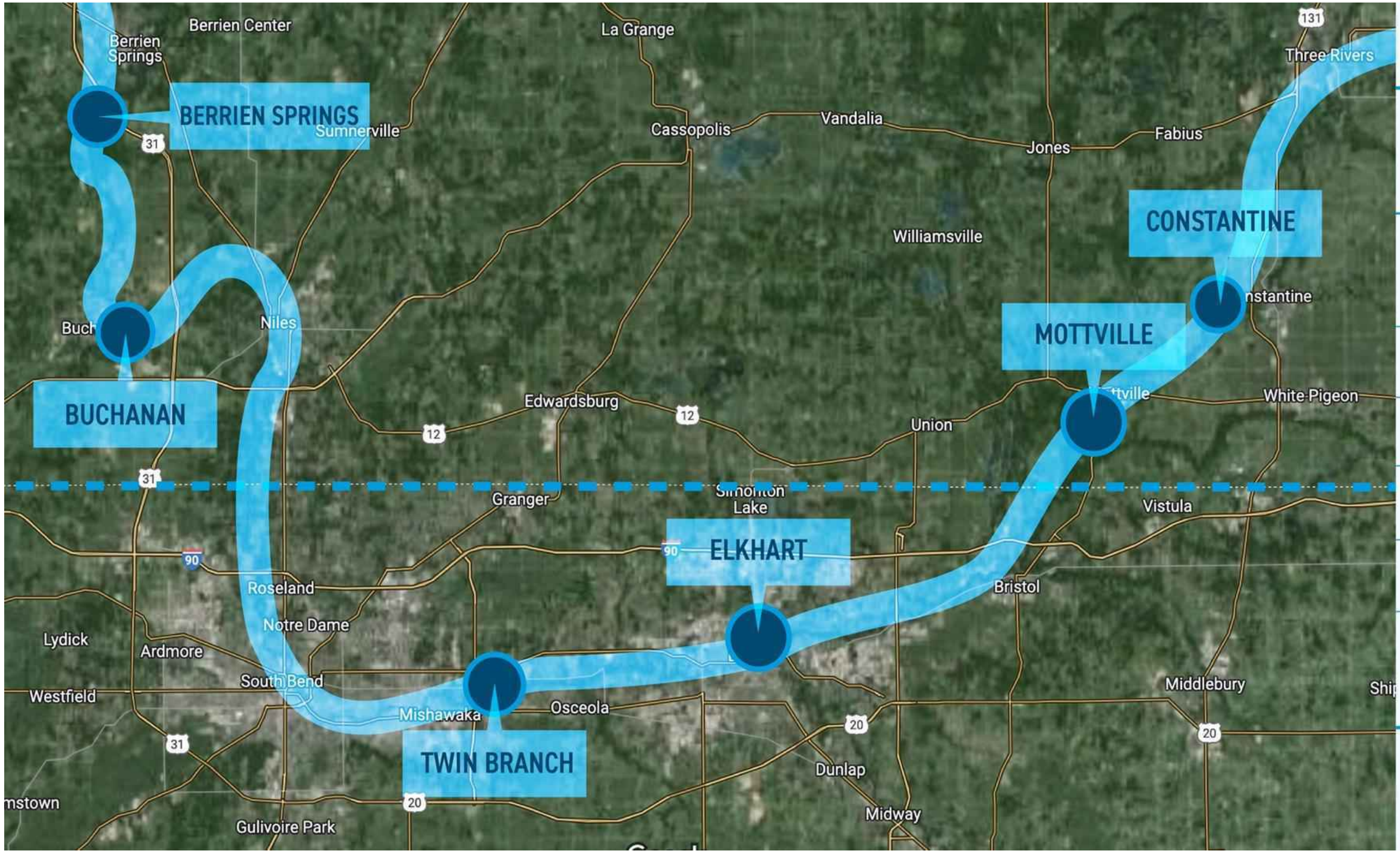
# Cook Analysis Considerations

- Cook Relicensing
  - U1 Current License Expiration Q4 2034
  - U2 Current License Expiration Q4 2037
  - Evaluate economics of Subsequent License Renewal (SLR)

## Costs Considered in Cook Relicensing Analysis

- Subsequent Renewal Operating License
- One-Time Inspection Costs
- Dry Cask Fuel Storage Pad Extension
- Capital Improvement Costs
- On-Going Capital Costs
- Fixed Operations & Maintenance (FO&M) Costs

# I&M Hydroelectric Generation Overview



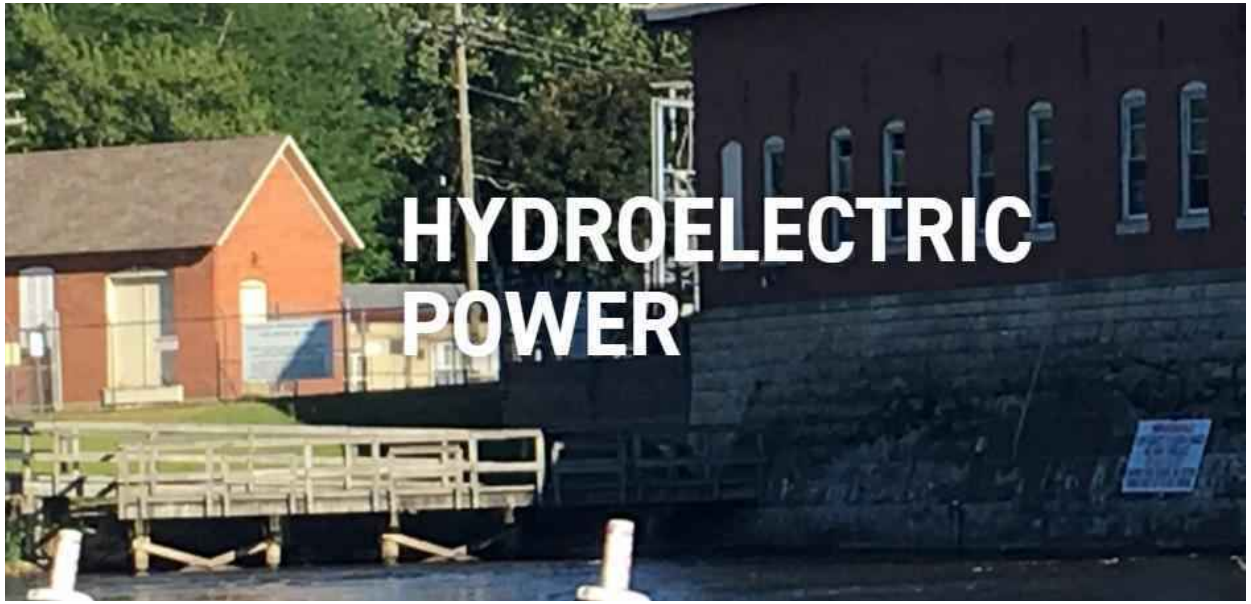

| Hydro Facility | Year Installed | License Expiration | Lifespan (years) |
|---|---|---|---|
| Berrien Springs | 1908 | 2036 | 128 |
| Buchanan | 1919 | 2036 | 117 |
| Constantine | 1921 | 2053* | 132 |
| Elkhart | 1913 | 2033 | 117 |
| Mottville | 1923 | 2033 | 110 |
| Twin Branch | 1904 | 2036 | 132 |

* Anticipated 30 year extension of current license by FERC

# Hydro Analysis Considerations

- Hydro Relicensing
  - Affects Elkhart & Mottville units with license expirations within next 10 years.
  - I&M engaged WSP as an independent consultant to assist with evaluating I&M's hydroelectric assets
  - Evaluation of license renewal includes:
    - Updated decommissioning study
    - Socio-economic analysis
    - Public engagement process
    - Independent evaluation of long-term operating costs

- Costs Considered in Hydro (Elkhart and Mottville) Relicensing Analysis
  - On-Going Capital Costs
  - FO&M Costs
  - Decommissioning Costs




Q&A
INDIANA MICHIGAN POWER
An AEP Company

# IURC Pillars and 2024 IRP Objectives

| IURC Pillar | IRP Objective | IURC Pillar Definition |
|---|---|---|
| Reliability* | Maintain capacity reserve margin and the consideration of reliance on the market for the benefit of customers. | (A) the adequacy of electric utility service, including the ability of the electric system to supply the aggregate electrical demand and energy requirements of end use customers at all times, taking into account:<br>(i) scheduled; and<br>(ii) reasonably expected unscheduled; outages of system elements; and<br>(B) the operating reliability of the electric system, including the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components. |
| Affordability | Maintain focus on cost and risks to customers | Including ratemaking constructs that result in retail electric utility service that is affordable and competitive across residential, commercial, and industrial customer classes. |
| Resiliency* | Maintain diversity of resources and fleet dispatchability | Including the ability of the electric system or its components to:<br>(A) adapt to changing conditions; and<br>(B) withstand and rapidly recover from disruptions or off-nominal events. |
| (Grid) Stability* | Maintain a fleet of flexible and dispatchable resources | Including the ability of the electric system to:<br>(A) maintain a state of equilibrium during:<br>(i) normal and abnormal conditions; or<br>(ii) disturbances; and<br>(B) deliver a stable source of electricity, in which frequency and voltage are maintained within defined parameters, consistent with industry standards. |
| Environmental Sustainability | Maintain focus on portfolio environmental sustainability benefits and compliance costs | Including:<br>(A) the impact of environmental regulations on the cost of providing electric utility service; and<br>(B) demand from consumers for environmentally sustainable sources of electric generation. |

* I&M operates in the PJM Regional Transmission Organization (RTO) which also supports these three pillars through its planning processes

# Portfolio Performance Indicators

| IURC Pillar | IRP Objective | Performance Indicator | Metric Description |
|---|---|---|---|
| Reliability | Maintain capacity reserve margin and the consideration of reliance on the market for the benefit of customers. | Energy Market Exposure – Purchases | Cost and volume exposure of market purchases (Costs and MWhs % of Internal Load) in 2033 and 2044 |
| | | Energy Market Exposure - Sales | Revenue and volume exposure of market sales (Revenues and MWhs % of Internal Load) in 2033 and 2044 |
| | | Planning Reserves | Target Reserve Margin |
| Affordability | Maintain focus on cost and risks to customers | Net Present Value Revenue Requirement (NPVRR)<br>Levelized Rate ($/MWh) | Portfolio 30yr NPVRR<br><br>Portfolio 30yr Levelized Rate (NPVRR/Levelized Energy) |
| | | Near-Term Rate Impacts (CAGR) | 7-year CAGR of Annual Rate |
| | | Portfolio Resilience | Range of Portfolio NPVRR and associated Rate Impact ($/MWh) (at rqd IRP Planning Period) costs dispatched across all Scenarios |
| Resiliency | Maintain diversity of resources and fleet dispatchability | Resource Diversity | Diversity Index inclusive of Capacity and Energy Diversity |
| | | Fleet Resiliency | % Dispatchable Capacity of Company Peak Load |
| (Grid) Stability | Maintain fleet of flexible and dispatchable resources | Fleet Resiliency | % Dispatchable Capacity of Company Peak Load |
| Environmental Sustainability | Maintain focus on portfolio environmental sustainability benefits and compliance costs | Emissions Change | $CO_2$, $NO_x$, $SO_2$ emissions change compared to 2005 levels |
| | | Total Portfolio Costs (NPVRR) | Considered under Affordability Pillar above |

# Update on PJM Capacity Market Changes

- On January 30, 2024, FERC issued an Order accepting the capacity market changes proposed by PJM in October 2023 in docket ER24-99 at the direction of the PJM Board.
- This Order accepts PJM's proposal to implement proposed changes to capacity accreditation and increased required reserve margin to better account for winter risks.
- The Key elements of ER24-99 are:
  - ***Market Structure***: PJM will maintain an annual market design that uses enhanced resource adequacy risk modeling that considers risks throughout the year to establish the appropriate planning reserve margin.
  - The ***Required Reserve Margin*** will be approximately 3% higher than the current level based on enhanced risk modeling, and this will apply in both the auction markets (RPM) and for the Fixed Resource Requirement (FRR or "self-supply") Alternative.
  - ***Capacity Resource Accreditation***: PJM will adopt the annual version of the marginal ELCC approach that is a blend of summer and winter capabilities. This will reduce the capacity accreditation of gas, solar and storage resource, while wind will have a modest increase in accreditation and nuclear and coal will have minimal impact.
- PJM will hold the 2025/26 delivery year Base Residual Auction (BRA) beginning July 17, 2024.

# Preliminary PJM ELCCs

| ELCC Class | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|
| Onshore Wind | 35% | 33% | 28% | 25% | 23% | 21% | 19% | 17% | 15% |
| Offshore Wind | 61% | 56% | 47% | 44% | 38% | 37% | 33% | 27% | 20% |
| Fixed-Tilt Solar | 7% | 6% | 5% | 5% | 4% | 4% | 4% | 4% | 3% |
| Tracking Solar | 11% | 8% | 7% | 7% | 6% | 5% | 5% | 5% | 4% |
| Landfill Intermittent | 54% | 55% | 55% | 56% | 56% | 56% | 56% | 56% | 54% |
| Hydro Intermittent | 38% | 40% | 37% | 37% | 37% | 37% | 39% | 38% | 38% |
| 4-hr Storage | 56% | 52% | 55% | 51% | 49% | 42% | 42% | 40% | 38% |
| 6-hr Storage | 64% | 61% | 65% | 61% | 61% | 54% | 54% | 53% | 52% |
| 8-hr Storage | 67% | 64% | 67% | 64% | 65% | 60% | 60% | 60% | 60% |
| 10-hr Storage | 76% | 73% | 75% | 72% | 73% | 68% | 69% | 70% | 70% |
| Demand Resource | 70% | 66% | 65% | 63% | 60% | 56% | 55% | 53% | 51% |
| Nuclear | 95% | 95% | 95% | 96% | 95% | 96% | 96% | 94% | 93% |
| Coal | 84% | 84% | 84% | 85% | 85% | 86% | 86% | 83% | 79% |
| Gas Combined Cycle | 79% | 80% | 81% | 83% | 83% | 85% | 85% | 84% | 82% |
| Gas Combustion Turbine | 61% | 63% | 66% | 68% | 70% | 71% | 74% | 76% | 78% |
| Gas Combustion Turbine Dual Fuel | 79% | 79% | 80% | 80% | 81% | 82% | 83% | 83% | 83% |
| Diesel Utility | 92% | 92% | 92% | 92% | 92% | 93% | 93% | 93% | 92% |
| Steam | 74% | 73% | 74% | 75% | 74% | 75% | 76% | 74% | 73% |

https://www.pjm.com/-/media/planning/res-adeq/elcc/preliminary-elcc-class-ratings-for-period-2026-2027-through-2034-2035.ashx

# PJM Interconnection Reform & FERC Order 2023

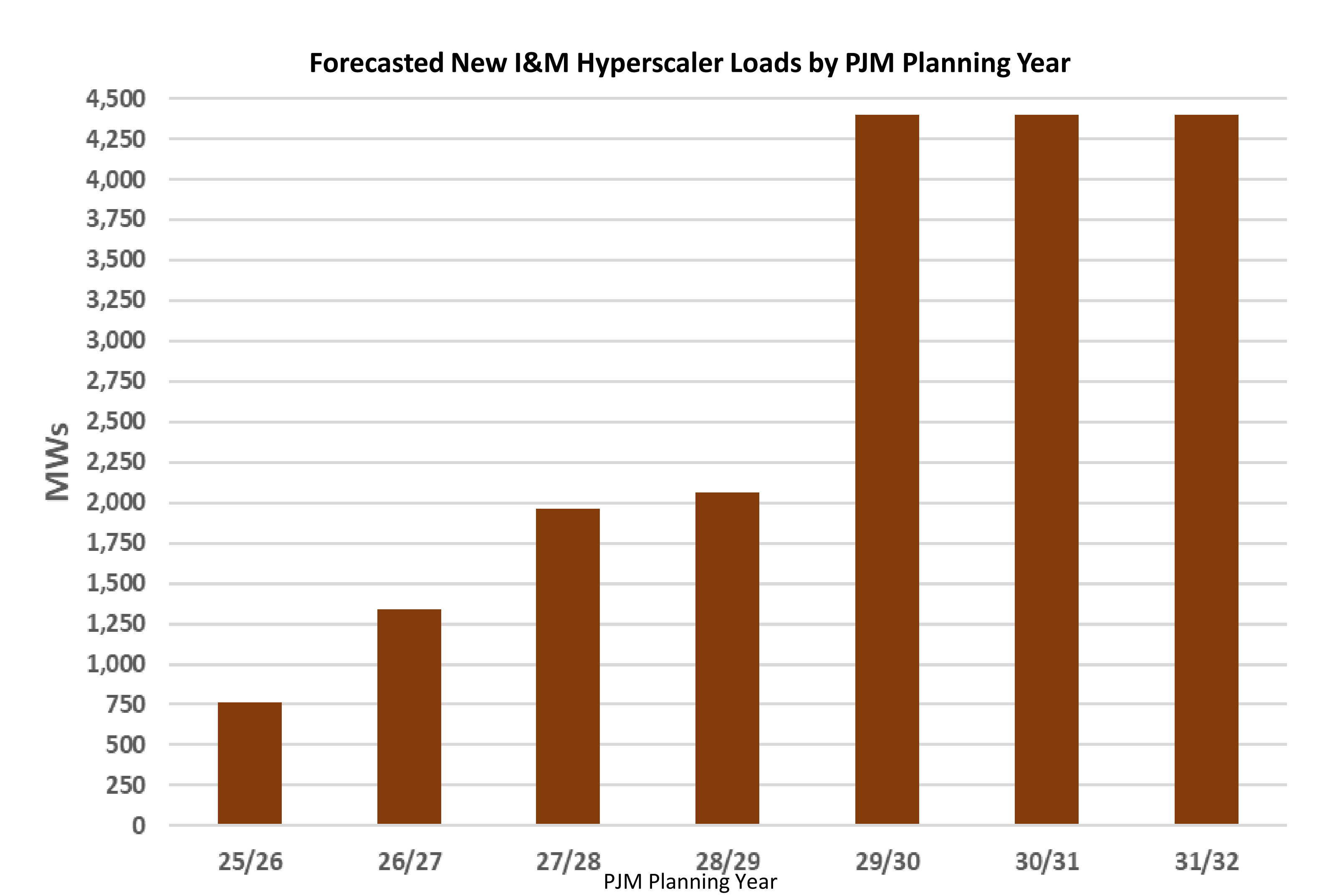
- FERC Order (Docket ER22-2110-000/001): On November 29, 2022, FERC approved PJM's Generator Interconnection Queue Reforms subject to compliance filings.
    - Transitions from a serial "First in, First Out" approach to a "First Ready-First Serve" clustered approach and establishes increased security and readiness deposits throughout the study process.
    - On July 10, 2023, PJM commenced transition activities for their reformed interconnection process that included defined "transition cycles" to analyze projects currently in the interconnection queue over the next two years. New interconnection requests will be studied under the new process starting in 2026.
- FERC Order 2023 regarding Interconnection Reform: PJM made compliance filing on May 16, 2024.
    - Requires a first-ready, first-served cluster study process that is generally consistent with PJM's new process.
    - Includes reforms intended to increase the speed of Interconnection queue processing including deadlines and penalties for the transmission provider; these aspects are the subject of multiple requests for rehearing and appeals.
    - Further incorporates technological advancements into the interconnection process.

# Capacity Interconnection Rights Transfers: "Retire & Replace"

- **<u>MISO</u>**: On May 15, 2019, FERC accepted MISO's enhanced generator replacement process.
  - Within one year of deactivation, the existing generator submits an Interconnection Request with a study deposit that will be processed in a serial fashion outside of the interconnection queue process.
  - MISO performs a Replacement Impact Study and if no material impact is identified then the project typically can receive a Generation Interconnection Agreement in 10-12 months.
- **<u>PJM</u>**: Existing generation owners are permitted to transfer their Capacity Interconnection Rights (CIRs) to an affiliated or non-affiliated entity, but if the new generating resource is a different generation type, the project must enter the interconnection queue to be studied like a new project.
  - The existing Generation Capacity Resource owner must initiate the CIR transfer within one year after the deactivation date.
  - A new project entering the interconnection study queue today will not be studied until 2026 and the study process then takes approximately two years; PJM's FERC approved queue reforms will significantly reduce the study backlog over time.
- **<u>Seeking process change in PJM</u>**: AEP is advocating for changes in the PJM stakeholder process to establish an expedited retire-replacement process like MISO's.
  - If successfully advanced in the stakeholder process, current timeline is for a solution to be endorsed and filed at FERC by mid-Summer 2024. If approved, processing of interconnection applications under a new process could begin during the 1st Qtr. of 2025.

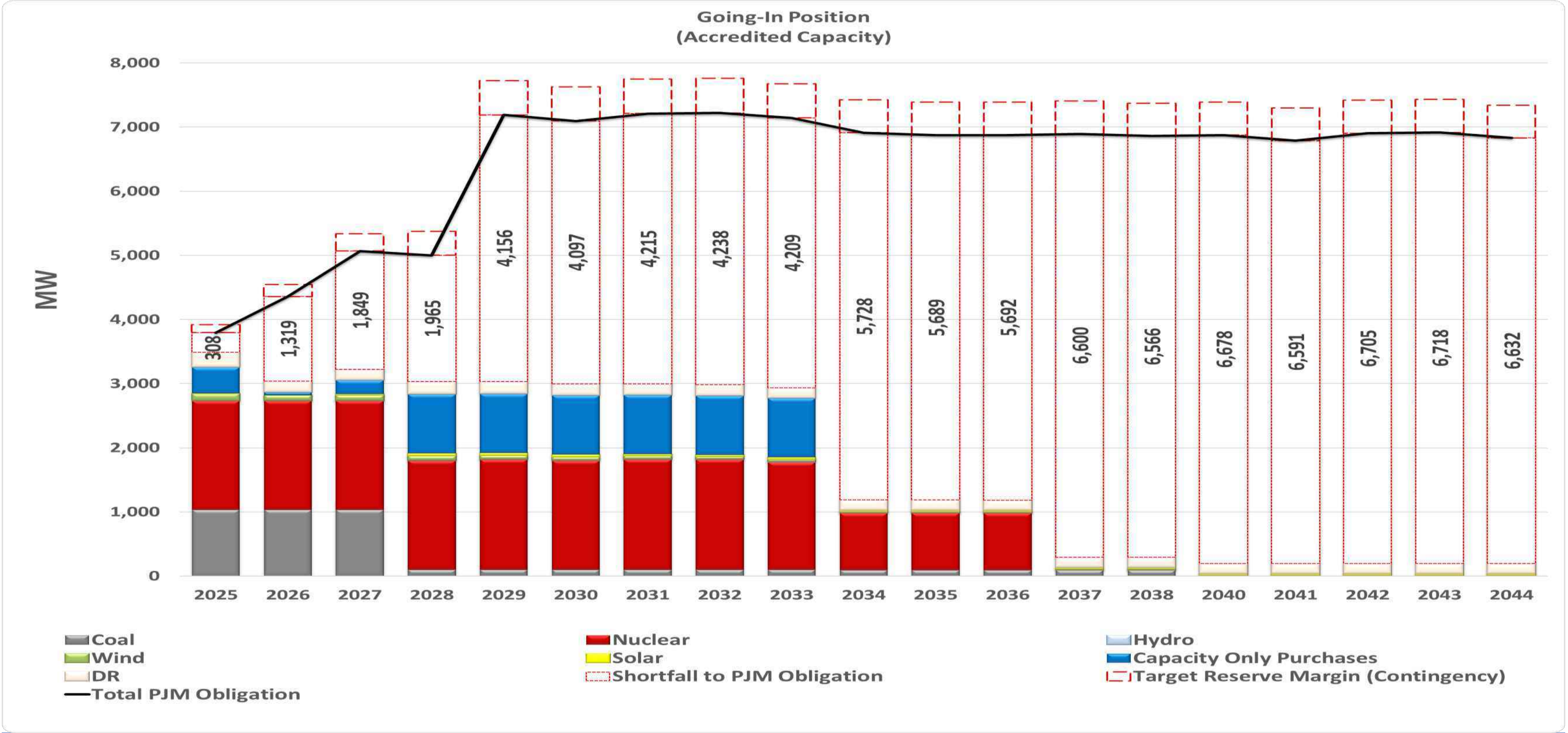
# Considerations for New Hyperscaler Loads (HSL) in IRP

- New load forecasted to more than double the current peak load served by I&M and occur over the next five to six years
- AEP and PJM will identify any transmission upgrades necessary to serve the new load
- I&M will utilize short-term existing PJM resources that provide a bridge to a long-term generation resource portfolio
- The long-term generation portfolio will be optimized through the IRP process to identify the best mix of resources to serve all Indiana customers
- Additional post-2030 HSL will be considered as part of a sensitivity (phase 2 load)



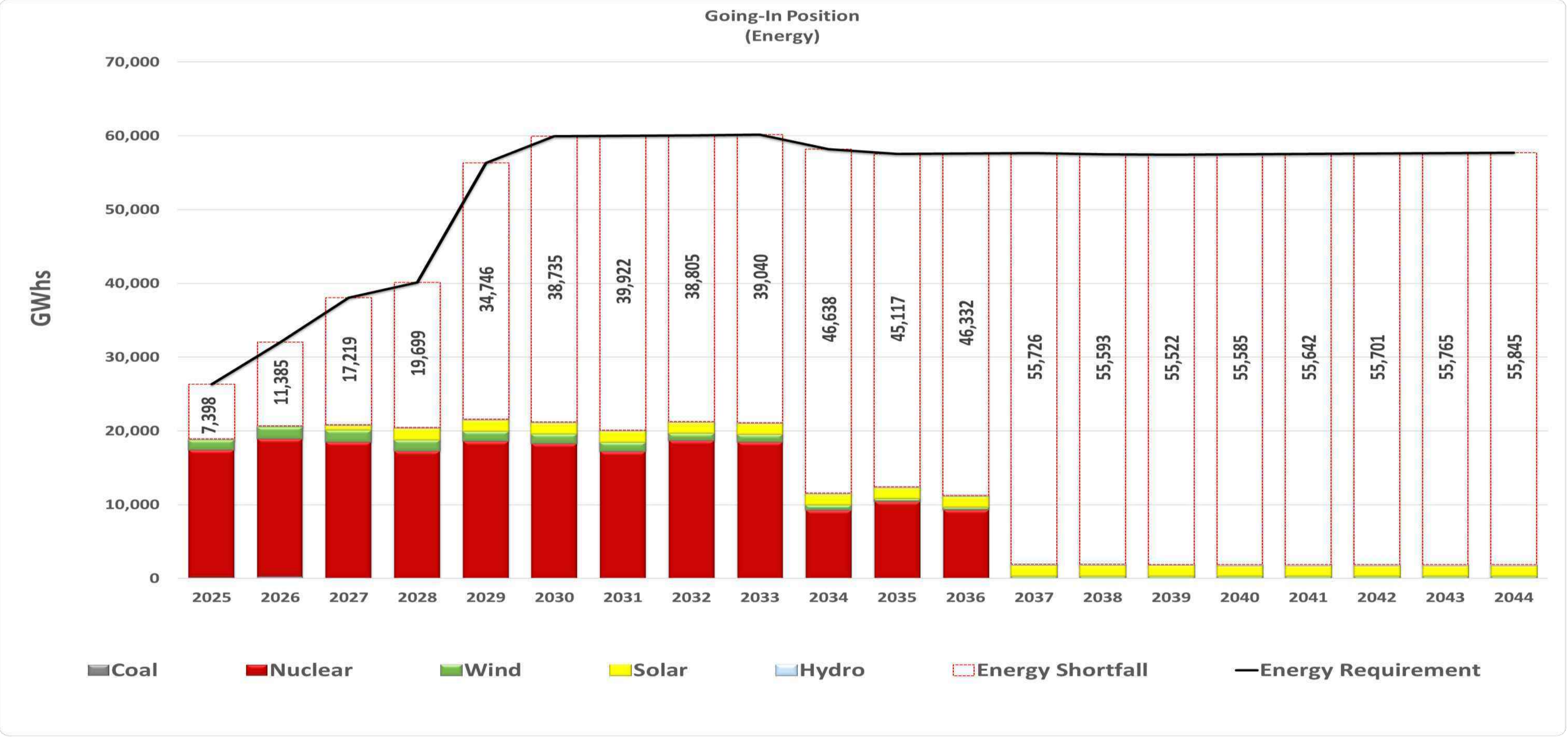

**Note: Forecasted loads are under development and subject to final updates.**

# Capacity Needs Assessment (Preliminary Going-In Position)




- To reasonably capture contingency risk around future uncertainties such as changes to load obligations and available capacity, a probabilistic risk analysis is being performed to evaluate a 'Target Reserve Margin. The final Target Reserve Margin is still under development, but is shown above for illustrative purposes.

# Energy Needs Assessment (Preliminary Going-In Position)



# Q&A
# Short Break

INDIANA MICHIGAN POWER
An AEP Company

# Market Scenarios and Commodities Pricing

Values forecasted based on modeling of Eastern Interconnect

| Scenario | Load | Gas Price | Environmental Regulations |
|---|---|---|---|
| Base | Base | Base | Pre-EPA 2023 Proposed Rules |
| High Economic Growth | High | High | |
| Low Economic Growth | Low | Low | |
| Enhanced Environmental Regulations (EER) | Base | Base | EPA 2023 Proposed Rules |

# Fundamentals Enhanced Environmental Regulation (EER) Scenario

## Scenario

**Scenario Models EPA's 111d Rule Changes**

- Proposed Rule Published May 11, 2023

**Generators impacted:**

- Exiting coal units
- Existing natural gas units >300 MW
- New gas units

**Scenario Summary:**

- ~50% power price increase on expiration of IRA credits mid-2040s

## Dispatchable Generation Options

**Existing coal units' options to continue operation past 2032 must:**

- Limit capacity factor to 20%, retire by 2035
- Blend 40% Natural Gas with coal, retire by 2040
- Install CCS

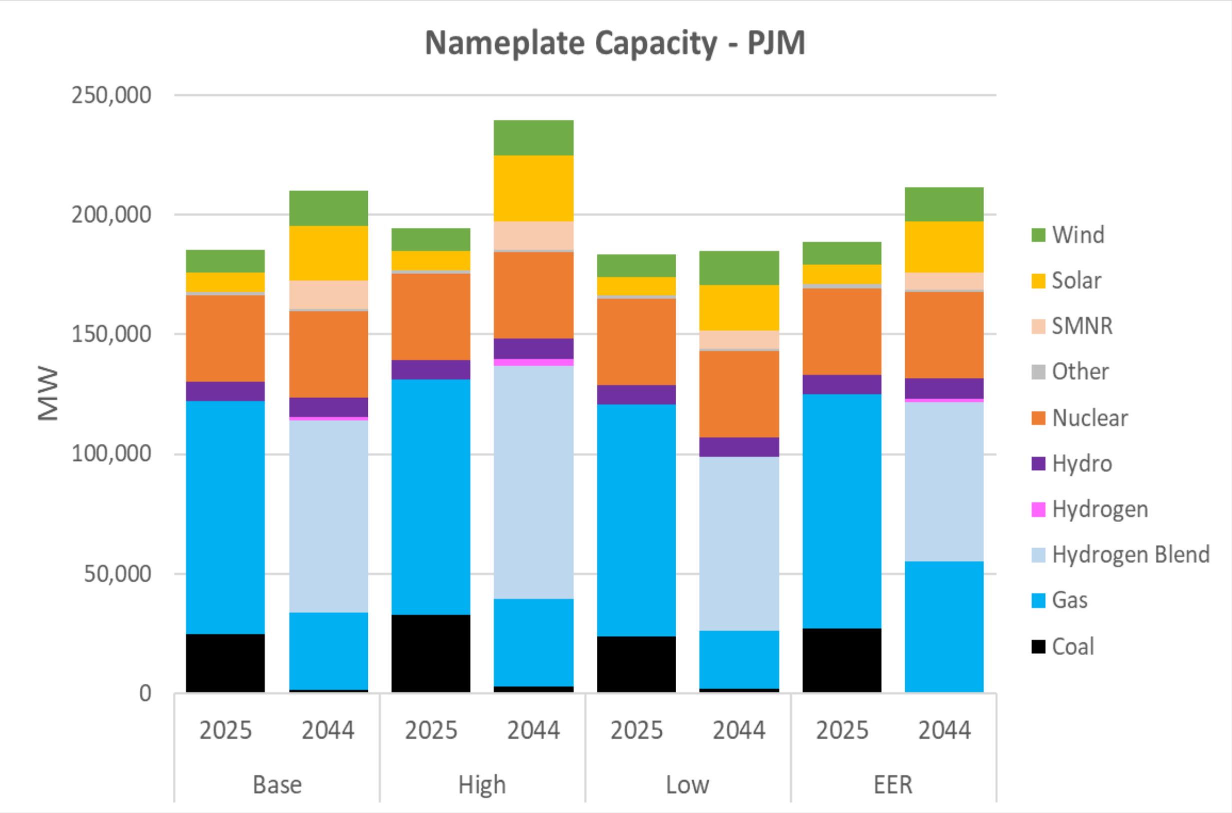
**Existing Natural Gas Units >300 MW and 50% Capacity Factor:**

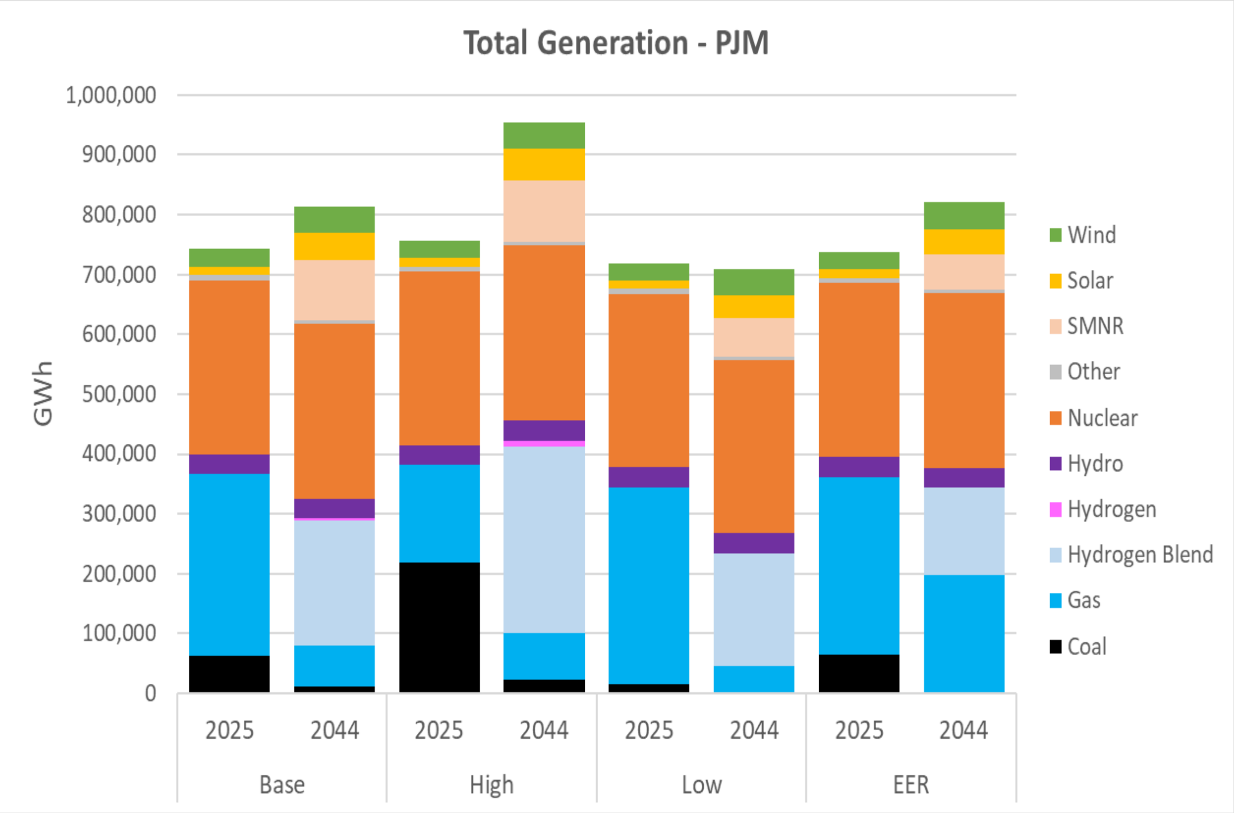
- Up to 96% hydrogen 4% natural gas fuel blend
- Install CCS

**New Gas Units:**

- Adhere to carbon emission performance standard
- Up to 96% hydrogen 4% natural gas fuel blend
- Install CCS

# PJM Supply Mix Changes

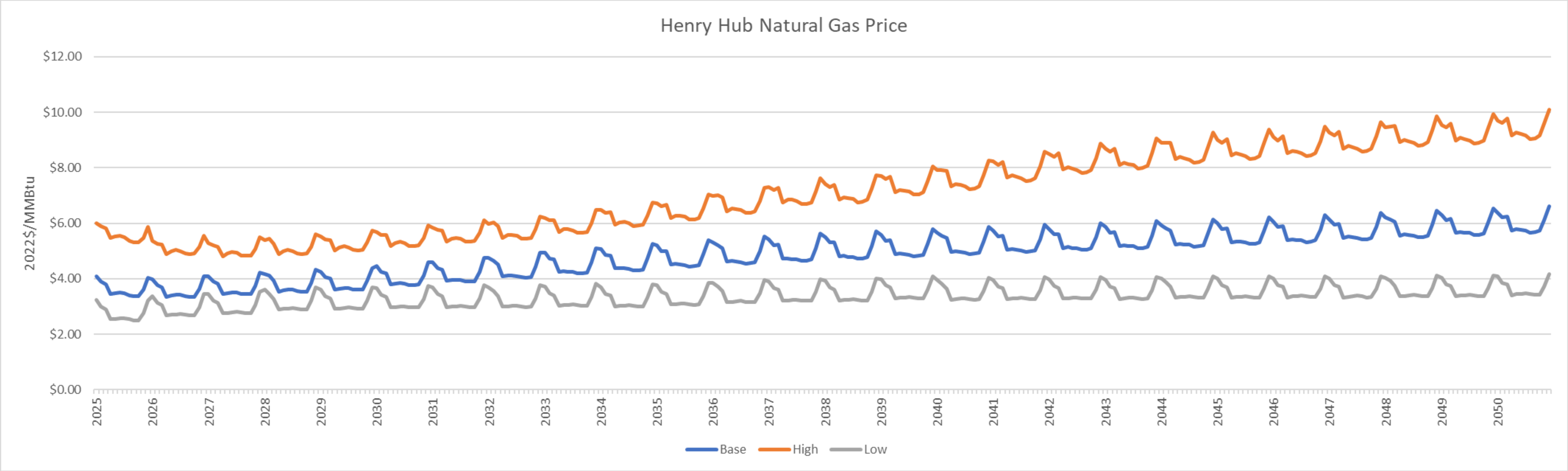



- Under all scenarios, coal is replaced primarily by NG/Hydrogen Blend units
- Solar sees significant growth in the long term
- Wind growth is moderate

- Nuclear and natural gas generation dominate the supply mix
- Natural gas/Hydrogen Blend units provide reliable, dispatchable generation as coal plants are retired

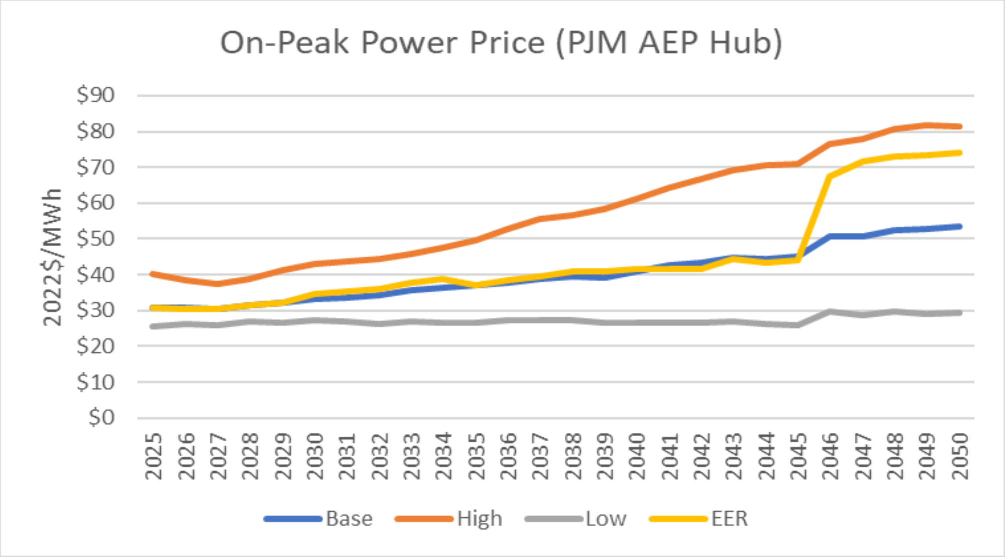
# Natural Gas Inputs

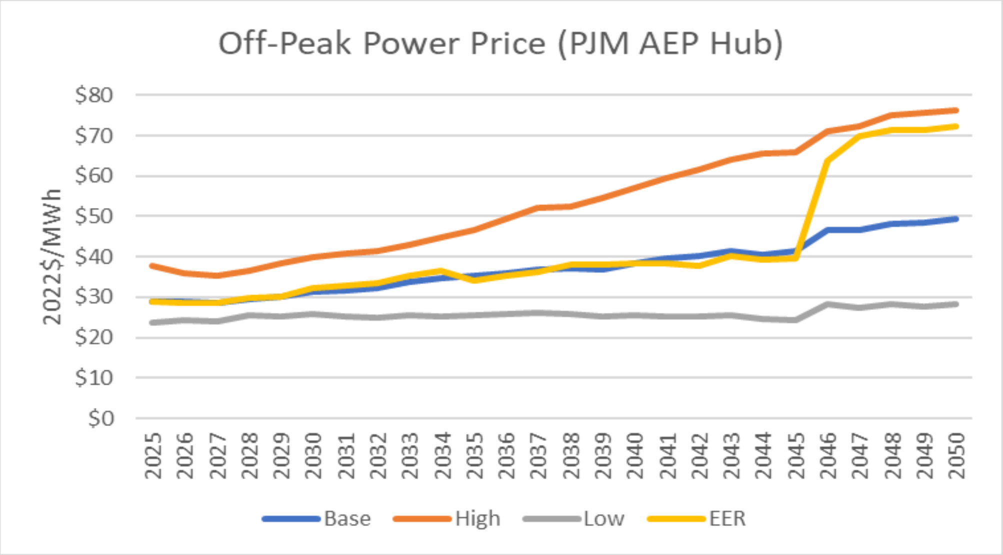



- Base case assumes that natural gas demand will increase as natural gas replaces coal
- High and Low cases have similar assumptions to Base except for WTI prices and LNG exports
    - High case assumes higher WTI prices and LNG exports
    - Low case assumes lower WTI prices and LNG exports

# PJM Market Prices

- Under all scenarios, energy prices are mainly influenced by natural gas prices
- Peak/Off-Peak spread averages are as follows:
    - Base: $2.71/MWh
    - High: $3.89/MWh
    - Low: $1.47/MWh
    - EER: $2.69/MWh



# Supply Side Resources

**I&M proposes three categories of supply side resources for the selection of an optimal resource mix that is resilient to future uncertainties.**

## Intermediate & Peaking Options

- H-Class 430 MW single-shaft natural gas combined cycle (NGCC)*
- H-Class 1,080 MW multi-shaft NGCC*
- F-Class 760 MW multi-shaft NGCC*
- 430 MW H-class single shaft NGCC with 90% carbon capture
- F-Class 240 MW natural gas combustion turbine (NGCT*)
- 100 MW aeroderivative unit
- 20 MW reciprocating engine

## Renewable & Storage Options

- Utility-scale onshore wind
- Utility-scale solar photovoltaic
- Utility-scale hybrid solar photovoltaic (3:1)
- Storage Resources
  - Lithium-ion battery: 4, 6, 8, 10-hour
  - Long Duration (e.g. 100-hour)

## Advanced Generation Options

- Small modular nuclear reactors

## Market Capacity Options

- Bi-Lateral Purchases
- Pre-Existing Assets

Note: *New NGCC/CT units are assumed to be retrofittable to burn 100% hydrogen

# Potential Generation Resource Timing Strategies

***Given large load growth expected for I&M over next decade requires careful consideration of resource type and timing***

## Short-Term Capacity Market

- I&M will seek short-term capacity through bilateral contracts for existing resources in PJM.
- Expect majority of capacity in early years to come from short-term market reducing over time as new resources are acquired

## Acquisition of Existing Assets

- I&M is currently evaluating opportunities for existing generation resources and re-powering of existing facilities
- Requires ability to “strike fast” in response to solicitations from potential seller’s
- Expect market to tighten later in decade; need to move now to be competitive

## Mid and Long-Term Resources

- I&M will use both traditional RFPs and self-development for owned and purchase power agreements
- I&M is also evaluating strategic partnerships with OEMs, EPC contractors, and developers to lock in manufacturing slots, PJM queue positions, and development opportunities.

# Planned IRP Cases

| Portfolio | Market Scenario | I&M IN Load [1] | Gas Price | Technology Cost | Energy Price | Environmental Regulations |
|---|---|---|---|---|---|---|
| Base | Base | Base | Base | Base | Base | Pre-EPA 2023 Proposed Rules |
| High Economic Growth | High | High | High | Base | High | |
| Low Economic Growth | Low | Low | Low | Base | Low | |
| Enhanced Environmental Regulations (EER) | EER [2] | Base | Base | Base | Base | EPA 2024 111(d) Final Rules [2] |

[1] All Cases include Hyperscaler Loads.

[2] EER Market Scenario is based on Proposed EPA rules as previously described. Resource selections will be based on final EPA rules.

# Proposed Alternative Sensitivities

| Portfolio | Market Scenario | I&M IN Load[1] | Gas Price | Technology Cost | Energy Pricing | Environmental Regulations |
|---|---|---|---|---|---|---|
| High IN Load | Base | **High** | Base | Base | Base | Pre-EPA 2023 Proposed Rules |
| Low IN Load | Base | **Low** | Base | Base | Base | |
| High Technology Costs | Base | Base | Base | **Base + 25%** | Base | |
| Base w/ Phase 2 HSL | Base | **Base+Ph2 HSL** | Base | Base | Base | |
| Base w/Env. Regs | Base | Base | Base | Base | Base | **EPA 2024 111(d) Final Rules** |

[1] All Cases include Hyperscaler Loads; Base w/Phase 2 HSL includes additional load growth post 2030.

# Stakeholder Alternative Portfolios Sensitivities

| Portfolio | Scenario | I&M Load | Gas Price | Technology Cost | Env. Regs | Settlement R'qmt |
|---|---|---|---|---|---|---|
| Rockport 1 2025 | Base | Base | Base | Base | Pre-EPA 2023 Proposed Rules | RP1 Retire in 2025 |
| Rockport 1 2026 | Base | Base | Base | Base | | RP1 Retire in 2026 |
| OVEC 2030 | Base | Base | Base | Base | | OVEC Resources exit in 2030 |

# New EPA Section 111 GHG Standards
# *Greenhouse gas emission limits*

**_Indiana Portfolio Resource Optimization to Include Final EPA 111d Rules_**

- Applies to existing coal and gas steam units and new combustion turbine units
- EPA will perform a separate rulemaking for existing combustion turbine units and will extend the rulemaking until later in 2024.
- Existing Coal Options:
  (1) Install 90% carbon capture by 2032; or
  (2) 40% gas co-firing by 2030 **<u>and</u>** retire by 2039; or
  (3) Retire by 2032
- Existing Gas Steam limits are based on routine O&M practices, not CCS
- New Gas Combustion Options:
  (1) Baseload (>40% capacity factor): 800 lb $CO_2$/MWh gross changing to 90% CCS by 2032 (note: hydrogen co-firing removed as an option)
  (2) Intermediate: (20-40% cap factor): 1170 lb $CO_2$/MWh gross
  (3) Low Load: (<20 cap factor): 160 lb $CO_2$/mmBtu
- Limited Reliability Mechanisms could extend compliance deadline by 1 year. Requires RTO certification and EPA approval.

# Q&A

Indiana Michigan Power
An AEP Company

# Planned Portfolio Performance Comparison

The IRP Performance Indicators compare the performance of the candidate portfolios under each of the market scenarios.
The results inform the Company on the trade-offs between candidate portfolios across performance indicators and metrics defined under each Pillar.

| Pillar | Affordability | | | Reliability | | | Reliability/ Resiliency | Grid Stability Resiliency | Environmental Sustainability | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Portfolio** | ***Short Term*** *7-yr Rate CAGR, Base Case* | ***Long Term*** *Portfolio NPVRR, Base Case* | ***Portfolio Resilience:*** *High Minus Low Scenario Range, Portfolio NPVRR* | ***Energy Market Risk*** *Purchases* | ***Energy Market Risk*** *Sales* | ***Planning Reserves*** *% Reserve Margin* | ***Resource Diversity*** | ***Fleet Resiliency****: Dispatchable Capacity* | ***Emissions Analysis:*** *% Change from 2005 Baseline - Base Case* ***$CO_2$, NOx, $SO_2$*** | | |
| Year Ref. | 2025-2031 | 2025-2054 | 2025-2054 | 2033 \| 2044 | 2033 \| 2044 | 2033 \| 2044 | 2033 \| 2044 | 2033 \| 2044 | 2033 \| 2044 | | |
| Units | % | $MM/ Levelized Rate | $MM/ Levelized Rate | Costs of Market Purchases & MWHs % of Total Demand | Revenues of Market Sales & MWHs % of Total Demand | % | Portfolio Index | Dispatchable Nameplate MW/ % of Company Peak Demand | % Change $CO_2$ | NOx | $SO_2$ |
| **Reference Portfolio** | | | | | | | | | | | |
| | | | | | | | | | | | |
| | | | | | | | | | | | |

# Affordability

The Affordability indicators compare the cost to customers under Base Case market scenario conditions over the short- and long-term and the Portfolio cost range when evaluated across the different market scenarios.

| Performance Indicator | Metric | Description |
|---|---|---|
| Near-term | 7-year Rate CAGR under the Base Case (2025-2031) | • I&M measures and considers the expected Compound Annual Growth Rate ("CAGR") of expected system costs for the years 2025-2031 as the metrics for the short-term performance indicator.<br>• A lower number is better, indicating slower growth in customer rates. |
| Long-term | Portfolio NPVRR under the Base Case (2025-2054) | • I&M measures and considers the growth in Net Present Value Revenue Requirement ("NPVRR") over 30 years as the long-term metric.<br>• NPVRR represents total long-term cost paid by I&M related to power supply. This includes plant O&M costs, fuel costs, environmental costs, net purchases and sales of energy and capacity, property and income taxes, and the return on capital.<br>• I&M also evaluates the levelized rate for this indicator, which is the fixed charge needed on a per MWh basis to recover the 30-yr NPVRR.<br>• A lower number is better, indicating lower costs to supply customers with power. |
| Portfolio Resilience | High Minus Low Scenario Range 30-yr NPVRR (2025-2054) | • I&M measures and considers the range of 30-yr NPVRR reported by each portfolio across all PJM market scenarios. This metric reports the difference between the highest and lowest cost scenarios reported by the candidate portfolio on an NPVRR and levelized rate basis.<br>• A lower number is better, indicating a tighter grouping of expected customer costs across a wide range of long-term market conditions. |

# Reliability

The Reliability indicators compare the amount of excess reserves and the reliance on market resources to serve customers across candidate portfolios.

| Performance Indicator | Metric | Description |
|---|---|---|
| Planning Reserves | Reserve Margin % 2033 and 2044 | • I&M measures and considers the amount of average amount of firm capacity in each candidate portfolio in 2033 and 2044.<br>• A higher number is better, indicating more reserves are available to meet PJM requirements. |
| Energy Market Risk | 2033 & 2044 Portfolio Cost Range of market purchases, MWhs as % of internal Load | • I&M measures and considers the reliance of each candidate portfolio on market purchases to balance seasonal generation with customer load.<br>• The metric reports the cost of market purchases and MWhs as a % of internal load in 2033 & 2044<br>• A lower number indicates less reliance on the market to meet customer needs |
| | 2033 & 2044 Portfolio Revenue Range of market sales, MWhs as % of internal Load | • I&M measures and considers the reliance of each candidate portfolio on market sales to balance seasonal generation with customer load.<br>• The metric reports the revenues of market sales and MWhs as a % of internal load in 2033 & 2044<br>• A lower number indicates less reliance on the market to meet customer needs |

# Resiliency

The Resiliency indicators compare the amount of dispatchable capacity in the fleet and the technology diversity for capacity and energy of the Indiana generating mix across candidate portfolios.

| Performance Indicator | Metric | Description |
|---|---|---|
| Resource Diversity | Sum of the Capacity Diversity Index and Energy Diversity Index in 2033 and 2044 | • I&M measures and considers the capacity and energy diversity of new technologies added to its portfolio when comparing candidate portfolios.<br>• The metric will use the Shannon-Weiner Index to measure the number of different technologies and their respective contribution to the portfolio totals for both capacity and energy diversity for each Portfolio in year 2033 and 2044.<br>• A higher number is better, a portfolio that includes diverse resources for both capacity and energy delivery mitigates customers' performance risk when conditions for that technology are unfavorable. |
| Fleet Resiliency | Nameplate MW of dispatchable units in 2033 and 2044 | • I&M measures and considers the total amount of dispatchable units added to the portfolio by years 2033 and 2044 to compare candidate resource plans.<br>• The metric for this indicator is the total Nameplate MW of ramping technologies included in the candidate resource plan.<br>• A higher number is better, indicating greater ability to ramp generation up or down to react to market conditions and follow load. |

# (Grid) Stability

The Grid Stability indicator compares the amount of dispatchable capacity in the fleet, and the technology diversity of the Indiana generating mix across candidate portfolios.

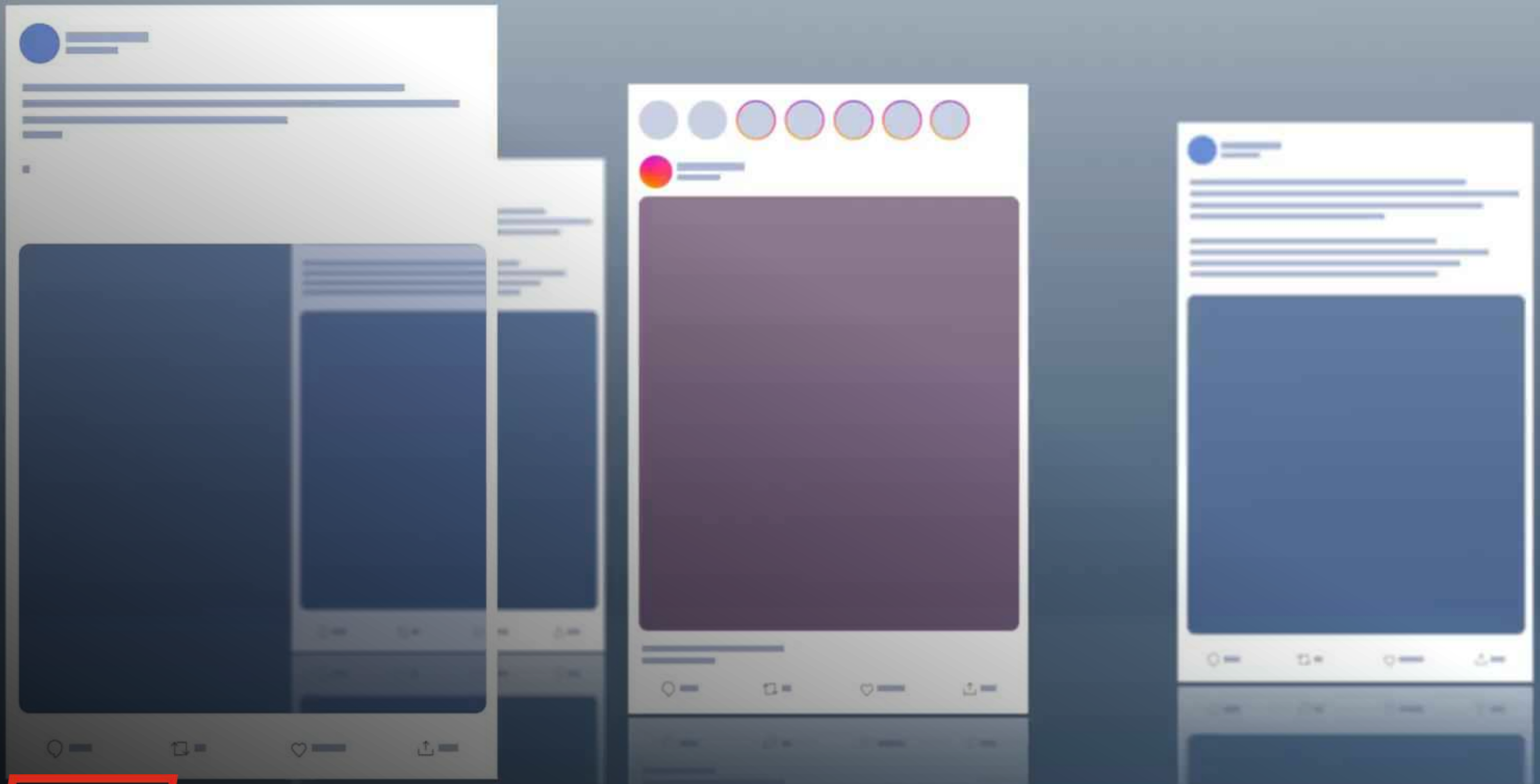
| Performance Indicator | Metric | Description |
|---|---|---|
| Fleet Resiliency | Nameplate MW of dispatchable units in 2033 and 2044 | • I&M measures and considers the total amount of dispatchable units added to the portfolio by years 2033 and 2044 to compare candidate resource plans.<br>• The metric for this indicator is the total Nameplate MW of ramping technologies included in the candidate resource plan.<br>• A higher number is better, indicating greater ability to ramp generation up or down to react to market conditions and follow load. |

# Sustainability

I&M also considered a Sustainability indicator to compare portfolio performance towards meeting corporate sustainability targets.

| Performance Indicator | Metric | Description |
|---|---|---|
| $CO_2$, NOx, $SO_2$, Emissions | 2033 & 2044 % Change from 2005 Baseline - Reference Case | • I&M measures and considers the total amount of expected $CO_2$, NOx and $SO_2$ emissions of each candidate portfolio on the Scorecard.<br>• This metric compares the forecast emissions of candidate portfolios in 2033 and 2044 under Reference Case market conditions with actual historical emissions from the year 2005.<br>• A higher number indicates greater levels of emissions reductions have been achieved and customers are less exposed to potential future $CO_2$ costs. |

# Stakeholder Feedback and Discussion



INDIANA MICHIGAN POWER
An AEP Company

**Indiana Michigan Power Company**

2024 Indiana Integrated Resource Plan

Stakeholder Workshop #1 Meeting Minutes

June 27, 2024

**1.) Welcome and Introductions:**

*Greg Soller covered slide 1*

Greg Soller, Indiana Michigan (I&M) Manger of Resource Planning, called the meeting to order at 1:04 PM. Greg welcomed participants to the 2024 Indiana Integrated Resource Plan (IRP) stakeholder workshop and introduced Andrew Williamson, I&M Director of Regulatory Services.

*Andrew Williamson covered slides 2-3*

Andrew introduced I&M Leadership and the I&M IRP Planning Team who will be conducting the 2024 Indiana IRP internally with engagement and feedback from I&M stakeholders. Andrew also introduced 1898 & Co., who is supporting I&M with stakeholder engagement during the 2024 IRP.

Andrew covered the agenda for the Stakeholder Workshop and introduced Brian Despard, 1898 & Co. Senior Project Manager and moderator for the Stakeholder Workshop.

*Brian Despard covered slides 4-5*

Brian explained the webinar functionality and presented participation guidelines for the meeting. Relevant stakeholder questions regarding the IRP process were permitted at any time to be answered between sections.

Additional questions and stakeholder feedback related to this meeting were encouraged to be sent to I&MIRP@aep.com. As this meeting was not recorded or transcribed, questions and answers will be provided at the stakeholder website at: Indiana Stakeholder Engagement Process (indianamichiganpower.com).

**2.) Stakeholder Meeting Objectives:**

*Brian Despard covered slide 6*

Brian covered the stakeholder meeting objectives: transparency regarding the objectives and assumptions that form the basis of the IRP, and the gathering of productive stakeholder feedback to help shape the IRP.

Stakeholder feedback and input is welcomed on a broad variety of topics pertaining to the IRP, including objectives, market conditions and pricing assumptions, capacity needs, proposed study cases, and more.

**3.) Company Overview and Updates:**

*Andrew Williamson covered slides 7-8*

Andrew Williamson presented background on I&M and direction that the company has taken since the last IRP, conducted in 2021. I&M's objectives are to responsibly serve its more than 614,000 retail customers and wholesale customers, while meeting system reliability criteria established by the PJM Regional Transmission Organization.

Andrew also presented I&M's current generation mix. Existing and new generation resources with start terms between 2025-2028 will serve to provide for I&M's immediate needs.

I&M is conducting two 2024 IRPs, one in Indiana and one in Michigan, to serve load in both territories in accordance with differing state policies and needs. The Indiana IRP aims to identify load-serving resources that meet standards set by the Indiana Utility Regulatory Commission's (IURC) "Five Pillars."

**4.) 2024 IRP Highlights, Process, & Stakeholder Engagement:**

*Greg Soller covered slides 9-12*

Greg Soller presented on the 2024 Indiana IRP highlights, process, and stakeholder engagement timeline.

Key topics for the 2024 Indiana IRP include discussing relicensing the Cook Nuclear Plant and hydroelectric assets, navigating the transition to state-specific planning, facing challenges brought about by significant future I&M load growth, and recognizing dynamic market conditions that will impact generation for this and future IRPs.

This IRP calls for close coordination between I&M, American Electric Power (AEP), and a diverse group of I&M stakeholders. These three entities, throughout the IRP process, will collaboratively set and modify IRP objectives, market assumptions regarding supply and demand, and portfolio performance criteria.

Agreed-upon inputs will be used to evaluate multiple resource portfolios under multiple market scenarios and sensitivities. Portfolios will be subject to scenario-based risk analysis before a preferred portfolio is selected and a short-term action plan is developed.

Following an IRP Planning Technical Conference for necessary software licensing, today's meeting marks the "official kickoff" of Indiana IRP stakeholder engagement. This is to be followed by three more stakeholder meetings before the 2024 Indiana IRP is submitted in early 2025. The second stakeholder meeting, slated for August-September 2024, will discuss assumptions, inputs, and modeling result drivers. Technical conferences will also be held to analyze modelling inputs and processes more deeply.

**5.) General IRP Requirements, 2021 Action Plan, 2024 Commitments:**

*Greg Soller covered slides 12-14*

Greg discussed IRP compliance requirements in Indiana, emphasizing why stakeholder feedback is crucial to this project's success. I&M maintains their obligation to evaluate a broad range of resources to provide a resource mix that aligns with IURC's Five Pillars of reliability, affordability, resiliency, stability, and environmental sustainability.

Greg presents outcomes from the 2021 IRP; I&M secured capacity needed to meet 2024-2025 PJM reliability standards, issued RFPs in 2022 and 2023, and has commenced efforts to evaluate the relicensing of the 2.2GW Cook Nuclear Plant, a cornerstone of I&M's current generation mix. A handful of 2021 IRP outcomes provide a basis for I&M commitments in the 2024 I&M IRP. I&M will evaluate the retirement of Rockport Unit 1 in both 2025 and 2026 as opposed to the 2028 target identified in the 2021 IRP. In addition, I&M commits to modelling their exit from the OVEC Inter-Company Power Agreement (ICPA) in 2030.

For transparency, during the 2024 IRP I&M commits to providing modelling licenses for regulatory stakeholders, publishing a schedule of data releases, and disclosing cost and performance analysis results for energy efficiency and longer-duration storage resources.

**6.) Cook and Hydro Relicensing:**

*Andrew Williamson covered slides 15-18*

Andrew Williamson presented an overview of the Cook Nuclear Plant, the importance of the unit to meeting I&M's load, and considerations for relicensing of the plant. Andrew introduced Mohamed Abukaram, I&M Manager of Resource Planning.

Mohamed provided benefits of the unit including massive amounts of carbon-free generation, reliability, and low, stable costs. Andrew also discussed I&M's longstanding financial investment towards keeping Cook operational beyond its current license date.

Mohamed discussed the licenses of U1 and U2 of Cook in 2034 and 2037, respectively. Andrew expressed I&M's obligation to evaluate the economics of Subsequent License Renewal (SLR), and the costs that must be considered in such an evaluation.

Andrew provided an overview of hydroelectric generation along the St. Joseph River System. During the 2024 IRP, I&M will be conducting analysis regarding 40-year renewal on the licenses of Elkhart and Mottville, both set to expire in 2033.

Mohamed informed stakeholders that I&M engaged WSP to assist with evaluation of I&M's hydroelectric assets and potential renewal of Elkhart and Mottville from financial and socio-economic viewpoints.

**7.) IURC Pillars,2024 IRP Objectives, & Performance Indicators:**

*Greg Soller covered slides 20-21*

Greg Soller presented the IURC pillars, 2024 IRP objectives, and performance indicators, emphasizing the alignment of primary objectives with proposed metrics and resulting IRP goals. These objectives are crucial for understanding the different dynamics and how they leverage PJM resources to serve customers with the least cost portfolios.

The IRP objectives set by I&M align with the IURC Five Pillars, which are robust and ensure reliability through minimum capacity and market sales. The five pillars are: Affordability, Resiliency, Stability, Environmental Sustainability, and Reliability

Greg also conducted preliminary discussion of performance indicators for these metrics. I&M strives to set IRP goals that tie directly to each of the five pillars and meet and exceed PJM operating thresholds to maintain a standard of self-reliance.

**8.) PJM Update:**

*Josh Burkholder covered slides 22-25*

Josh Burkholder presented updates on the PJM capacity market and interconnection reforms. Throughout 2023, PJM worked on proposals that were eventually accepted by FERC. These updates included an enhanced risk evaluation system that considers various weather and load scenarios throughout the year, which will increase installed capacity reserve margins by roughly 3%.

Josh also explained that PJM will adopt a marginal Effective Load Carrying Capability (ELCC) approach that blends different resources' capabilities during winter and summer, providing a more accurate accreditation of capacity resources.

PJM's new "First Ready, First Serve" interconnection approach, beginning in 2026 will cluster projects ready to proceed, reducing the interconnection queue time to about 18 months from start to finish. This process will undergo transition cycles to manage existing interconnection backlog. The "Retire and Replace" scenarios include MISO's FERC-approved expedited process for interconnection right transfers, which PJM is advocating to adopt similarly.

Preliminary ELCC values for different resource classes over the next ten years were reviewed, providing adjustment factors based on class averages. The updates highlight the importance of improved market structure and capacity analysis, with changes effective for the 2025/2026 Base Residual Auction (BRA). These reforms aim to enhance PJM's capacity market efficiency and interconnection process, ensuring a more robust and responsive system to meet future energy demands.

**9.) Capacity and Energy Needs Review (Going-in Position):**

*Greg Soller covered slides 26-28*

Greg presented on the capacity and energy needs, highlighting the implications of Hyperscale Loads (HSL) and the upcoming retirement of significant power plants.

Load growth driven by HSL presents both opportunities and challenges for I&M during the IRP process, as does retirement of the Burkhead Coal Plant by 2028. The implications of Cook license expirations are also essential to recognize for the going-in position, as significant reduction in nuclear capacity between 2033 and 2037 provides for a bigger gap between present and needed energy and capacity.

The stakeholder process must be robust, exploring alternatives to meet energy needs for these considerations and more. I&M seeks to not only secure capacity and energy to meet PJM requirements but exceed them to mitigate future uncertainties. Greg emphasized the importance of solutions and strategies for transitioning from coal and other capacity-only purchases that will cease by 2028. Planning beyond minimum reserve margins is necessary to manage risks and uncertainties.

**10.) IRP Fundamentals: Market Scenarios and Base Assumptions:**

*Mark O'Brien covered slides 30-34*

Mark O'Brien presented the IRP fundamentals covering market scenarios and base assumptions. Currently, scenarios include high, base, and low market conditions as well as an Enhanced Environmental Regulation (EER) scenario which utilizes proposed EPA 111d Rule Changes and would affect coal and gas units, both new and existing. The goal of the discussion is to form a basis of understanding for the varying market and regulatory conditions that may impact the optimal resource mix.

Market conditions considered during scenario selection include load growth and gas prices. Mark presented on anticipated PJM Generation Mix, which followed some base assumptions across all scenarios, such as coal replacement via natural gas and hydrogen blends. Solar growth across PJM is significant in all scenarios, with moderate growth for wind. Gas prices reflect demand across differing mixes of natural gas utilization and account for WTI prices and LNG imports.

Finally, Mark presented PJM market prices which are driven primarily by gas supply and demand, and sharply increase for the EER case to reflect EPA policy changes and expiration of certain beneficial credits.

**11.) Technology Alternatives and Resource Timing Strategies:**

*Greg Soller covered slides 35-36*

Greg Soller presented the discussion on technology alternatives and resource timing strategies, categorized into three major areas: gas resources (intermediate and peaking), renewable and storage, and advanced generation.

The presentation emphasized that gas resources provide essential capacity and energy as needed, while intermittent storage needs to be expanded to support proposed renewables. Advanced generation, such as small modular nuclear reactors, is attracting public attention, though costs are yet to be fully determined. Given Indiana's rapidly increasing capacity and energy needs, reliance solely on newbuilds is impractical, making pre-existing assets crucial through power purchase agreements (PPAs) and other contracts.

Potential timing strategies were explored, with a significant focus on leveraging existing assets to meet near-term needs, which will be discussed in detail in the second stakeholder meeting. Request for proposals (RFPs) will be conducted for mid- to long-term resources, while self-development and strategic partnership remain viable options.

The value of renewable and storage options was highlighted, including the benefits to customers and potential tax advantages. Considerations for small modular reactors were also discussed.

**12.) IRP Proposed Cases and Sensitivities:**

*Greg Soller covered slides 37-40*

Greg Soller discussed the IRP's proposed cases for analysis of portfolios under different market and demand conditions, as well a case that includes Enhanced Environmental Regulation, for which assumptions were reviewed and will be provided to stakeholders.

Greg also discussed sensitivities to be applied to modelling efforts, such as low and high load scenarios for Indiana with the outlying market remaining stable. Other base case derivatives included Phase 2HSL additions and scenarios with the 2024 EPA 111(d) Final Rules.

Finally, Greg revisited previous discussion on special sensitivities I&M is committed to analyzing, including 2025/2026 Rockport requirements and the removal of OVEC resources by 2030.

**13.) Proposed Portfolio Performance Metrics:**

*Greg Soller covered slides 42-47*

Greg outlined the proposed portfolio performance metrics aligned with IURC's five pillars of affordability, reliability, resiliency, grid stability, and sustainability. The proposed scorecard and matrix was analyzed according to these pillars to ensure a comprehensive evaluation.

**Affordability** was proposed to be examined in both near- and long-term scenarios under a base case, with an emphasis on a slower growth rate in the near term and its impact on deferred decisions and long-term implications. Per I&M, evaluation should also consider the risks and customers face if market conditions change after decisions are made.

**Resiliency** was proposed to be measured using the Shannon-Weiner index, summing capacity and energy diversity indices for 2033 and 2044. This index provides for equal value weighting for capacity and energy to reflect the value of dispatchable nameplate capacity.

**Grid Stability** should be quantified in a way that recognizes the necessity of addressing system stability through ISO management, dispatch, and load balancing, considering thermal and storage options.

**Sustainability's** guiding metrics should measure the impacts of portfolios on reducing $CO_2$, $NO_x$, and $SO_2$ emissions, weighing these reductions against the associated costs for consumers in I&M's service footprint. Emphasis was placed on the balance between consumer desires and delivery costs, evaluating the percent change from 2005 to understand the implications in different portfolios (Slide 47).

**14.) Final Questions, Discussion, Action Items, and Adjourn**

*Brian Despard covered slide 48*

## APPENDIX A – QUESTIONS VERBALLY ASKED AND ANSWERED DURING MEETING #1

| Question | Response |
|---|---|
| I&M had a planning technical conference in early June with certain stakeholders, is that correct? | Yes, we met with CAC and OUCC about some of the DSM and energy efficiency inputs that have been part of other agreements and commitments we have made. |
| What will be the cadence of technical/confidential stakeholder meetings? We want those to be at a regular cadence aligned with the public stakeholder meetings. Typically, we have a technical meeting with those with NDAs before each public meeting. | There is no cadence yet, there needs to be flexibility and we do not want to put any hard dates in. The technical meetings will be with the stakeholders working with modeling licenses. |
| Registering for meeting website said there would be separate meetings for Michigan and Indiana. Will I&M be holding stakeholder meetings jointly with both states going forward? | Beginning with this IRP, I&M is transitioning to a state-specific integrated resource planning model. This is an important change that has been given significant consideration. The change will allow I&M to tailor its future resource plans and decision to the needs and energy policies specific to each individual state which will best position I&M to meet the ongoing needs of its customers and comply with state energy policies. I&M has had several conversations with both state commissions and other stakeholders to discuss the importance and value associated with this change. This meeting is the beginning of the 2024 IRP for Indiana and the 2024 IRP for Michigan is expected to begin in the August/September time frame. |
| Follow up from above question: Does this mean that Indiana and Michigan are splitting into separate LSEs? | No, that will not be necessary. What this change means is that we will be evaluating our future resource needs and tailoring a preferred resource plan or portfolio to meet those needs on a state-specific basis. In the future, resources will be acquired specific to that states needs and consistent with that states IRP to best position I&M and its respective state commission to ensure reliability and resource adequacy for customers, as well as compliance with each state's unique energy policies. |

| Question | Response |
|---|---|
| Follow up from above question: How does this work in practice? How are you going to manage cost allocation for units you own, does this change in some way compared to previous IRPs? | Our plan is for the cost allocation of current resources to remain consistent with current practices and past IRPs. As an example, the IRP is using the most recently allocation factors for its going in resources. I&M will be making future filings with both state commissions to address cost allocation for current resources as needed. However, future resources would expect to be specific to one state and therefore the costs will be fully assigned to that state, which in many ways simplifies the cost allocation process. |
| Follow up from above question: Why is I&M conducting IRPs for a Multi-State company in different states? This seems to limit the impact the state of Michigan has because so much of the load is in Indiana. Could you explain why this change is better and why it makes sense for rate payers? | The impact that Indiana or Michigan have on future resources decisions will be directly influenced by each states load and resource needs.<br><br>This change best positions I&M to ensure the future resources it seeks approval of from either state align its respective energy policies. This alignment is important and makes of sense since the energy policies of a given state apply to the retail load within that state. Additionally, today Indiana represents more than 80% of the retail load I&M serves and that percentage will continue to grow as I&Ms Indiana retail load grows considerably over the next several years. The significant load growth in Indiana will require a significant amount of additional generation resources in the future and it's important that Indiana has the oversight and control over ensuring those resources are approved to serve that load growth in Indiana. This change means that as we make resources decisions in the future, we can tailor these decisions to one state or the other while not requiring one state to flex to the other states energy policies or be resource needs. |

| Question | Response |
|---|---|
| Following the above question: It will be important to figure out how to address cost allocation for each state. As an example, let's say your Michigan plan retires a unit. Is the assumption that the cost of that unit is then borne by Indiana rate payers? | Cost allocation is not expected to be an issue. There are plans in place to replace Rockport. We have already made the necessary resource approval filings in Indiana and will file for approval in Michigan in July. The next major retirement that is a possibility is the Cook Nuclear Plant. The Cook relicensing decision will be a focus of both the Indiana and Michigan 2024 IRPs and the decision is expected to be consistent across both states despite being modeled independently. As mentioned previously, the IRP will model Cook on a state-specific basis consistent with the current allocation of Cook to each respective state. I&M does not envision there being a situation where you have a resource plan related to existing assets where there is a retirement of a facility in one state, but not in the other. |
| Could you help me understand some of the data center aspects. What portion of this load growth is data centers that have been publicly announced versus data centers that are expressing interest and are less firm? What are the milestones, from initial conversation to final decision, to confirm that the data center load growth is real? | Slide 26 represents the summation of loads that I&M has interconnection agreements in place or in development. Approximately 75% of the load shown has been publicly announced, the rest are yet to be announced. Based on what we know today, there is confidence that the load as shown will materialize over this period but there may be differences in timing and the amount of load that materializes in a given year. |
| Follow up from above question: What kind of protections are there for consumers? If there are large investments being made for these data centers how will you ensure that there is not a cost shift if the data centers shut down early? This seems like a tremendous risk to existing customers if I&M overestimates how much load growth will occur. What assurances or protection do consumers have in place to protect them from that outcome? | I&M is in the process of preparing a filing to modify its industrial power tariff to propose a consistent set of terms and conditions of service that would apply to large load customers to better address and balance risk. These changes include higher minimum billing demands, longer contract terms, credit requirements and charges if a customer would significantly reduce its load or cease operation during the contract period. These changes will better position I&M and all of its customers to have a better set of protections in place to address unforeseen events that could occur in the future. I&M has plans to make that tariff filing relatively soon. |
| Discussion of metrics: "These are the metrics we will use"- Does that mean that those metrics are final? | No, these are proposed Metrics for this first Stakeholder Meeting. We will look to reconcile feedback to the metrics following Stakeholder Meeting 2. |
| Could you provide info for stakeholders who have not heard the index term before; the way you measure generation diversity through an index? Can you provide an example of how that calculation works? | The Shannon-Weiner index is proposed for the Diversity metric. Information on this index is available on the internet to get more understanding. In summary, the index considers the number of different types of resources and their contribution towards the total. |

| Question | Response |
|---|---|
| Follow up from above question: When you say you are counting the number of slices of pie along with the size of each slice, does that mean that each generator, regardless of technology type, counts as a slice of pie, and that the measure of that generator's contribution will be its firm capacity? | The firm capacity of each generator type is going to be looked at. We will also evaluate the energy index by generator type |
| Follow up from above question: Do you have a draft load and peak forecast that you can share with us? | Load and peak forecasts, there will be a data release for the PLEXOS side of modelling with peak and energy demand forecasts. |
| Regarding the Capacity Needs Assessment (Slide T28) and Energy Needs Assessment (Slide T28), (i) does this include I&M's current wholesale commitments with the needs (aka 12.6% of I&M load), (ii) what are the types of "wholesale" customers within this category and (iii) since this is focused only on Indiana only, how are capacity assets across Michiana and Indiana reflected against the needs? | Capacity needs and energy needs does include I&M's wholesale commitments. Capacity assets will be allocated based on the respective IN and MI wholesale jurisdictional allocations. |
| Why are you using the proposed EPA Rule rather than final rule? | With the final rule, no fully prescribed treatment for existing natural gas exists. It does have an emission limit that they need to stay under, but there isn't any treatment like retrofitting carbon capture and sequestration or various types of fuel blend that are explicitly stated under that scenario.<br>So we see the proposed rule as being more aggressive and something that's probably a bit more likely to occur as the EPA develops the rules over the next year or so for existing natural gas plants. |
| Where does the hydrogen come from in your simulations? It did not appear that renewables increased significantly in the later year your slide was showing. | Blue hydrogen is assumed to be the hydrogen source. The forecasted cost of blue hydrogen is generally lower than green hydrogen production. Blue hydrogen relies upon the mature steam methane reformation process and natural gas is readily available as a feedstock. The higher marginal cost of green hydrogen production is due to the more expensive and relatively new hydrolyzer technology. |
| Following the above question: Could you provide these pricing inputs? | Yes, the hydrogen forecasts will be provided to Stakeholders. |
| Following the above question: Why would only behind-the-meter renewables be used to make hydrogen? | For clarification, behind the meter generation is assumed for green hydrogen production. To maximize the return on investment via credits, green hydrogen producers are assumed to produce hydrogen with all available renewable generation available to them each hour. This assumption is further supported by the IRS' proposed treatment to qualify for green hydrogen credits. The IRS has proposed that a facility |

| Question | Response |
|---|---|
| | will only qualify for green hydrogen credits if new renewable generation is installed. Additionally, the IRS has included stipulations of hourly matching of credits with hydrogen production and are proposing that the renewable power and hydrogen production be within the same geographic region. |
| Greg, we'd like to provide feedback on the scenarios and sensitivities as well, but it's not possible to do that in a vacuum, e.g., I don't know what "base" technology costs means. Will you be providing all this data so we can review and comment? | Yes, all that information will be given to stakeholders. We will be working on the release schedule of the data and inputs as we go forward with the technical stakeholder meetings. |
| Following the above question: EIA capital cost assumptions: Do those approximate the inputs you are using? | No, the Company has found through its RFPs that EIA benchmark costs are a bit low. While we start with EIA as a baseline, capital costs are updated with insights from our RFPs. |
| Slide 45-Relationship between Pillars and metrics; how do you translate pillars into metrics? Stability is a balance (not too much not too little). Stability challenges and how to measure it. Will the metric measure what type and how much of stability services each resource offers? Would the portfolios need to satisfy some minimum amount of stability services? | One of the things that doesn't really occur in the IRP is location-specific sitting. The IRP identifies resources to support the Company's capacity position, but those resources include different operational characteristics that provide grid stability attributes available to PJM to effectively manage the grid. |
| Follow up to the above question: I appreciate the challenge. My thought here is not that you're going to undertake some sort of transmission planning study or even a generator retirement study in conjunction with IRP. I'm suggesting that you use the analysis that your transmission planners have done to help inform the grid needs that you're already aware of. I think that's a really helpful starting place as you think about replacement generation in particular and also to also understand where new generic resources could be located as well. You know where violations are and your system right now, you know where you might need to make some sort of change to operations or change to lines would be very helpful information. | The Company appreciates this feedback and will review it with its Transmission Planning team. |

Appendix 4, Exhibit B: Workshop #2 September 24, 2024

Meeting Presentation

Meeting Minutes

Indiana Michigan Power Company

# INDIANA IRP STAKEHOLDER MEETING #2

September 24, 2024

INDIANA MICHIGAN POWER

An AEP Company

# Welcome & Introductions

## I&M Leadership Team

David Lucas | Vice President, Regulatory and Finance

Andrew Williamson | Director, Regulatory Services

Ed Locigno | Regulatory Analysis & Case Manager

Stacie Gruca | Manager, Regulatory Services

Austin DeNeff | Regulatory Consultant Senior

## 1898 & Co.

Brian Despard | Senior Project Manager

## GDS Associates, Inc.

Jeffrey Huber | Principal, Energy Efficiency

## I&M IRP Planning

Dylan Drugan | Manager, Resource Planning

Mohamed Abukaram | Director, Resource Planning

## I&M Infrastructure Development

Tim Gaul | Director, Regulated Infrastructure Development

## I&M Load Forecasting

Trenton Feasel | Manager, Economic Forecasting

# Agenda

| Time (EST) | Agenda Topic | Lead |
| --- | --- | --- |
| *1:00-1:10* | **Welcome & Introductions** | **Andrew Williamson** |
| *1:10-1:20* | **Going-In Capacity Position Review** | **Dylan Drugan** |
| *1:20-1:45* | **Load Forecast Assumptions and Methodology** | **Trenton Feasel** |
| *1:45-2:00* | **DSM Modeling Inputs** | **Jeffrey Huber** |
| *2:00-2:10* | **Short Break** | |
| *2:10-2:25* | **Market Assessment of Existing and New Resources**<br>• Queue Analysis Of New Resources | **Tim Gaul** |
| *2:25-3:00* | **Resource Modeling Parameters**<br>• Resource costs, build limits, and availability | **Dylan Drugan** |
| *3:00-3:10* | **Short Break** | |
| *3:10-3:35* | **Key Modeling Inputs**<br>• Assumptions related to IRA credits, Cook, Hydro, and Storage<br>• Implementing Stakeholder Feedback | **Mohamed Abukaram** |
| *3:35-3:45* | **Market Scenarios and Sensitivities**<br>• Stakeholder Meetings 3A and 3B | **Dylan Drugan** |
| *3:45-4:00* | **Open Discussion**<br>• Feedback From Stakeholders | **Andrew Williamson** |

# Preliminary PJM ELCC and FPR Forecasts

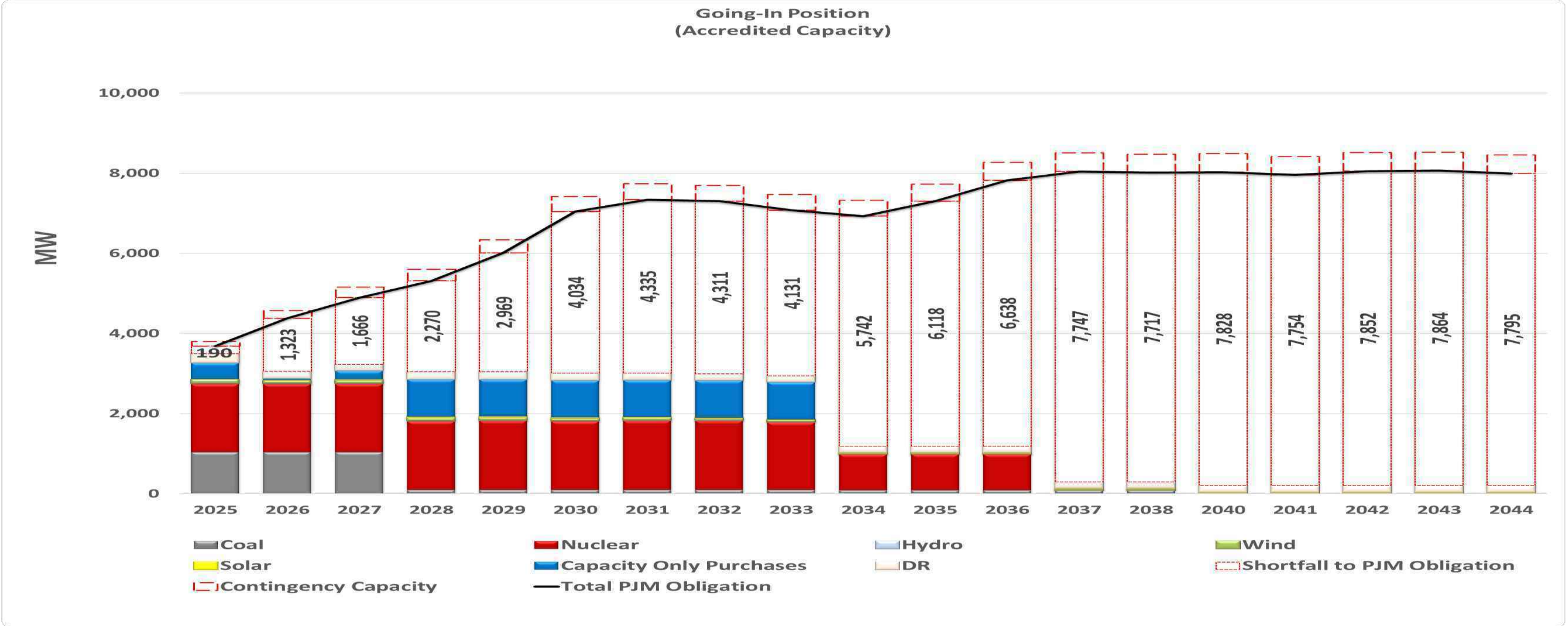
| ELCC Class | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|
| Onshore Wind | 35% | 33% | 28% | 25% | 23% | 21% | 19% | 17% | 15% |
| Offshore Wind | 61% | 56% | 47% | 44% | 38% | 37% | 33% | 27% | 20% |
| Fixed-Tilt Solar | 7% | 6% | 5% | 5% | 4% | 4% | 4% | 4% | 3% |
| Tracking Solar | 11% | 8% | 7% | 7% | 6% | 5% | 5% | 5% | 4% |
| Landfill Intermittent | 54% | 55% | 55% | 56% | 56% | 56% | 56% | 56% | 54% |
| Hydro Intermittent | 38% | 40% | 37% | 37% | 37% | 37% | 39% | 38% | 38% |
| 4-hr Storage | 56% | 52% | 55% | 51% | 49% | 42% | 42% | 40% | 38% |
| 6-hr Storage | 64% | 61% | 65% | 61% | 61% | 54% | 54% | 53% | 52% |
| 8-hr Storage | 67% | 64% | 67% | 64% | 65% | 60% | 60% | 60% | 60% |
| 10-hr Storage | 76% | 73% | 75% | 72% | 73% | 68% | 69% | 70% | 70% |
| Demand Resource | 70% | 66% | 65% | 63% | 60% | 56% | 55% | 53% | 51% |
| Nuclear | 95% | 95% | 95% | 96% | 95% | 96% | 96% | 94% | 93% |
| Coal | 84% | 84% | 84% | 85% | 85% | 86% | 86% | 83% | 79% |
| Gas Combined Cycle | 79% | 80% | 81% | 83% | 83% | 85% | 85% | 84% | 82% |
| Gas Combustion Turbine | 61% | 63% | 66% | 68% | 70% | 71% | 74% | 76% | 78% |
| Gas Combustion Turbine Dual Fuel | 79% | 79% | 80% | 80% | 81% | 82% | 83% | 83% | 83% |
| Diesel Utility | 92% | 92% | 92% | 92% | 92% | 93% | 93% | 93% | 92% |
| Steam | 74% | 73% | 74% | 75% | 74% | 75% | 76% | 74% | 73% |

https://www.pjm.com/-/media/planning/res-adeq/elcc/preliminary-elcc-class-ratings-for-period-2026-2027-through-2034-2035.ashx

| Delivery Year | Forecast Pool Requirement (% of Peak Load) |
|---|---|
| 2026/27 | 93.67% |
| 2027/28 | 92.69% |
| 2028/29 | 92.75% |
| 2029/30 | 93.47% |
| 2030/31 | 92.96% |
| 2031/32 | 92.72% |
| 2032/33 | 92.10% |
| 2033/34 | 89.99% |
| 2034/35 | 87.09% |

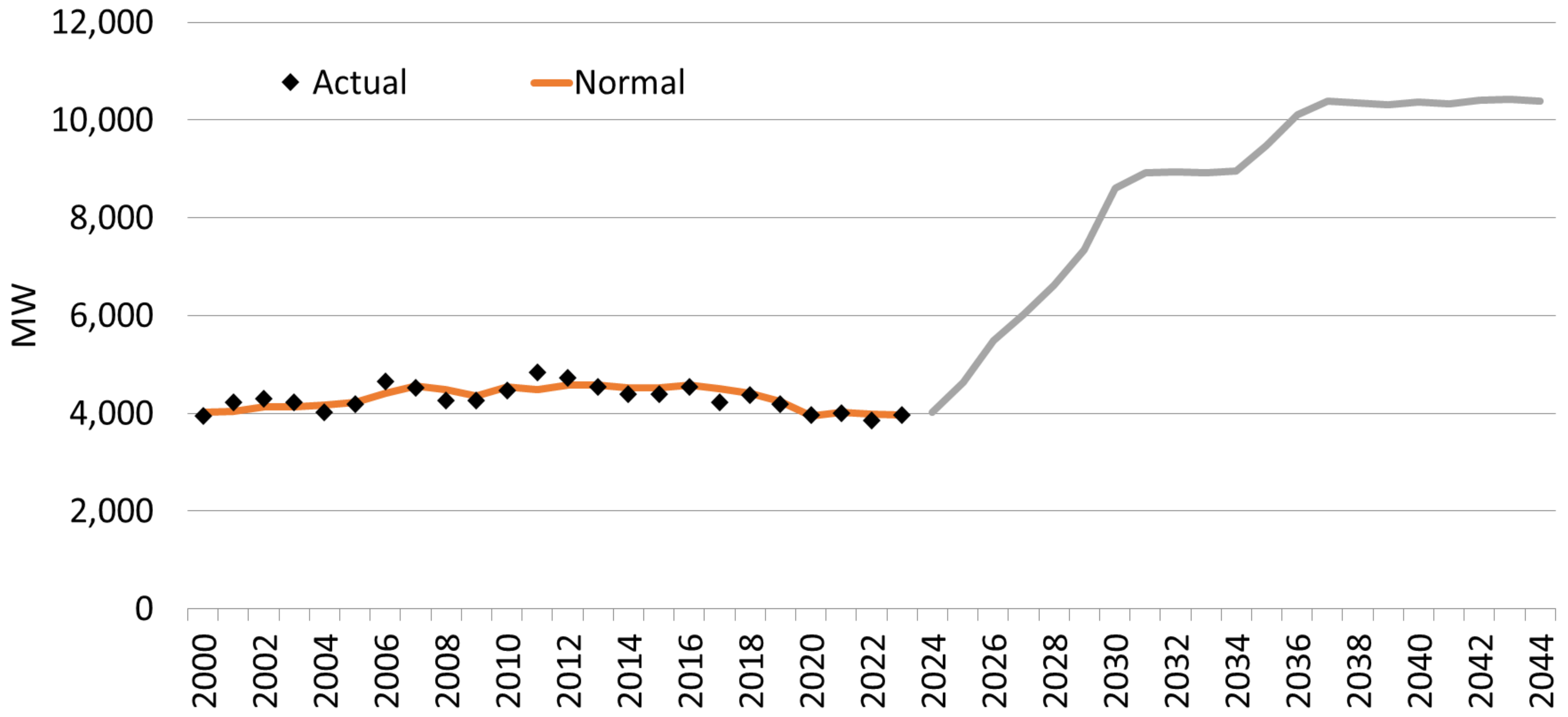
- I&M’s forecasted capacity need is influenced by the accredited capacity PJM recognizes for I&M’s resources (i.e., ELCC Class values) as well as by the load requirement PJM sets (i.e., the “FPR” or Forecast Pool Requirement).
- PJM’s forecasted decline in ELCC class values for resources such as wind, solar, and storage is offset, in part, by a lower forecasted peak load requirement (i.e., a lower FPR).

# Capacity Needs Assessment (Preliminary Going-In Position)



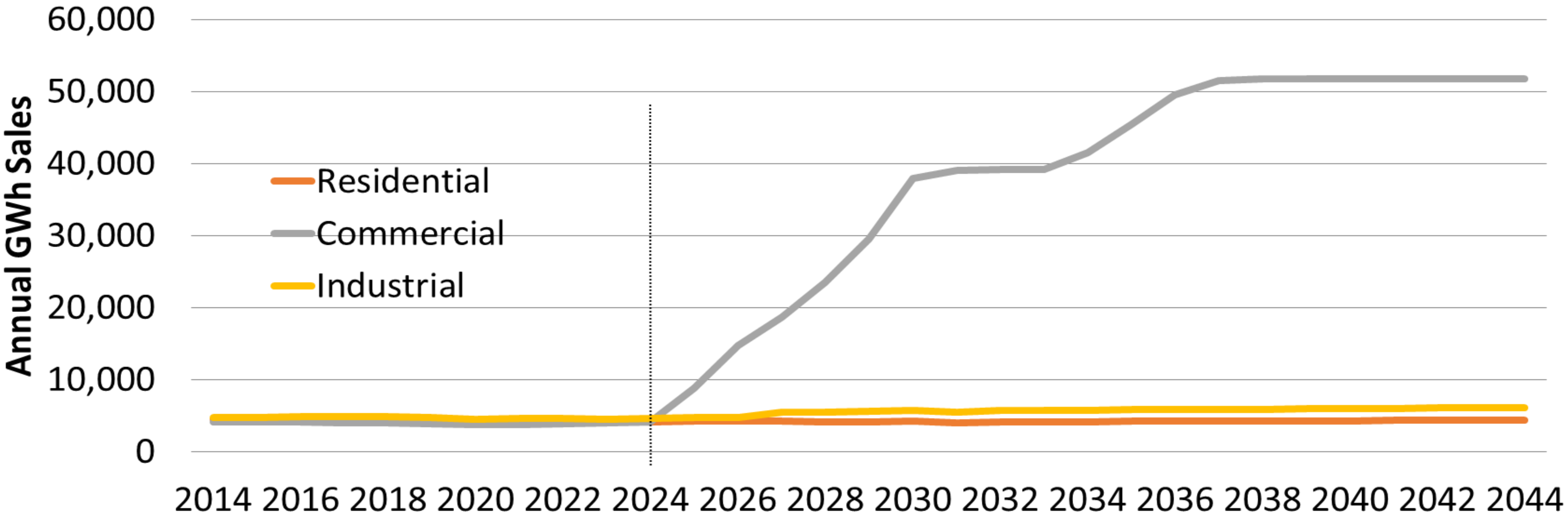

- To reasonably capture contingency risk around future uncertainties such as changes to load obligations and available capacity, a probabilistic risk analysis was performed to evaluate a reasonable amount of 'Contingency Capacity' needed for planning purposes.
- The analysis resulted in planning for Contingency Capacity at a level of 5% above the PJM load obligation by 27/28;
  - PJM Load Obligation is ~93% of peak load in 27/28 and, in turn, Contingency Capacity level is at ~98% of peak load (~93% + 5%);
  - Additional 5% for Contingency Capacity results in planning for up to an additional ~450 MW above the PJM Load Obligation.

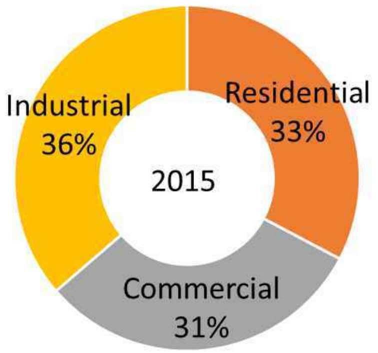
# I&M Peak Demand Forecast

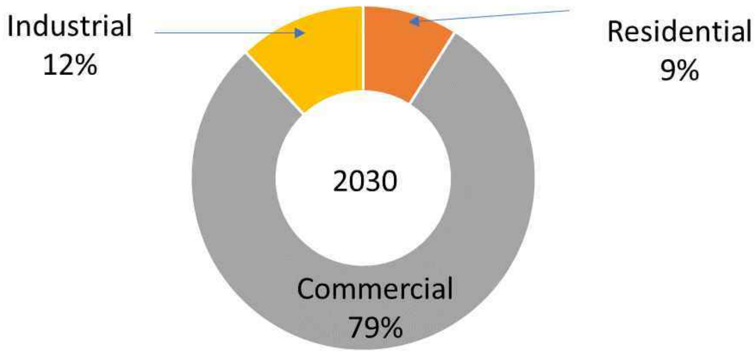



I&M's peak demand forecast is projected to grow at an 8.3% CAGR from 2024-2034, driven by the addition of hyperscaler data center loads in Indiana.

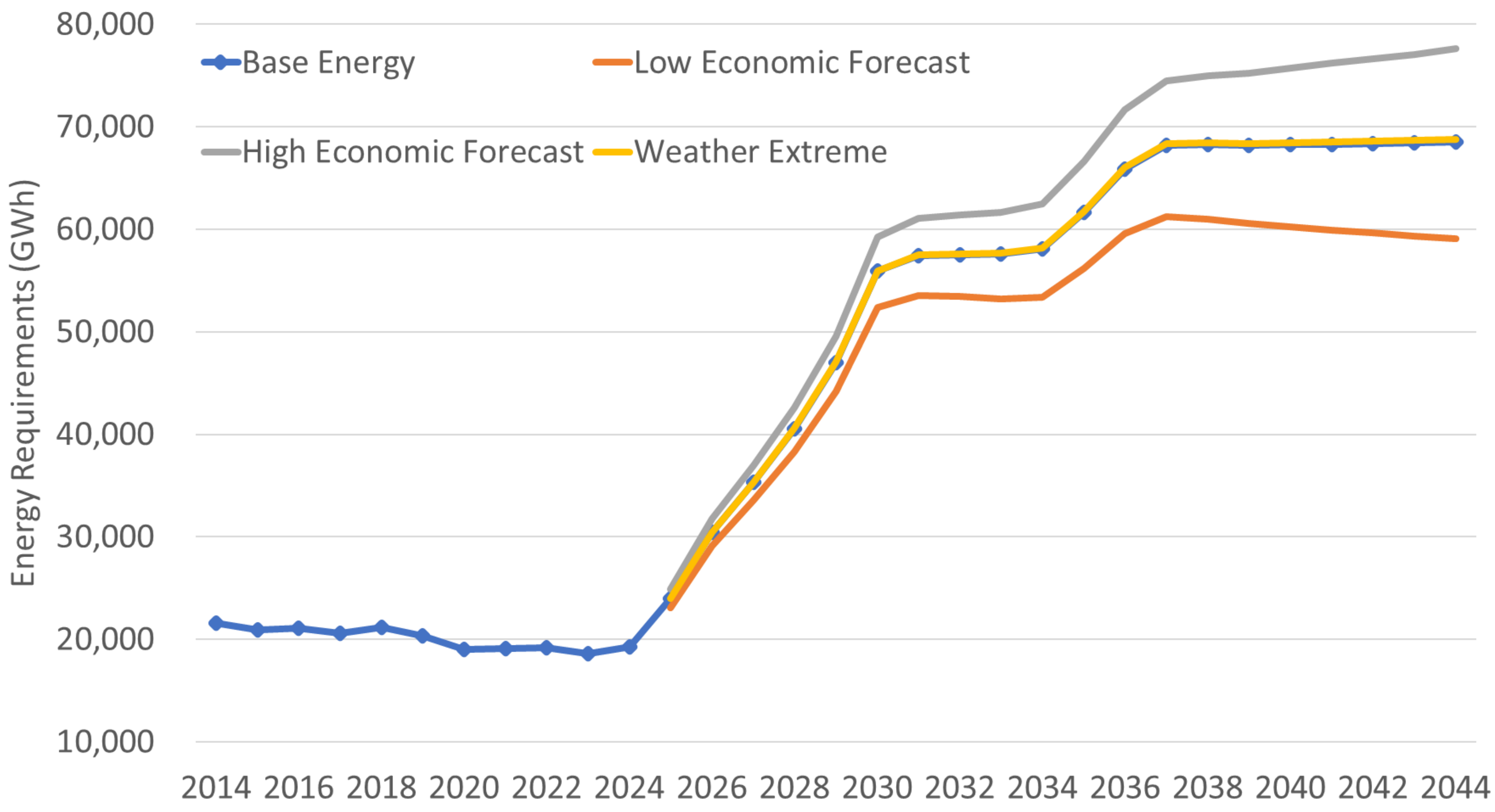
# Indiana GWh Sales
# (Weather Normalized History & Forecast)



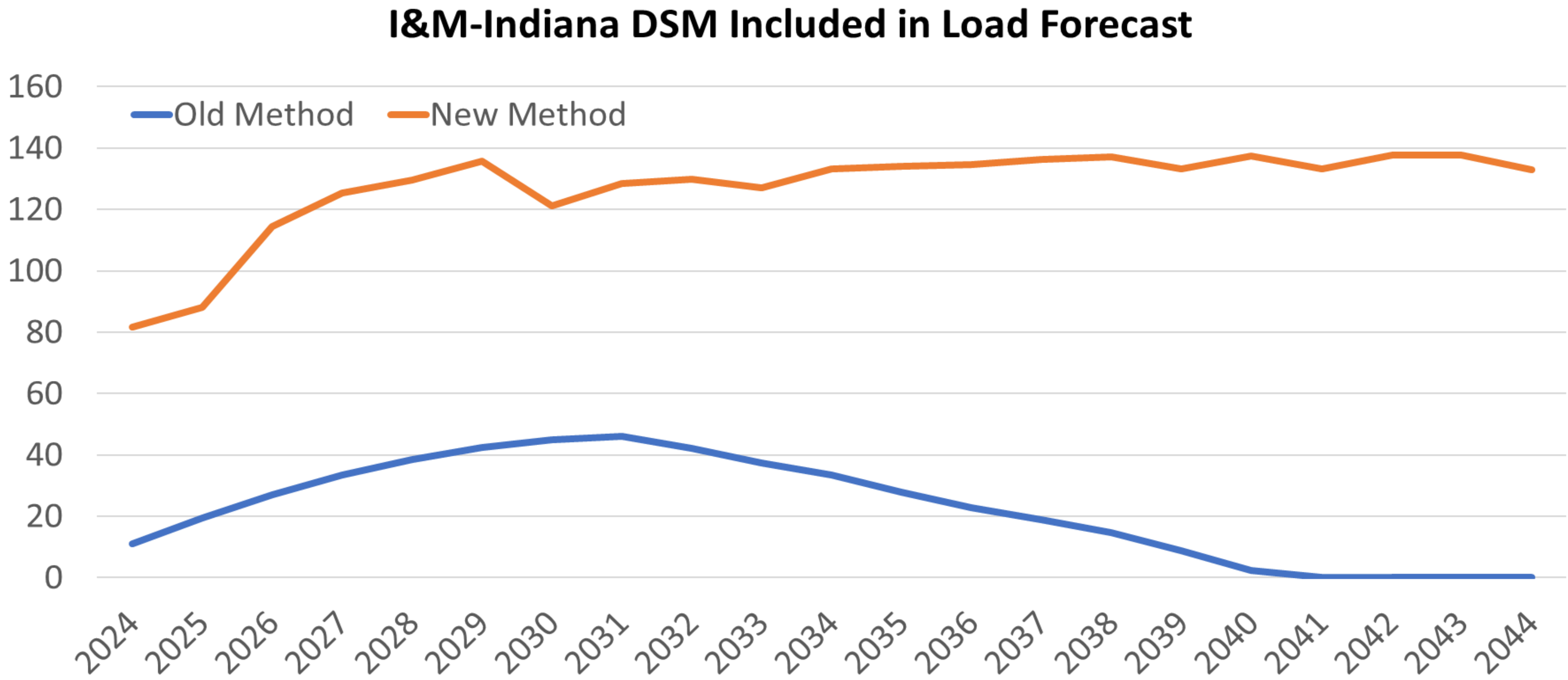



# Load Forecast Scenarios

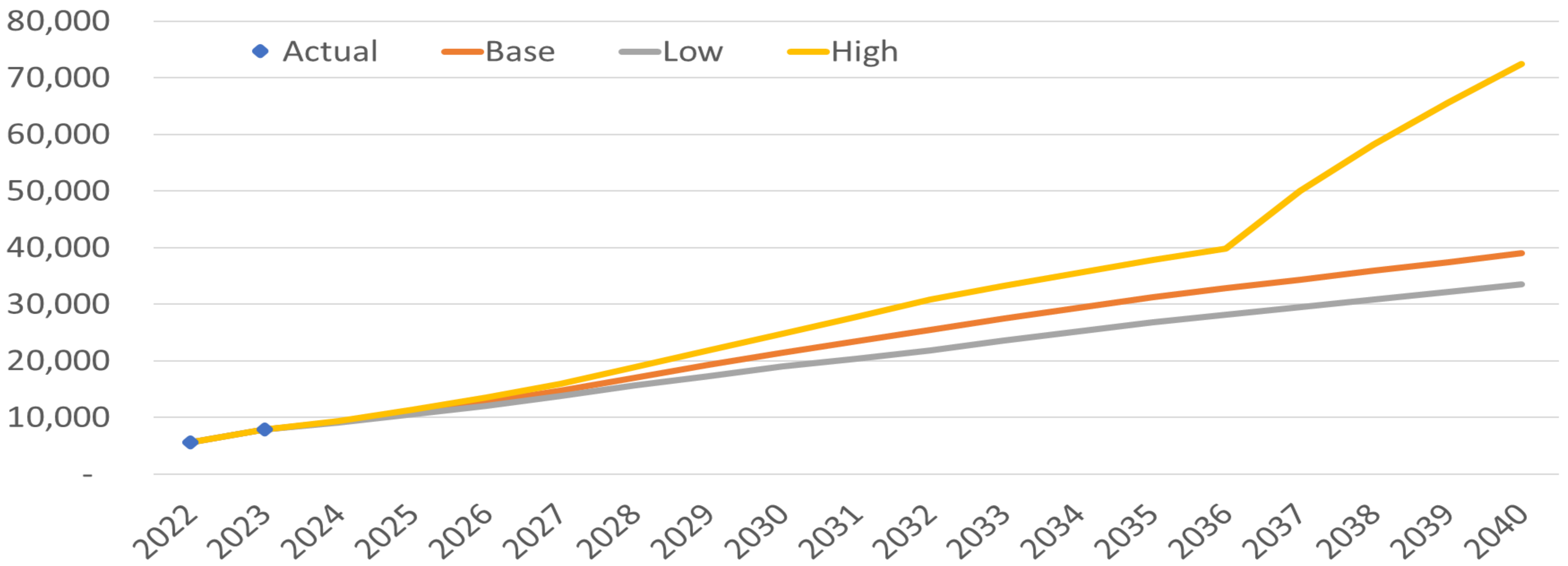


# Controlling for DSM/EE



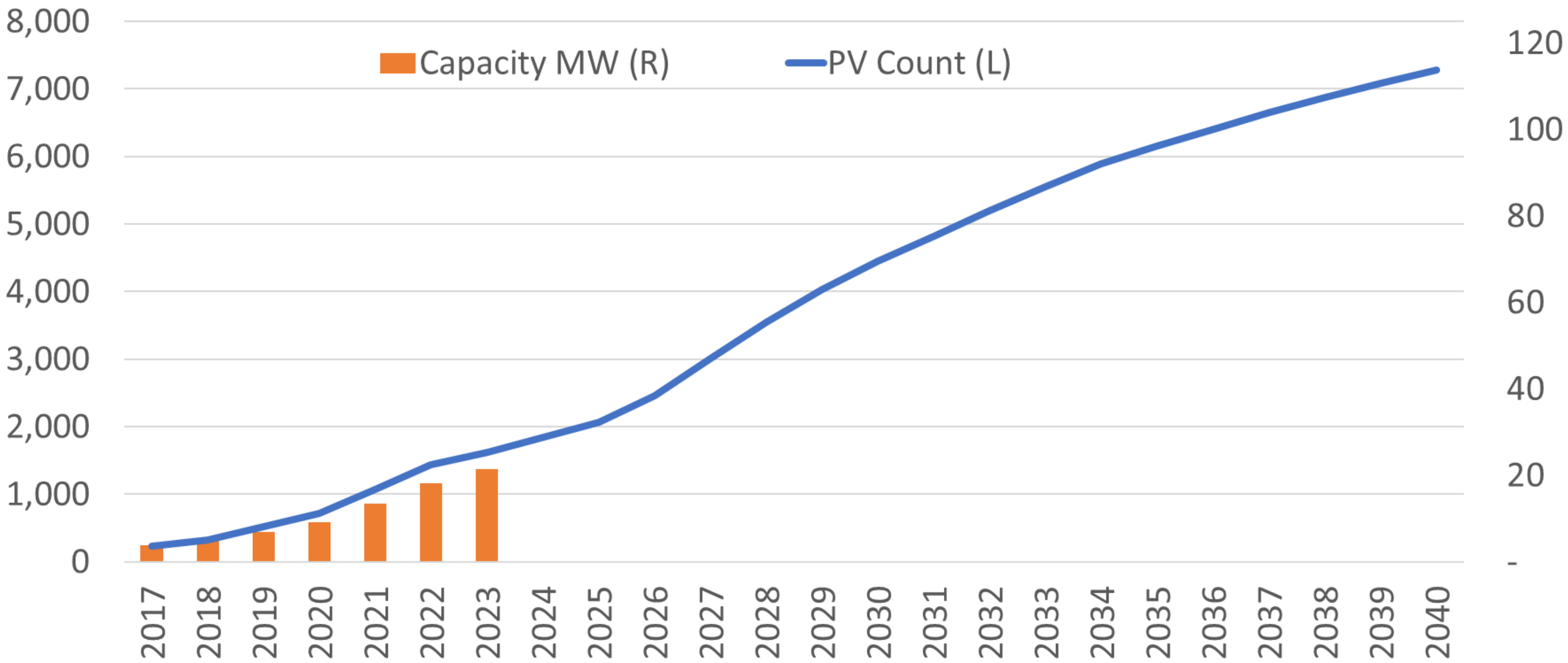

Per Rockport Unit 2 Declination of Jurisdiction Settlement in CN 45546, I&M now explicitly accounts for DSM programs in its econometric model as an additional independent variable. This has led to DSM having a greater impact on the forecast than the prior degradation approach. DSM was a post model adjustment in the “Old Method” and degraded over time. DSM is used as an explanatory variable in the “New Method” and does not reflect the degradation in the “Old Method.”

# Indiana Electric Vehicle Count Forecast




Despite projected 12% annual growth over the next decade, EVs will make up a small portion of the roughly 1.8M vehicles in the I&M Indiana territory. There is upside to the should affordability improve and/or mandates occur, as illustrated by the high forecast scenario.

# Indiana Solar Forecast




At the end of 2023, customer-owned solar reached a total nameplate capacity of 21 MW, or about 0.5% of I&M's 2023 peak. Adoption is projected to continue increasing as costs are projected to fall. By 2040, customer-owned solar is projected to decrease retail energy by about 0.4%.

# Market Potential Study Savings and DSM Inputs for IRP

## Energy Efficiency

- RAP and Enhanced RAP Potential Savings were provided for input into the IRP using 6 total bundles and a few minor adjustments:
  - 1 non-residential bundle, 3 residential market rate bundles, and 2 income-qualified bundles
  - 3 residential bundles include behavior, low/medium cost, and high-cost measures
  - 2 income-qualified bundles include traditional income-qualified program savings as well as additional potential impacts from federal funded programs
  - EE impacts were adjusted to reflect net savings (not gross) at the generation level (line loss adjustments)
  - Avoided transmission and distribution capacity benefits were treated as a reduction in annual program costs
  - Each sector bundle has its own 8,760 shape based on measure mix

## Demand Response

- RAP provided for 2 bundles that includes 14 programs / sub-segments. Bundles are sector-based.
- Each DR program type was modeled separately with its own seasonal MW potential and annual cost profile.
- Avoided transmission and distribution capacity benefits were treated as a reduction in annual DR program cost.
- Residential
  - DLC Central AC Switch, DLC Thermostat, DLC Water Heating, DLC EV Charging, EV Rate, Behavioral (iControl), Time of Use Rate, Critical Peak Pricing Rate
- C&I
  - DLC Thermostat, Curtailable Rate, Real Time Pricing Rate, Time of Use Rate, Critical Peak Pricing Rate, Capacity Bidding

# EE Bundles

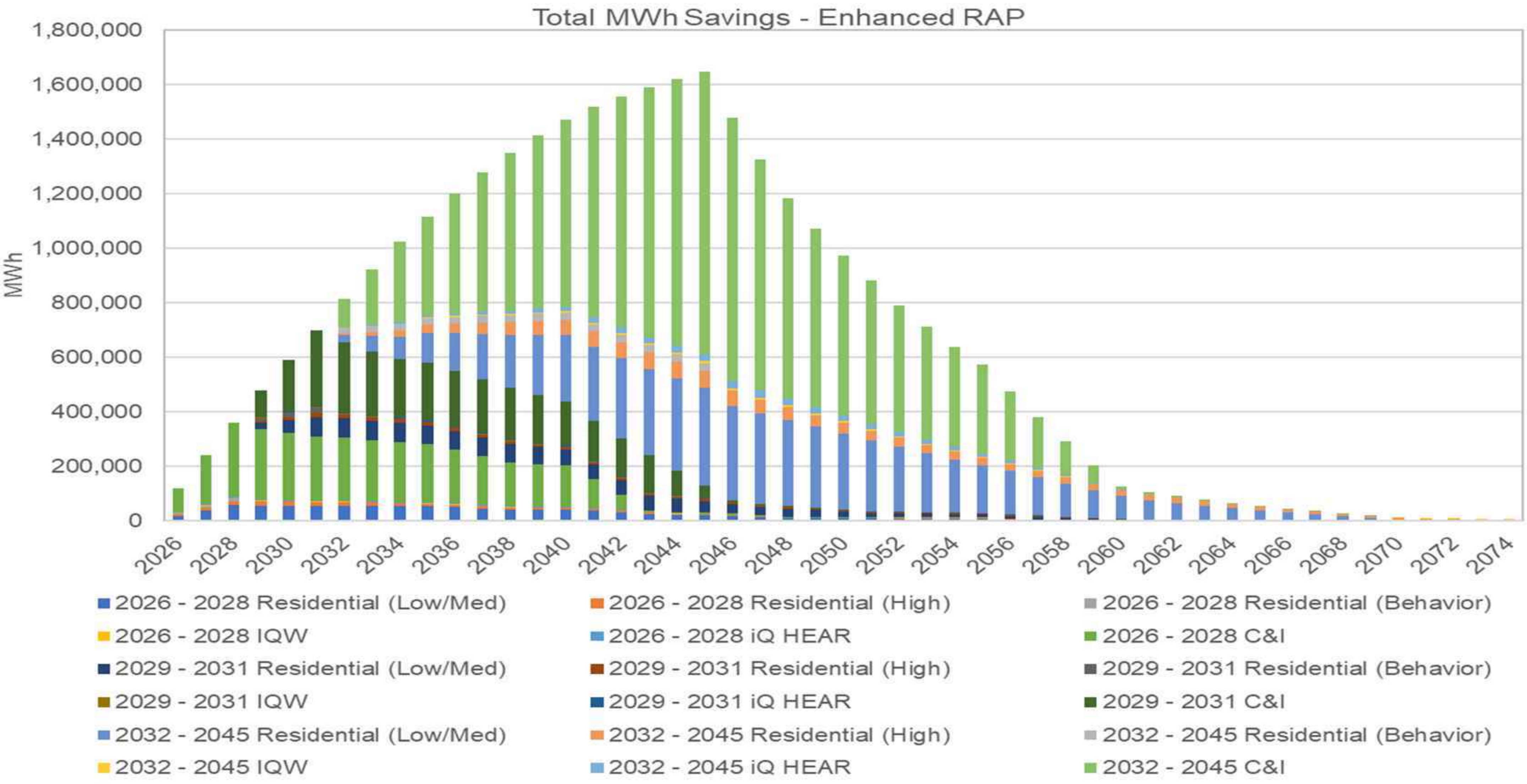
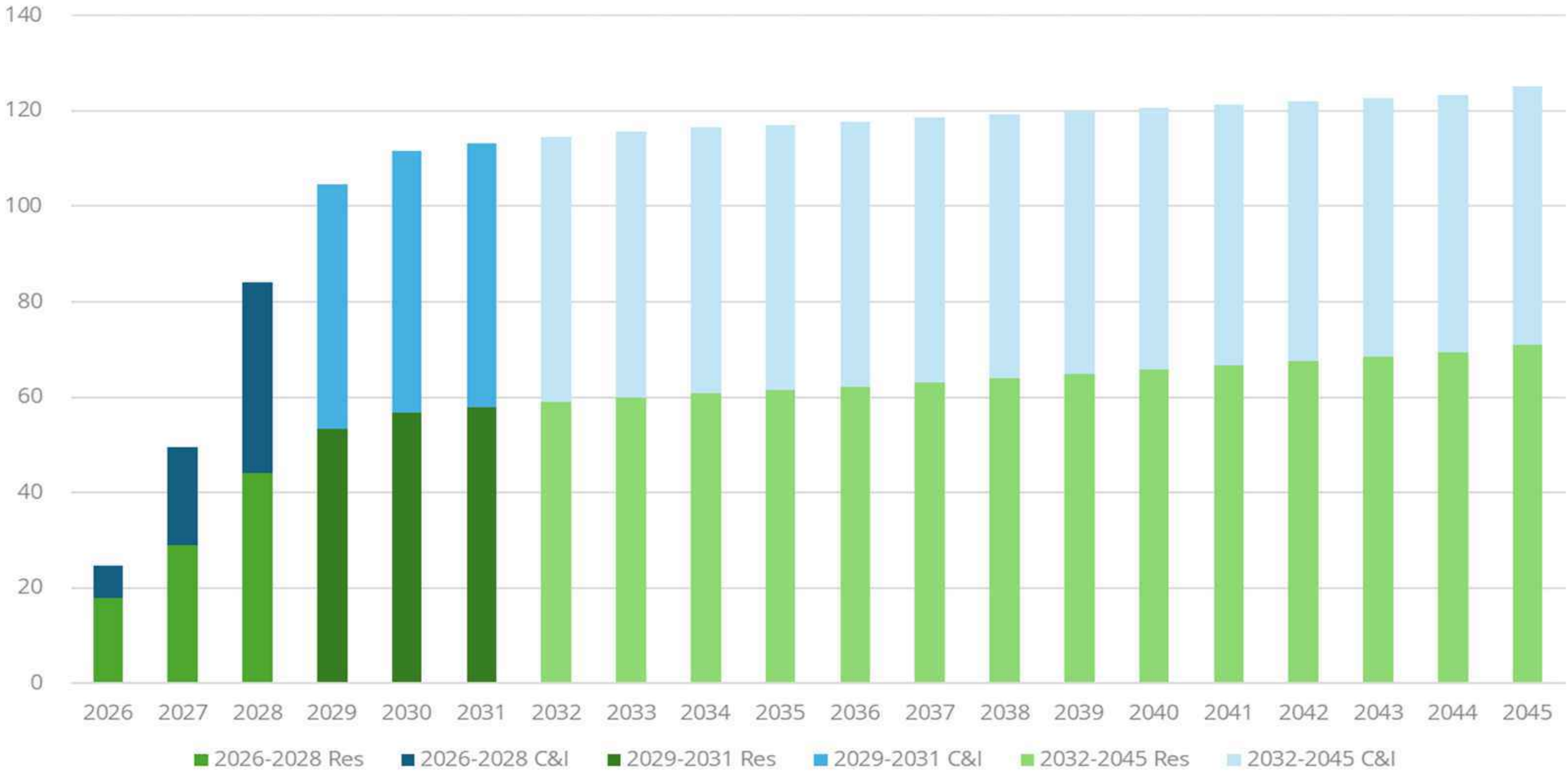



Chart reflects cumulative savings potential available to be selected by the model.

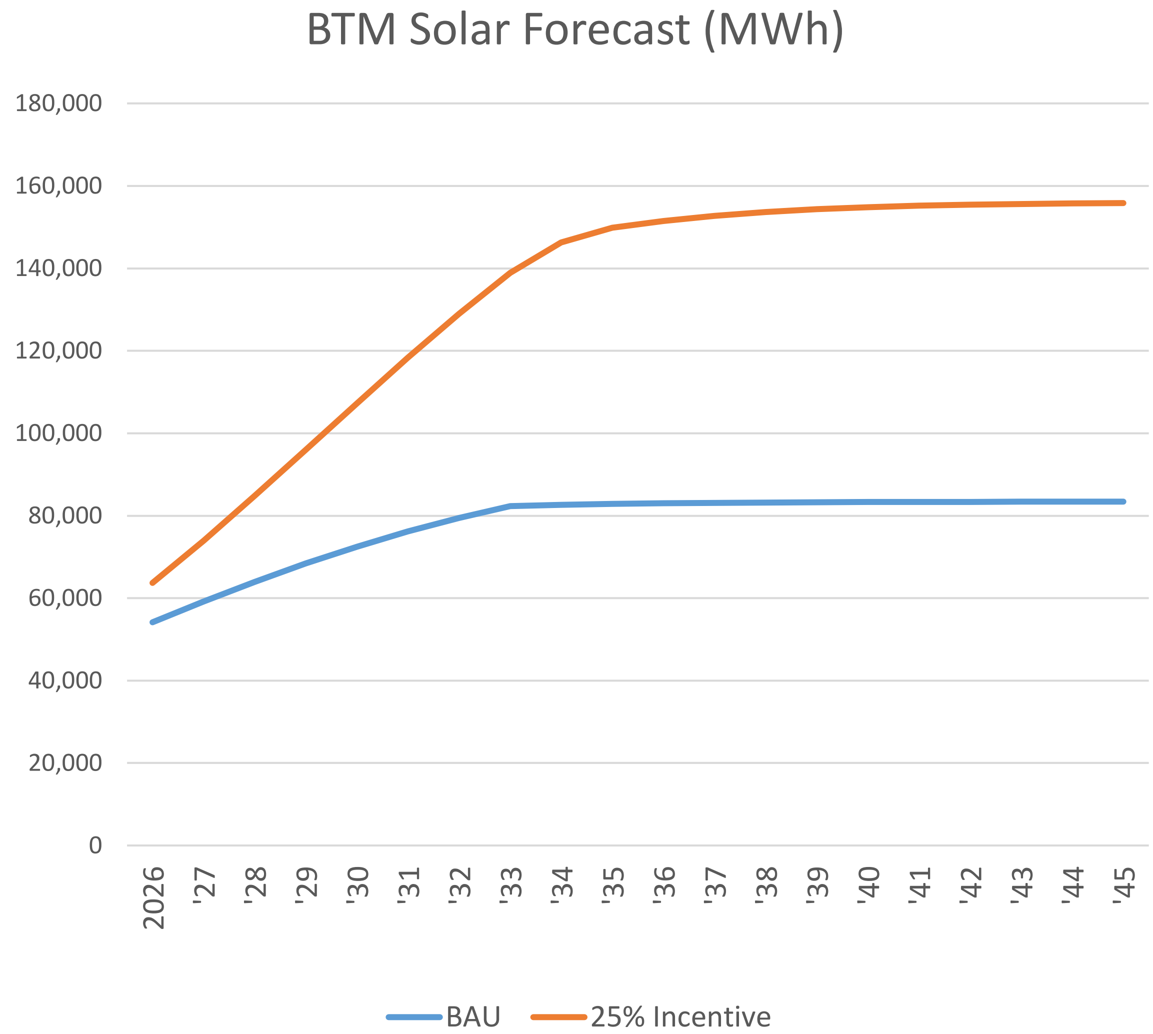
# DR Bundles by Sector




- Preliminary chart that reflects cumulative savings potential for cost-effective measures only;
- However, all DR potential will be available to be selected in model;
- In addition, DER measures (solar and solar + storage) are also being developed and will be available for model selection.

# DER Resources

- Behind the Meter (BTM) Solar
  - IRP Inputs based on incremental impacts above and beyond business as usual/no intervention forecast
  - Assumes utility intervention (25% incentive) for solar PV installs
  - PV installs assumed across residential and nonresidential sectors




- Battery Storage
  - Battery Storage considered as part of the Demand Response analysis
  - Program opportunity was tethered to the BTM Solar Forecast that assumes the 25% utility intervention

- Preliminary chart that reflects cumulative savings potential for cost-effective measures only;
- However, all DR potential will be available to be selected in model;
- In addition, DER measures (solar and solar + storage) are also being developed and will be available for model selection.

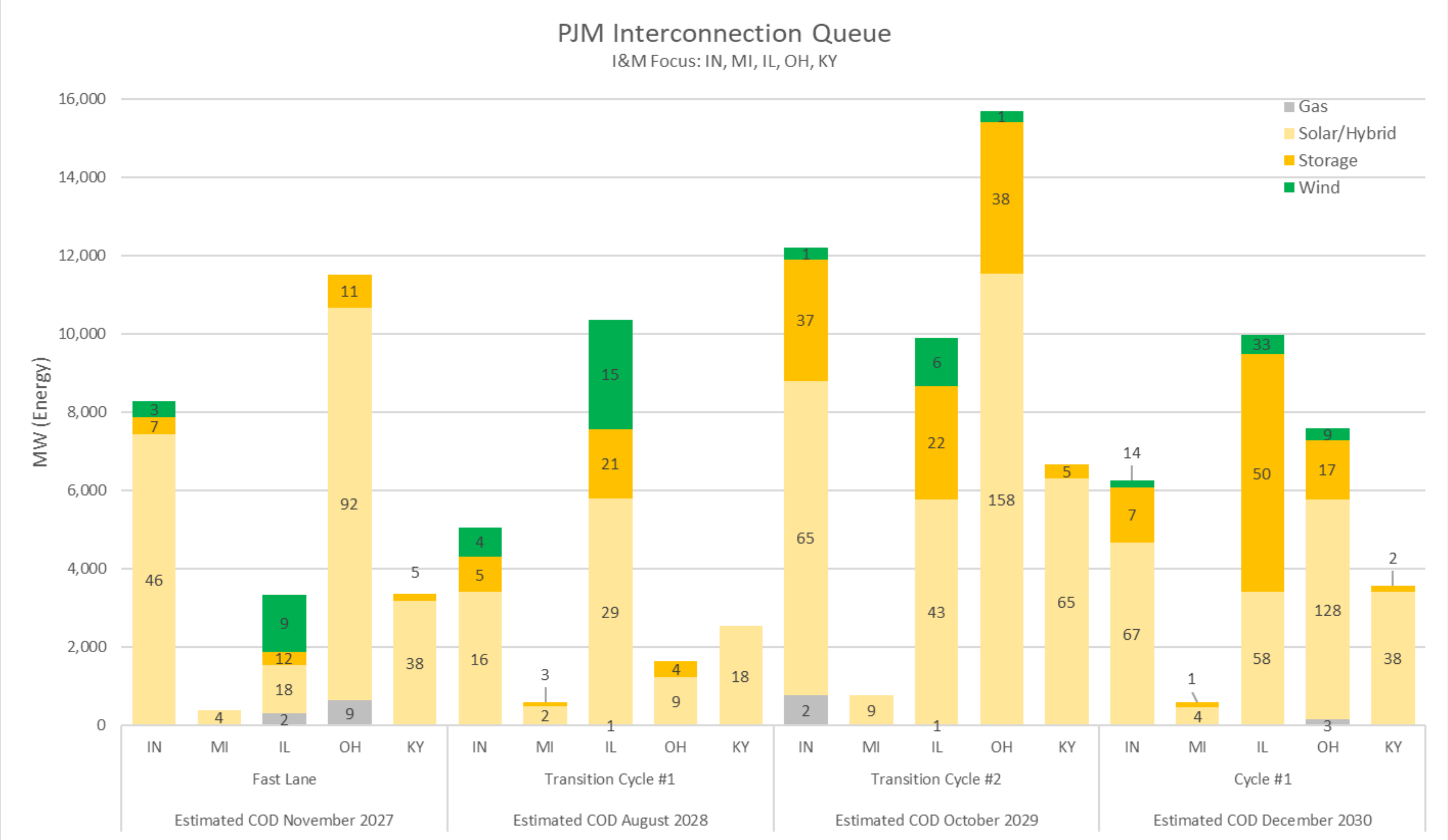
INDIANA MICHIGAN POWER
An AEP Company

# CVR Inputs

| First Full Year In-Service | # of CVR Projects | Annual Projected Energy Savings (kWh) | Annual Projected Demand Savings (kW) | Sum of Capital Cost | Sum of Annual O&M Cost |
|---|---|---|---|---|---|
| **2025** | 25 | 25,949,992 | 695 | $20,504,336 | $386,059 |
| **2026** | 34 | 31,731,801 | 1,105 | $27,418,013 | $525,040 |
| **2027** | 14 | 16,230,802 | 436 | $11,729,327 | $216,193 |
| **2028** | 6 | 4,942,409 | 158 | $3,174,476 | $92,654 |
| **2029** | 10 | 9,560,529 | 354 | $7,056,004 | $154,424 |
| **2030** | 1 | 1,506,137 | 19 | $565,204 | $15,442 |

- CVR useful life is 20 years. Project annual energy and demand savings will be included in the model for 20 years from “First Full Year In-Service”;
- All CVR savings shown above will be forced into the model.

# Resource Availability – IN, MI, IL, OH, KY




**NOTE: Stacked Bar Chart Labels Represent Project Counts**

# Resource Modeling Parameters (Baseload Resources)

| Base Load (New Resources) | | | | | |
|---|---|---|---|---|---|
| **Resource Type** | **First Year Available** | **Annual Build Limit (MW)** | **Cumulative Build Limit through 2030 (MW)** | **Total Cumulative Build Limit Through Planning Horizon (MW)** | **Overnight Cost[1] $/kW** |
| **NUCLEAR SMALL MODULAR REACTOR** | 2037 | 600 | N/A | 5,100 | $11,700 |
| **NEW NG COMBINED CYCLE (2x1)** | 2031 | 1,030 | N/A | 5,600 | $1,800 |
| **NEW NG COMBINED CYCLE (1x1)** | 2031 | 420 | N/A | | $2,000 |
| **NEW NG COMBINED CYCLE W/CARBON CAPTURE SYSTEM (CCS)** | 2035 | 380 | N/A | 3,800 | $4,300 |

| Base Load (Existing Resources) | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Resource Type** | **First Year Available** | **Last Year Available** | **Annual Build Limit (MW)** | **Cumulative Build Limit through 2030 (MW)** | **Total Cumulative Build Limit Through Planning Horizon (MW)** | **Overnight Cost[1] $/kW** | **Overnight Cost[1] $/MW-D** |
| **EXISTING NG COMBINED CYCLE (5 YEAR)** | 2028 | 2031 | 1,800 | 3,600 | 5,400 | N/A | $485 |
| **EXISTING NG COMBINED CYCLE (10 YEAR)** | 2028 | 2031 | | | | | |
| **EXISTING NG COMBINED CYCLE (20 YEAR)** | 2028 | 2031 | | | | $1,100 | N/A |

Note 1: Costs represent nominal dollars in the first year that the resource is available.

# Resource Modeling Parameters (Peaking Resources)

## Peaking (New Resources)

| Resource Type | First Year Available | Annual Build Limit (MW) | Cumulative Build Limit through 2030 (MW) | Total Cumulative Build Limit Through Planning Horizon (MW) | Overnight Cost[1] $/kW |
|---|---|---|---|---|---|
| NEW COMBUSTION TURBINE | 2030 | 920 | 920 | 6,670 | $1,500 |
| COMBUSTION TURBINES AERODERIVATIVE | 2031 | 330 | N/A | 1,320 | $2,020 |
| RECIPROCATING INTERNAL COMBUSTION ENGINES (RICE) | 2031 | 100 | N/A | 400 | $3,300 |

## Peaking (Existing Resources)

<table>
<tr><th>Resource Type</th><th>First Year Available</th><th>Last Year Available</th><th>Annual Build Limit (MW)</th><th>Cumulative Build Limit through 2030 (MW)</th><th>Total Cumulative Build Limit Through Planning Horizon (MW)</th><th>Overnight Cost[1] $/kW</th><th>Overnight Cost[1] $/MW-D</th></tr>
<tr><td>EXISTING NG COMBUSTION TURBINE (5 YEAR)</td><td>2028</td><td>2031</td><td rowspan="3">1,000</td><td rowspan="3">3,000</td><td rowspan="3">4,000</td><td rowspan="2">N/A</td><td rowspan="2">$320</td></tr>
<tr><td>EXISTING NG COMBUSTION TURBINE (10 YEAR)</td><td>2028</td><td>2031</td></tr>
<tr><td>EXISTING NG COMBUSTION TURBINE (20 YEAR)</td><td>2028</td><td>2031</td><td>$540</td><td>N/A</td></tr>
</table>

Note 1: Costs represent nominal dollars in the first year that the resource is available.

# Resource Modeling Parameters (Intermittent Resources)

INDIANA MICHIGAN POWER
An AEP Company

| Intermittent (Wind & Solar) | | | | | | |
|---|---|---|---|---|---|---|
| Resource Type | First Year Available | Annual Build Limit (MW) | Cumulative Build Limit through 2030 (MW) | Total Cumulative Build Limit Through Planning Horizon (MW) | Overnight Cost[1] $/kW | Overnight Cost[1] $/MWh |
| WIND (15 YEAR) | 2029 | 600 | 800 | 3,200 | N/A | $86 |
| WIND (30 YEAR) | 2031 | 400 | N/A | | $3,000 | N/A |
| SOLAR (15 YEAR) | 2028 | 600 | 1,200 | 4,800 | N/A | $85 |
| SOLAR (35 YEAR)[2] | 2028 | 600 | 1,200 | 4,800 | $2,500 | N/A |
| SOLAR w/STORAGE (4-HOUR) | 2028 | 600 | 750 | 1,350 | $3,100 | N/A |

| Intermittent (Storage) | | | | | |
|---|---|---|---|---|---|
| Resource Type | First Year Available | Annual Build Limit (MW) | Cumulative Build Limit through 2030 (MW) | Total Cumulative Build Limit Through Planning Horizon (MW) | Overnight Cost[1] $/kW |
| NEW STORAGE (4-HOUR) | 2028 | 250 | 500 | 3,000 | $2,000 |
| NEW STORAGE (6-HOUR) | 2029 | 150 | 300 | 1,800 | $3,000 |
| NEW STORAGE (8-HOUR) | 2029 | 100 | 200 | 1,200 | $4,000 |
| NEW STORAGE (100-HOUR) | 2032 | 40 | N/A | 240 | $2,800 |

Note 1: Costs represent nominal dollars in the first year that the resource is available.
Note 2: I&M plans to incorporate recent stakeholder feedback by modeling a subset of solar resources that are eligible for the Energy Community Tax Credit Bonus

# IRA Tax Credit Inputs

## Investment Tax Credits (ITC)

- ITC applied to Solar, Storage and SMNR
- Additional Energy Community Credits assumed for subset of renewable options
- Schedule of ITC
  - 2025-36: 30% credit
  - 2037: 22.5%
  - 2038: 15%
  - 2039+: 0%

## Production Tax Credits

- PTC applied to Wind
- Schedule of PTC
  - 2025-36: applied to all new build wind for the first 10 years of life (~ in the range of $40/MWh-$58/MWh)
  - 2037: PTC reduced by 25%
  - 2038: PTC reduced by 50%
  - 2039+: No PTC applied to new builds from this year onwards

## Carbon Capture Storage Tax Credits

- Credit applied to Carbon Capture Storage technologies for every MWh produced
- Schedule of Carbon Capture Storage Tax Credits
  - 2025-36: applied to all new build CC with CCS for the first 12 years of life (~ in the range of $29/MWh-$44/MWh)
  - 2037+: No CCS tax credits applied to new build from this year onwards

# Cook Subsequent License Renewal (SLR) Analysis

## Cook Relicensing Optimization

- U1 Current License Expiration Q4 2034;
- U2 Current License Expiration Q4 2037;
- Model will optimize the decision to retire or relicense while considering economics and reliability.

## Costs Considered in Cook Relicensing Analysis

- **NOTE:** these are estimates in 2023 Dollars and do not include items such as AFUDC, Overhead Costs, Cost Escalations, etc.;
- **Subsequent License Renewal (SLR) Cost**: $42.5M;
- **One-Time inspection Costs after SLR received:** $20M;
- **Dry Cask Fuel Storage Pad Extension Cost:** $4.1M (reflects assumed DOE reimbursement of certain costs) ;
- **Capital Improvement Costs to support an additional 20 years of life:** $250M;
- On-Going Capital Costs (OGC) and Fixed Operations & Maintenance (FO&M) Cost schedules.

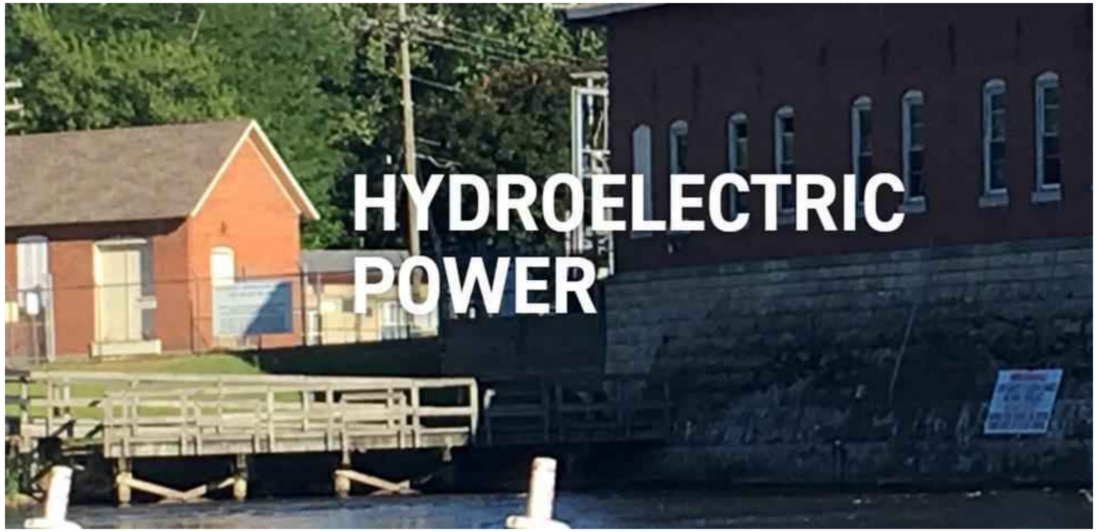
# Hydro Subsequent Renewed Operating License Analysis

## Hydro Relicensing Optimization

- Analysis only performed on Hydro units that have license expirations occurring within the next 10 years;
- Elkhart Current License Expiration Q4 2030;
- Mottville Current License Expiration Q4 2033;
- Model will optimize the decision to retire or relicense while considering economics and reliability.

## Costs Considered in Hydro Relicensing Analysis

- **NOTE:** These are estimates and do not include items such as AFUDC, Overhead Costs, Cost Escalations, etc.;
- Operating License Renewal Cost:
    - $1M for Elkhart and $1M for Mottville;
- On-Going Capital Costs (OGC) and Fixed Operations & Maintenance (FO&M) Cost schedules;
- Decommissioning Costs:
    - Elkhart: $262M
    - Mottville: $115M



# Storage Modeling Inputs & Methodology (Utility Scale)

## Utility Scale Storage Resource Options

### *Modeling Steps*

- Storage resources are dispatched against Fundamental Market Prices in an hourly chronological production cost model run;
- The Generation and Charge Costs are extracted and placed as inputs in the Expansion Planning Optimization;

### *Day Ahead, Real Time, and Ancillary Services Market Revenue*

- Value in the Ancillary Service and RT Energy Markets are captured through Fixed Cost reductions in the Expansion Planning Optimization. Additional volatility in the DA Market is captured in the same fashion.

| Utility - Scaled Storage Options Specs per Block | | | | | |
|---|---|---|---|---|---|
| Technology | Power (MW) | Duration | Capacity (MWh) | RTE% | Expected Life (years) |
| Lithium - Ion | 50 | 4 | 200 | 87% | 20 |
| Lithium - Ion | 50 | 6 | 300 | 87% | 20 |
| Lithium - Ion | 50 | 8 | 400 | 87% | 20 |
| Lithium - Ion | 50 | 10 | 500 | 87% | 20 |
| Iron - Air | 20 | 100 | 2000 | 40% | 20 |

# Storage Modeling Inputs & Methodology (Distribution-Sited)

## Distribution Storage Resource Options

### *Modeling Steps*

- Distribution Storages Resources are dispatched against Fundamental Market Prices in an hourly chronological production cost model run;
- The Generation and Charge Costs are extracted and placed as inputs in the Expansion Planning Optimization.

### *2 Use Cases*

- **“Thermal” Use Case**
  - Storage placed at stations nearing thermal overload conditions. Storage adds additional capacity at station and defers the need for upgrades (e.g., upgrading to a larger transformer);
  - Capital cost of storage will be reduced by estimated deferred cost of distribution upgrade;
  - Storage restricted from receiving energy revenues in peak months (mid-July to mid-August) but can receive energy revenues in the remaining months.
- **“Reliability” Use Case**
  - Storage placed at stations that have had historical reliability issues.
  - 50% of storage capacity always reserved to address reliability events. Remaining 50% of capacity can be used for energy market.
  - Capital cost of storage will be reduced by estimated Avoided Customer Minutes of Interruption (CMI) savings from improved reliability.

**Distribution Storage Resource Option Specs**

| Target Station(s) | Technology | Power (MW) | Capacity (MWh) | RTE% | Direct Capital Est ($M | Need By (Date) | Expected Life (years) | Primary Use Case |
|---|---|---|---|---|---|---|---|---|
| County Road 4 | Lithium - Ion | 3 | 12 | 87% | $18 | 4/1/2028 | 20 | Thermal |
| Robison Park | Lithium - Ion | 3 | 12 | 87% | $18 | 12/1/2028 | 20 | Thermal |
| Colfax | Lithium - Ion | 3 | 12 | 87% | $18 | 6/1/2029 | 20 | Thermal |
| Summit | Lithium - Ion | 4 | 16 | 87% | $24 | 6/1/2028 | 20 | Thermal |
| Beech Rd | Lithium - Ion | 3 | 12 | 87% | $18 | 6/1/2033 | 20 | Thermal |
| Pleasant-Yoder | Lithium - Ion | 1 | 4 | 87% | $6 | 12/31/2028 | 20 | Reliability |
| Whitaker-Elk | Lithium - Ion | 3 | 12 | 87% | $18 | 12/31/2028 | 20 | Reliability |

Note*: The Direct Capital Est is deducted by Deferred Capital Cost for Thermal use cases and CMI Savings for Reliability use cases

# Implementing Stakeholder Feedback: Carbon-Free Sensitivity

**Carbon-Free Sensitivity Modeling Considerations**

- I&M will model a Carbon-Free Sensitivity that optimizes a portfolio that:
  - Meets total system needs and
  - Serves the energy requirements of HSL and large industrial customers with carbon-free resources.
- Model results will provide insight into how early HSL and large industrial customers' energy requirements could be met with carbon-free resources.
- Any market purchases that the model selects will not count as a carbon-free resource.

# Market Scenarios

| Scenario | Load | Gas Price | Environmental Regulations |
|---|---|---|---|
| **Base** | Base | Base | Pre-EPA 111d 2023 Proposed Rules |
| **High Economic Growth** | High | High | |
| **Low Economic Growth** | Low | Low | |
| **Enhanced Environmental Regulations (EER)** | Base | Base | EPA 111d 2023 Proposed Rules |

# Proposed Market Sensitivities

| Sensitivities | Load | Gas Price | Environmental Regulations |
|---|---|---|---|
| **Base under EPA 111d Requirements** | Base | Base | EPA 111d 2024 Final Rules |
| **Carbon-Free Sensitivity** | Base | Base | Pre-EPA 111d 2023 Proposed Rules |
| **Base with High IN Load** | High | Base | |
| **Base with Low IN Load** | Low | Base | |
| **Rockport Unit 1 Retires 2025** | Base | Base | |
| **Rockport Unit 1 Retires 2026** | Base | Base | |
| **Exit OVEC ICPA in 2030** | Base | Base | |
| **High Technology Cost** | Base | Base | |

# Public Stakeholder Meetings 3A & 3B

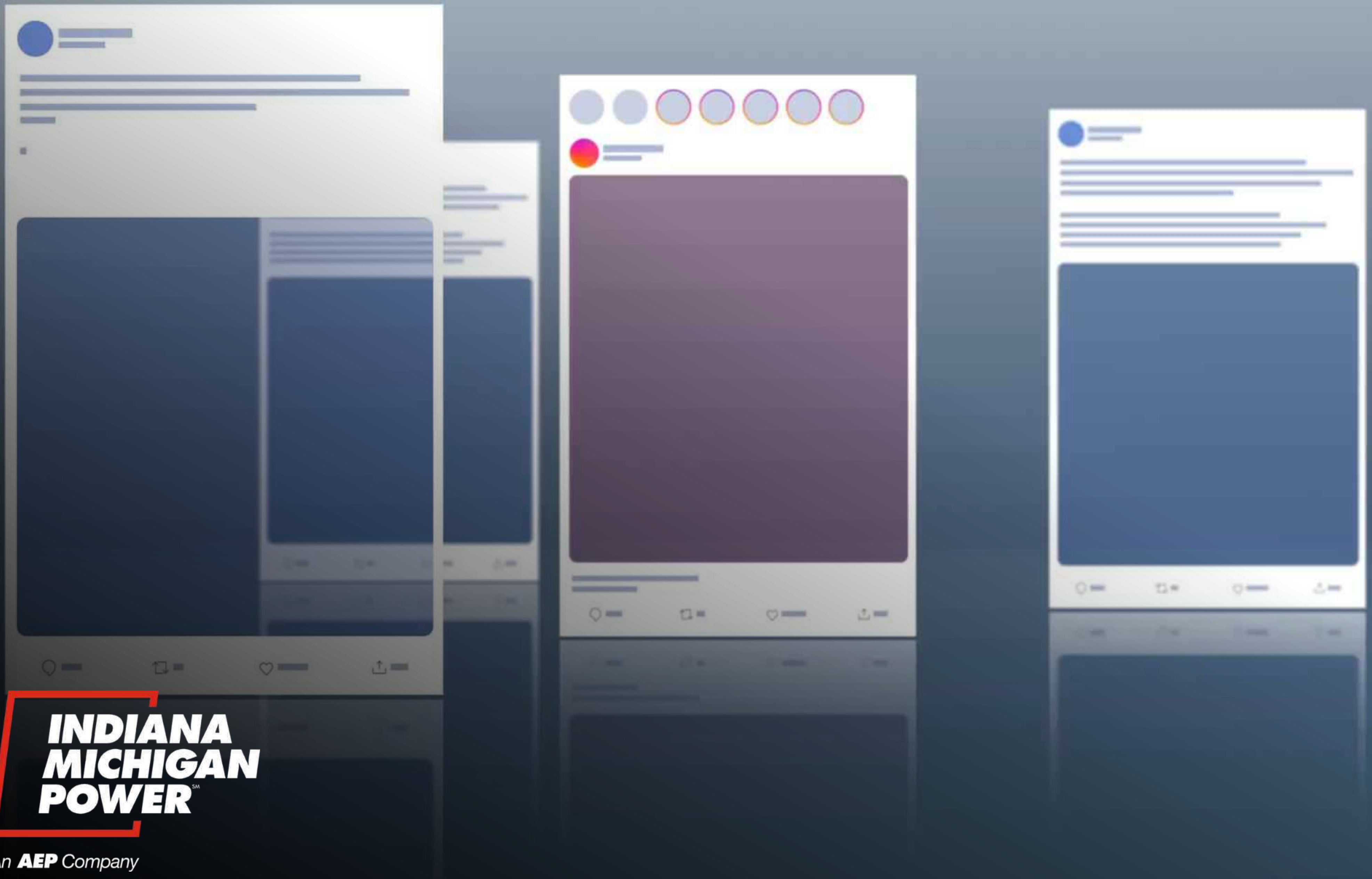
## Modeling Results to be Presented at Stakeholder Meetings 3A and 3B

- I&M will begin modeling 4 market scenarios & 8 market sensitivities and present modeling results in 2 upcoming stakeholder meetings (i.e., 3A and 3B);
- I&M is targeting December 2024 to hold Stakeholder Meeting 3A and February 2025 to hold Stakeholder Meeting 3B.

| Scenario | Stakeholder Meeting 3A or 3B |
|---|---|
| Base | 3A |
| High Economic Growth | 3B |
| Low Economic Growth | 3B |
| Enhanced Environmental Regulations (EER) | 3B |

| Sensitivities | Stakeholder Meeting 3A or 3B |
|---|---|
| Base under EPA 111d Requirements | 3A |
| Carbon-Free Sensitivity | 3A |
| Base with High IN Load | 3A |
| Base with Low IN Load | 3A |
| Rockport Unit 1 Retires 2025 | 3B |
| Rockport Unit 1 Retires 2026 | 3B |
| Exit OVEC ICPA in 2030 | 3B |
| High Technology Cost | 3B |

# Feedback and Discussion



INDIANA MICHIGAN POWER
An AEP Company

# APPENDIX

# Portfolio Performance Indicators

| IURC Pillar | IRP Objective | Performance Indicator | Metric Description |
|---|---|---|---|
| Reliability | Maintain capacity reserve margin and the consideration of reliance on the market for the benefit of customers. | Energy Market Exposure – Purchases | Cost and volume exposure of market purchases (Costs and MWhs % of Internal Load) in 2033 and 2044 |
| | | Energy Market Exposure - Sales | Revenue and volume exposure of market sales (Revenues and MWhs % of Internal Load) in 2033 and 2044 |
| | | Planning Reserves | Target Reserve Margin |
| Affordability | Maintain focus on cost and risks to customers | Net Present Value Revenue Requirement (NPVRR)<br>Levelized Rate ($/MWh) | Portfolio 30yr NPVRR<br><br>Portfolio 30yr Levelized Rate (NPVRR/Levelized Energy) |
| | | Near-Term Rate Impacts (CAGR) | 7-year CAGR of Annual Rate |
| | | Portfolio Resilience | Range of Portfolio NPVRR and associated Rate Impact ($/MWh) (at rqd IRP Planning Period) costs dispatched across all Scenarios |
| Resiliency | Maintain diversity of resources and fleet dispatchability | Resource Diversity | Diversity Index inclusive of Capacity and Energy Diversity |
| | | Fleet Resiliency | % Dispatchable Capacity of Company Peak Load |
| (Grid) Stability | Maintain fleet of flexible and dispatchable resources | Fleet Resiliency | % Dispatchable Capacity of Company Peak Load |
| Environmental Sustainability | Maintain focus on portfolio environmental sustainability benefits and compliance costs | Emissions Change | $CO_2$, $NO_x$, $SO_2$ emissions change compared to 2005 levels |
| | | Total Portfolio Costs (NPVRR) | Considered under Affordability Pillar above |

# Fundamentals Enhanced Environmental Regulation (EER) Scenario

## Scenario

**Scenario Models EPA's 111d Rule Changes**

- Proposed Rule Published May 11, 2023

**Generators impacted:**

- Exiting coal units
- Existing natural gas units >300 MW
- New gas units

**Scenario Summary:**

- ~50% power price increase on expiration of IRA credits mid-2040s

## Dispatchable Generation Options

**Existing coal units' options to continue operation past 2032 must:**

- Limit capacity factor to 20%, retire by 2035
- Blend 40% Natural Gas with coal, retire by 2040
- Install CCS

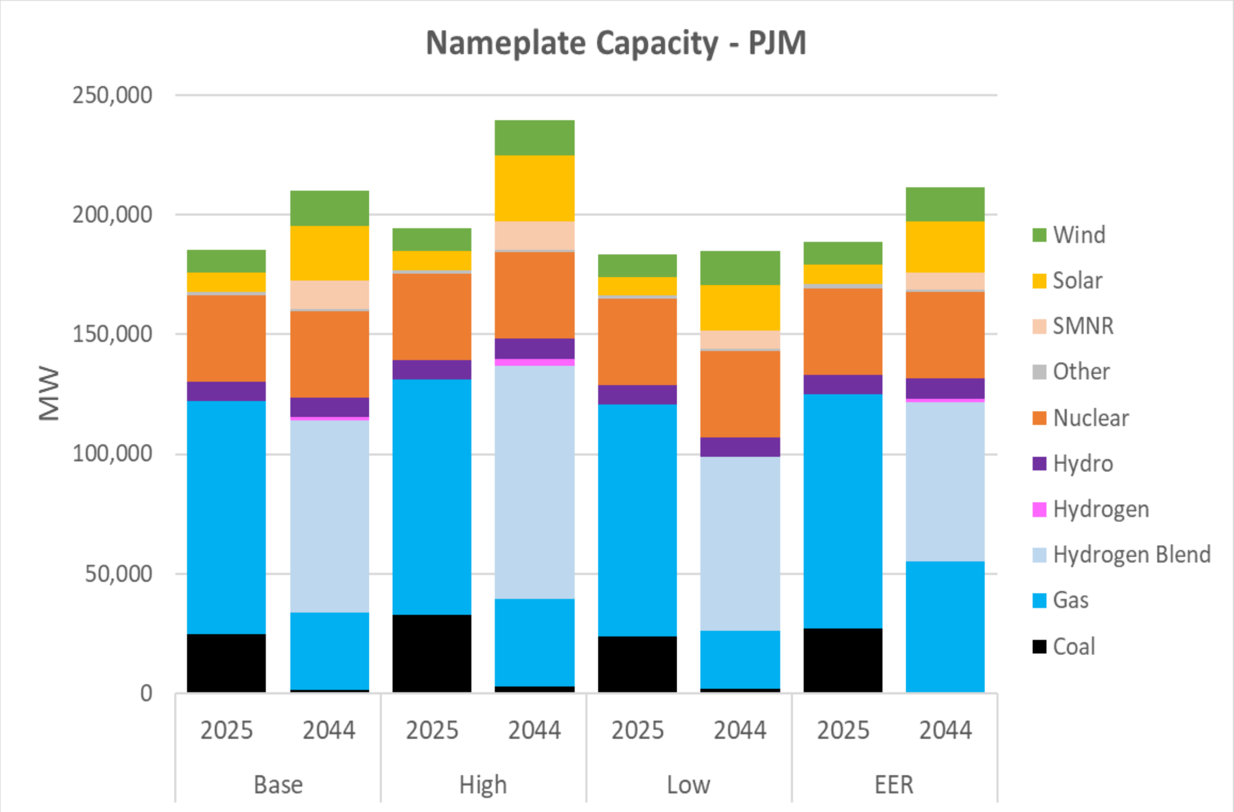
**Existing Natural Gas Units >300 MW and 50% Capacity Factor:**

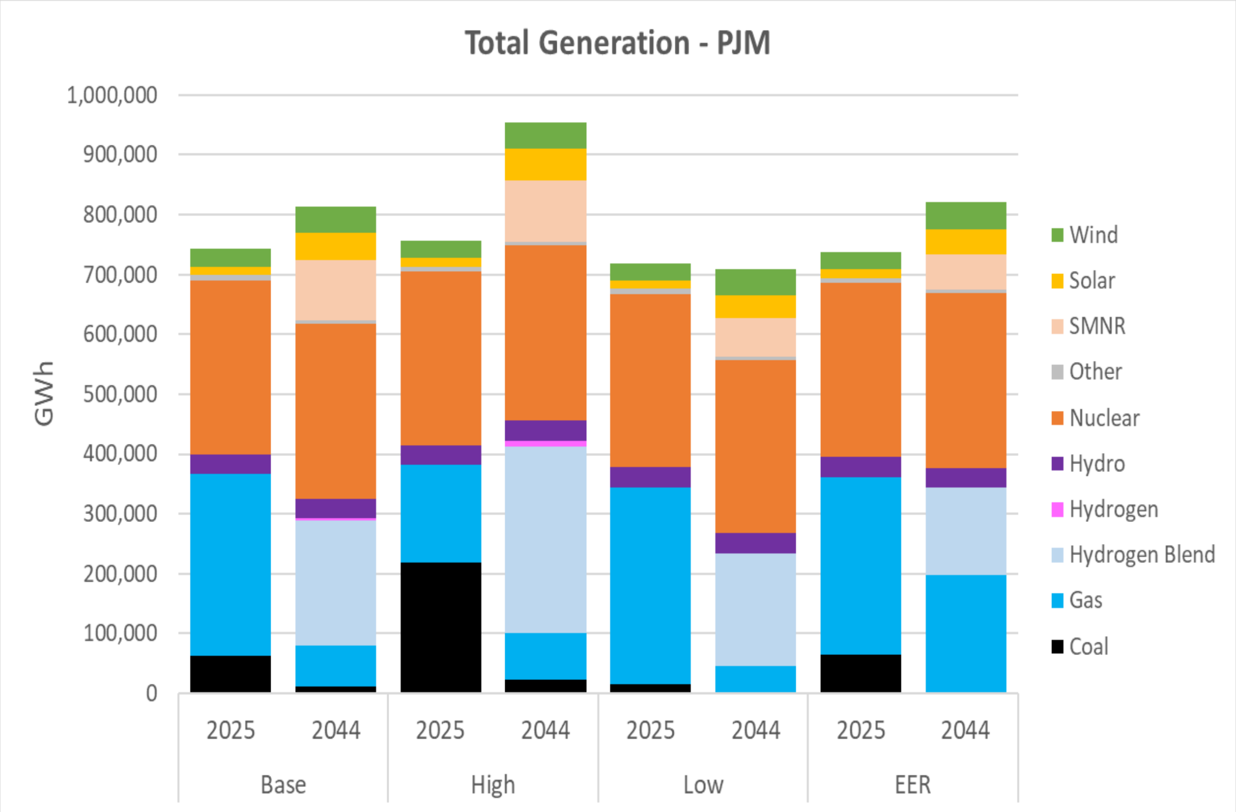
- Up to 96% hydrogen 4% natural gas fuel blend
- Install CCS

**New Gas Units:**

- Adhere to carbon emission performance standard
- Up to 96% hydrogen 4% natural gas fuel blend
- Install CCS

# PJM Supply Mix Changes

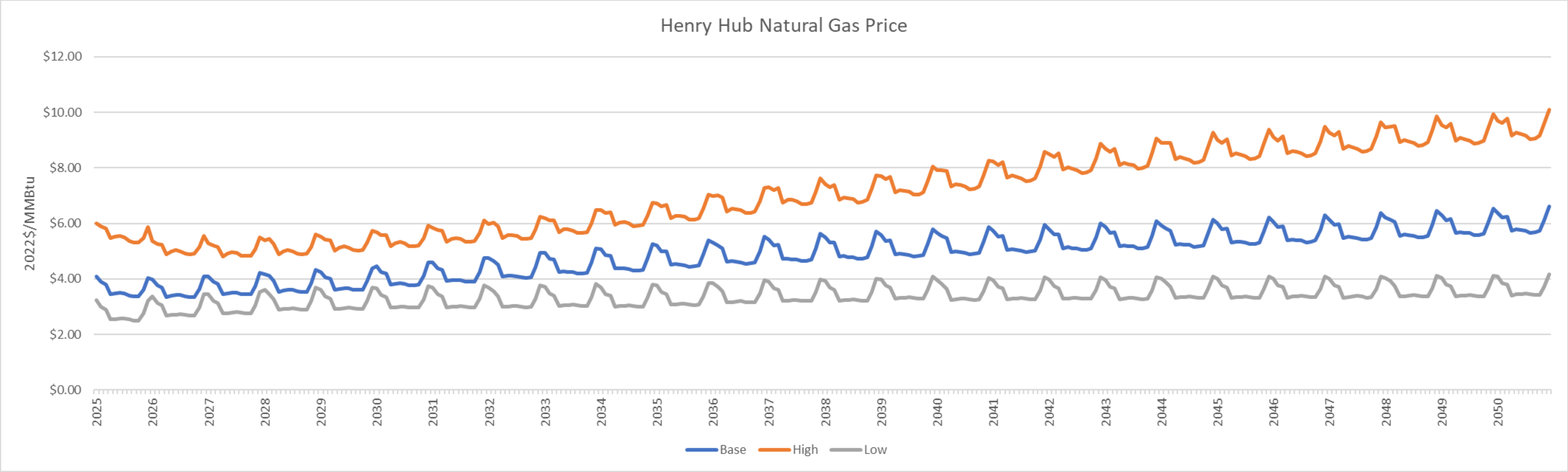



- Under all scenarios, coal is replaced primarily by NG/Hydrogen Blend units
- Solar sees significant growth in the long term
- Wind growth is moderate

- Nuclear and natural gas generation dominate the supply mix
- Natural gas/Hydrogen Blend units provide reliable, dispatchable generation as coal plants are retired

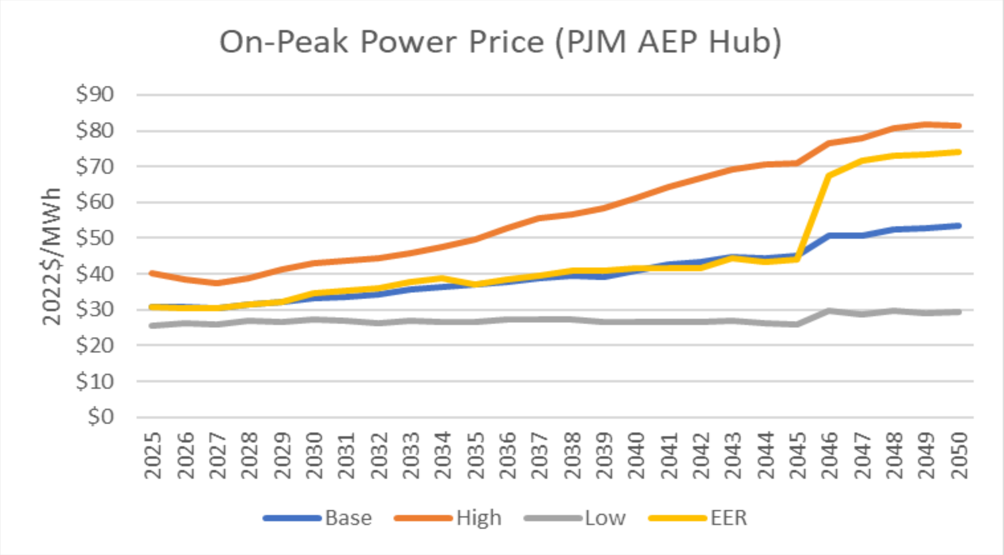
# Natural Gas Inputs

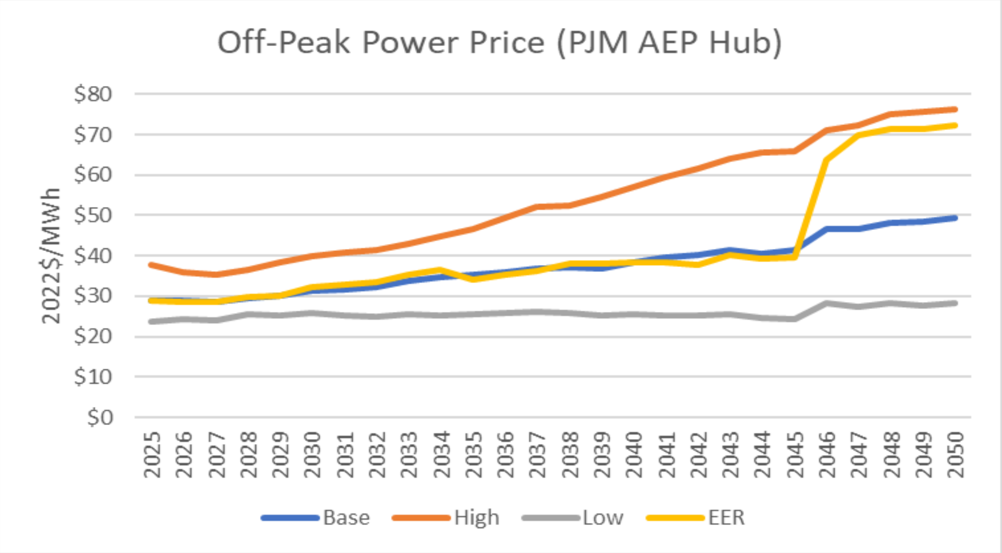



- Base case assumes that natural gas demand will increase as natural gas replaces coal
- High and Low cases have similar assumptions to Base except for WTI prices and LNG exports
    - High case assumes higher WTI prices and LNG exports
    - Low case assumes lower WTI prices and LNG exports

# PJM Market Prices

- Under all scenarios, energy prices are mainly influenced by natural gas prices
- Peak/Off-Peak spread averages are as follows:
    - Base: $2.71/MWh
    - High: $3.89/MWh
    - Low: $1.47/MWh
    - EER: $2.69/MWh



# Indiana Michigan Power Company's 2024 Indiana Integrated Resource Plan

## Stakeholder Workshop #2

## September 24, 2024

## Table of Contents

## Welcome & Introductions

*Dylan Drugan covered slides 1-3.*

Dylan Drugan, Indiana Michigan Power (I&M) Manager, Resource Planning, called the meeting to order at 1:00 EDT on September 24, 2024.

Dylan welcomed stakeholders to the 2024 Indiana Integrated Resource Plan (IRP) Stakeholder Meeting #2. Dylan introduced I&M IRP, Infrastructure Development, and Load Forecast team members as well as Jeffrey Huber, Principal with GDS Associates, Inc. who is assisting I&M with market potential study inputs. Dylan also introduced I&M Leadership including Andrew Williamson, Director, Regulatory Services.

Andrew provided an overview of the meeting's purpose; this is a collaborative workshop to discuss modeling software, methodology, and assumptions that will drive I&M's decision-making process for the Indiana IRP. I&M values stakeholder collaboration, and Andrew encouraged stakeholders to ask questions and provide feedback throughout the meeting. Andrew announced the scheduling of Indiana IRP Stakeholder Meeting #3, which will be split into meetings 3A in December and 3B in February.

Dylan concluded introductions with Brian Despard, Senior Project Manager with 1898 & Co. (a part of Burns & McDonnell), who is assisting with the stakeholder process for the Indiana IRP.

Dylan presented the meeting agenda, briefly covering each topic of discussion that follows herein. Dylan reiterated that although there is a time set aside for open discussion as per the agenda, stakeholders are encouraged to provide input and ask questions at any time during the meeting.

## Going-In Capacity Position Review

*Dylan Drugan covered slides 4-5.*

Dylan presented preliminary PJM Electric Load Carrying Capability (ELCC) and Forecast Pool Requirement (FPR) metrics.

Dylan described ELCC as a measure of accredited capacity by resource class that I&M must account for when analyzing resources for load obligation purposes. He noted that within PJM, renewable resource ELCCs decrease over time to account for increasing future penetration, lowering the accredited capacity on a percentage basis for these resources over time.

FPR denotes to what percentage of peak load PJM members, including I&M, must plan for to meet reserve margins. Like ELCC, FPR values decline over time, serving to offset the difficulties provided by declining accreditation figures for renewable resources.

Dylan then presented the capacity needs assessment, also known as the preliminary "going-in position." These values, adjusted from previous Indiana IRP meetings, reflect new preliminary PJM ELCC value forecasts. Overall, the decline in resource ELCC class values is partially offset by a lower forecasted FPR. Dylan also noted that FPR methodology, which was previously based on installed capacity, is now based on accredited capacity, resulting in PJM members, including I&M, being able to carry less than their peak load requirements.

Capacity totals in the capacity needs assessment assume no action on many decisions that the IRP process will be investigating, such as the relicensing of Cook Nuclear Plant and retirement of Rockport Generating Station. Shortfall values are not indicative of the goal I&M holds in acquiring year-over-year capacity that exceeds annual PJM obligation by roughly 5% to avoid overreliance on PJM under extreme conditions and other potential risks.

## Q&A Related to Going-In Capacity Position

1. What is the ELCC assumption for years after 2034/2035?
   a. 2034/2035 ELCC values are held constant for all years past 2034/2035.

Dylan introduced Trenton Feasel, I&M Manager, Economic Planning.

# Load Forecast Assumptions and Methodology

*Trenton Feasel covered slides 6-11.*

Trenton provided stakeholders with an overview of I&M's latest peak demand forecast assumptions. Significant forecasted changes in peak demand are demonstrated, accounting for a peak demand increase of roughly ~8.3% each year over the next decade within I&M. Trenton noted that hyperscale load (HSL) additions within Indiana are the primary driver for this sharp increase; commercial load is expected to grow much faster than industrial and residential load, from 31% of I&M's total load obligation in 2015 to 79% by 2030. This is largely due to the projected growth of data centers.

Trenton presented stakeholders with the load forecast scenarios that inform the overall energy requirements I&M must meet, noting the drivers of high and low economic growth. These scenarios form the band in which the base energy forecast falls. Also noted is an "extreme weather" scenario using data from Purdue University that shows a subtle increase over base energy projections.

Trenton informed stakeholders that there has been a change in methodology as to how I&M accounts for control of Demand Side Management (DSM) and Energy Efficiency (EE) projects in its load forecasts. These have historically been studied and provided as a post-model adjustment to load. Following the Rockport Unit 2 declination of jurisdictional settlement, I&M committed to making EE and DSM assumptions an independent variable in econometric models. This has caused a sharp increase in the value of DSM/EE in load forecasts.

Finally, Trenton discussed electric vehicles and rooftop solar. Electric vehicle growth within I&M's Indiana territory tends to be less aggressive than USA-wide figures and does not contribute to load growth as much as may be seen in IRP filings from different entities. Similarly, a growing, albeit small portion of I&M's customer base is adopting the use of rooftop solar, leading to only a 0.4% decrease in I&M Indiana energy retail needs by 2040.

## Q&A Related to Load Forecast Assumptions and Methodology

2. For the DSM slide 9, what is the unit of the y-axis?
    a. The units on the y-axis of slide 9 are megawatts (MW).
3. Do you model data centers separately or as part of the commercial model?
    a. Data center loads are forecasted separately from the traditional commercial load.

4. Any forecast on Community Solar installations or are they counted for in Rooftop Solar?
    a. No, we do not have a separate forecast for community solar installations. The current forecast for customer-owned solar is largely reflective of rooftop solar.

Jeffrey Huber, Principal Consultant with GDS Associates, Inc. was introduced.

# DSM Modeling Inputs

*Jeffrey Huber covered slides 12-15; and*
*Jon Walter, I&M Regulatory Manager covered slide 16.*

Jeffrey briefly reviewed market potential study savings and the DSM inputs being used in the Indiana IRP. Modeling will utilize different EE and Demand Response (DR) bundles as shown on slide 12.

Jeffrey shared graphical overviews of energy savings being offered by these EE and DR bundles by sector.

Jeffrey discussed the potential opportunities for DER resources, including BTM solar and battery storage, with utility intervention at a 25 incentive for solar PV installs, with the saving potential for these resources as shown on slide 15.

Dylan introduced Jon Walter, I&M Regulatory Manager.

Jon discussed the Conservation Voltage Reduction (CVR) saving that will be forced into the model as shown on slide 16. He emphasized that this does not represent any new or incremental CVR beyond what was already planned.

## Q&A Related to DSM Modeling Inputs

5. What are the cost assumptions for the EE bundles on slide 12? Full incremental cost of the measures? Additional program costs added?
    a. The cost assumptions for EE bundles are a bit of a mix and depend on what type of programs are being operated. For programs that are typically replaced at time of sale or market opportunity, generally an incremental cost is assumed. The full cost is assumed when programs are more of a retrofit basis. The assumptions about the measure cost we're putting in, the utility

cost, it's the utility incentive. It is the portion of that cost that the incentive is covering. Regarding income-qualified programs, the utility incentive generally covers 100% the income-qualified customer's cost. For other programs, the incentive is a percentage of that program's measure cost, whether it's incremental or full cost in the assumption. The bundle costs reflect only the utility's incentive costs and administration costs, not the full customer cost to implement the measure.

6. Do you assume data centers are energy-efficient?
    a. No explicit assumptions are made regarding energy efficiency around data centers.
7. Has I&M posted the methodology for T&D capacity avoided costs on the IRP webpage?
    a. This information has not been posted to the IRP webpage but is available and can be provided upon request via the I&M IRP email (I&MIRP@aep.com).
8. Is there potential for EE/DR savings associated with data centers?
    a. There are no assumptions made about EE/DR savings for data centers in the modeling. The expectation is that most of if not all the hyperscale large data center loads would be EE opt out customers, so they are not included in the energy efficiency potential analysis. Also, there are questions about demand response opportunities, whether data centers would participate via I&M or other markets. We are having conversations with data center customers about opportunities. For these hyperscale large data centers, there may be future opportunities to incorporate more efficient technology, but the current expectation is that those future opportunities would just allow data centers to expand their business beyond their current customer base which won't necessarily result in lower overall loads.
9. What assumptions are being made with the increased interest in I&M's territory by solar developers to install utility sized solar arrays at 200 MW and greater?
    a. This question will be addressed on an upcoming slide.

10. Is I&M considering modeling any CVR savings incremental to the savings presented in slide 16 based on costs?
    a. No. We did evaluate additional future incremental deployments beyond what is shown on slide 16, since those deployments did not turn out to be cost effective through cost effectiveness modeling. Only the CVR savings shown on slide 16 are forced into the model.
11. What do we mean by "forced" into the model?
    a. Forced into the model means the CVR savings will be included as part of our portfolio; it will not be an option to be selected or evaluated amongst other resources - it will be forced in.

Dylan introduced Tim Gaul, Director, Regulated Infrastructure Development for I&M.

## Market Assessment of Existing and New Resources

*Tim Gaul covered slide 17.*

Tim presented availability in PJM's Interconnection Queue for resources eligible to serve load and contribute to capacity requirements in I&M's Indiana territory. Resources being considered are geographically and technologically diverse, with a variety of projects in Indiana, Michigan, Illinois, Ohio, and Kentucky being presented. Projects are sorted based on queue cluster and potential COD: "Fast Lane" projects, Transition Cycles #1 and #2, and Cycle #1 projects under PJM's new queue methodology are all being considered.

Tim walked stakeholders through the graph, talking through splits by both project number, megawatts available, and technology type. Solar projects constitute much of the available queue capacity and volume of projects through the presented queue cycles, especially within Indiana. Wind is in very limited supply, and most projects reflected are additional capacity for existing projects. Storage projects increase in both volume and capacity in later queue cycles, making them more viable in the future. Finally, very few new gas projects are in the queue. The primary source of resources eligible for consideration in our near-term RFPs will come from offers provided by owners of existing gas assets.

## Q&A Related to Market Assessment of Existing & New Resources

12. Can't storage be added to existing assets to compensate for renewable accreditations going down as a result of declining ELCCs?
    a. Yes. Adding new storage to an existing asset would increase the ELCC value of the resource. However, the additional ELCC value gained is often limited relative to the cost of the storage addition.

# Resource Modeling Parameters

*Dylan Drugan covered slide 18-20.*

Dylan presented an overview of key resource modeling parameters that will be shared with stakeholders. Examples of parameters include capacity, availability, lifespan, financial assumptions, energy production, and more.

Baseload resources include small modular reactors (SMRs) and combined cycles (CCs), and existing gas resources. These resources would help meet large load ramps in a short amount of time. Dylan explained that RFP results are used to inform these modeling parameters.

Peaking resources include combustion turbines (CTs) and reciprocating internal combustion engines (RICE). Dylan explained that these resources help add small amounts of capacity to meet reserve margin requirements and economically optimize resource additions.

Intermittent resources include wind, solar, and storage. Dylan emphasized that a subset of solar resources will be modeled as if they qualify for the Energy Community Tax Credit Bonus.

## Q&A Resource Modeling Parameters

13. What is the basis for the annual build limits shown on slide 18 especially for existing resources given the resource summary you shared on slide 17?
    a. The annual build limits, which are specific to a particular resource, are based on work we did with our infrastructure development team. The limits are informed by what we're seeing in the market and what we think is feasible to be able to procure in one year. Specifically, the limits consider the

timeline and availability of new resources at various stages of the PJM queue, as well as the availability and remaining life of existing, operational resources that potentially could be procured by I&M. The limits also consider the Company's experience in its 2022 and 2023 RFPs, including the number of bids/MWs received in the RFPs and the percentage of projects that experience development challenges that delay the commercial operation date or terminate the project. We also considered regulatory timelines associated with resources.

Limits on existing resources are based on our assessment of what is available in the market based on research of existing assets, responses to previous RFPs open to existing resources from a similar footprint, and outreach to potential sellers of existing resource assets gauging interest in contracting with I&M. In particular on slide 17, we are saying that through 2030, we think there is about 3,600 MW of existing resources available in the market and that the most we would be able to procure in a year is 1,800 MW of the 3,600 MW.

14. Do overnight costs for the NG resources include any cost for new gas pipeline extensions or firm transportation costs for natural gas?

    a. No. Generally, IRP modeling consists of modeling generic resources that are not location specific. Costs related to gas pipeline extensions and firm transportation tend to be location-specific costs. While these costs are not included in the overnight cost to build a NG resource, these costs can be considered when the Company receives bids through its RFP process and has a need to evaluate location-specific costs such as gas pipeline extensions and/or firm fuel.

15. How do tax credits inform model choices? Are these accounted for in 'overnight costs,' e.g., for NG with CCS?

    a. The overnight costs do not include PTCs or ITCs, however PTCs and ITCs are included in the IRP modeling.

16. Does NG assume Section 111d compliance?

    a. The Reference Case will not assume Fundamental and Operating conditions that reflect 111d impacts. We will run a scenario that will model a future with

111d compliance in place. 111d impacts are handled through the economic dispatch in the production cost modeling in the Enhanced Environmental Regulations scenario. Also, the capacity factor percentages on existing and new resources that are operating beyond 2032 will be capped based on 111d. So, we could see limited operation from NG resources which will result in less GHG output.

17. Is overnight cost based on RFP responses?
    a. Costs for new and existing resources consider some of the responses we've received through past RFPs. The Company continues to still fine-tune costs for existing resources and the costs shown are subject to change.
18. Does new NG assume dual fuel or onsite LNG to support operations?
    a. No, new NG resource overnight costs do not include dual-fuel capability or on-site LNG.
19. Does the discount on existing resource pricing compared to new resource pricing come with any downsides such as shorter lifetime or anything that would influence the selection of those resources compared to the new resources?
    a. We have not established final pricing for existing resources, but we anticipate the final pricing will reflect asset life and other factors specific to the resource when they are priced.
20. What is the rationale behind the first year available for combined-cycles being 2031? Is it mostly due to the challenges of buying turbines or is there more to it?
    a. The first year available for combined-cycle projects is based on several factors, including lead time and availability for new combustion turbine orders, timeline to build, regulatory approval, air and water permitting, and limited representation of combined cycle projects in the current interconnection queue.
21. Regarding the build limits given large load growth over the next six years - this would constrain the model from picking renewable energy and storage. Due to these limits, we are going to mostly see carbon based resources added. Also, it seems build limits overall are too constraining to be able to meet expected demand growth

with cost-effective resources. Do you think the build limits are too constraining to be able to meet expected load growth?

a. As noted in the answer to question 13, the annual build limits are based on work we did with our infrastructure development team, informed by what we're seeing in the market. We do not think the build limits are too constraining to be able to meet the load growth. We will evaluate the build limits as we model the different scenarios and sensitivities and adjust the build limits if they become a constraint to meet the load growth.

Dylan introduced Mohamed Abukaram, Director, Resource Planning.

## Key Modeling Inputs

*Mohamed Abukaram Covered Slides 21-25*

Mohamed Abukaram, Director, Resource Planning & Operational Analysis, presented an overview of Inflation Reduction Act of 2022 (IRA) tax credit assumptions being applied to the Indiana IRP analysis. Investment Tax Credits (ITCs) will be applied to capital costs for solar, storage, and small modular nuclear reactor projects at 30% through 2036 before a "phase out" period through 2039.

Production Tax Credits (PTCs) will be applied to wind projects in place of ITCs. These $40/MWh-$58/MWh credits are applied through the first 10 years of asset life for projects completed in the 2025-2036 window. Like ITCs, these credits will decrease gradually for projects completed in 2037 and 2038, before being phased out entirely in 2039.

Finally, Carbon Capture Storage (CCS) credits are applied in the range of $29/MWh-$$44/MWh for the first 12 years of asset life for new combined cycle plants completed between 2025-2036.

Mohamed also discussed the Cook Subsequent License Renewal (SLR) analysis being conducted as part of this IRP. He shared model input assumptions such as current license expiration dates and assumed costs for relicensing the Cook Nuclear Plant. Similarly, Mohamed discussed relicensing cost assumptions for the Elkhart and Mottville Hydro Plants.

Finally, Mohamed discussed storage modeling inputs and methodology for utility scale and distribution-sited resources. For utility scale resources, storage is dispatched against fundamental market prices within a production cost model with hourly generation and charge costs then used as inputs in expansion planning (PLEXOS). Storage options considered are lithium-ion batteries of durations from 4-8 hours, and iron-air storage.

Distribution-sited storage will be modeled under two cases: the Thermal Use Case, where storage is sited at stations nearing thermal overload conditions, and the Reliability Use Case. Where storage is placed at stations with historic reliability need. The intent with both cases is to improve capacity for existing resources.

### Q&A Related to Key Modeling Inputs

22. How come you are crediting ITC/PTC to 2036 when the law says 2032?
    a. According to our internal tax group, there are some provisions in the IRA that enable us to go out an additional 4 years.
23. How did you determine the value for avoided customer minutes of interruption (CMI)?
    a. The interruption cost estimator (ICE) tool was used to estimate CMI costs. We looked at our different distribution stations and analyzed the CMI that was there historically and what can be improved by placing a distribution of storages of the sizes seen in the table on slide 25. We equated the CMI that can be saved and the associated dollar amount by placing storage at these stations. These savings were then deducted from the capital cost of putting the storage at that site.

## Market Scenarios & Sensitivities

*Dylan Drugan Covered Slides 26-29.*

Dylan discussed a new carbon-free sensitivity that was developed with stakeholder feedback. This sensitivity meets the total system needs and serves hyperscaler energy requirements.

Dylan also reviewed the scenarios and sensitivities that will be evaluated in the IRP and forecasts being used for each. He explained that Meeting 3 will be divided into two sections (3A and 3B) to allow time to walk through each scenario and sensitivity.

## Q&A Market Scenarios & Sensitivities

24. It is unclear why you are calling the new rule 111d. It is 111b that applies to new gas.
    a. While the presentation primarily refers to 111d, both 111b and 111d are considered in the IRP as both new and existing resources are being considered.
25. Is I&M also considering a low technology cost sensitivity?
    a. Not currently. The High Technology sensitivity will reflect the most up to date bids that we're seeing in the marketplace, which we expect to be higher than current prices. We are seeing upward pressure on market prices given the lack of resources and increasing demand and we expect that this trend will continue in the near term.
26. Does "Pre EPA 111d 2023 Proposed Rules" on slide 28 mean a situation where the EPA 111(d) rule was repealed or no longer exists?
    a. The "Pre EPA 111d 2023 Proposed Rules" scenario reflects fundamentals for our power prices and fuel prices developed prior to those rules. These are the set of fundamentals that we are using in our base high and low scenarios in this IRP. The proposed EPA 111d rules were incorporated into fundamentals that will be used in the Enhanced Environmental Regulations (EER) scenario.
27. For the Exit OVEC sensitivity, are you assuming the OVEC units are closed or that you will buy out of obligations?
    a. In such a scenario, I&M would no longer utilize OVEC as a generation resource but would continue to be responsible for the financial obligations that I&M would have under the contract and exit the contract early. I&M would replace OVEC with another generation resource to serve customers.
28. EPA deleted requirements on existing gas from Final Rule stating it planned to have a separate rulemaking. What are you assuming?
    a. We are currently assuming the 2023 proposed 111d rules under our Enhanced Environmental Regulations case.
29. Are the 111d assumptions applied to existing units PJM-wide in the analysis?

a. Only in the Enhanced Environmental Regulation scenario uses 111d assumptions. The assumptions are applied to all generating units in PJM in the Fundamentals forecast.

## Open Discussion

Dylan asked stakeholders one final time for any unanswered questions. All questions and answers asked during the presentation are located under their appropriate segments.

Andrew made closing remarks, thanking stakeholders for their time and contributions to the Indiana IRP Technical Conference and overall process. Any unanswered questions, requests, or follow-up feedback is encouraged to be submitted to I&MIRP@aep.com.

# Appendix 4, Exhibit C: Workshop #3a December 18, 2024

## Meeting Presentation

## Meeting Minutes

Indiana Michigan Power Company

# INDIANA IRP STAKEHOLDER MEETING #3A

December 18th, 2024

INDIANA MICHIGAN POWER

An AEP Company

# Welcome & Introductions

## I&M Leadership Team

David Lucas | Vice President, Regulatory and Finance

Andrew Williamson | Director, Regulatory Services

Ed Locigno | Regulatory Analysis & Case Manager

Regiana Sistevaris | Manager, Regulatory Services

Austin DeNeff | Regulatory Consultant Senior

## 1898 & Co.

Brian Despard | Senior Project Manager

## I&M Resource Planning

Josh Burkholder | Managing Director, Resource Planning

Kayla Zellers | Director, Resource Planning

Mohamed Abukaram | Director, Resource Planning

Mark Sklar-Chik | Staff Analyst, Resource Planning

## I&M Infrastructure Development

Tim Gaul | Director, Regulated Infrastructure Development

Justin Dehan | Manager, Regulated Infrastructure Development

# Agenda

| Time (EST) | Agenda Topic | Lead |
|---|---|---|
| *2:00-2:10* | **Welcome & Introductions** | **Andrew Williamson**<br>**Josh Burkholder**<br>**Brian Despard** |
| *2:10-2:15* | **Going-In Capacity Position Review** | **Kayla Zellers** |
| *2:15-2:20* | **Resource Modeling Parameters Update** | **Kayla Zellers** |
| *2:20-2:30* | **Key Modeling Inputs & Modeling Status Update** | **Kayla Zellers** |
| *2:30-3:00* | **Expansion Plan Modeling Results**<br>• Scenarios: Base Reference, Enhanced Environmental Regulations (EER)<br>• Sensitivity: Base Under EPA 111(b)(d) Requirements | **Mohamed Abukaram** |
| *3:00-3:10* | **Short Break** | |
| *3:10-4:00* | **Expansion Plan Modeling Results**<br>• Scenarios: High, Low<br>• Sensitivities: Low Carbon: Transition to Objective, Low Carbon: Expanded Build limits | **Mohamed Abukaram** |
| *4:00-4:10* | **Short Break** | |
| *4:10-4:30* | **Results Comparison and Draft Portfolio Performance Indicators** | **Kayla Zellers** |
| *4:30-4:35* | **Remaining Modeling and Next Steps** | **Kayla Zellers** |
| *4:35-5:00* | **Open Discussion**<br>• Feedback From Stakeholders | **Andrew Williamson**<br>**Josh Burkholder** |

# Participation

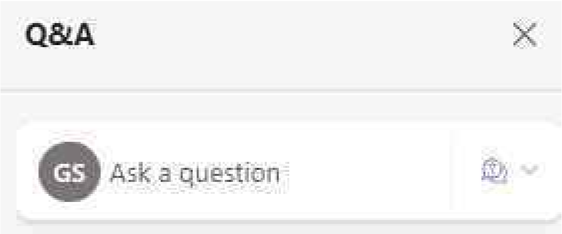
Participants joining today's meeting will be in a "listen-only" mode. Please use the "Raise" function to be recognized and unmuted.

During the presentation, please enter questions at any time into the Teams Q&A feature. Questions will be addressed after each section. At the end of the presentation, we will open up the floor for additional questions, thoughts,  ideas, and suggestions.

All questions and answers will be logged and provided on the IRP website.  Any questions not answered during the meeting will be answered after the meeting and provided in the Q&A log posted to the IRP website.

Questions, thoughts, ideas, and suggestion related to Stakeholder Meeting 3A can be provided to I&MIRP@aep.com following this meeting.

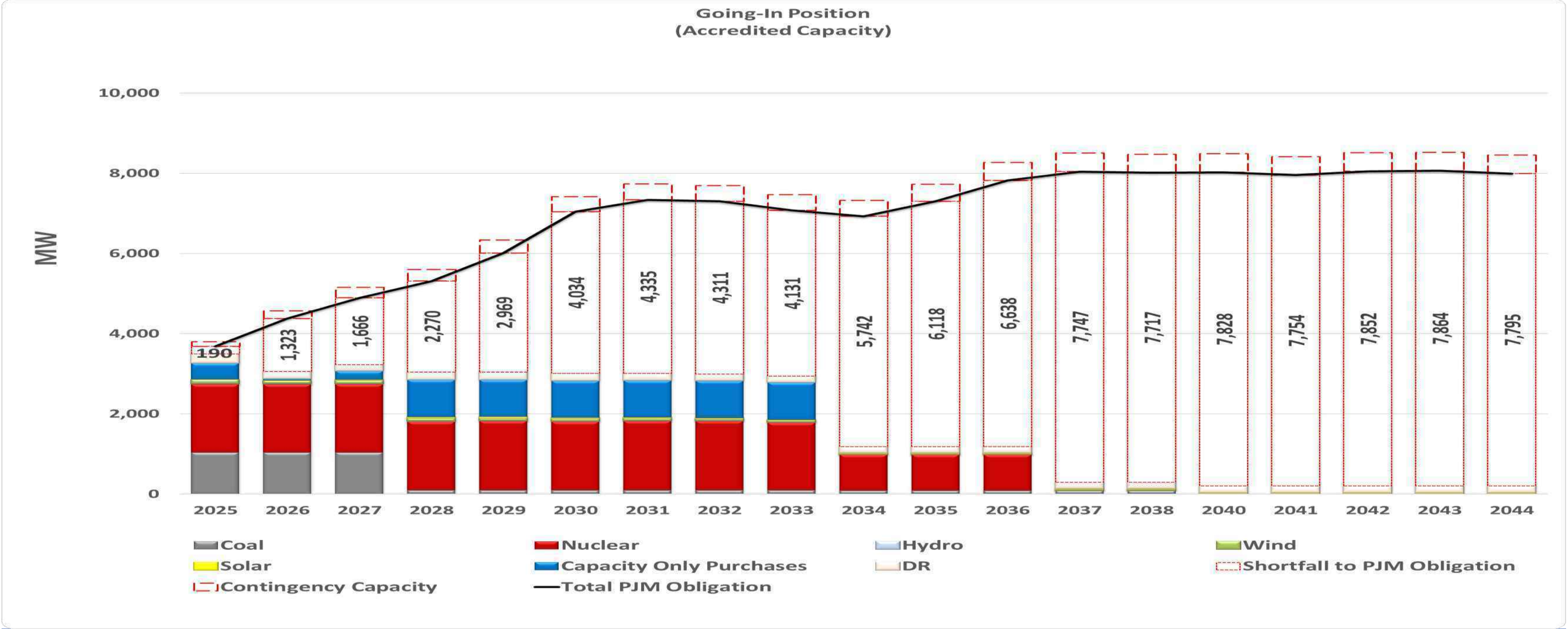

Click the Q&A feature at the top of the Teams screen



# Guidelines

- Please focus questions, thoughts, ideas, and suggestions to the IRP process and the content being discussed in this meeting. Time will be taken during this meeting to respond to questions.
- Please respect other participants and their views by not addressing other participants directly and not commenting on the views expressed by others.
- This meeting will not be recorded or transcribed.
- Any further questions or comments can be provided to I&MIRP@aep.com.

# Capacity Needs Assessment




- To reasonably capture contingency risk around future uncertainties such as changes to load obligations and available capacity, a probabilistic risk analysis was performed to evaluate a reasonable amount of 'Contingency Capacity' needed for planning purposes
- The analysis resulted in planning for Contingency Capacity at a level of 5% above the PJM load obligation by 27/28
    - PJM Load Obligation is ~93% of peak load in 27/28 and, in turn, Contingency Capacity level is at ~98% of peak load (~93% + 5%)
    - Additional 5% for Contingency Capacity results in planning for up to an additional ~450 MW above the PJM Load Obligation

# Resource Modeling Parameters

| Resource Type | First Year Available | Last Year Available | Annual Build Limit (MW) | Cumulative Build Limit through 2030 (MW) | Total Cumulative Build Limit Through Planning Horizon (MW) | Installed Cost[1] \$/kW | Installed Cost[1] \$/MW-D |
|---|---|---|---|---|---|---|---|
| **EXISTING NG COMBUSTION TURBINE (5 YEAR)** | 2028 | 2031 | 1,000 | 3,000 | 4,000 | N/A | ~~\$320~~ \$493 |
| **EXISTING NG COMBUSTION TURBINE (10 YEAR)** | 2028 | 2031 | | | | | |
| **EXISTING NG COMBUSTION TURBINE (20 YEAR)** | 2028 | 2031 | | | | ~~\$540~~ \$644 | N/A |
| **EXISTING NG COMBINED CYCLE (5 YEAR)** | 2028 | 2031 | 1,800 | 3,600 | 5,400 | N/A | ~~\$485~~ \$680 |
| **EXISTING NG COMBINED CYCLE (10 YEAR)** | 2028 | 2031 | | | | | |
| **EXISTING NG COMBINED CYCLE (20 YEAR)** | 2028 | 2031 | | | | \$1,100 | N/A |
| **WIND (15 YEAR)** | ~~2029~~ 2028 | N/A | ~~600~~ 200 | ~~800~~ 400 | ~~3200~~ 4000 | N/A | \$86 |
| **WIND (30 YEAR)** | 2031 | N/A | 400 | N/A | | \$3,000 | N/A |

Note 1: Costs represent nominal dollars in the first year that the resource is available

# Key Modeling Points and Constraints

## Energy Import/Export Limit

- Market import and export and limits were set. The EPA Section 111(b)(d) cases had slightly higher limits due to the CF% limits imposed on thermal resources

## Short Term Capacity

- Short Term Capacity Prices: Based on gross CONE values that PJM has published to date
  - 25/26: $451.61/MW-day
  - 26/27+: $695.83/MW-day
- The model will exhaust all other available long-term resources before selecting short term capacity

## EPA Compliant Gas Unit Capacity Factor

- These constraints are modeled in the EPA Section 111(b)(d) cases – Enhanced Environmental Regulations and Base under EPA Section 111(b)(d)

| Energy Import/Export Limit | | |
|---|---|---|
| **Years** | **Reference, High, Low, Low Carbon Scenarios** | **EER, Base under EPA Section 111(b)(d) Scenarios** |
| 2025-28 | 60% | 60% |
| 2029-30 | 50% | 50% |
| 2031-33 | 30% | 35% |
| 2034+ | 20% | 25% |

| EPA Compliant Gas Unit Capacity Factors | | | |
|---|---|---|---|
| **Resource Type** | **Capacity Factor Limit** | **Starting Year Enforced** | **EPA Section 111 Rule (b)(d)** |
| Existing CC | 50% | 2030 | Proposed |
| Existing CT | 50% | 2030 | Proposed |
| New CC | 40% | Immediate | Final |
| New CT | 20% | Immediate | Final |

# Public Stakeholder Meetings 3A & 3B

## Modeling Results to be Presented at Stakeholder Meetings 3A and 3B

- I&M is modeling 4 market scenarios & 9 market sensitivities and will present modeling results in stakeholder meetings (i.e., 3A and 3B)

| Scenario | Stakeholder Meeting 3A or 3B |
|---|---|
| Base Reference | 3A |
| High Economic Growth | 3A |
| Low Economic Growth | 3A |
| Enhanced Environmental Regulations (EER) | 3A |

| Sensitivities | Stakeholder Meeting 3A or 3B |
|---|---|
| Base under EPA Section 111(b)(d) Requirements | 3A |
| Low Carbon: Transition to Objective | 3A |
| Low Carbon: Expanded Build Limits | 3A |
| Base with High IN Load | 3B |
| Base with Low IN Load | 3B |
| Rockport Unit 1 Retires 2025 | 3B |
| Rockport Unit 1 Retires 2026 | 3B |
| Exit OVEC ICPA in 2030 | 3B |
| High Technology Cost | 3B |

# Base Reference Case Portfolio

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 325 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 28 | 1,500 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 59 | 1,875 |
| 2028 | 200 | 599 | 450 | 0 | 1,800 | 0 | 1,000 | 0 | 94 | 0 |
| 2029 | 200 | 596 | 450 | 0 | 2,700 | 0 | 1,000 | 0 | 100 | 0 |
| 2030 | 200 | 593 | 450 | 0 | 3,600 | 0 | 1,500 | 0 | 97 | 0 |
| 2031 | 200 | 590 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 96 | 0 |
| 2032 | 200 | 587 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 115 | 0 |
| 2033 | 200 | 584 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 131 | 0 |
| 2034 | 200 | 581 | 450 | 1,030 | 3,600 | 0 | 2,000 | 0 | 144 | 0 |
| 2035 | 200 | 578 | 450 | 1,030 | 3,600 | 0 | 2,000 | 888 | 156 | 0 |
| 2036 | 200 | 575 | 450 | 2,060 | 3,600 | 0 | 2,000 | 888 | 169 | 0 |
| 2037 | 200 | 572 | 450 | 2,060 | 3,600 | 0 | 2,000 | 888 | 177 | 0 |
| 2038 | 200 | 569 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 185 | 0 |
| 2039 | 200 | 566 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 193 | 0 |
| 2040 | 200 | 563 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 201 | 0 |
| 2041 | 200 | 560 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 206 | 0 |
| 2042 | 200 | 557 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 211 | 0 |
| 2043 | 0 | 554 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 213 | 0 |
| 2044 | 0 | 551 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 220 | 0 |

**Purpose of Scenario:**

- Evaluating the most economical solution to meet capacity and energy needs considering all base modeling parameters and assumptions; establishes the point of reference for other scenarios and sensitivities

**Observations through 2030:**

- Short Term Capacity purchases until new resources become available in 2028
- Solar, wind, storage, and gas resources selected in 2028 in response to load growth by 2030
- Selected all available existing CC's by 2030 and existing CT's were selected to meet capacity obligation
- DR, EE, DER, CVR increase as the load and energy increase with the HSL

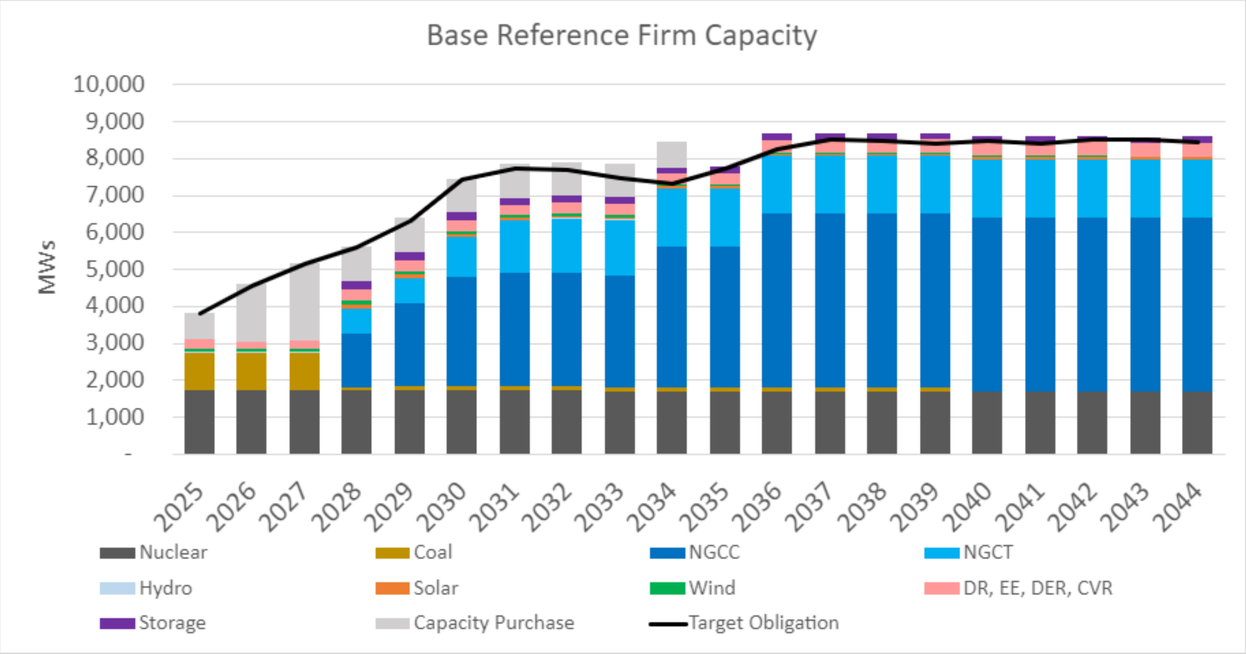
**Observations for 2031+:**

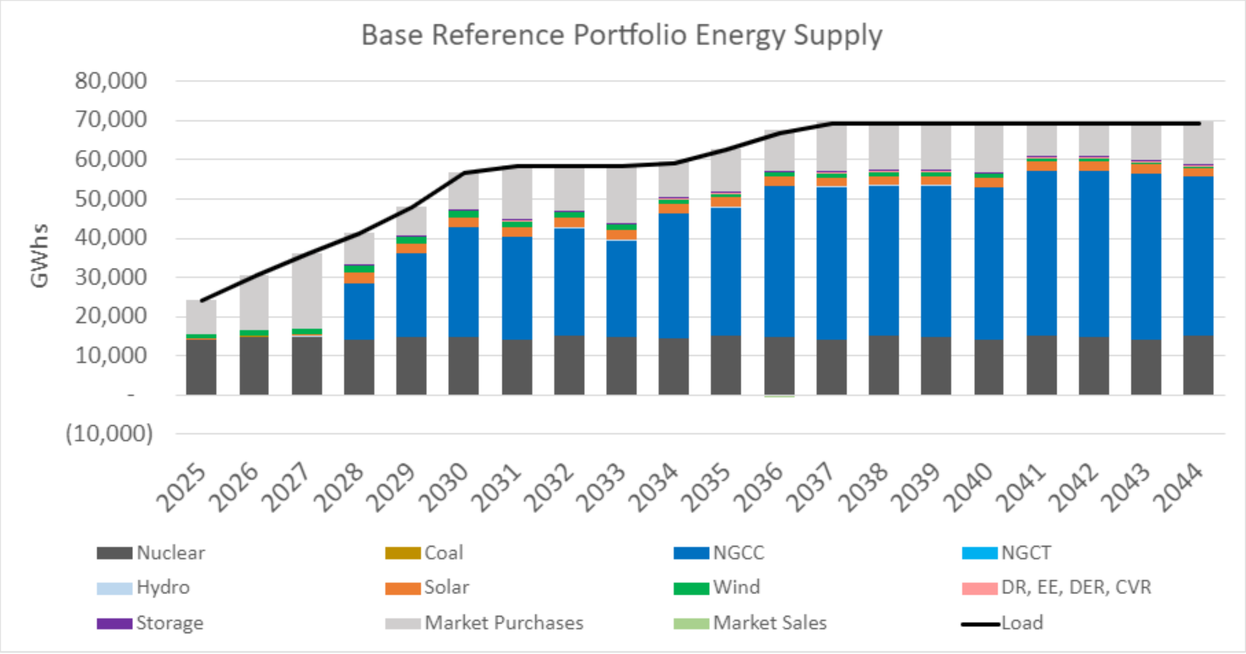
- New CC built in 2034 and 2036 to meet the load growth in the same period and the expiration of existing capacity purchase agreements
- Cook SLR selected in 2035 and 2038



*Nuclear includes Cook SLR

# Base Reference Case Portfolio




**Observations:**

- Nuclear resources provide consistent Carbon-free capacity and energy
- Natural gas resources are generally the most economic options to meet the growing capacity obligations and needed energy supply
- Capacity additions in 2033 and 2034 built in preparation of load increases that occur from 2034-2037



*Nuclear includes Cook SLR

# Enhanced Environmental Regulations Case Portfolio

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 325 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 26 | 1,500 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 56 | 1,875 |
| 2028 | 200 | 1,496 | 350 | 0 | 1,800 | 0 | 1,000 | 0 | 88 | 0 |
| 2029 | 200 | 1,489 | 350 | 0 | 2,700 | 0 | 1,000 | 0 | 112 | 0 |
| 2030 | 200 | 1,481 | 350 | 0 | 3,600 | 0 | 1,500 | 0 | 127 | 0 |
| 2031 | 600 | 1,474 | 350 | 0 | 5,400 | 0 | 1,500 | 0 | 142 | 0 |
| 2032 | 1,000 | 2,065 | 350 | 0 | 5,400 | 0 | 1,500 | 0 | 158 | 0 |
| 2033 | 1,400 | 2,653 | 350 | 0 | 5,400 | 0 | 1,500 | 0 | 169 | 0 |
| 2034 | 1,800 | 3,238 | 350 | 0 | 5,400 | 0 | 1,500 | 0 | 178 | 0 |
| 2035 | 2,200 | 3,371 | 350 | 0 | 5,400 | 0 | 1,500 | 888 | 190 | 0 |
| 2036 | 2,600 | 3,952 | 350 | 0 | 5,400 | 0 | 1,500 | 888 | 201 | 0 |
| 2037 | 3,000 | 4,530 | 350 | 0 | 5,400 | 0 | 1,500 | 888 | 208 | 0 |
| 2038 | 3,200 | 4,507 | 350 | 0 | 5,400 | 0 | 1,500 | 1,880 | 215 | 0 |
| 2039 | 3,200 | 4,484 | 350 | 0 | 5,400 | 0 | 1,500 | 1,880 | 220 | 0 |
| 2040 | 3,200 | 4,461 | 350 | 0 | 5,400 | 0 | 1,500 | 1,880 | 224 | 0 |
| 2041 | 3,200 | 4,437 | 350 | 0 | 5,400 | 0 | 1,500 | 1,880 | 227 | 0 |
| 2042 | 3,200 | 4,414 | 350 | 0 | 5,400 | 230 | 1,500 | 1,880 | 230 | 0 |
| 2043 | 3,000 | 4,114 | 350 | 0 | 5,400 | 230 | 1,500 | 1,880 | 232 | 0 |
| 2044 | 3,000 | 4,092 | 350 | 0 | 5,400 | 230 | 1,500 | 1,880 | 233 | 0 |

**Purpose of Scenario:**

- Evaluating the most economical solution to meet capacity and energy needs considering implementation of EPA Section 111(b)(d) greenhouse gas rules and associated market commodity price impacts

**Observations through 2030:**

- Solar, wind, storage, and gas resources selected in 2028 in response to load growth by 2030
- Selected all available existing CC's by 2030 and existing CT's were selected to meet capacity obligation
- Additional solar resources selected due to limited capacity factors on thermal resources
- DR, EE, DER, CVR increase as the load and energy increase with the HSL

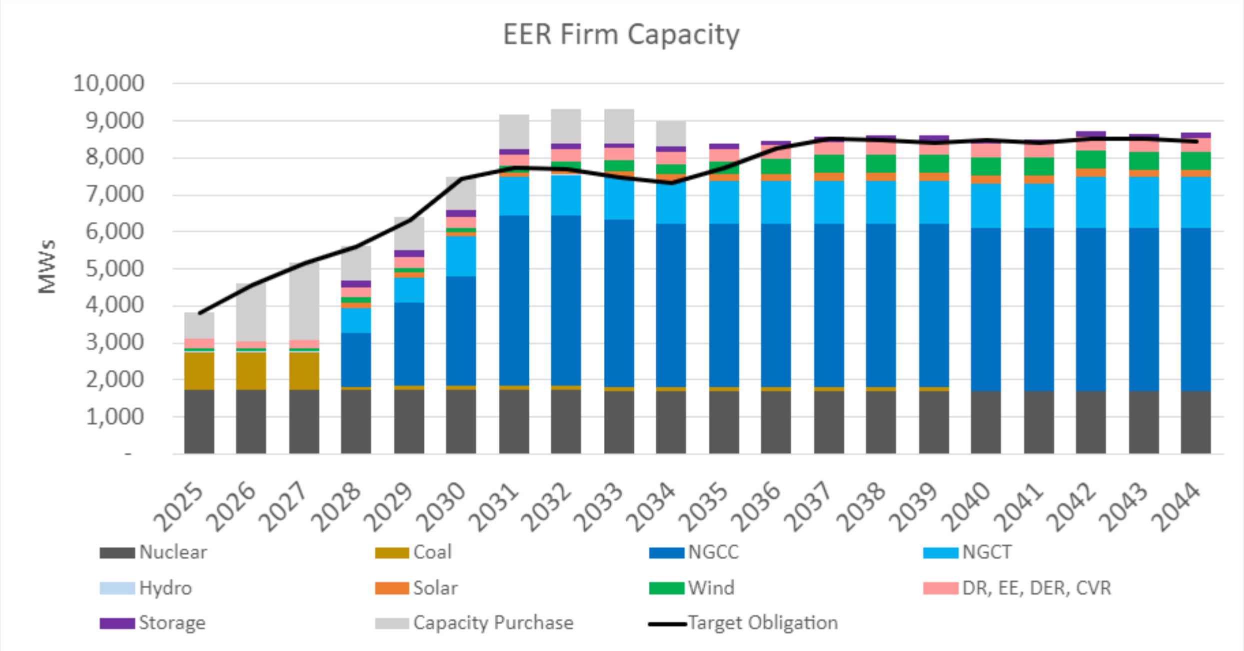
**Observations for 2031+:**

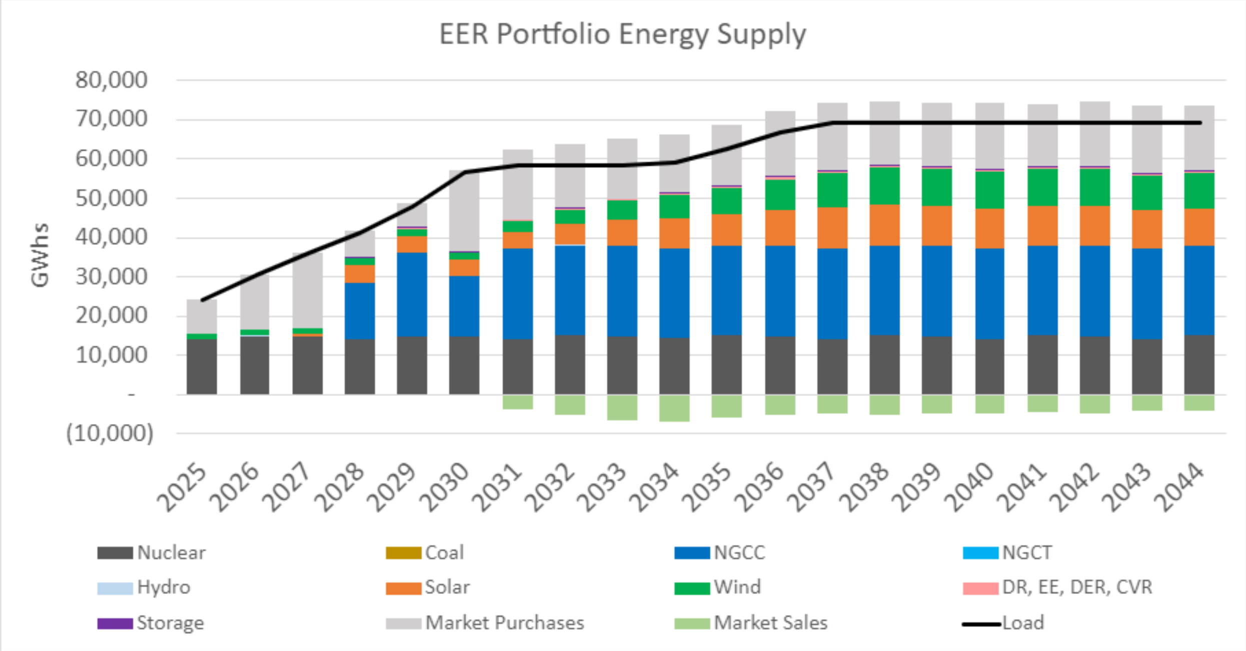
- Substantially more wind and solar selected than reference scenario
- Additional existing CC's selected to meet the load growth in the same period and the expiration of existing capacity purchase agreements
- Cook SLR selected in 2035 and 2038
- Additional EE selected compared to reference scenario



*Nuclear includes Cook SLR

# Enhanced Environmental Regulations Case Portfolio




**Observations:**

- Capacity factor limitations associated with EPA Section 111(b)(d) compliance result in significantly more energy contributions from other resources
- Nuclear and natural gas resources that have higher accreditation values are selected to cover most of the capacity obligation
- Capacity additions in 2031-2034 built in preparation of load increases that occur from 2034-2037 and to provide necessary energy supply to meet import limits
- Added renewable resources result in additional energy market sales starting in 2031



*Nuclear includes Cook SLR

# Base Under EPA Section 111(b)(d) Sensitivity

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 325 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 27 | 1,500 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 57 | 1,875 |
| 2028 | 200 | 1,047 | 400 | 0 | 1,800 | 0 | 1,000 | 0 | 90 | 0 |
| 2029 | 200 | 1,042 | 400 | 0 | 2,700 | 0 | 1,000 | 0 | 114 | 0 |
| 2030 | 200 | 1,037 | 400 | 0 | 3,600 | 0 | 1,500 | 0 | 130 | 0 |
| 2031 | 600 | 1,481 | 400 | 0 | 5,400 | 0 | 1,500 | 0 | 146 | 0 |
| 2032 | 1,000 | 2,072 | 400 | 0 | 5,400 | 0 | 1,500 | 0 | 162 | 0 |
| 2033 | 1,400 | 2,660 | 400 | 0 | 5,400 | 0 | 1,500 | 0 | 173 | 0 |
| 2034 | 1,800 | 3,245 | 400 | 0 | 5,400 | 0 | 1,500 | 0 | 182 | 0 |
| 2035 | 2,200 | 3,527 | 400 | 0 | 5,400 | 0 | 1,500 | 888 | 194 | 0 |
| 2036 | 2,600 | 4,108 | 400 | 0 | 5,400 | 0 | 1,500 | 888 | 204 | 0 |
| 2037 | 3,000 | 4,685 | 400 | 0 | 5,400 | 0 | 1,500 | 888 | 212 | 0 |
| 2038 | 3,000 | 4,661 | 400 | 0 | 5,400 | 0 | 1,500 | 1,880 | 218 | 0 |
| 2039 | 3,000 | 4,637 | 400 | 0 | 5,400 | 0 | 1,500 | 1,880 | 223 | 0 |
| 2040 | 3,000 | 4,613 | 400 | 0 | 5,400 | 0 | 1,500 | 1,880 | 228 | 0 |
| 2041 | 3,000 | 4,589 | 400 | 0 | 5,400 | 0 | 1,500 | 1,880 | 231 | 0 |
| 2042 | 3,000 | 4,565 | 400 | 0 | 5,400 | 230 | 1,500 | 1,880 | 233 | 0 |
| 2043 | 2,800 | 4,541 | 400 | 0 | 5,400 | 230 | 1,500 | 1,880 | 235 | 0 |
| 2044 | 2,800 | 4,517 | 400 | 0 | 5,400 | 230 | 1,500 | 1,880 | 236 | 0 |

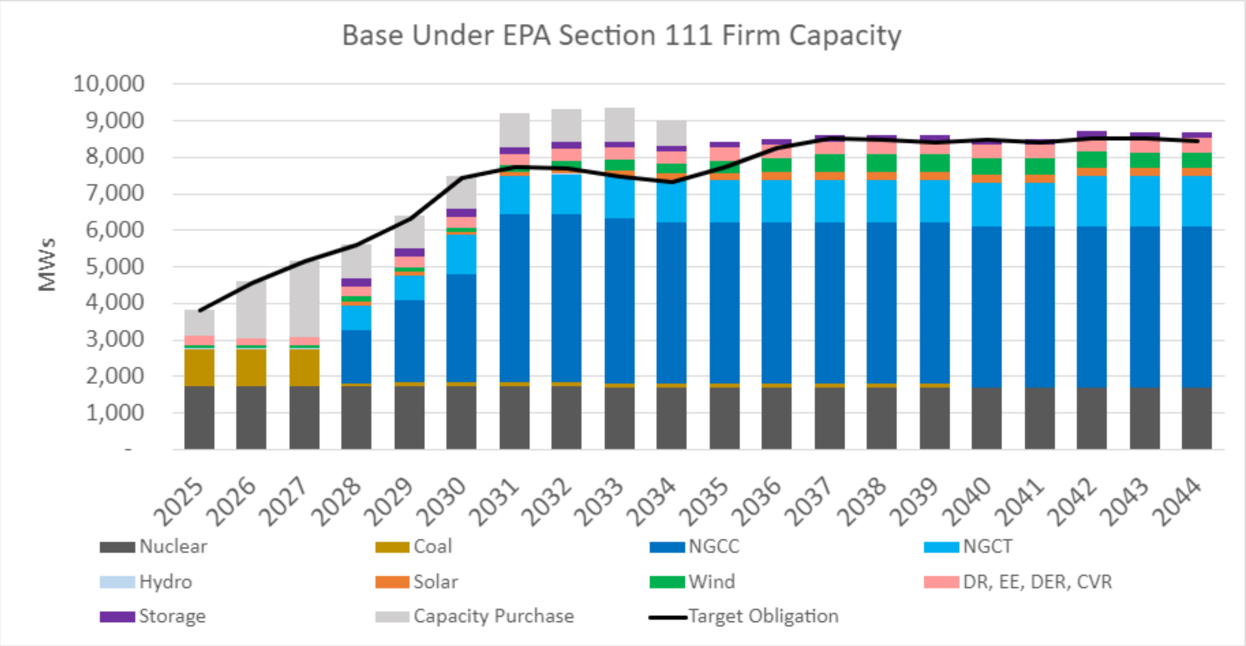
*Nuclear includes Cook SLR

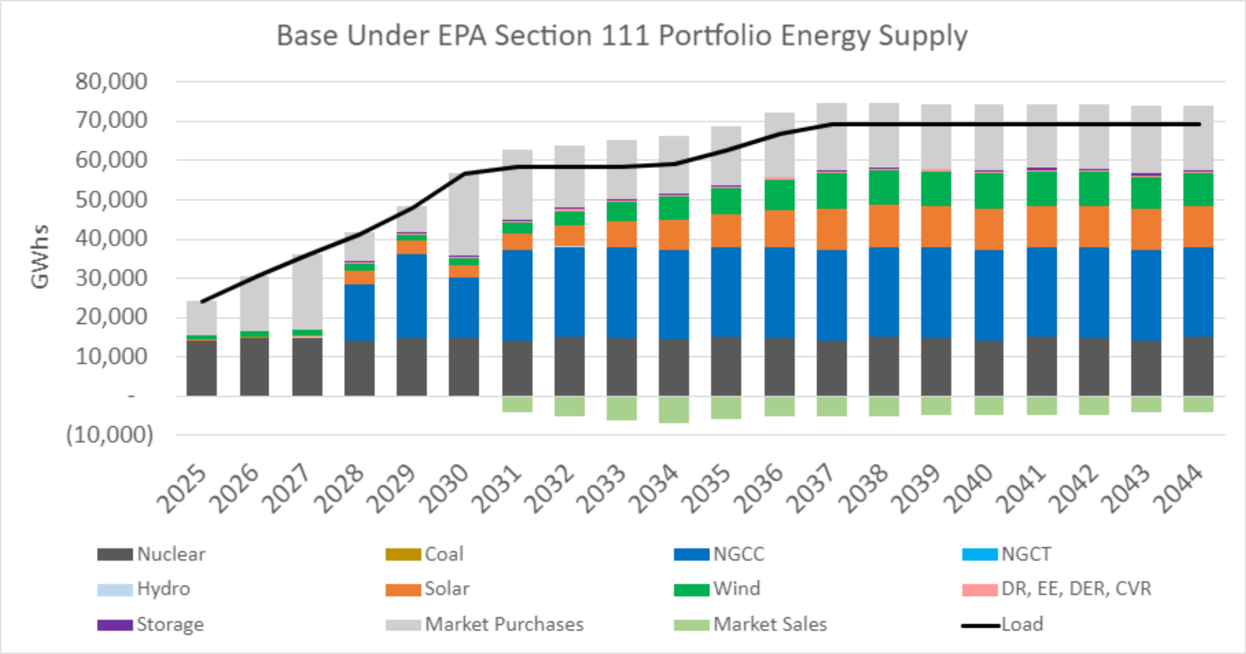
**Purpose of Scenario:**
- Evaluating the most economical solution to meet capacity and energy needs considering implementation of EPA Section 111(b)(d) greenhouse gas rules and base modeling parameters and assumptions

**Observations through 2030:**
- Solar, wind, storage, and gas resources selected in 2028 in response to load growth by 2030
- Selected all available existing CC's by 2030 and existing CT's were selected to meet capacity obligation
- Additional solar resources selected due to limited capacity factors on thermal resources
- DR, EE, DER, CVR increase as the load and energy increase with the HSL

**Observations for 2031+:**
- Substantially more wind and solar selected than reference scenario
- Additional existing CC's selected to meet the load growth in the same period and the expiration of existing capacity purchase agreements
- Cook SLR selected in 2035 and 2038
- Additional EE selected compared to reference scenario

# Base Under EPA Section 111(b)(d) Sensitivity




**Observations:**

- Results are very similar to Enhanced Environmental Regulations scenario
- Capacity factor limitations associated with EPA Section 111(b)(d) compliance result in significantly more energy contributions from other resources
- Nuclear and natural gas resources that have higher accreditation values are selected to cover most of the capacity obligation
- Capacity additions in 2031-2034 built in preparation of load increases that occur from 2034-2037 and to provide necessary energy supply to meet import limits
- Added renewable resources result in additional energy market sales starting in 2031

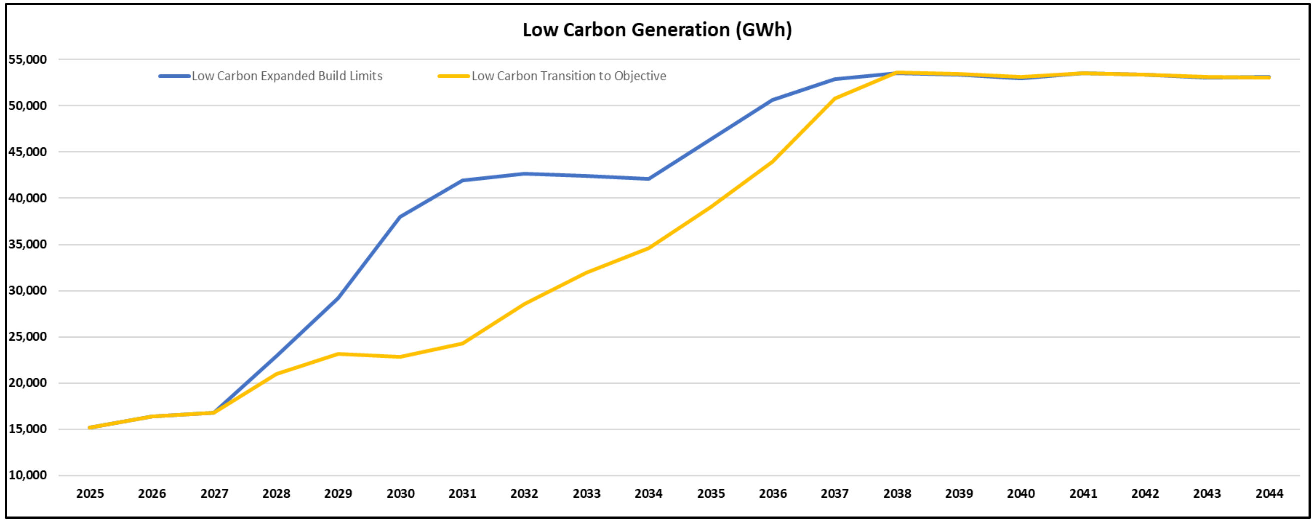


*Nuclear includes Cook SLR

# 10 Minute Break

# Low Carbon Sensitivities: Objective Comparison

- The Low Carbon Objective is to annually generate carbon-free energy that meets or exceeds our largest industrial customer energy requirements, including hyperscale customers
- In the Low Carbon: Transition to Objective sensitivity, the wind and solar resource build limit assumptions result in a transition period from 2028-2037 fully achieving the Low Carbon Objective starting in 2038
- In the Low Carbon: Expanded Build Limits sensitivity, the wind and solar build limits are increased to achieve the Low Carbon Objective throughout the planning horizon




| Resource Type | Current Build Limits: Annual Build Limit (MW) | Current Build Limits: Cumulative Build Limit through 2030 (MW) | Current Build Limits: Total Cumulative Build Limit Through Planning Horizon (MW) | Expanded Build Limits: Annual Build Limit (MW) | Expanded Build Limits: Cumulative Build Limit through 2030 (MW) | Expanded Build Limits: Total Cumulative Build Limit Through Planning Horizon (MW) |
|---|---|---|---|---|---|---|
| WIND (15 YEAR) | 200 | 400 | 4,000 | 1,600 | 3,400 | 6,800 |
| WIND (30 Year) | 400 | N/A | | 3,200 | N/A | |
| SOLAR (15 Year) | 600 | 1,200 | 4,800 | 1,050 | 2,100 | 4,800 |
| SOLAR (35 Year) | 600 | 1,200 | 4,800 | 1,050 | 2,550 | 5,400 |
| SOLAR w/STORAGE (4-HOUR) | 600 | 750 | 1350 | 1,050 | 1,650 | 1,650 |

# Low Carbon Sensitivity: Transition to Objective

| Year | Nameplate MW | | | | | | | | Accredited MW | | Objective Achievement (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity | |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 325 | 100% |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 27 | 1,500 | 100% |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 58 | 1,875 | 95% |
| 2028 | 200 | 1,796 | 300 | 0 | 1,800 | 0 | 1,000 | 0 | 92 | 0 | 92% |
| 2029 | 400 | 2,235 | 300 | 0 | 1,800 | 0 | 2,000 | 0 | 111 | 0 | 79% |
| 2030 | 400 | 2,224 | 300 | 0 | 2,700 | 0 | 2,500 | 0 | 121 | 0 | 60% |
| 2031 | 800 | 2,662 | 300 | 0 | 2,700 | 0 | 3,500 | 0 | 131 | 0 | 62% |
| 2032 | 1,200 | 3,845 | 300 | 0 | 2,700 | 0 | 3,500 | 0 | 149 | 0 | 72% |
| 2033 | 1,600 | 5,023 | 300 | 0 | 2,700 | 0 | 3,500 | 0 | 162 | 0 | 81% |
| 2034 | 2,000 | 6,194 | 300 | 0 | 2,700 | 0 | 3,500 | 0 | 173 | 0 | 82% |
| 2035 | 2,600 | 7,360 | 300 | 0 | 2,700 | 0 | 3,500 | 888 | 185 | 0 | 85% |
| 2036 | 3,200 | 8,968 | 450 | 0 | 2,700 | 230 | 3,500 | 888 | 197 | 0 | 87% |
| 2037 | 3,400 | 10,269 | 500 | 0 | 2,700 | 230 | 3,500 | 1,488 | 205 | 0 | 96% |
| 2038 | 3,400 | 10,217 | 500 | 0 | 2,700 | 230 | 3,500 | 2,780 | 211 | 0 | 100% |
| 2039 | 3,400 | 10,164 | 500 | 0 | 2,700 | 230 | 3,500 | 2,780 | 217 | 0 | 100% |
| 2040 | 3,400 | 10,261 | 500 | 0 | 2,700 | 230 | 3,500 | 2,780 | 223 | 0 | 100% |
| 2041 | 3,400 | 10,208 | 500 | 0 | 2,700 | 230 | 3,500 | 2,780 | 227 | 0 | 100% |
| 2042 | 3,400 | 10,155 | 500 | 0 | 2,700 | 230 | 3,500 | 2,780 | 230 | 0 | 100% |
| 2043 | 3,200 | 9,548 | 500 | 0 | 2,700 | 230 | 3,500 | 3,080 | 233 | 0 | 100% |
| 2044 | 3,000 | 9,359 | 500 | 0 | 2,700 | 230 | 3,500 | 3,080 | 235 | 0 | 100% |

**Purpose of Scenario:**

- Evaluating the most economical solution to achieve the Low Carbon Objective as quickly as possible given the base assumptions for wind and solar build limits

**Observations through 2030:**

- Wind and solar selected near build limits
- Selecting CT's and CC's to meet remaining capacity and energy needs
- DR, EE, DER, CVR increase as the load and energy increase with the HSL

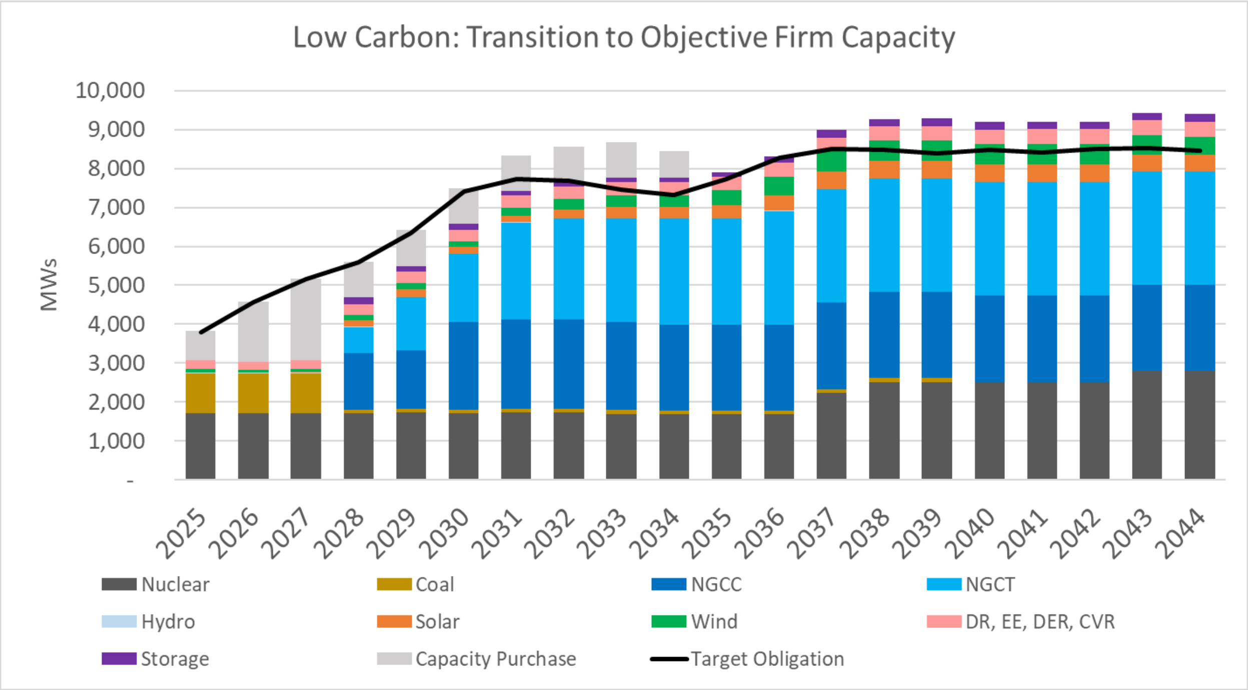
**Observations for 2031+:**

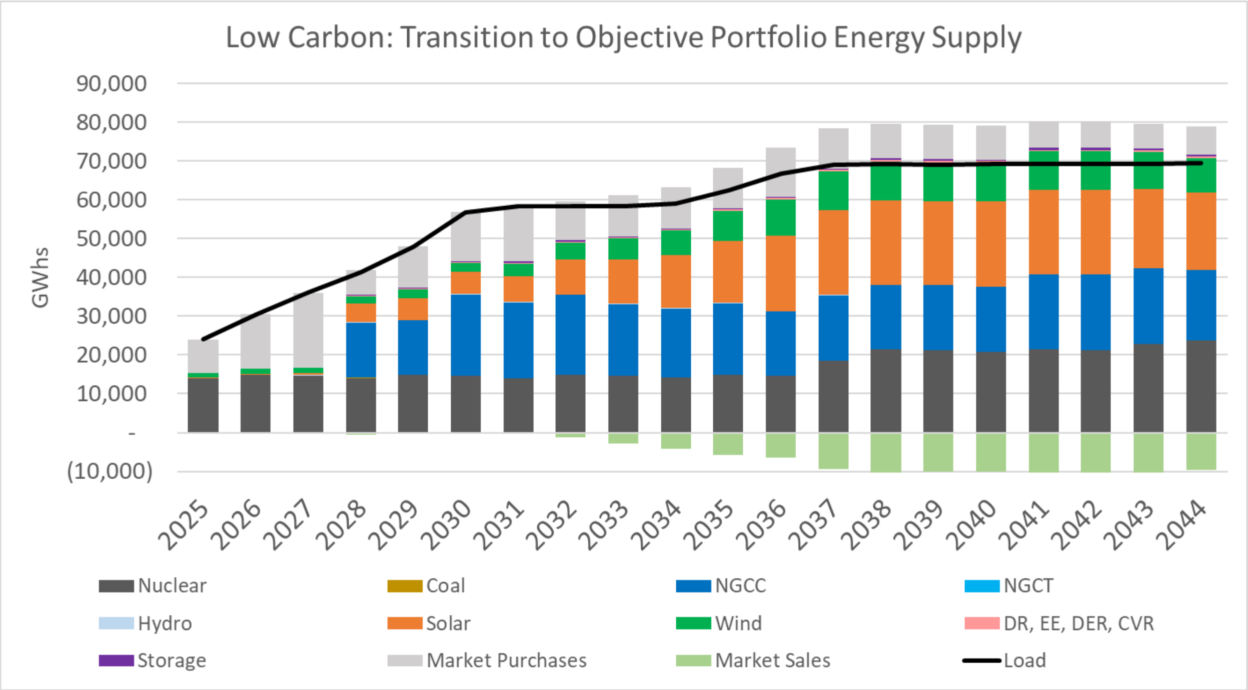
- SMR selected in 2037, increasing to 1,200MW by 2043
- Substantially more solar and wind selected to meet the carbon-free objective
- Additional CT's selected to meet capacity obligation
- Cook SLR selected in 2035 and 2038



*Nuclear includes Cook SLR and SMR

# Low Carbon Sensitivity: Transition to Objective




**Observations:**

- Carbon-free resources provide significant portion of energy supply starting in 2028 and achieves the Low Carbon Objective by 2038
- Nuclear and natural gas resources that have higher accreditation values provide much of the capacity obligation
- Capacity additions in 2031-2034 built in preparation of load increases that occur from 2034-2037
- Higher levels of renewable resources drive higher energy market sales starting in 2033



*Nuclear includes Cook SLR and SMR

# Low Carbon Sensitivity: Expanded Build Limits

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 325 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 19 | 1,500 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 38 | 1,900 |
| 2028 | 1,200 | 1,347 | 0 | 0 | 1,800 | 0 | 1,000 | 0 | 56 | 0 |
| 2029 | 1,800 | 3,285 | 0 | 0 | 1,800 | 0 | 2,000 | 0 | 69 | 0 |
| 2030 | 3,400 | 5,513 | 300 | 0 | 1,800 | 0 | 3,000 | 0 | 80 | 0 |
| 2031 | 5,000 | 5,485 | 300 | 0 | 1,800 | 0 | 4,000 | 0 | 90 | 0 |
| 2032 | 5,000 | 5,457 | 300 | 0 | 1,800 | 0 | 4,000 | 0 | 108 | 0 |
| 2033 | 5,000 | 5,430 | 300 | 0 | 1,800 | 0 | 4,000 | 0 | 122 | 0 |
| 2034 | 5,000 | 5,701 | 300 | 0 | 1,800 | 0 | 4,000 | 0 | 134 | 0 |
| 2035 | 5,400 | 7,019 | 300 | 0 | 1,800 | 0 | 4,000 | 888 | 147 | 0 |
| 2036 | 6,200 | 8,030 | 300 | 0 | 1,800 | 230 | 4,000 | 888 | 158 | 0 |
| 2037 | 6,200 | 8,438 | 300 | 0 | 1,800 | 230 | 4,000 | 1,188 | 167 | 0 |
| 2038 | 6,200 | 8,394 | 300 | 0 | 1,800 | 230 | 4,000 | 2,180 | 175 | 0 |
| 2039 | 6,200 | 8,351 | 300 | 0 | 1,800 | 230 | 4,000 | 2,180 | 182 | 0 |
| 2040 | 6,200 | 8,457 | 350 | 0 | 1,800 | 230 | 4,000 | 2,180 | 187 | 0 |
| 2041 | 6,200 | 8,412 | 350 | 0 | 1,800 | 230 | 4,000 | 2,180 | 192 | 0 |
| 2042 | 6,200 | 8,368 | 350 | 0 | 1,800 | 230 | 4,000 | 2,180 | 195 | 0 |
| 2043 | 5,000 | 8,047 | 350 | 0 | 1,800 | 230 | 4,000 | 2,780 | 198 | 0 |
| 2044 | 4,600 | 8,222 | 350 | 0 | 1,800 | 230 | 4,000 | 2,780 | 200 | 0 |

**Purpose of Scenario:**

- Evaluating the most economical solution to achieve the Low Carbon Objective starting 2028 with increased wind and solar build limits

**Observations through 2030:**

- Substantial expansion in build limits for wind and solar required to meet the carbon-free objective
- Selecting all available existing CT's by 2030 to meet capacity obligation
- Substantially fewer existing CC's selected compared to reference scenario
- EE, DER, CVR increase as the load and energy increase with the HSL

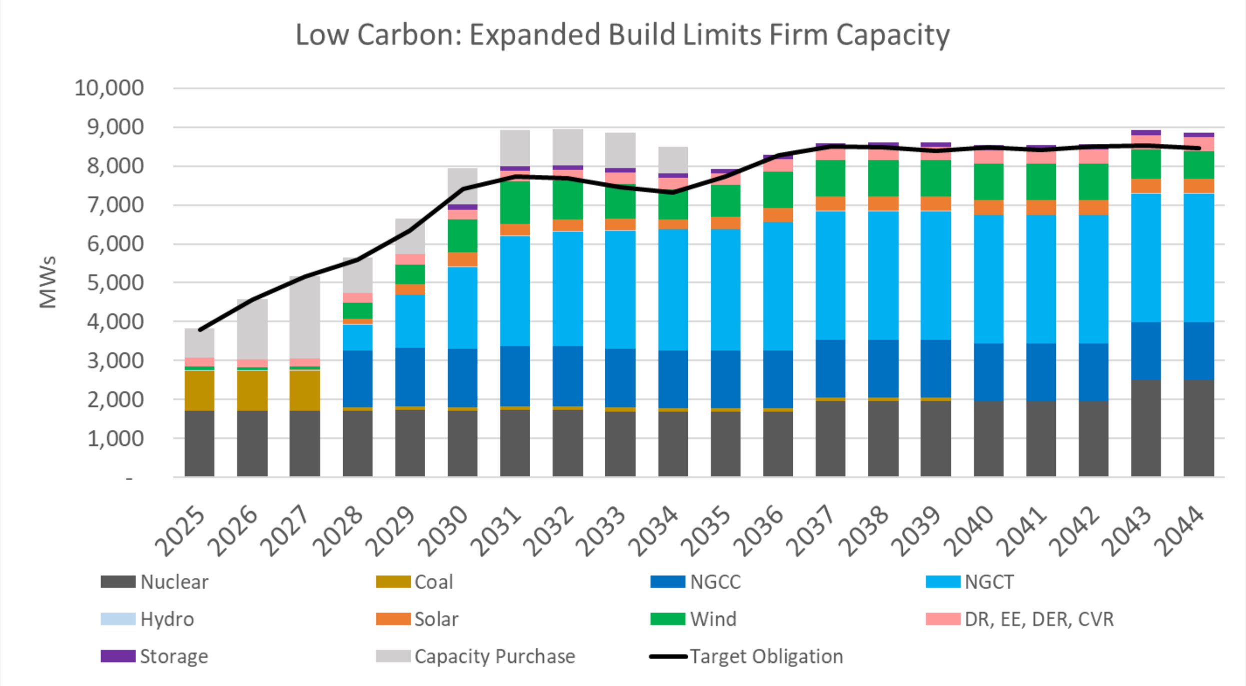
**Observations for 2031+:**

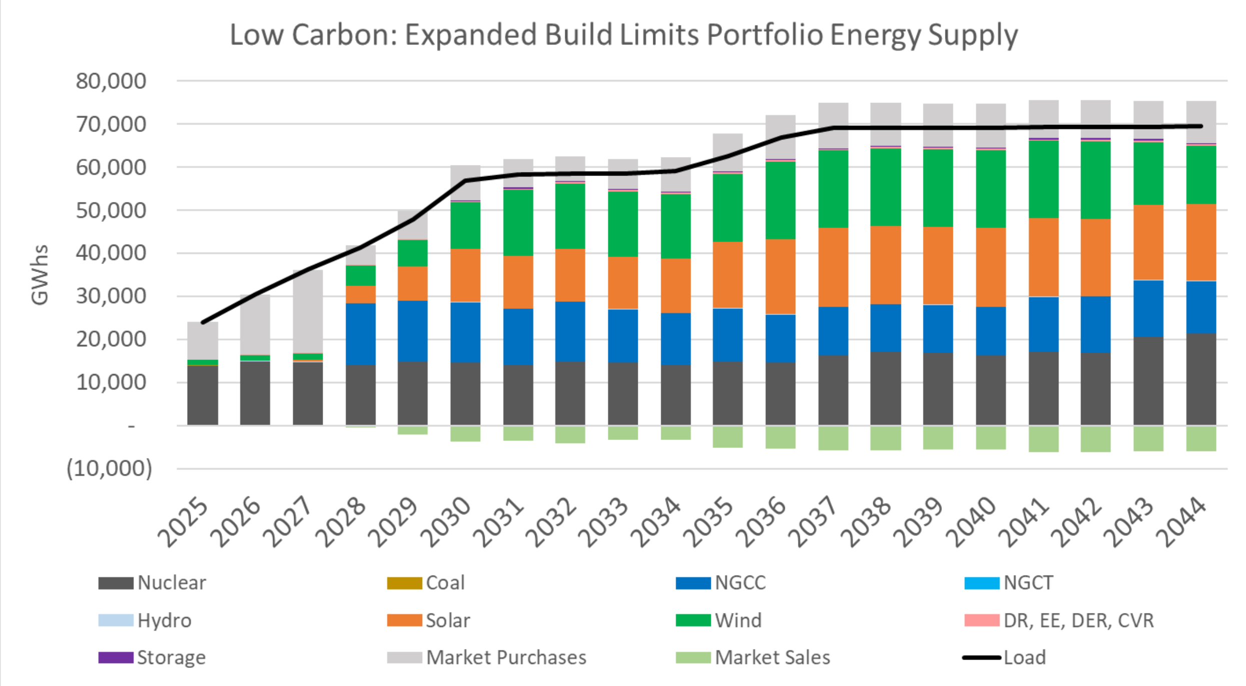
- SMR selected in 2037 when first made available and again in 2043
- Substantially more solar and wind selected to meet the carbon-free objective
- Additional CT's selected to meet capacity obligation
- Cook SLR selected in 2035 and 2038



*Nuclear includes Cook SLR and SMR

# Low Carbon Sensitivity: Expanded Build Limits



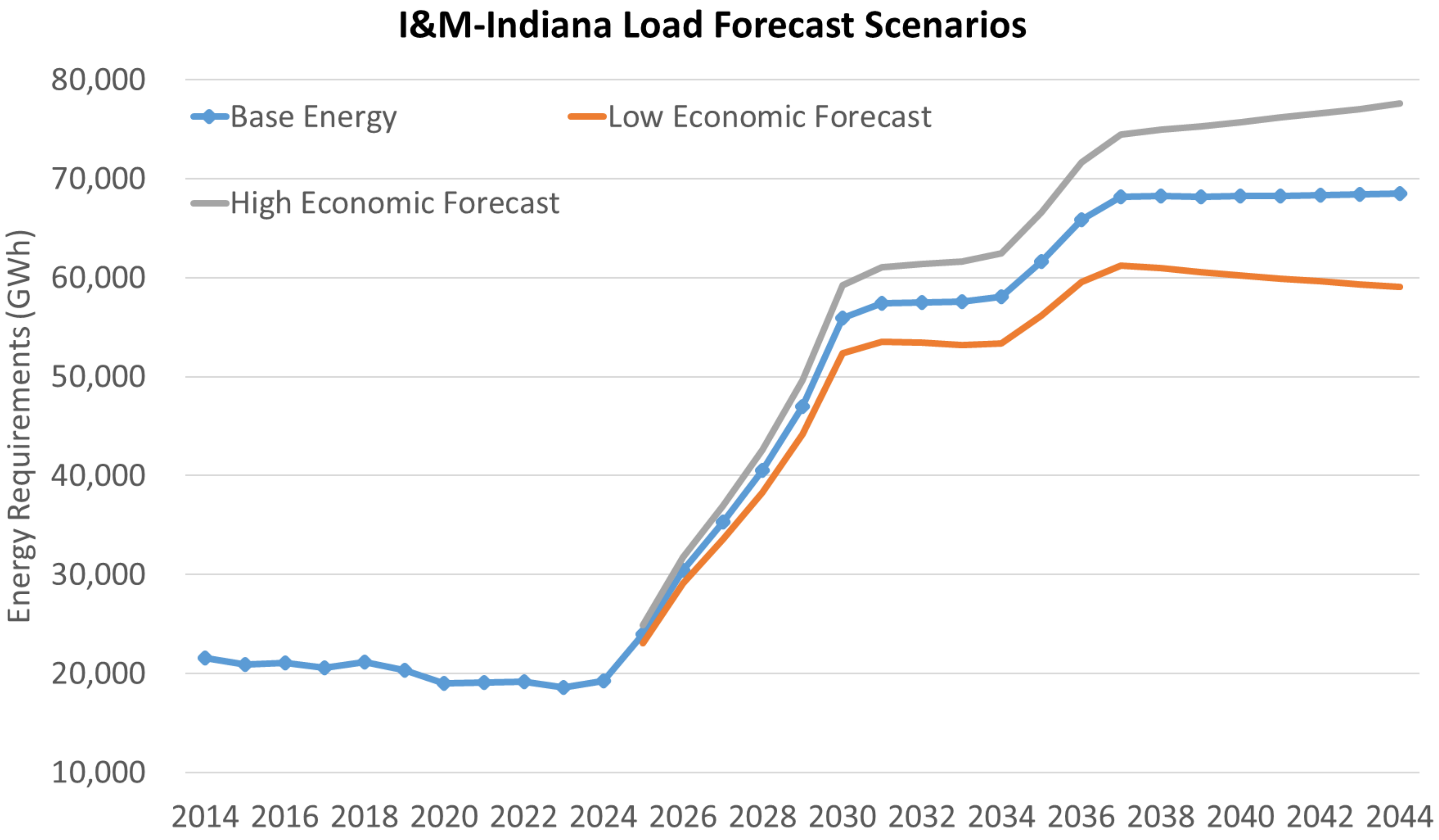

**Observations:**

- Achieves the Low Carbon Objective starting in 2028 and Carbon-free resources provide much of the energy supply throughout the planning horizon
- Nuclear and natural gas resources continue to provide much of the capacity obligation
- Capacity additions in 2030-2034 built in preparation of load increases that occur from 2034-2037
- Higher levels of renewable resources drive higher energy market sales starting in 2029
- More balanced mix of wind and solar selected due to the higher wind build limits available and the complimentary nature of the resources



*Nuclear includes Cook SLR and SMR

# High and Low Cases: Load Forecast Scenarios



# High Case Portfolio

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage** | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 350 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 28 | 1,650 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 59 | 2,000 |
| 2028 | 200 | 1,796 | 451 | 0 | 1,800 | 0 | 1,000 | 0 | 94 | 200 |
| 2029 | 200 | 1,787 | 451 | 0 | 2,700 | 0 | 2,000 | 0 | 119 | 0 |
| 2030 | 200 | 1,778 | 454 | 0 | 2,700 | 0 | 3,000 | 0 | 135 | 0 |
| 2031 | 600 | 1,769 | 454 | 0 | 3,600 | 0 | 3,500 | 0 | 151 | 0 |
| 2032 | 1,000 | 1,760 | 454 | 0 | 3,600 | 0 | 3,500 | 0 | 167 | 0 |
| 2033 | 1,400 | 1,751 | 454 | 0 | 3,600 | 0 | 3,500 | 0 | 179 | 0 |
| 2034 | 1,800 | 1,891 | 454 | 1,030 | 3,600 | 0 | 3,500 | 0 | 188 | 0 |
| 2035 | 2,000 | 2,480 | 454 | 1,030 | 3,600 | 0 | 3,500 | 888 | 201 | 0 |
| 2036 | 2,400 | 3,066 | 454 | 1,030 | 3,600 | 0 | 3,500 | 888 | 212 | 0 |
| 2037 | 2,800 | 3,648 | 454 | 1,030 | 3,600 | 0 | 3,500 | 888 | 220 | 0 |
| 2038 | 3,200 | 3,630 | 454 | 1,030 | 3,600 | 0 | 3,500 | 1,880 | 226 | 0 |
| 2039 | 3,200 | 3,611 | 454 | 1,030 | 3,600 | 0 | 3,500 | 1,880 | 231 | 0 |
| 2040 | 3,200 | 3,592 | 454 | 1,030 | 3,600 | 0 | 3,500 | 1,880 | 236 | 0 |
| 2041 | 3,200 | 3,573 | 454 | 1,030 | 3,600 | 0 | 3,500 | 1,880 | 239 | 0 |
| 2042 | 3,200 | 3,555 | 454 | 1,030 | 3,600 | 230 | 3,500 | 1,880 | 242 | 0 |
| 2043 | 3,000 | 2,982 | 454 | 1,030 | 3,600 | 230 | 3,500 | 1,880 | 245 | 0 |
| 2044 | 3,000 | 3,266 | 454 | 1,030 | 3,600 | 230 | 3,500 | 1,880 | 246 | 0 |

**Purpose of Scenario:**

- Evaluating the most economical solution to meet capacity and energy needs considering all high economic forecast modeling parameters and assumptions

**Observations through 2030:**

- Solar, wind, storage, and gas resources selected in 2028; significantly more solar than reference scenario
- Selected all available existing CT's by 2030 and existing CC's were selected to meet energy needs
- DR, EE, DER, CVR increase as the load and energy increase with the HSL

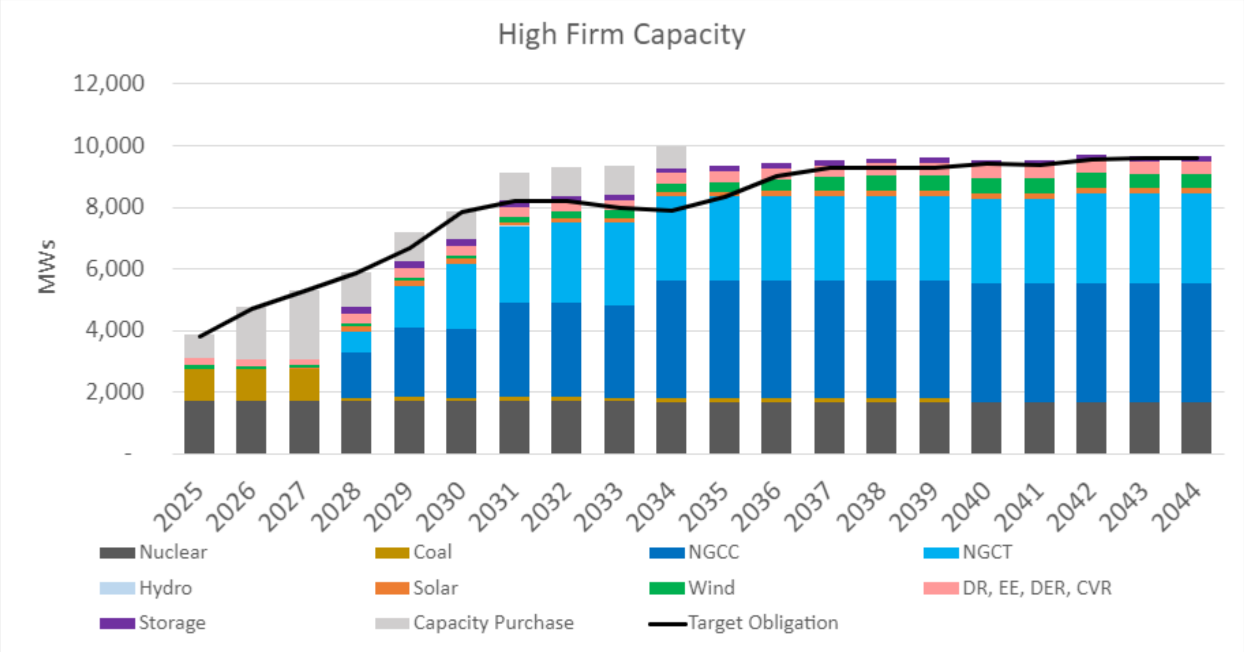
**Observations for 2031+:**

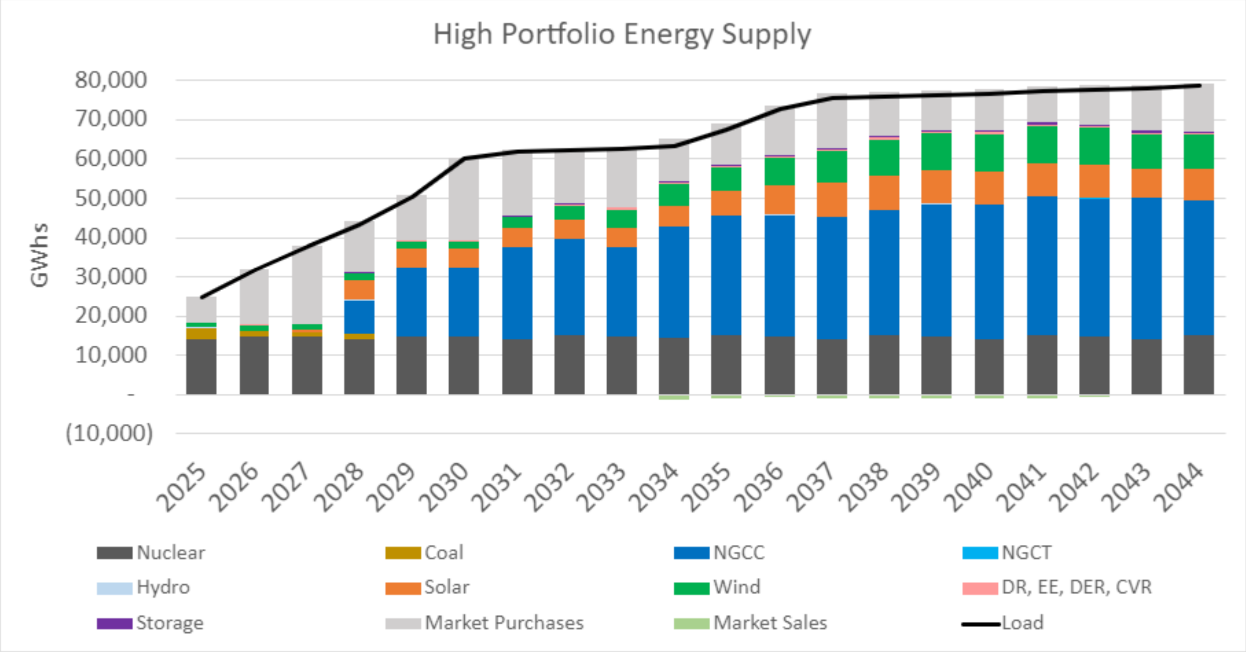
- Significantly more wind is selected compared to the reference scenario
- Fewer new CC's selected compared to the reference scenario due to the additional wind and solar selected
- Additional existing CT's selected compared to the reference scenario to meet capacity obligation
- Cook SLR selected in 2035 and 2038
- Additional EE selected compared to reference scenario

*Nuclear includes Cook SLR

** Storage includes Distribution-Sited Storage resources

# High Case Portfolio




**Observations:**

- Nuclear resources provide consistent Carbon-free capacity and energy
- Higher load growth and high economic forecast result in additional renewable resources compared to the Base Reference Case that provide significant energy supply
- Natural gas resources continue to provide much of the capacity obligation and significant energy supply
- Capacity additions in 2031-2035 built in preparation of load increases that occur from 2034-2037



*Nuclear includes Cook SLR

# Low Case Portfolio

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 75 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 23 | 1,275 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 49 | 1,525 |
| 2028 | 200 | 0 | 0 | 0 | 1,800 | 0 | 1,000 | 0 | 79 | 0 |
| 2029 | 200 | 0 | 0 | 0 | 2,700 | 0 | 1,000 | 0 | 90 | 0 |
| 2030 | 200 | 0 | 0 | 0 | 3,600 | 0 | 1,500 | 0 | 94 | 0 |
| 2031 | 200 | 0 | 0 | 0 | 3,600 | 0 | 1,500 | 0 | 98 | 0 |
| 2032 | 200 | 0 | 0 | 0 | 3,600 | 0 | 1,500 | 0 | 97 | 0 |
| 2033 | 200 | 0 | 0 | 0 | 3,600 | 0 | 1,500 | 0 | 94 | 0 |
| 2034 | 200 | 0 | 0 | 1,030 | 3,600 | 0 | 1,500 | 0 | 92 | 0 |
| 2035 | 200 | 0 | 0 | 1,030 | 3,600 | 0 | 1,500 | 888 | 91 | 0 |
| 2036 | 200 | 0 | 0 | 2,060 | 3,600 | 0 | 1,500 | 888 | 88 | 0 |
| 2037 | 200 | 0 | 0 | 2,060 | 3,600 | 0 | 1,500 | 888 | 85 | 0 |
| 2038 | 200 | 0 | 0 | 2,060 | 3,600 | 0 | 1,500 | 1,880 | 82 | 0 |
| 2039 | 200 | 0 | 0 | 2,060 | 3,600 | 0 | 1,500 | 1,880 | 79 | 0 |
| 2040 | 200 | 0 | 0 | 2,060 | 3,600 | 0 | 1,500 | 1,880 | 78 | 0 |
| 2041 | 200 | 0 | 0 | 2,060 | 3,600 | 0 | 1,500 | 1,880 | 70 | 0 |
| 2042 | 200 | 0 | 0 | 2,060 | 3,600 | 0 | 1,500 | 1,880 | 64 | 0 |
| 2043 | 0 | 0 | 0 | 2,060 | 3,600 | 0 | 1,500 | 1,880 | 57 | 0 |
| 2044 | 200 | 0 | 0 | 2,060 | 3,600 | 0 | 1,500 | 1,880 | 56 | 0 |

**Purpose of Scenario:**

- Evaluating the most economical solution to meet capacity and energy needs considering all low economic forecast modeling parameters and assumptions

**Observations through 2030:**

- Wind and gas resources selected in 2028 in response to load growth by 2030
- Selected all available existing CC's by 2030 and existing CT's were selected to meet capacity obligation
- Fewer DR, EE, DER, CVR are selected compared to reference scenario

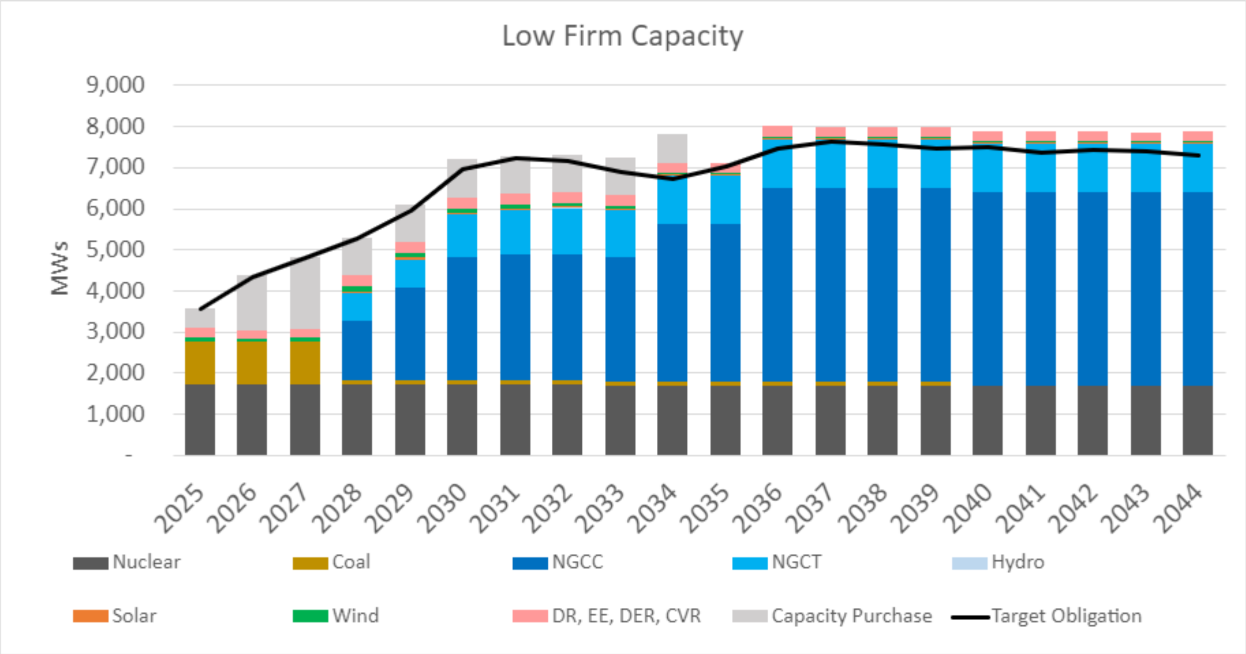
**Observations for 2031+:**

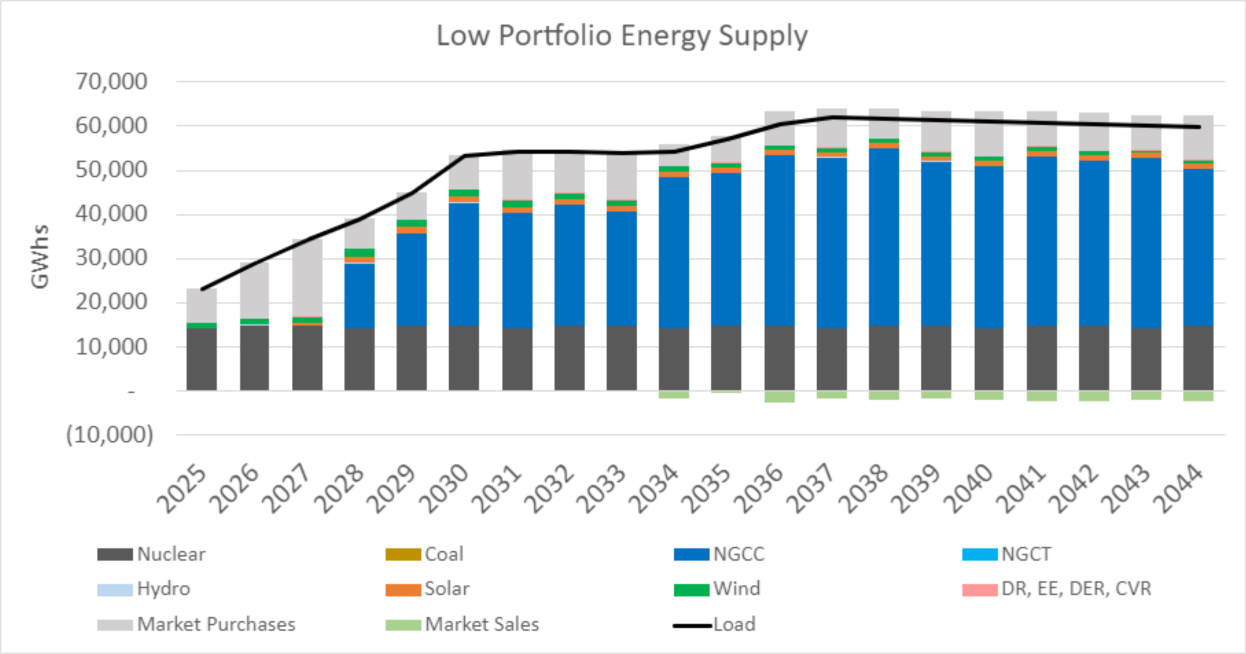
- New CC built in 2034 and 2036 to meet the load growth in the same period and the expiration of existing capacity purchase agreements
- Fewer existing CT's selected compared to reference scenario due to lower capacity obligation
- Cook SLR selected in 2035 and 2038



*Nuclear includes Cook SLR

# Low Case Portfolio




**Observations:**

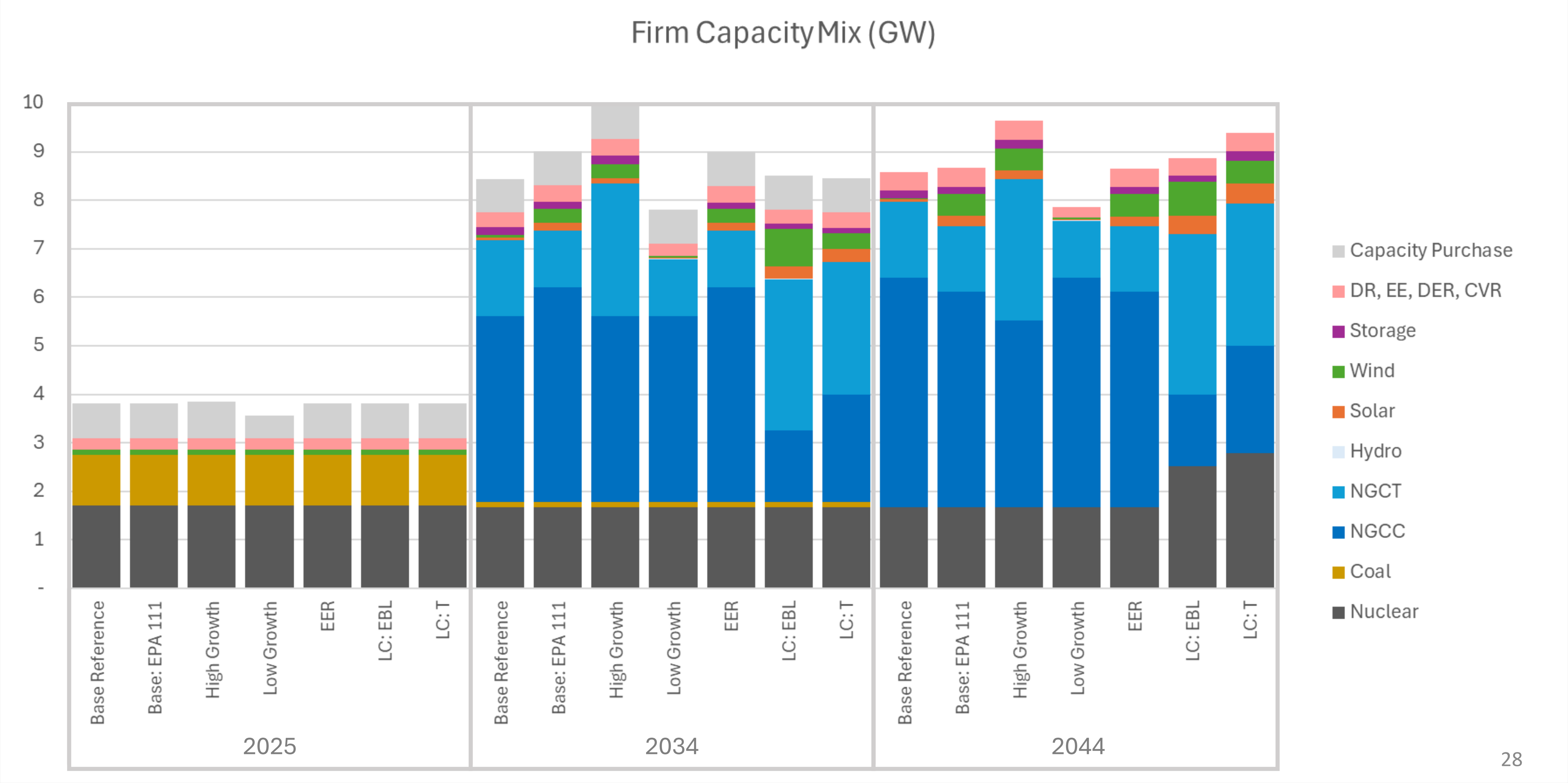
- Nuclear resources provide consistent Carbon-free capacity and energy
- Lower load growth and low economic forecast result in fewer renewable resources compared to the Base Reference Case
- Natural gas resources provide much of the capacity obligation and energy supply
- Capacity additions in 2033-2034 built in preparation of load increases that occur from 2034-2037



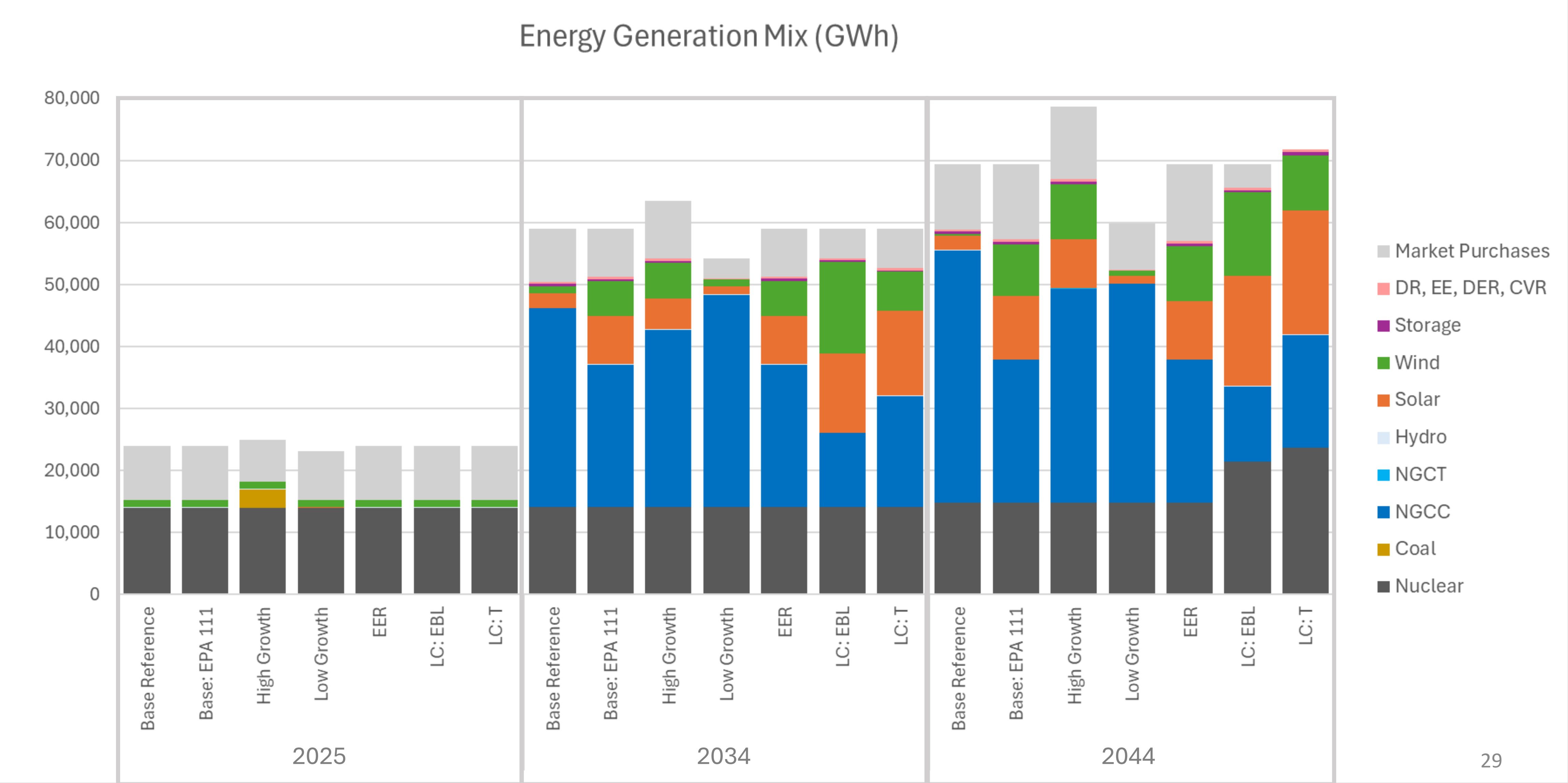
*Nuclear includes Cook SLR

# 10 Minute Break

# Results Summary Comparison



# Results Summary Comparison



# Results Summary Comparison

| Portfolio | 2034 Nameplate Capacity Additions (MW) | | | | | | | | 2044 Nameplate Capacity Additions (MW) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | NGCT | NGCC | Nuclear* | DR, EE, DER, CVR* | **Total Additions** | Wind | Solar | Storage | NGCT | NGCC | Nuclear* | DR, EE, DER, CVR* | **Total Additions** |
| **Base Reference** | 200 | 581 | 450 | 2,000 | 4,630 | 0 | 144 | **8,005** | 0 | 551 | 450 | 2,000 | 5,660 | 1,880 | 220 | **10,761** |
| **Enhanced Environmental Regulations** | 1,800 | 3,238 | 350 | 1,500 | 5,400 | 0 | 178 | **12,466** | 3,000 | 4,092 | 350 | 1,730 | 5,400 | 1,880 | 233 | **16,685** |
| **Base Under EPA Section 111(b)(d)** | 1,800 | 3,245 | 400 | 1,500 | 5,400 | 0 | 182 | **12,527** | 2,800 | 4,517 | 400 | 1,730 | 5,400 | 1,880 | 236 | **16,963** |
| **Low Carbon: Transition** | 2,000 | 6,194 | 300 | 3,500 | 2,700 | 0 | 173 | **14,867** | 3,000 | 9,359 | 500 | 3,730 | 2,700 | 3,080 | 235 | **22,604** |
| **Low Carbon: Expanded Build Limits** | 5,000 | 5,701 | 300 | 4,000 | 1,800 | 0 | 134 | **16,935** | 4,600 | 8,222 | 350 | 4,230 | 1,800 | 2780 | 200 | **22,182** |
| **High Growth** | 1,800 | 1,891 | 454 | 3,500 | 4,630 | 0 | 188 | **12,463** | 3,000 | 3,266 | 450 | 3,730 | 4,630 | 1,880 | 246 | **17,202** |
| **Low Growth** | 200 | 0 | 0 | 1,500 | 4,630 | 0 | 92 | **6,422** | 200 | 0 | 0 | 1,500 | 5,660 | 1,880 | 56 | **9,296** |

*DR, EE, DER, CVR values are accredited

** Cook SLR is not included in this table as all cases select the relicensing

# Portfolio Performance Indicators

| IURC Pillar | IRP Objective | Performance Indicator | Metric Description |
|---|---|---|---|
| Reliability | Maintain capacity reserve margin and the consideration of reliance on the market for the benefit of customers. | Energy Market Exposure – Purchases | NPV of market purchases and average volume exposure of market purchases (Costs and MWhs % of Internal Load) over 10 and 20 years. Lower values are better. |
| | | Energy Market Exposure – Sales | NPV of market sales and average volume exposure of market sales (Revenues and MWhs % of Internal Load) over 10 and 20 years. Lower values are better. |
| | | Planning Reserves | Average Target Reserve Margin over 10 and 20 years. Closest value to the % Target. |
| Affordability | Maintain focus on power supply cost and risks to customers | Net Present Value Revenue Requirement (NPVRR) | Portfolio 30yr NPVRR (power supply costs). Lower values are better. |
| | | Near-Term Power Supply Cost Impacts (CAGR) | 7-year CAGR of Annual Power Supply Cost. Lower values are better. |
| | | Portfolio Resilience | Range of Portfolio NPVRR (power supply costs) dispatched across all Scenarios. Lower values are better. |
| Resiliency | Maintain diversity of resources and fleet dispatchability | Resource Diversity | Percent change in Diversity Index inclusive of Capacity and Energy Diversity in years 2034 and 2044. Higher values are better. |
| | | Fleet Resiliency | Average % dispatchable capacity of company peak load over 10 and 20 years. Higher values are better. |
| (Grid) Stability | Maintain fleet of flexible and dispatchable resources | | |
| Environmental Sustainability | Maintain focus on portfolio environmental sustainability benefits and compliance costs | Emissions Change | $CO_2$, NOx, $SO_2$ emissions change compared to 2005 levels in years 2034 and 2044. Higher values are better. |
| | | Net Present Value Revenue Requirement (NPVRR) | Considered under Affordability Pillar above |

# Draft Portfolio Performance Comparison

| Pillar | Affordability | | | Environmental Sustainability | | |
|---|---|---|---|---|---|---|
| ***Performance Indicators and Metrics*** | ***Short Term*** *7-yr Rate CAGR* Power Supply $/MWh | ***Long Term*** *Supply Portfolio NPVRR* | ***Portfolio Resilience:*** *High Minus Low Scenario Range, Portfolio NPVRR* | ***Emissions Analysis:*** *% Change from 2005 Baseline* | | |
| Year Ref. | 2024-2031 | 2025-2044 | 2025-2044 | 2034 \| 2044 | | |
| Units | % | $B | $B | % Change $CO_2$ | % Change NOx | % Change $SO_2$ |
| **Base Reference** | -0.5% | $31.9 | [to be developed] | 2034: -39%<br>2044: -24% | 2034: -94%<br>2044: -93% | 2034: -100%<br>2044: -100% |
| **Base Under EPA Section 111(b)(d)** | 0.7% | $33.2 | [to be developed] | 2034: -56%<br>2044: -55% | 2034: -95%<br>2044: -95% | 2034: -100%<br>2044: -100% |
| **Low Carbon: Expanded Build Limits** | 4.4% | $41.3 | [to be developed] | 2034: -77%<br>2044: -77% | 2034: -97%<br>2044: -97% | 2034: -100%<br>2044: -100% |
| **Low Carbon: Transition** | 1.3% | $39.8 | [to be developed] | 2034: -65%<br>2044: -65% | 2034: -96%<br>2044: -96% | 2034: -100%<br>2044: -100% |
| **High Growth** | 1.5% | $39.2 | [to be developed] | 2033: -46%<br>2044: -34% | 2033: -95%<br>2044: -93% | 2033: -100%<br>2044: -100% |
| **Low Growth** | -2.3% | $25.6 | [to be developed] | 2034: -35%<br>2044: -35% | 2034: -93%<br>2044: -94% | 2034: -100%<br>2044: -100% |

# Draft Portfolio Performance Comparison

| Pillar | Reliability | | | Reliability/ Resiliency | Grid Stability Resiliency |
|---|---|---|---|---|---|
| ***Performance Indicators and Metrics*** | ***Energy Market Risk*** *Purchases* | ***Energy Market Risk*** *Sales* | ***Planning Reserves*** *% Reserve Margin* | ***Resource Diversity*** | ***Fleet Resiliency:*** *Dispatchable Capacity* |
| Year Ref. | 10 years \| 20 years | 10 years \| 20 years | 10 years \| 20 years | 10 years \| 20 years | 10 years \| 20 years |
| Units | NPV of Market Purchases & MWhs % of Total Demand | NPV of Market Sales & MWhs % of Total Demand | Average of Annual PRM % | Portfolio Index Percent Change from 2025 | Dispatchable Nameplate MW/ % of Company Peak Demand |
| **Base Reference** | 10 Years: \$2.6B (27%)<br>20 Years: \$4.3B (22%) | 10 Years: \$0.0B (0.1%)<br>20 Years: \$0.1B (0.3%) | 10 Years: -0.7%<br>20 Years: -3.4% | Capacity: 31% \| 19%<br>Energy: 173% \| 139% | 10 Years: 86%<br>20 Years: 93% |
| **Base Under EPA Section 111(b)(d)** | 10 Years: \$3.1B (31%)<br>20 Years: \$5.5B (28%) | 10 Years: \$0.5B (4.0%)<br>20 Years: \$1.4B (5.7%) | 10 Years: 5.5%<br>20 Years: -0.2% | Capacity: 36% \| 38%<br>Energy: 281% \| 299% | 10 Years: 92%<br>20 Years: 92% |
| **Low Carbon: Expanded Build Limits** | 10 Years: \$2.1B (22%)<br>20 Years: \$3.6B (18%) | 10 Years: \$0.4B (3.6%)<br>20 Years: \$1.4B (6.0%) | 10 Years: 4.5%<br>20 Years: -0.8% | Capacity: 56% \| 52%<br>Energy: 317% \| 311% | 10 Years: 85%<br>20 Years: 85% |
| **Low Carbon: Transition** | 10 Years: \$2.7B (27%)<br>20 Years: \$4.1B (20%) | 10 Years: \$0.2B (1.6%)<br>20 Years: \$1.7B (7.7%) | 10 Years: 2.0%<br>20 Years: 0.5% | Capacity: 53% \| 54%<br>Energy: 302% \| 304% | 10 Years: 88%<br>20 Years: 91% |
| **High Growth** | 10 Years: \$4.0B (30%)<br>20 Years: \$6.6B (23%) | 10 Years: \$0.1B (0.5%)<br>20 Years: \$0.3B (0.9%) | 10 Years: 3.9%<br>20 Years: -0.7% | Capacity: 41% \| 43%<br>Energy: 71% \| 79% | 10 Years: 91%<br>20 Years: 93% |
| **Low Growth** | 10 Years: \$1.8B (24%)<br>20 Years: \$2.5B (19%) | 10 Years: \$0.0B (0.3%)<br>20 Years: \$0.2B (1.9%) | 10 Years: -0.3%<br>20 Years: -1.5% | Capacity: 18% \| 5%<br>Energy: 161% \| 154% | 10 Years: 89%<br>20 Years: 97% |

# Remaining Modeling and Next Steps

## Stakeholder Meeting 3A

- Meeting Minutes will be posted on 1/10/25. Extension in timeline to post due to the holidays.

## Stakeholder Meeting 3B: 1/27/2025

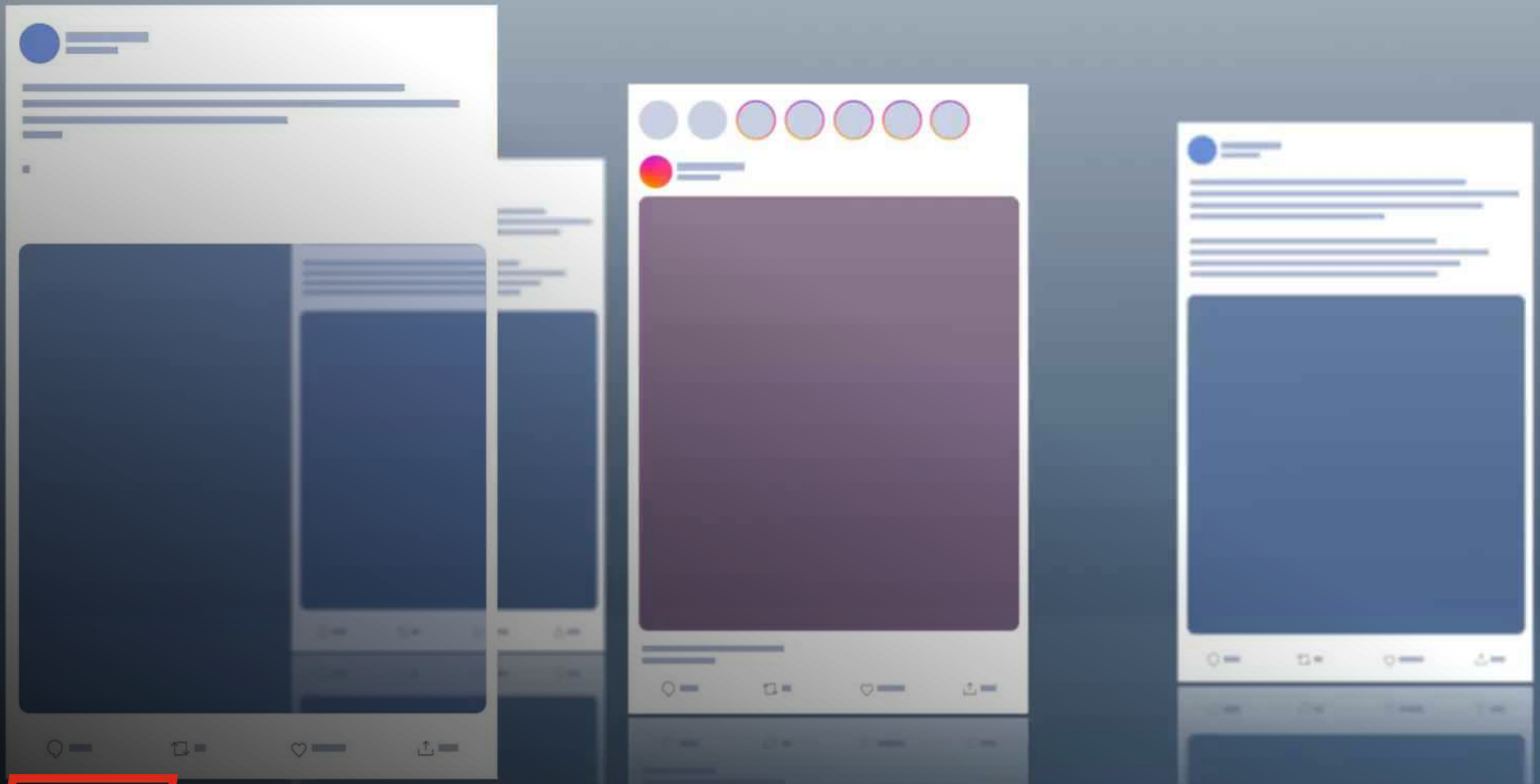
- Remaining Sensitivities to be modeled
  - Base with High and Low IN Load
  - Rockport Unit 1 Retires 2025 and 2026
  - Exit OVEC ICPA in 2030
  - High Technology Cost

## Stakeholder Meeting 4: 3/5/2025

- Risk Analysis
- Preferred Plan

## Submit IRP: 3/28/2025

# Feedback and Discussion



INDIANA MICHIGAN POWER
An AEP Company

# Resource Modeling Parameters (Baseload Resources)

| Base Load (New Resources) | | | | | |
|---|---|---|---|---|---|
| **Resource Type** | **First Year Available** | **Annual Build Limit (MW)** | **Cumulative Build Limit through 2030 (MW)** | **Total Cumulative Build Limit Through Planning Horizon (MW)** | **Installed Cost[1] $/kW** |
| NUCLEAR SMALL MODULAR REACTOR | 2037 | 600 | N/A | 5,100 | $11,700 |
| NEW NG COMBINED CYCLE (2x1) | 2031 | 1,030 | N/A | 5,600 | $1,800 |
| NEW NG COMBINED CYCLE (1x1) | 2031 | 420 | N/A | | $2,000 |
| NEW NG COMBINED CYCLE W/CARBON CAPTURE SYSTEM (CCS) | 2035 | 380 | N/A | 3,800 | $4,300 |

| Base Load (Existing Resources) | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Resource Type** | **First Year Available** | **Last Year Available** | **Annual Build Limit (MW)** | **Cumulative Build Limit through 2030 (MW)** | **Total Cumulative Build Limit Through Planning Horizon (MW)** | **Installed Cost[1] $/kW** | **Installed Cost[1] $/MW-D** |
| EXISTING NG COMBINED CYCLE (5 YEAR) | 2028 | 2031 | | | | N/A | ~~$485~~ $680 |
| EXISTING NG COMBINED CYCLE (10 YEAR) | 2028 | 2031 | 1,800 | 3,600 | 5,400 | | |
| EXISTING NG COMBINED CYCLE (20 YEAR) | 2028 | 2031 | | | | $1,100 | N/A |



Note 1: Costs represent nominal dollars in the first year that the resource is available

# Resource Modeling Parameters (Peaking Resources)

| Peaking (New Resources) | | | | | |
|---|---|---|---|---|---|
| Resource Type | First Year Available | Annual Build Limit (MW) | Cumulative Build Limit through 2030 (MW) | Total Cumulative Build Limit Through Planning Horizon (MW) | Installed Cost[1] $/kW |
| NEW COMBUSTION TURBINE | 2030 | 920 | 920 | 6,670 | $1,500 |
| COMBUSTION TURBINES AERODERIVATIVE | 2031 | 330 | N/A | 1,320 | $2,020 |
| RECIPROCATING INTERNAL COMBUSTION ENGINES (RICE) | 2031 | 100 | N/A | 400 | $3,300 |

| Peaking (Existing Resources) | | | | | | | |
|---|---|---|---|---|---|---|---|
| Resource Type | First Year Available | Last Year Available | Annual Build Limit (MW) | Cumulative Build Limit through 2030 (MW) | Total Cumulative Build Limit Through Planning Horizon (MW) | Installed Cost[1] $/kW | Installed Cost[1] $/MW-D |
| EXISTING NG COMBUSTION TURBINE (5 YEAR) | 2028 | 2031 | 1,000 | 3,000 | 4,000 | N/A | ~~$320~~ $493 |
| EXISTING NG COMBUSTION TURBINE (10 YEAR) | 2028 | 2031 | | | | | |
| EXISTING NG COMBUSTION TURBINE (20 YEAR) | 2028 | 2031 | | | | ~~$540~~ $644 | N/A |

Note 1: Costs represent nominal dollars in the first year that the resource is available

# Resource Modeling Parameters (Intermittent Resources)

INDIANA MICHIGAN POWER
An AEP Company

| Intermittent (Wind & Solar) | | | | | | |
|---|---|---|---|---|---|---|
| Resource Type | First Year Available | Annual Build Limit (MW) | Cumulative Build Limit through 2030 (MW) | Total Cumulative Build Limit Through Planning Horizon (MW) | Installed Cost[1] $/kW | Installed Cost[1] $/MWh |
| WIND (15 YEAR) | ~~2029~~ 2028 | ~~600~~ 200 | ~~800~~ 400 | ~~3200~~ 4000 | N/A | $86 |
| WIND (30 YEAR) | 2031 | 400 | N/A | | $3,000 | N/A |
| SOLAR (15 YEAR) | 2028 | 600 | 1,200 | 4,800 | N/A | $85 |
| SOLAR (35 YEAR)[2] | 2028 | 600 | 1,200 | 4,800 | $2,500 | N/A |
| SOLAR w/STORAGE (4-HOUR) | 2028 | 600 | 750 | 1,350 | $3,100 | N/A |

| Intermittent (Storage) | | | | | |
|---|---|---|---|---|---|
| Resource Type | First Year Available | Annual Build Limit (MW) | Cumulative Build Limit through 2030 (MW) | Total Cumulative Build Limit Through Planning Horizon (MW) | Installed Cost[1] $/kW |
| NEW STORAGE (4-HOUR) | 2028 | 250 | 500 | 3,000 | $2,000 |
| NEW STORAGE (6-HOUR) | 2029 | 150 | 300 | 1,800 | $3,000 |
| NEW STORAGE (8-HOUR) | 2029 | 100 | 200 | 1,200 | $4,000 |
| NEW STORAGE (100-HOUR) | 2032 | 40 | N/A | 240 | $2,800 |



Note 1: Costs represent nominal dollars in the first year that the resource is available

# Preliminary PJM ELCC and FPR Forecasts

| ELCC Class | 2026/ 27 | 2027/ 28 | 2028/ 29 | 2029/ 30 | 2030/ 31 | 2031/ 32 | 2032/ 33 | 2033/ 34 | 2034/ 35 |
|---|---|---|---|---|---|---|---|---|---|
| Onshore Wind | 35% | 33% | 28% | 25% | 23% | 21% | 19% | 17% | 15% |
| Offshore Wind | 61% | 56% | 47% | 44% | 38% | 37% | 33% | 27% | 20% |
| Fixed-Tilt Solar | 7% | 6% | 5% | 5% | 4% | 4% | 4% | 4% | 3% |
| Tracking Solar | 11% | 8% | 7% | 7% | 6% | 5% | 5% | 5% | 4% |
| Landfill Intermittent | 54% | 55% | 55% | 56% | 56% | 56% | 56% | 56% | 54% |
| Hydro Intermittent | 38% | 40% | 37% | 37% | 37% | 37% | 39% | 38% | 38% |
| 4-hr Storage | 56% | 52% | 55% | 51% | 49% | 42% | 42% | 40% | 38% |
| 6-hr Storage | 64% | 61% | 65% | 61% | 61% | 54% | 54% | 53% | 52% |
| 8-hr Storage | 67% | 64% | 67% | 64% | 65% | 60% | 60% | 60% | 60% |
| 10-hr Storage | 76% | 73% | 75% | 72% | 73% | 68% | 69% | 70% | 70% |
| Demand Resource | 70% | 66% | 65% | 63% | 60% | 56% | 55% | 53% | 51% |
| Nuclear | 95% | 95% | 95% | 96% | 95% | 96% | 96% | 94% | 93% |
| Coal | 84% | 84% | 84% | 85% | 85% | 86% | 86% | 83% | 79% |
| Gas Combined Cycle | 79% | 80% | 81% | 83% | 83% | 85% | 85% | 84% | 82% |
| Gas Combustion Turbine | 61% | 63% | 66% | 68% | 70% | 71% | 74% | 76% | 78% |
| Gas Combustion Turbine Dual Fuel | 79% | 79% | 80% | 80% | 81% | 82% | 83% | 83% | 83% |
| Diesel Utility | 92% | 92% | 92% | 92% | 92% | 93% | 93% | 93% | 92% |
| Steam | 74% | 73% | 74% | 75% | 74% | 75% | 76% | 74% | 73% |

https://www.pjm.com/-/media/planning/res-adeq/elcc/preliminary-elcc-class-ratings-for-period-2026-2027-through-2034-2035.ashx

| Delivery Year | Forecast Pool Requirement (% of Peak Load) |
|---|---|
| 2026/27 | 93.67% |
| 2027/28 | 92.69% |
| 2028/29 | 92.75% |
| 2029/30 | 93.47% |
| 2030/31 | 92.96% |
| 2031/32 | 92.72% |
| 2032/33 | 92.10% |
| 2033/34 | 89.99% |
| 2034/35 | 87.09% |

- I&M’s forecasted capacity need is influenced by the accredited capacity PJM recognizes for I&M’s resources (i.e., ELCC Class values) as well as by the load requirement PJM sets (i.e., the “FPR” or Forecast Pool Requirement)
- PJM’s forecasted decline in ELCC class values for resources such as wind, solar, and storage is offset, in part, by a lower forecasted peak load requirement (i.e., a lower FPR)

# Affordability

The Affordability indicators compare the cost to customers under Base Case market scenario conditions over the short- and long-term and the Portfolio cost range when evaluated across the different market scenarios.

| Performance Indicator | Metric | Description |
|---|---|---|
| Near-term | 7-year Power Supply Cost CAGR under the Base Case (2024-2031) | • I&M measures and considers the expected Compound Annual Growth Rate (“CAGR”) of expected power supply costs for the years 2024-2031 as the metric for the short-term performance indicator<br>• A lower number is better, indicating slower growth in power supply costs |
| Long-term | Portfolio NPVRR under the Base Case (2025-2044) | • I&M measures and considers the growth in Net Present Value Revenue Requirement (power supply costs) over 20 years as the long-term metric<br>• NPVRR represents total long-term cost paid by I&M related to power supply. This includes plant O&M costs, fuel costs, environmental costs, net purchases and sales of energy and capacity, property and income taxes, and the return on capital<br>• A lower number is better, indicating lower costs to supply customers with power |
| Portfolio Resilience | High Minus Low Scenario Range 20-yr NPVRR (2025-2044) | • I&M measures and considers the range of 20-yr NPVRR reported by each portfolio across all PJM market scenarios. This metric reports the difference between the highest and lowest cost scenarios reported by the candidate portfolio on an NPVRR<br>• A lower number is better, indicating a tighter grouping of expected customer costs across a wide range of long-term market conditions |

# Reliability

The Reliability indicators compare the amount of excess reserves and the reliance on market resources to serve customers across candidate portfolios.

| Performance Indicator | Metric | Description |
|---|---|---|
| Planning Reserves | Reserve Margin % | • I&M measures and considers the average amount of firm capacity in each candidate portfolio over 10 and 20 years<br>• A higher number is better, indicating more reserves are available to meet PJM requirements |
| Energy Market Risk | Portfolio Cost Range of market purchases, MWhs as % of internal Load | • I&M measures and considers the reliance of each candidate portfolio on market purchases to balance seasonal generation with customer load<br>• The metric reports the NPV of the cost of market purchases and the average MWhs as a % of internal load over 10 and 20 years<br>• A lower number indicates less reliance on the market to meet customer needs |
| | Portfolio Revenue Range of market sales, MWhs as % of internal Load | • I&M measures and considers the reliance of each candidate portfolio on market sales to balance seasonal generation with customer load<br>• The metric reports the NPV of the cost of market sales and the average MWhs as a % of internal load over 10 and 20 years<br>• A lower number indicates less reliance on the market to meet customer needs |

# Resiliency

The Resiliency indicators compare the amount of dispatchable capacity in the fleet and the technology diversity for capacity and energy of the Indiana generating mix across candidate portfolios.

| Performance Indicator | Metric | Description |
| --- | --- | --- |
| Resource Diversity | Percent Change of the Capacity and Energy Diversity Index in 2034 and 2044 | • I&M measures and considers the capacity and energy diversity of new technologies added to its portfolio when comparing candidate portfolios<br>• The metric will use the Shannon-Weiner Index to measure the number of different technologies and their respective contribution to the portfolio totals for both capacity and energy diversity for each Portfolio. A percent change from 2025 is calculated in year 2034 and 2044<br>• A higher number is better. A portfolio that includes diverse resources for both capacity and energy delivery mitigates customers' performance risk when conditions for that technology are unfavorable |
| Fleet Resiliency | Nameplate MW of dispatchable units in 2034 and 2044 | • I&M measures and considers the average amount of dispatchable units added to the portfolio over 10 and 20 years<br>• The metric for this indicator is the average of total Nameplate MW of dispatchable units as a percent of company peak demand<br>• A higher number is better, indicating greater ability to ramp generation up or down to react to market conditions and follow load |

# (Grid) Stability

The Grid Stability indicator compares the amount of dispatchable capacity in the fleet, and the technology diversity of the Indiana generating mix across candidate portfolios.

| Performance Indicator | Metric | Description |
|---|---|---|
| Fleet Resiliency | Nameplate MW of dispatchable units in 2034 and 2044 | • I&M measures and considers the average amount of dispatchable units added to the portfolio over 10 and 20 years<br>• The metric for this indicator is the average of total Nameplate MW of dispatchable units as a percent of company peak demand<br>• A higher number is better, indicating greater ability to ramp generation up or down to react to market conditions and follow load |

# Sustainability

I&M also considered a Sustainability indicator to compare portfolio performance towards meeting corporate sustainability targets.

| Performance Indicator | Metric | Description |
|---|---|---|
| $CO_2$, NOx, $SO_2$, Emissions | 2034 & 2044 % Change from 2005 Baseline | • I&M measures and considers the total amount of expected $CO_2$, NOx and $SO_2$ emissions of each candidate portfolio.<br>• This metric compares the forecasted emissions of candidate portfolios in 2034 and 2044 under Reference Case market conditions with actual historical emissions from the year 2005.<br>• A higher number indicates greater levels of emissions reductions have been achieved and customers are less exposed to potential future $CO_2$ costs. |

# Indiana Michigan Power Company's 2024 Indiana Integrated Resource Plan

Stakeholder Workshop #3A

December 18, 2024

## Table of Contents

# Welcome & Introductions

*Kayla Zellers covered Slide 1.*

Kayla Zellers, Director of Resource Planning at Indiana Michigan Power Company (I&M), called the meeting to order at 2:00 PM on December 18, 2024. Kayla welcomed participants to Stakeholder Meeting 3A for I&M's 2024 Indiana Integrated Resource Plan and introduced Andrew Williamson, I&M Director of Regulatory Services.

*Andrew Williamson covered Slide 2.*

Andrew welcomed stakeholders to Meeting 3A. Andrew reminded them that, as discussed at prior meetings, Meeting 3 (modeling results) has been split into two meetings to accommodate the high volume of scenarios being analyzed for the Indiana IRP. Meeting 3B will be held on January 27, 2025. Andrew also announced that I&M has recently filed an extension, requesting a submittal deadline of March 28, 2025 for the Indiana IRP.

Andrew reiterated that this IRP is a collaboration between I&M and its stakeholders and that feedback, questions and comments are encouraged during this meeting and at any time during the process.

Andrew then introduced the remainder of the I&M Leadership team present at the meeting before introducing Josh Burkholder, Managing Director of Resource Planning for I&M.

Josh introduced the remainder of the I&M Resource Planning Team, including Kayla, Mohamed Abukaram, Director of Resource Planning, and Mark Sklar-Chik, Staff Analyst. Josh also introduced the I&M Infrastructure Development Team that were in attendance to help field stakeholder questions regarding market conditions that informed analysis for this IRP. Finally, Josh introduced 1898 & Co., a consulting firm assisting I&M with coordinating stakeholder engagement and conducting technical portfolio analysis.

Josh presented an overview of this meeting's contents. Seven sets of scenario and sensitivity results are being presented at Meeting 3A to help stakeholders understand them and the analysis behind them. This represents approximately half of the results planned for this IRP. Furthermore, a comparison of these results will be presented. Josh reminded stakeholders that this is a preliminary presentation of results; I&M is forming no conclusions regarding a preferred portfolio until a full set of results has been presented for all analyzed scenarios and sensitivities. Josh thanked stakeholders for their participation.

*Kayla Zellers covered Slide 3.*

Kayla stepped through the agenda, presented in the order established within these posted minutes. Kayla reminded stakeholders that questions and comments are welcomed throughout the meeting and introduced Brian Despard, Senior Project Manager with 1898 & Co., to walk through guidelines for stakeholder participation.

*Brian Despard Covered Slides 4-5.*

Brian discussed stakeholder participation- questions would be allowed anytime during the presentation via Microsoft Teams' "Raise Hand" and "Q&A" functions. Any questions regarding the Indiana IRP can be submitted to I&MIRP@aep.com anytime. All questions and answers recorded during this meeting (or shortly after, via email) have been provided within these minutes.

Finally, Brian presented guidelines for constructive participation.

# Going-In Capacity Position Review

*Kayla Zellers covered Slide 6.*

Kayla presented the Capacity Needs Assessment ("Going-in Position"), noting the significant load growth I&M anticipates in Indiana as a primary driver of the IRP and thus important for review.

Kayla walked stakeholders through the going-in position chart, demonstrating the PJM obligation I&M is expected to meet and the surplus capacity I&M strives to meet for contingency. Annual accredited capacity is demonstrated, as is the additional capacity this IRP would need to identify to meet these goals.

Kayla called specific attention to a few individual years. 2028 is the first year in which the IRP model can select generation resources and is also the year in which Rockport Unit 1 Generating Station is planned to cease operations. In 2030-31 the model allows for the selection of additional resources and shows additional hyperscaler load growth. Finally, 2034 is marked by the expiration of roughly 870 megawatts of capacity-only purchases and 800 megawatts of accredited capacity from Cook Nuclear Plant Unit 1, which is available for relicensing selection in the model.

## Q&A Related to Going-In Capacity Position

1. An October 25, 2024 submission by AEP to PJM titled "2024 Load Forecast Adjustments" identifies 6,045 MW of load growth for I&M by 2030. This is much higher than what is depicted on slide 6 for 2030. Can you please explain the difference between these two forecasts, and which one is the current forecast for I&M?
    a. Since the October forecast, I&M pushed some of the forecasted load out into 2034. I&M previously provided load forecast details to technical stakeholders in technical conferences. If anyone would like additional details on the current load forecast, we would be more than willing to follow up on that after the session.

# Resource Modeling Parameters Update

*Kayla Zellers covered Slide 7.*

Kayla updated stakeholders on changes in resource modeling parameters since Stakeholder Meeting 2. These changes include pricing changes for existing natural gas Combustion Turbine (CT) and Combined Cycle (CC) plants. Stakeholders previously requested a review of prices for these resource types, and I&M's Infrastructure Development team provided the higher prices shown in the table on slide 7.

Wind modeling parameters were also updated; for 15-year wind resources, the first year available was shifted from 2029 to 2028, and annual and cumulative build limits through 2030 were decreased. However, the total cumulative build limit through the planning horizon (2024-2044) for all wind assets was increased from 3,200 MW to 4,000 MW. These changes were made based on the best available market information and stakeholder feedback.

## Q&A Related to Resource Modeling Parameters

2. I had a question about the slide you were just talking about (slide 7). As you know, we discussed last time whether the original cost estimates for those existing thermal units were in line with the market. Given the demand for capacity, not just in the PJM footprint but elsewhere, I'm curious how you arrived at these numbers. What was the process you went through to develop the increases shown here?

   a. We provided feedback on cost estimates as part of the technical Stakeholder Comments, which are available on the IRP website at the following link: Indiana Stakeholder Engagement Process. Also, we have an RFP out now and have ongoing contacts with the market that help drive our cost updates. We consider these estimates to be consistent with the current market.

3. How will you represent those units in terms of things like operating life and other characteristics? Are those going to be identical to the new resources, or will those be different for these? Can you speak to what those specific assumptions are? In terms of book life, do you have what your average assumptions are for these existing units?

   a. For existing gas plant options, we computed a 20-year average for asset life in the model, but also have 10 and 5-year options. We modeled multiple options for existing Combined Cycles and Combustion Turbines with 5-, 10- and 20-year remaining asset lives. The variable and fixed costs for these assets are consistent with their remaining lives (5, 10 or 20 years) according to the market data we have received. For heat rates, we took specifications from the market and used that intelligence to derive the model inputs. For example, a heat rate for an existing combined cycle would be higher than for a new combined cycle build. Other existing gas plant parameters such as variable O&M Costs and Forced Outage Rates are also differentiated from new build gas plant parameters based on market information.

# Key Modeling Inputs & Modeling Status Update

*Kayla Zellers Covered Slides 8-9.*

Kayla discussed key modeling points and constraints, including adding an energy import/export limit for each scenario. These limits are slightly higher for scenarios where thermal resources are imposed with capacity factor limitations, which were also presented to stakeholders as modeling constraints. Short-term capacity prices on slide 8 were discussed.

Kayla updated stakeholders on modeling progress, providing a list of which scenarios and sensitivity results would be discussed during Meeting 3A and which ones would be shared during Meeting 3B. Kayla noted that instead of reviewing the Base Scenario High and Low Load Growth sensitivities as planned for Meeting 3A, the High and Low Economic Growth scenarios would be discussed. The Base Scenario with High and Low Load Growth will be discussed at Meeting 3B. Finally, Kayla explained the renaming of the "Carbon Free" scenario to "Low Carbon" and its expansion to two scenarios for further analysis.

## Q&A Related to Key Modeling Inputs & Modeling Status

4. If I recall correctly, you had to allow a higher level of purchases in the early years of the model because otherwise there just wouldn't be enough energy to serve the load and the load forecast. The conundrum that poses from my viewpoint is that relaxing those kinds of constraints within your model on the one hand might be a matter of necessity in order to actually reach a feasible solution, but on the other hand might not actually reflect the situation that is most economic for rate payers or the one that is feasible on the ground. And part of the reason that I say that is that we've also had a discussion about the market prices that you're modeling and I had indicated previously that the development of those commodity forecasts was not based on any modeling that actually assumed the large loads that are in your load forecast. And so, it feels like we're kind of avoiding the elephant in the room, so to speak, which is that the level of additional load within the load forecast is likely to have a material impact on market prices that's not part of the commodity price forecast. And we're also assuming that energy is basically freely available. But then sort of counter intuitively it ratchets down over time, which seems misaligned with where the market is. There's a lot of concern about whether there's enough capacity or energy right now. Whether these regions will be in shortfall right now and instead we're assuming the opposite as we go through the modeling period. So, I guess what I would like to recommend is that you actually try to model a scenario that gets at those dynamics, a scenario that has significantly higher commodity prices, for example. So even if that's just increasing those market prices by 25% in every hour of the simulation and then rationing down the level of purchases to 30%, I think that would be really informative in terms of whether that's a feasible solution, first of all and second of all, how much less load you'd have to serve in order for that to be feasible solution if it's not.
    a. The market import and export percentages that are displayed are upper limits, representing the maximum amount of market energy purchases or sales that can be made on an annual basis. Though based on the modeling

results, you will find that the market imports were on average far below these upper limits, particularly in the first 6 years of the modeling horizon. As far as the market prices are concerned, we did model a high load and high commodity price sensitivity, and in that case, you will also find that the percentage of market imports were also on average far below the upper limits, particularly in the earlier stages of the planning horizon.

5. Market purchases, we tend to look at that on an annual basis and if you sort of drill down into the specifics of your production cost modeling there and to be certain periods in which those purchases tend to accumulate in other periods in which they don't. And so, if you're doing an annual look that you are not reaching that 60% limit, for example, you might be reaching that limit and sort of key hours of the year. And I'm curious if that's part of the look you guys have done at the modeling so far.
    a. To address this, we will be performing a comprehensive stochastic risk analysis where load, market prices and commodities will be varied. With this analysis market risk will be assessed at a granular level.

Kayla reintroduced Mohamed Abukaram, Director of Resource Planning, who would present on expansion plan modeling results.

# Expansion Plan Modeling Results

*Mohamed Abukaram covered slides 10-26.*

Mohamed introduced stakeholders to the presentation layout that would be followed for all scenarios and sensitivities. Each set of results was displayed on two slides, one with a table showing cumulative nameplate capacity for resources throughout the forecast period.[1] The second slide contains two charts—a stacked bar chart of cumulative firm capacity and a stacked bar chart of annual energy supply, both over the forecast period. Both charts display resources included in the going-in position and incremental resource additions selected by the capacity expansion model. I&M observations regarding each table/graph are shared on their respective slides.

[1] Demand Response (DR), Energy Efficiency (EE), Distributed Energy Resources (DER), and Conservation Voltage Reduction Resources (CVR) were categorized together and displayed as Accredited Capacity. Short-term capacity was also displayed as Accredited Capacity and is shown as one-year purchases.

### *Base Reference Case*

Mohamed presented the results of the Base Reference Case. This scenario was designed to project the optimal mix of resources to meet capacity and energy requirements under base load and commodity prices. This case is a reference for all scenarios and sensitivities for this IRP.

The capacity table shows market purchases to fill short-term (2025-2027) capacity needs before selecting natural gas and renewable resources in 2028 to meet capacity and energy requirements. Growing demand in the mid-2030s is met by adding a combined cycle in 2034 and renewing Cook Nuclear Units 1 and 2 in 2035 and 2038, respectively. Mohamed noted that the IRP model selected Cook renewal as the optimal decision in every set of results presented at Meeting 3A.

The capacity bar chart demonstrates capacity purchases through 2034 due to Montpelier and Kindle Lawrenceburg contract. The IRP model also selected license extensions for the Elkhart and Motteville hydro plants, set to expire within the next 10 years, for all scenarios and sensitivities. Mohamed noted that nuclear and gas resources with high accreditation rates represent most of the firm capacity. The capacity chart also shows increased capacity additions in 2034 due to increasing load and expiration of capacity purchases.

The energy bar chart shows Cook generation and market purchases through 2027, followed by significant gas and nuclear energy supplemented by portfolio renewables and market purchases throughout the study period.

### *Enhanced Environmental Regulations (EER) Scenario*

Mohamed presented the results of the EER Scenario, which shows the selected portfolio under Environmental Protection Agency (EPA) Section 111 rules, limiting annual capacity factors for existing CCs and CTs to 50%, new CCs to 40%, and new CTs to 20%. EER-reflected commodity prices are also inputs to this scenario.

This scenario shows a significant increase in renewables due to limited gas generation. Solar is the primary renewable selected in 2028, before high amounts of wind are selected to meet capacity and energy needs in the mid-2030s. Gas units are still selected as a cost-effective solution to energy and capacity needs. More existing CCs are selected due to tighter capacity factor limitations on new CCs, and fewer CTs are selected as wind already fills the needed capacity shortfall.

The bar charts show that the majority of capacity and energy contributions come from gas but also demonstrate increased renewable capacity and energy compared to the Base Reference Case. The capacity chart also shows an increase in supply-side resources to mitigate market import limits and prepare for mid-2030s load increases. The energy chart shows an increase in market imports to help serve load, as well as market sales from 2031 from a heavier thermal and renewable mix.

## *Base Under EPA 111(b)(d) Requirements Sensitivity*

Mohamed presented the results of the Base Under 111(b)(d) Requirements Sensitivity, which projects the optimal portfolio under EPA rules similar to what was shown in the EER Scenario. Mohamed noted that unlike the EER scenario runs, the Base Under EPA 111(b)(d) case was run with base case commodity prices.

The similarities between this portfolio and the EER Scenario show that EPA 111 restrictions drove portfolio selection more than commodity prices in each set of results. Similar to the EER case, more renewables are selected due to capacity factor limitations on gas generation. Natural gas remains essential in this portfolio to meet capacity and energy needs cost-effectively.

The bar charts also show firm capacity and energy mixes similar to the EER Scenario, with gas providing the majority of capacity and energy. Renewables, supply-side resources, and purchases, like in the EER Scenario, are more prominent in the Base Under EPA 111(b)(d) results than the Base Reference Case.

## *Low Carbon: Transition to Objective Sensitivity*

Mohamed began the discussion by explaining why “Carbon Free” was renamed “Low Carbon” and split into two sensitivities. The Low-Carbon sensitivities aim to produce enough annual energy from carbon-free resources to meet or exceed the energy requirements of I&M’s largest industrial customers. Production and Investment Tax Credits (PTCs and ITCs) were extended throughout the planning horizon, as previously requested by stakeholders.

Low Carbon was split into two sensitivities to represent different ways I&Ms low-carbon goals could be met. The first, Transition to Carbon Emissions Objective, assumed the base build limits assumed by all other scenarios, resulting in a transition period from 2028 to 2037 before the carbon emissions objective can be realized in 2038. The second Low

Carbon sensitivity, Expanded Build Limits, loosened these constraints, allowing the carbon emissions objective to be achieved earlier in the planning horizon. Mohamed shared a table comparing build limits, as well as a graph that showed carbon-free resource generation on an annual basis for each Low Carbon sensitivity.

Mohamed then presented the results of the Low Carbon: Transition to Objective Scenario. Starting in 2028, a large amount of solar and wind are selected, with the energy of these assets resulting in fewer CCs being selected. CTs are selected more in this sensitivity than the Base Reference Case, as renewable capacity alone is insufficient to meet PJM obligations. In this scenario, Small Modular Reactors (SMRs) are added in 600 MW increments in 2037 and 2043 to provide high energy production essential to meeting the carbon-free resource objective. An additional metric is provided for the Low Carbon Sensitivities: “Objective Achievement Percentage”, which represents the percentage of load from I&M’s largest industrial customers served by carbon-free resources. This objective fluctuates as load advances faster or slower than build limits allow renewables to be built and serve load. 100% of the objective is met in 2038, which is maintained through the forecast.

Like the other scenarios, the capacity chart shows that thermal resources meet most of the PJM capacity obligation. Nuclear capacity increases due to SMR additions, as do capacity contributions from renewables and supply-side resources. The energy mix chart shows a decrease in thermal-generated energy contributions and a high amount of market sales and purchases as contributions from renewables increase over time.

### *Low Carbon: Expanded Build Limits Sensitivity*

Mohamed presented results from the Low Carbon: Expanded Build Limits Sensitivity. Due to the expanded build limits, starting in 2028 more solar and wind are added than in the Transition to Objective Sensitivity. Less CC capacity is added than in the Transition to Objective Sensitivity, as renewables provide enough energy to reduce the need for CC generation. More CTs are selected to offset the absence of CC capacity used in most scenarios to meet PJM obligations. 300 MW and 600 MW of SMR capacity were selected in 2037 and 2043, respectively.

The firm capacity chart shows CTs meeting the majority of the capacity obligation, with lower CC figures than the Transition to Objective Case. Wind also shows a more significant increase in capacity in this sensitivity. Due to the expanded build limits, the energy graph shows more contributions from solar and wind earlier in the study period. Due to high renewables, market sales and purchases increase compared to the Base Reference Case.

### *High Economic Growth Scenario*

Mohamed presented the drivers of the High and Low economic growth scenarios. “High” corresponds to high load growth and commodity prices compared to the Base, while “low” refers to lower figures than the Base for the same metrics. The high and low load assumptions deviate from the Base assumption over time, with trends ending 10,000 GWh higher or lower than the base by 2044.

Mohamed presented the results of the High Scenario. The capacity table shows an increased selection of solar and wind due to increases in fuel prices. With wind meeting higher energy needs, less CC capacity is selected than in the Base Reference Case. More CTs are selected in this scenario than in the Base Reference Case to fill in gaps in capacity obligation requirements.

The firm capacity chart shows a similar capacity mix to the Base Reference Case, with most accredited capacity coming from gas resources. The energy mix chart, however, shows heightened contributions from wind and solar resources as opposed to gas generation, due to the increased renewable builds to meet energy requirements. Through 2030, 35% of demand is met by market energy imports. This figure decreases to 17% from 2031 through the end of the study period.

### *Low Economic Growth Scenario*

Mohamed presented the results of the Low Economic Growth Scenario. In this scenario, similar amounts of CC and wind capacity are selected compared to the Base Reference Case. Due to the decrease in commodity prices, energy needs, and capacity obligations, these CC and wind resources are sufficient to meet demand, resulting in no solar or storage being selected. Similarly, about 500 MW less CT capacity was selected than in the Base Reference Case.

The firm capacity and energy supply charts show significantly less contribution from renewables, storage, and supply-side resources than in the Base Reference Case. Through 2030, 29% of demand is met by market energy imports. This figure decreases to 15% from 2031 through the end of the study period.

Mohamed concluded the presentation of portfolio results, and thanked stakeholders for their participation, pausing for questions.

## Q&A Related to Expansion Plan Modeling Results

6. Could you please go over the concepts of "Existing CC" and "Existing CT"? These are facilities that have already been constructed and are operating, but not currently owned/operated by AEP or I&M? If so, where is I&M planning to find 5,000+ MW of existing gas CCs? Does this available capacity exist within PJM today?

    a. The cumulative build limit through 2030 for existing gas CCs is based on market availability and intelligence from our review. In our most recent RFP, we received over 45 bids from gas combined cycles and combustion turbines, totaling approximately 15 GW. The vast majority of bids were for existing generation.

7. Would it be reasonable to consider existing combined cycles and combustion turbines as being I&M internalizing resources that already exist in PJM? Meaning this internalization of existing resources is likely to drive a need for replacement resources by other market participants in the PJM.

    a. Yes, it is possible that I&M acquiring existing resources could create a need for replacement resources by other market participants in PJM.

8. Just to confirm, is it correct that the base scenario does not assume the recent changes to EPA Section 111(b)(d) are implemented? That is what the Base Under EPA Section 111(b)(d) Sensitivity is for?

    a. Yes, that is correct. The recent changes, or capacity factor limitations noted on slide 8 are implemented in the Base Under EPA Section 111(b)(d) Sensitivity and the Enhanced Environmental Regulations Scenario.

9. Why are residential and commercial customers not part of the low-carbon objective? Do you have a sensitivity that incorporates these customers into the low-carbon objective?

    a. The objective is to target an overall amount of I&M's load, not necessarily to assign carbon-free generation to specific customer types or specific customer load. The carbon-free generation percentage represents the full diversity of I&M's load, not just larger industrial customers. This helps inform the difference in the resource mix and the cost associated with achieving a certain amount of carbon-free generation.

10. What are the ramifications of adding significant new load without new generation in the AEP zone? Who would have to wrestle with those ramifications?

    a. I&M observed that most resources in our RFP are within the AEP zone or immediately adjacent to it. If the load continues to grow without new generation development, our assumption is that the market will respond by developing new generation over time.

11. I know we have put this request out there a couple of times now, but I want to reiterate and beg for it. We have been able to see RFP results from other utilities that were open to figuring out an arrangement that will make heightened confidentiality measures. Given how central these bids are to I&M's modeling, again, we would ask for that for transparency's sake. We really feel blind and given the public stakeholder nature of our IRP planning, would again just request that I&M facilitate our ability to see the RFP results as soon as possible. Even with the March due date, a lot of these plans and whatnot can be hard to move once they are baked, so again, just would ask for transparency's sake and the public stakeholder involvement, that we can use our existing non-disclosure agreement or anything additional to get some insight and transparency into the RFP bits. Thank you.

    a. The challenge providing recent RFP information is that we have a very competitive market and a significant near-term resource need. The confidentiality of this information is very important to maintaining I&M's competitiveness as it seeks to acquire new generation in the near future. We will discuss further the type of information we may be able to provide and follow up with you.

12. What is the certainty in implementing SMRs in the Low Carbon Portfolio? So far there are no implemented SMRs in the USA, and the ones that were planned on were plagued by cost & time extensions, namely NuScale Power ended its Utah project.

    a. We have received feedback on the SMR assumptions and provided additional feedback, which you can find on the IRP website at the following link: Indiana Stakeholder Engagement Process. To briefly answer, we have build limits reviewed in stakeholder meeting two, vetted by our generation engineering team. We base the limits on discussions with peer utilities and reviews of their Integrated Resource Plans; industry groups such as the Electric Power Research Institute and Nuclear Energy Institute; discussions with leading SMR suppliers; and our internal SMR feasibility and siting studies conducted for Indiana Michigan Power and Appalachian Power Company. See this link for additional information (Appalachian Power - SMR | Appalachian Power - SMR).

13. I see very little storage in any of the cases, which is surprising. Can you describe how you modeled storage? Can you also explain why so little storage is picked up in any of the scenarios?
    a. For the low carbon sensitivities, storage or any proportion of energy from storage was not considered a carbon-free resource to hit the objective, so there was no extra incentive for additional storage in these cases. For the other cases, we had 300 MW to 500 MW of storage selected as early as 2028. We model storage by simulating it in the energy market through energy arbitrage opportunities, also considering the value from ancillary service and real-time markets.

## Results Comparison and Draft Portfolio Performance Indicators

*Kayla Zellers covered Slides 28-34.*

Kayla reminded stakeholders that the individual case results represented only approximately half of the scenarios and sensitivities covered in this IRP. As a complete set of results becomes available, full comparisons of the results will be shared. A brief comparison of the covered results was shared to highlight early differences in results presented during Meeting 3A.

Kayla first shared a graph of accredited capacity for each case in 2025, 2034, and 2044. This information compares the results shared on the capacity charts for each scenario and sensitivity. Kayla noted that each scenario shows an approximate doubling of capacity from 2025 to 2044, necessitated by load growth in I&M's Indiana territory. Kayla also called attention to the similarities of each case in 2025, with short-term capacity supplementing existing nuclear and coal resources. Similarities continue in 2034 and 2044, with all portfolios relying on some combination of CCs and CTs supplementing Cook Nuclear, renewed in each case. Differences are also observed: in 2034 and 2044, Low Carbon and EPA 111 cases show an increase in renewables, and in 2044, Low Carbon cases show expanded nuclear capacity due to SMRs.

Kayla then shared a graph of the energy generation mix, again showing 2025, 2034, and 2044 data. Like capacity, energy increases significantly, nearly tripling over the study period. Similarities include nuclear, wind, and market purchases in 2025, gas providing significant generation in 2034 and 2044, and market purchases filling in gaps in energy needs. Differences shown include increased generation from renewables in the Low Carbon cases compared to other portfolios, indicating greater portfolio diversity.

Kayla also shared a table demonstrating the build plan for each case, shown as incremental additions through 2034 and 2044. Kayla called attention to the differing total capacity figures; EPA cases require more capacity than the Base Reference Case. Low Carbon cases show even higher capacity figures due to increased renewable resources with low accreditation percentages.

Kayla presented portfolio performance indicators designed to meet the “Five Pillars” established by the Indiana Utility Regulatory Commission (IURC). Kayla covered the five pillars of Reliability, Affordability, Resiliency, Grid Stability, and Environmental Sustainability. Kayla presented the metrics that I&M, with stakeholder feedback in Meetings 1 and 2, agreed would lead to a strong portfolio aligning with the five pillars. Kayla finally shared how these metrics would be evaluated and how a preferred score on these evaluation metrics would look. For the full table of these criteria, refer to Slide 31 of the posted Meeting 3A IRP Presentation.

Kayla walked through the draft portfolio performance indicator matrix, noting that EER results are not shown due to their similarity with Base with 111(b)(d) results. Kayla presented the Affordability and Environmental Sustainability results first.

For Affordability, Base Reference and Low Growth show the lowest values for Compound Annual Growth Rate (CAGR) and Net Present Value of Revenue Requirement (NPVRR). Low Carbon: Expanded Build Limits show the highest costs for both of these metrics. Kayla noted that high NPVRRs across all scenarios is due to the high load growth projected in I&M. NPVRR shows particularly high results for Base With 111(b)(d) and Low Carbon sensitivities, displaying the cost impact of compliance with stricter environmental regulations. Due to the importance of Affordability to I&M's customers, additional analysis of costs will be provided at future meetings.

Under the Environmental Sustainability pillar, it is noted that natural gas is the most economic option in all scenarios, impacting the percent change in carbon dioxide (CO2) emissions in each. Differences in CO2 emission reductions across scenarios can be attributed to the amount of renewable generation selected in each, as well as the kind of gas generation being chosen. All portfolios perform well in reducing NOX and SO2.

Kayla shared results for the Reliability, Resiliency, and Grad Stability Pillars. Reliability was evaluated from an energy market risk perspective, in which portfolios differ noticeably. Base Reference Case is among the portfolios that rely the least on market sales, while Low Carbon and Base with 111(b)(d) results show a greater dependence on market sales, due to the level of renewables selected. Energy purchases are mostly consistent, with Base With 111(b)(d) seeing higher energy market purchase risks.

Kayla stated that reliability was also evaluated under planning reserves as a percentage of the planning reserve margin, with average target values being -3.0% and -5.5% over 10 and 20 years, respectively. The target values represent the average PJM forecast pool requirement. The goal of this metric is to get modeled reserve margins values for the cases as close as possible to the target values without providing less reserve margin. The Base Reference Case shows the lowest 10 year average of planning reserves compared to the other cases. In the remainder of the cases, there are wide variations in the 10 year average ranging from -0.3% to 5.5%. Looking at the 20-year average reserve margins, there is a similar relationship amongst the cases where the Base Reference Case is the lowest while the remainder of the cases have closer or fairly consistent values.

Kayla described the diversity metrics, pointing out that the metric represents a 10 and 20 year percent change from the 2005 level. All cases, excluding High Growth and Low Growth, see improvement in capacity and energy diversity as compared to the Base Reference Case. One thing that was identified was that the relative diversity across the portfolios is really impacted by the different renewables that the model is selecting. In addition to the increased amount of renewables added in the Low Carbon cases, SMRs were selected, which adds another resource into the mix and further improves the Diversity Index for those cases.

Kayla moved on to discuss the grid stability and resiliency pillars focusing on dispatchable nameplate capacity. It was noted that significant dispatchable resources exist in each case due to the relicensing of Cook and the economic selection of natural gas resources. In the 10-year period, the Base Under EPA Section 111(b)(d) has the highest dispatchable percentage value due to the incremental amount of natural gas reserves resources economically selected compared to the other cases. In the 20 year period, the Base Reference Case, High Growth, and Low Growth scenarios provide the highest values for dispatchable capacity, however, all cases provide significant dispatchable resources compared to the company peak demand.

### Q&A Related to Results Comparison and Draft Portfolio Performance Indicators

14. Could you provide some insight into how your $CO_2$ emissions have changed between 2005 and today so we can understand how your emissions have changed over time?
    a. As of January 2025, I&M has the following information. $CO_2$ values are rounded to the nearest 0.01 million US tons.
        - I&M 2005 base year $CO_2$ emissions = 22.47M US tons
        - I&M 2024 $CO_2$ emissions = 5.63M US tons

15. Do any of the sensitivities include modeling replacement resources at Rockport site or uprate at Cook?
    a. No, none of the sensitivities include either of those options. However, we have an early retirement scenario related to Rockport that will be presented in the next stakeholder meeting. For this scenario, much of generation resource acquisition focuses on acquiring resources needed to replace capacity and energy needs once Rockport retires at the end of 2028. Regarding the uprate at Cook, we have looked at this in the past. We will continue to evaluate and consider it in the future.

## Remaining Modeling and Next Steps

*Kayla Zellers covered Slide 34.*

Kayla shared the tentative schedule for the remainder of the IRP process. Stakeholder Meeting 3B is scheduled for January 27, 2025, and will include a results presentation for the remaining sensitivities. Stakeholder Meeting 4 is scheduled for March 5, 2025, and will cover risk analysis and the preferred portfolio identified in this IRP. Finally, I&M will submit its Indiana IRP on March 28, 2025.

## Open Discussion

I&M staff thanked stakeholders for their participation and reminded them that any additional questions or feedback can be submitted to the IRP Email address at I&MIRP@aep.com. Staff fielded all remaining stakeholder questions and adjourned the meeting at 3:44 PM.

Appendix 4, Exhibit D: Workshop 3b January 27, 2025

Meeting Presentation

Meeting Minutes

Indiana Michigan Power Company

# INDIANA IRP STAKEHOLDER MEETING #3B

January 27, 2025

INDIANA MICHIGAN POWER
An AEP Company

# Welcome & Introductions

## I&M Leadership Team

David Lucas | Vice President, Regulatory and Finance

Andrew Williamson | Director, Regulatory Services

Ed Locigno | Regulatory Analysis & Case Manager

Regiana Sistevaris | Manager, Regulatory Services

Austin DeNeff | Regulatory Consultant Senior

## 1898 & Co.

Brian Despard | Senior Project Manager

## I&M Resource Planning

Josh Burkholder | Managing Director, Resource Planning

Kayla Zellers | Director, Resource Planning

Mohamed Abukaram | Director, Resource Planning

Mark Sklar-Chik | Staff Analyst, Resource Planning

## I&M Infrastructure Development

Tim Gaul | Director, Regulated Infrastructure Development

Justin Dehan | Manager, Regulated Infrastructure Development

# Agenda

| Time (EST) | Agenda Topic | Lead |
| --- | --- | --- |
| *1:00-1:10* | **Welcome & Introductions** | **Andrew Williamson<br>Josh Burkholder<br>Brian Despard** |
| *1:10-1:20* | **Review of Stakeholder Meeting 3A** | **Kayla Zellers** |
| *1:20-2:00* | **Expansion Plan Modeling Results**<br>• Scenario: Base Reference Review<br>• Sensitivities: Expanded Wind Availability (Base and EER), Base with High IN Load, Base with Low IN Load, High Tech Cost | **Mohamed Abukaram** |
| *2:00-2:10* | **Short Break** | |
| *2:10-2:40* | **Expansion Plan Modeling Results**<br>• Sensitivities: Rockport Unit 1 Retires 2025, Rockport Unit 1 Retires 2026, Exit OVEC ICPA in 2030 | **Mohamed Abukaram** |
| *2:40-3:00* | **Results Comparison and Draft Portfolio Performance Indicators** | **Kayla Zellers** |
| *3:00-3:10* | **Remaining Modeling and Next Steps** | **Kayla Zellers** |
| *3:10-3:30* | **Open Discussion**<br>• Feedback From Stakeholders | **Andrew Williamson<br>Josh Burkholder** |

# Participation

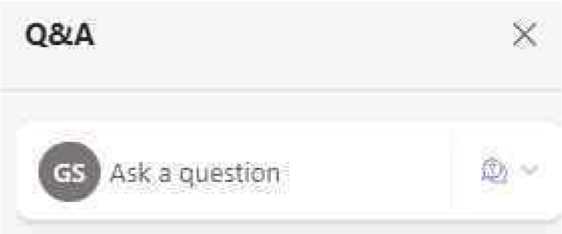
Participants joining today's meeting will be in a "listen-only" mode. Please use the "Raise" function to be recognized and unmuted.

During the presentation, please enter questions at any time into the Teams Q&A feature. Questions will be addressed after each section. At the end of the presentation, we will open up the floor for additional questions, thoughts, ideas, and suggestions.

All questions and answers will be logged and provided on the IRP website. Any questions not answered during the meeting will be answered after the meeting and provided in the Q&A log posted to the IRP website.

Questions, thoughts, ideas, and suggestion related to Stakeholder Meeting 3B can be provided to I&MIRP@aep.com following this meeting.


Click the Q&A feature at the top of the Teams screen



# Guidelines

- Please focus questions, thoughts, ideas, and suggestions to the IRP process and the content being discussed in this meeting. Time will be taken during this meeting to respond to questions.
- Please respect other participants and their views by not addressing other participants directly and not commenting on the views expressed by others.
- This meeting will not be recorded or transcribed.
- Any further questions or comments can be provided to I&MIRP@aep.com.

# Public Stakeholder Meetings 3A & 3B

**Modeling Results to be Presented at Stakeholder Meetings 3A and 3B**

- I&M is modeling 4 market scenarios & 11 market sensitivities and will present modeling results in stakeholder meetings (i.e., 3A and 3B)

| Scenario | Stakeholder Meeting 3A or 3B |
|---|---|
| Base Reference | 3A |
| High Economic Growth | 3A |
| Low Economic Growth | 3A |
| Enhanced Environmental Regulations (EER) | 3A |

| Sensitivities | Stakeholder Meeting 3A or 3B |
|---|---|
| Base under EPA Section 111(b)(d) Requirements | 3A |
| Low Carbon: Transition to Objective | 3A |
| Low Carbon: Expanded Build Limits | 3A |
| Base with High IN Load | 3B |
| Base with Low IN Load | 3B |
| Rockport Unit 1 Retires 2025 | 3B |
| Rockport Unit 1 Retires 2026 | 3B |
| Exit OVEC ICPA in 2030 | 3B |
| High Technology Cost | 3B |
| Expanded Wind Availability (Base) | 3B |
| Expanded Wind Availability (EER) | 3B |

# Base Reference Case Portfolio Review

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 325 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 28 | 1,500 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 59 | 1,875 |
| 2028 | 200 | 599 | 450 | 0 | 1,800 | 0 | 1,000 | 0 | 94 | 0 |
| 2029 | 200 | 596 | 450 | 0 | 2,700 | 0 | 1,000 | 0 | 100 | 0 |
| 2030 | 200 | 593 | 450 | 0 | 3,600 | 0 | 1,500 | 0 | 97 | 0 |
| 2031 | 200 | 590 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 96 | 0 |
| 2032 | 200 | 587 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 115 | 0 |
| 2033 | 200 | 584 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 131 | 0 |
| 2034 | 200 | 581 | 450 | 1,030 | 3,600 | 0 | 2,000 | 0 | 144 | 0 |
| 2035 | 200 | 578 | 450 | 1,030 | 3,600 | 0 | 2,000 | 888 | 156 | 0 |
| 2036 | 200 | 575 | 450 | 2,060 | 3,600 | 0 | 2,000 | 888 | 169 | 0 |
| 2037 | 200 | 572 | 450 | 2,060 | 3,600 | 0 | 2,000 | 888 | 177 | 0 |
| 2038 | 200 | 569 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 185 | 0 |
| 2039 | 200 | 566 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 193 | 0 |
| 2040 | 200 | 563 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 201 | 0 |
| 2041 | 200 | 560 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 206 | 0 |
| 2042 | 200 | 557 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 211 | 0 |
| 2043 | 0 | 554 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 213 | 0 |
| 2044 | 0 | 551 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 220 | 0 |

**Purpose of Scenario:**

- Evaluating the most economical solution to meet capacity and energy needs considering all base modeling parameters and assumptions
- Establishes the point of reference for other scenarios and sensitivities



*Nuclear includes Cook SLR

# Expanded Wind Availability Portfolios

| Resource Type | First Year Available | Last Year Available | Annual Build Limit (MW) | Cumulative Build Limit through 2030 (MW) | Total Cumulative Build Limit Through Planning Horizon (MW) |
|---|---|---|---|---|---|
| **WIND (15 YEAR)** | 2028 | N/A | ~~200~~ 1,200 | ~~400~~ 1,200 | 4,000 |
| **WIND (30 YEAR)** | 2031 | N/A | 400 | N/A | |

- The Expanded Wind Availability Portfolios were modeled to reflect updated market intelligence on available wind resources through 2030
- These expanded build limits were modeled under the Base Reference assumptions and the Enhanced Environmental Regulations (EER) assumptions. EPA compliant gas unit capacity factor constraints were applied in the Expanded Wind Availability (EER) sensitivity

**EPA Compliant Gas Unit Capacity Factors**

| Resource Type | Capacity Factor Limit | Starting Year Enforced | EPA Section 111 Rule (b)(d) |
|---|---|---|---|
| Existing CC | 50% | 2030 | Proposed |
| Existing CT | 50% | 2030 | Proposed |
| New CC | 40% | Immediate | Final |
| New CT | 20% | Immediate | Final |

# Expanded Wind Availability (Base) Portfolio

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 325 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 27 | 1,500 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 58 | 1,875 |
| 2028 | 1,200 | 150 | 0 | 0 | 1,800 | 0 | 1,000 | 0 | 92 | 0 |
| 2029 | 1,200 | 149 | 0 | 0 | 2,700 | 0 | 1,000 | 0 | 110 | 0 |
| 2030 | 1,200 | 148 | 0 | 0 | 3,600 | 0 | 1,500 | 0 | 120 | 0 |
| 2031 | 1,200 | 147 | 0 | 0 | 3,600 | 0 | 2,000 | 0 | 129 | 0 |
| 2032 | 1,200 | 147 | 0 | 0 | 3,600 | 0 | 2,000 | 0 | 146 | 0 |
| 2033 | 1,200 | 146 | 0 | 0 | 3,600 | 0 | 2,000 | 0 | 158 | 0 |
| 2034 | 1,200 | 145 | 0 | 1,030 | 3,600 | 0 | 2,000 | 0 | 168 | 0 |
| 2035 | 1,200 | 144 | 0 | 1,030 | 3,600 | 0 | 2,000 | 888 | 180 | 0 |
| 2036 | 1,200 | 144 | 0 | 2,060 | 3,600 | 0 | 2,000 | 888 | 191 | 0 |
| 2037 | 1,200 | 143 | 0 | 2,060 | 3,600 | 0 | 2,000 | 888 | 199 | 0 |
| 2038 | 1,200 | 142 | 0 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 206 | 0 |
| 2039 | 1,200 | 141 | 0 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 212 | 0 |
| 2040 | 1,200 | 141 | 0 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 217 | 0 |
| 2041 | 1,200 | 140 | 0 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 221 | 0 |
| 2042 | 1,200 | 139 | 0 | 2,060 | 3,600 | 230 | 2,000 | 1,880 | 225 | 0 |
| 2043 | 0 | 0 | 0 | 2,060 | 3,600 | 230 | 2,000 | 1,880 | 227 | 0 |
| 2044 | 0 | 0 | 0 | 2,060 | 3,600 | 230 | 2,000 | 1,880 | 229 | 0 |

**Purpose of Scenario:**

- Evaluating the most economical solution to meet capacity and energy needs considering all base modeling parameters and additional wind availability through 2030

**Observations through 2030:**

- Additional wind selected by the model reduces solar and storage resources compared to the reference scenario
- Selected all available existing CC's by 2030 and existing CT's were selected to meet capacity obligation similar to the reference scenario

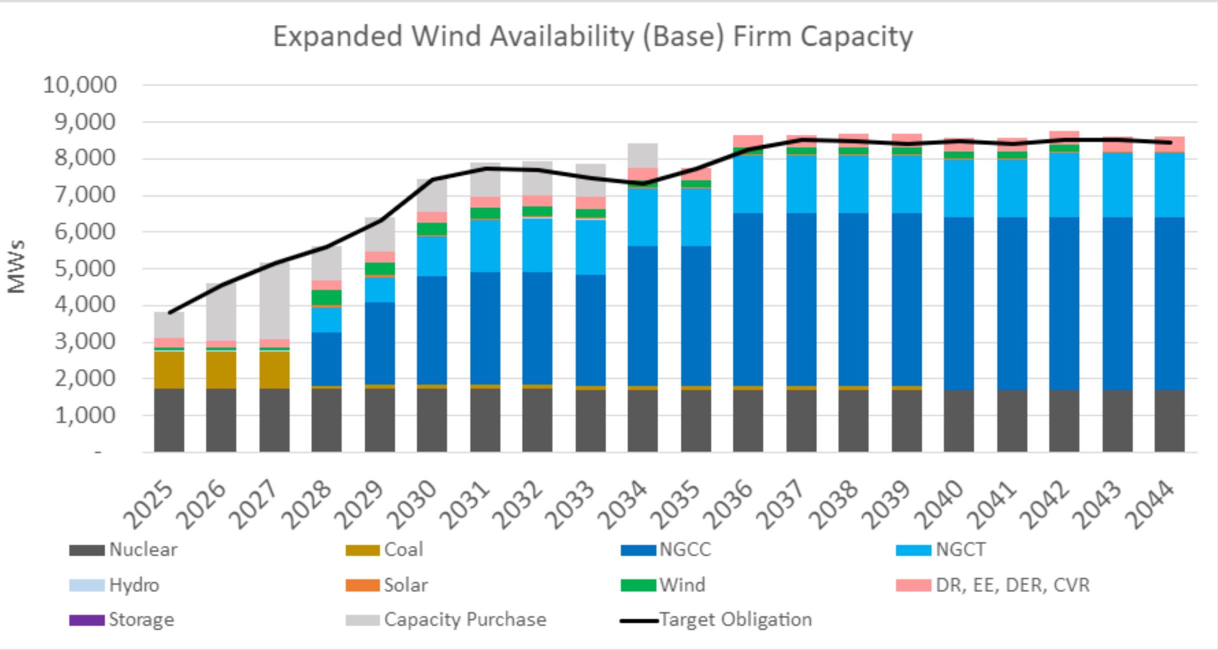
**Observations for 2031+:**

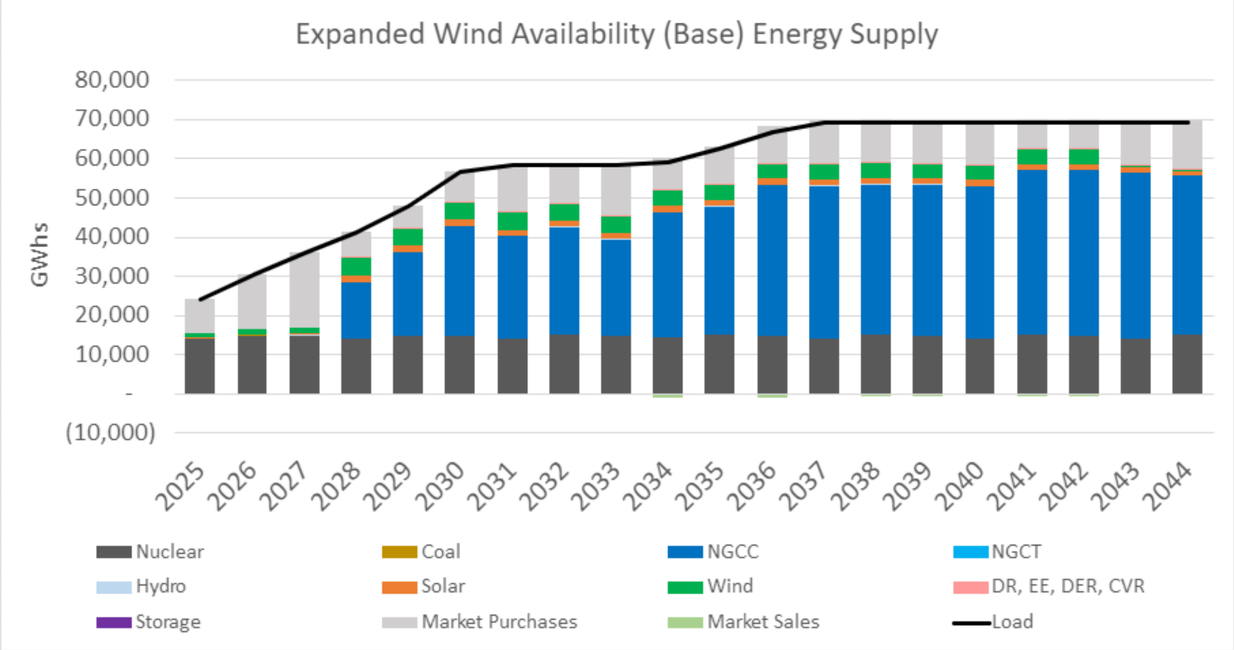
- New CC built in 2034 and 2036 to meet the load growth in the same period and the expiration of existing capacity purchase agreements similar to the reference scenario
- New CT built in 2042 compared to the reference scenario to meet capacity obligation
- Cook SLR selected in 2035 and 2038



*Nuclear includes Cook SLR

# Expanded Wind Availability (Base) Portfolio




**Observations:**

- Additional wind selected compared to the reference scenario providing additional capacity and energy in the portfolio
- Nuclear resources provide consistent Carbon-free capacity and energy
- Natural gas resources are generally the most economic options to meet the growing capacity obligations and needed energy supply
- Capacity additions in 2033 and 2034 built in preparation of load increases that occur from 2034-2037



*Nuclear includes Cook SLR

# Expanded Wind Availability (EER) Portfolio

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 325 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 27 | 1,500 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 57 | 1,875 |
| 2028 | 1,000 | 599 | 50 | 0 | 1,800 | 0 | 1,000 | 0 | 90 | 0 |
| 2029 | 1,000 | 596 | 50 | 0 | 2,700 | 0 | 1,000 | 0 | 113 | 0 |
| 2030 | 1,000 | 593 | 50 | 0 | 3,600 | 0 | 1,500 | 0 | 129 | 0 |
| 2031 | 1,400 | 590 | 50 | 0 | 5,400 | 0 | 1,500 | 0 | 143 | 0 |
| 2032 | 1,800 | 587 | 50 | 0 | 5,400 | 0 | 1,500 | 0 | 166 | 0 |
| 2033 | 2,200 | 1,182 | 50 | 0 | 5,400 | 0 | 1,500 | 0 | 182 | 0 |
| 2034 | 2,600 | 1,775 | 50 | 0 | 5,400 | 0 | 1,500 | 0 | 196 | 0 |
| 2035 | 2,800 | 2,364 | 50 | 0 | 5,400 | 0 | 1,500 | 888 | 212 | 0 |
| 2036 | 3,200 | 2,951 | 50 | 0 | 5,400 | 0 | 1,500 | 888 | 228 | 0 |
| 2037 | 3,600 | 3,534 | 50 | 0 | 5,400 | 0 | 1,500 | 888 | 240 | 0 |
| 2038 | 4,000 | 3,815 | 50 | 0 | 5,400 | 0 | 1,500 | 1,880 | 251 | 0 |
| 2039 | 4,000 | 3,796 | 50 | 0 | 5,400 | 0 | 1,500 | 1,880 | 260 | 0 |
| 2040 | 4,000 | 3,776 | 50 | 0 | 5,400 | 0 | 1,500 | 1,880 | 269 | 0 |
| 2041 | 4,000 | 3,757 | 50 | 0 | 5,400 | 0 | 1,500 | 1,880 | 276 | 0 |
| 2042 | 4,000 | 3,737 | 50 | 0 | 5,400 | 0 | 1,500 | 1,880 | 281 | 0 |
| 2043 | 3,000 | 4,167 | 50 | 0 | 5,400 | 230 | 1,500 | 1,880 | 286 | 0 |
| 2044 | 3,000 | 4,145 | 50 | 0 | 5,400 | 230 | 1,500 | 1,880 | 290 | 0 |

**Purpose of Scenario:**

- Evaluating the most economical solution to meet capacity and energy needs considering implementation of EPA Section 111(b)(d) greenhouse gas rules and associated market commodity price impacts with the expansion of wind availability through 2030

**Observations through 2030:**

- Additional wind selected by the model reduces solar and storage resources compared to the EER scenario
- Selected all available existing CC's by 2030 and existing CT's were selected to meet capacity obligation

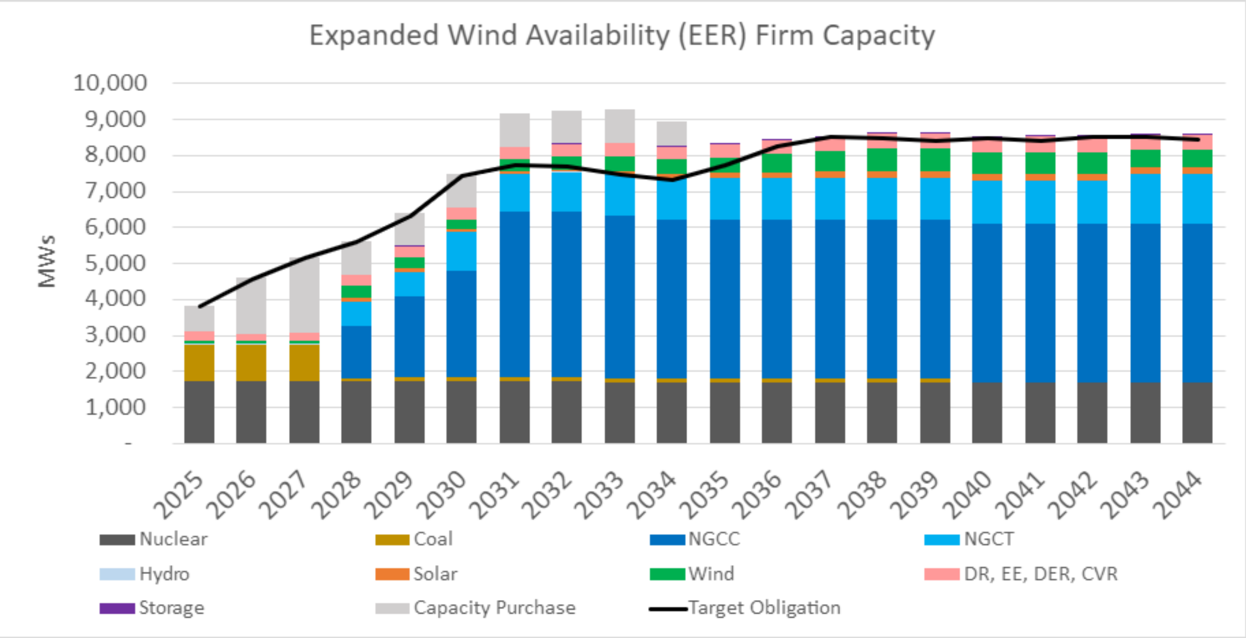
**Observations for 2031+:**

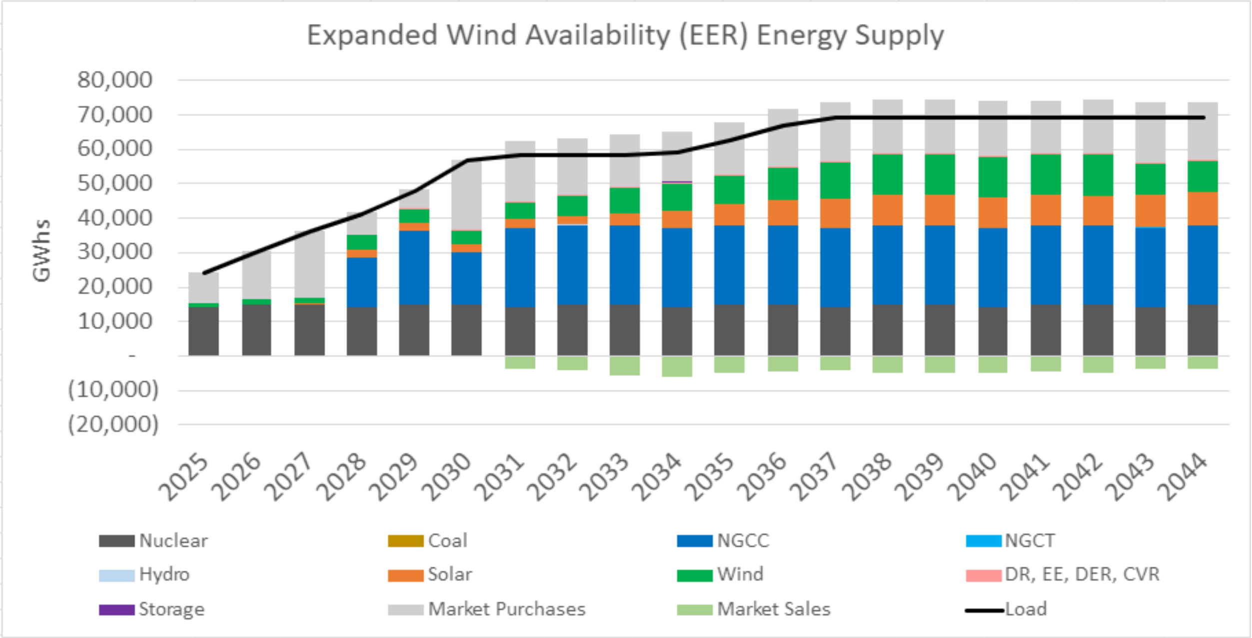
- Similar to the EER scenario, substantial wind, solar, and existing CC's selected to meet the load growth and the expiration of existing capacity purchase agreements
- Cook SLR selected in 2035 and 2038



*Nuclear includes Cook SLR

# Expanded Wind Availability (EER) Portfolio



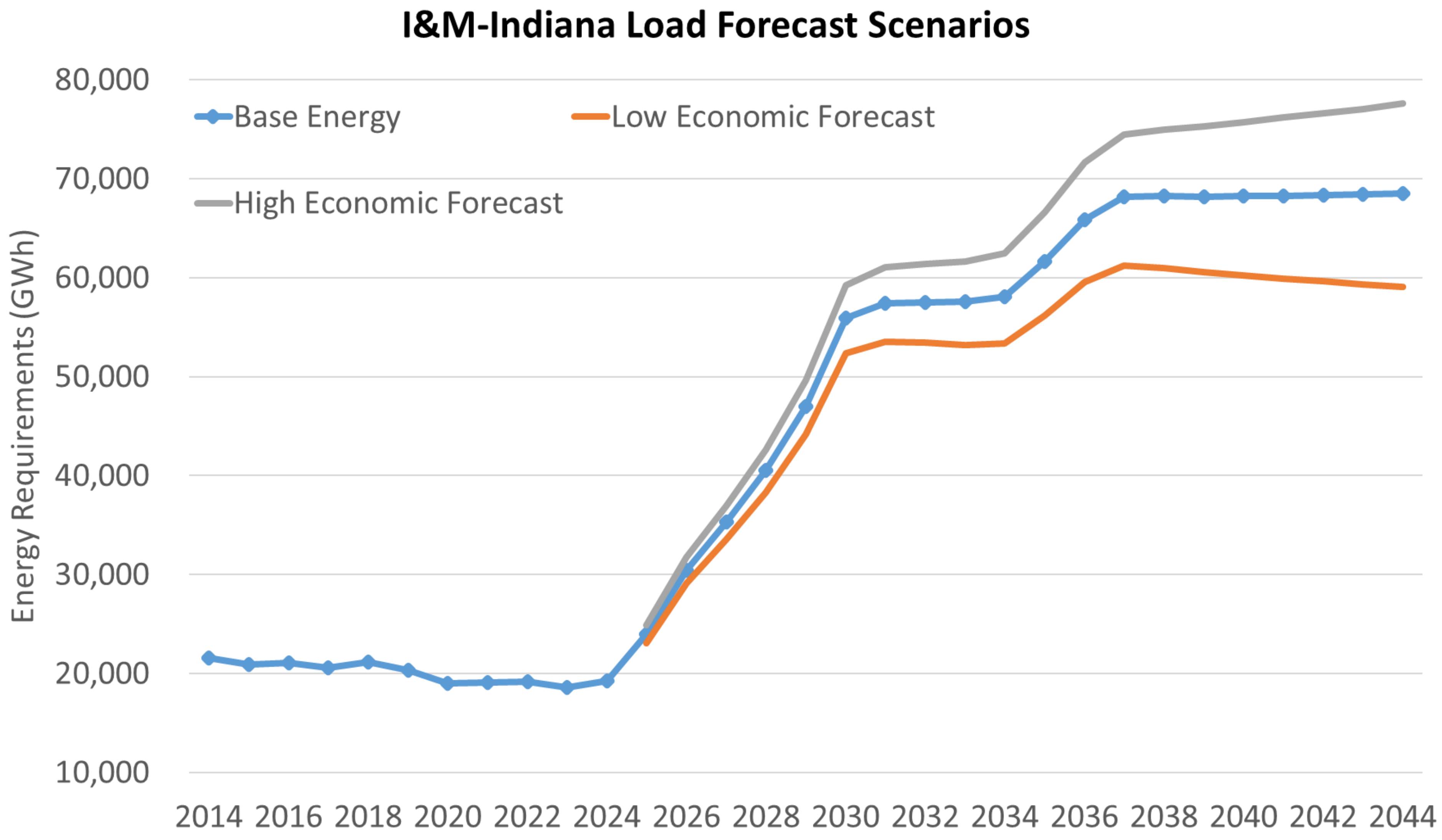

**Observations:**

- Additional wind selected in 2028 results in more wind capacity and energy throughout the planning horizon compared to the EER scenario
- Capacity factor limitations associated with EPA Section 111(b)(d) compliance result in significantly more energy contributions from other resources
- Nuclear and natural gas resources that have higher accreditation values are selected to cover most of the capacity obligation
- Capacity additions in 2031-2034 built in preparation of load increases that occur from 2034-2037 and to provide necessary energy supply to meet import limits
- Added renewable resources result in additional energy market sales starting in 2031



*Nuclear includes Cook SLR

# Base with High and Low Load Forecast Cases



# Base with High Load Portfolio

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage** | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 350 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 28 | 1,650 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 59 | 2,000 |
| 2028 | 200 | 1,796 | 451 | 0 | 1,800 | 0 | 1,000 | 0 | 94 | 200 |
| 2029 | 200 | 1,787 | 451 | 0 | 2,700 | 0 | 1,500 | 0 | 100 | 0 |
| 2030 | 200 | 1,778 | 451 | 0 | 3,600 | 0 | 2,000 | 0 | 97 | 0 |
| 2031 | 600 | 1,769 | 451 | 0 | 3,600 | 0 | 3,000 | 0 | 96 | 0 |
| 2032 | 600 | 1,760 | 451 | 0 | 3,600 | 0 | 3,000 | 0 | 95 | 0 |
| 2033 | 600 | 1,751 | 451 | 0 | 3,600 | 0 | 3,000 | 0 | 91 | 0 |
| 2034 | 600 | 1,742 | 451 | 1,030 | 3,600 | 0 | 3,000 | 0 | 88 | 0 |
| 2035 | 600 | 1,733 | 451 | 1,030 | 3,600 | 0 | 3,000 | 888 | 86 | 0 |
| 2036 | 600 | 1,724 | 451 | 2,060 | 3,600 | 0 | 3,000 | 888 | 84 | 0 |
| 2037 | 1,000 | 1,715 | 451 | 2,060 | 3,600 | 0 | 3,000 | 888 | 80 | 0 |
| 2038 | 1,200 | 1,706 | 451 | 2,060 | 3,600 | 0 | 3,000 | 1,880 | 76 | 0 |
| 2039 | 1,200 | 1,697 | 451 | 2,060 | 3,600 | 0 | 3,000 | 1,880 | 75 | 0 |
| 2040 | 1,200 | 1,688 | 451 | 2,060 | 3,600 | 0 | 3,000 | 1,880 | 74 | 0 |
| 2041 | 1,200 | 1,679 | 451 | 2,060 | 3,600 | 0 | 3,000 | 1,880 | 68 | 0 |
| 2042 | 1,200 | 1,670 | 451 | 2,060 | 3,600 | 230 | 3,000 | 1,880 | 62 | 0 |
| 2043 | 1,000 | 1,107 | 451 | 2,060 | 3,600 | 460 | 3,000 | 1,880 | 56 | 0 |
| 2044 | 1,000 | 1,251 | 451 | 2,060 | 3,600 | 460 | 3,000 | 1,880 | 55 | 0 |

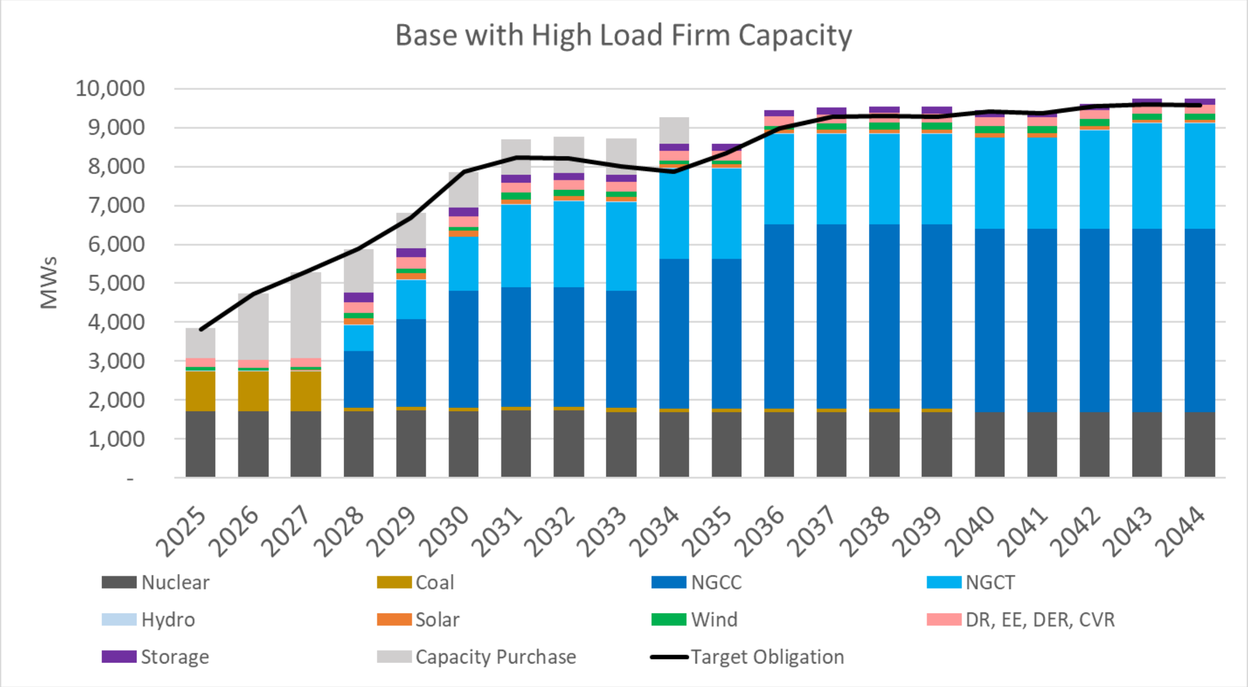
*Nuclear includes Cook SLR
** Storage includes Distribution-Sited Storage resources

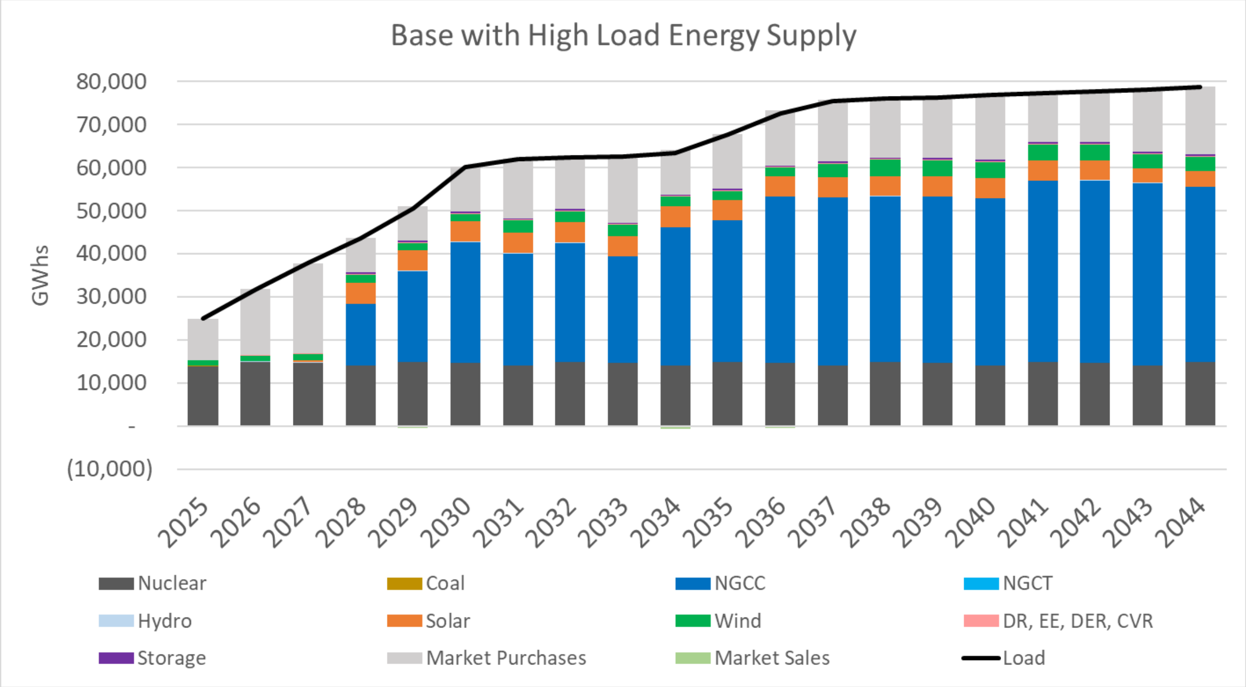
**Purpose of Scenario:**
- Evaluating the most economical solution to meet capacity and energy needs considering base modeling parameters and assumptions with High Load forecast scenario

**Observations through 2030:**
- Solar, wind, storage, and gas resources selected in 2028 in response to load growth by 2030
- Selected all available existing CC's by 2030 and existing CT's were selected to meet capacity obligation
- Increased Short Term Capacity purchased compared to reference scenario due to increased Capacity Obligation due to higher load
- Additional solar and CT resources selected by 2030 in response to higher load compared to reference scenario

**Observations for 2031+:**
- More wind and CT's are selected compared to the reference scenario
- New CC built in 2034 and 2036 to meet the load growth in the same period and the expiration of existing capacity purchase agreements similar to the reference scenario
- Cook SLR selected in 2035 and 2038

# Base with High Load Portfolio




**Observations:**

- Higher load growth results in additional renewable resources compared to the reference scenario that provide significant energy supply
- Nuclear resources provide consistent Carbon-free capacity and energy
- Natural gas resources are generally the most economic options to meet the growing capacity obligations and needed energy supply
- Capacity additions in 2031-2034 built in preparation of load increases that occur from 2034-2037 and to provide necessary energy supply to meet import limits



*Nuclear includes Cook SLR

# Base with Low Load Portfolio

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 75 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 23 | 1,275 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 49 | 1,525 |
| 2028 | 200 | 0 | 0 | 0 | 1,800 | 0 | 1,000 | 0 | 79 | 0 |
| 2029 | 200 | 0 | 0 | 0 | 2,700 | 0 | 1,000 | 0 | 97 | 0 |
| 2030 | 200 | 0 | 0 | 0 | 3,600 | 0 | 1,500 | 0 | 106 | 0 |
| 2031 | 600 | 0 | 0 | 0 | 3,600 | 0 | 2,000 | 0 | 115 | 0 |
| 2032 | 600 | 0 | 0 | 0 | 3,600 | 0 | 2,000 | 0 | 111 | 0 |
| 2033 | 800 | 0 | 0 | 0 | 3,600 | 0 | 2,000 | 0 | 105 | 0 |
| 2034 | 800 | 0 | 0 | 1,030 | 3,600 | 0 | 2,000 | 0 | 100 | 0 |
| 2035 | 800 | 0 | 0 | 1,030 | 3,600 | 0 | 2,000 | 888 | 99 | 0 |
| 2036 | 800 | 0 | 0 | 1,030 | 3,600 | 0 | 2,000 | 888 | 96 | 0 |
| 2037 | 1,200 | 0 | 0 | 1,030 | 3,600 | 0 | 2,000 | 888 | 92 | 0 |
| 2038 | 1,200 | 0 | 0 | 1,030 | 3,600 | 0 | 2,000 | 1,880 | 87 | 0 |
| 2039 | 1,200 | 0 | 0 | 1,030 | 3,600 | 0 | 2,000 | 1,880 | 84 | 0 |
| 2040 | 1,200 | 0 | 0 | 1,030 | 3,600 | 0 | 2,000 | 1,880 | 81 | 0 |
| 2041 | 1,200 | 0 | 0 | 1,030 | 3,600 | 0 | 2,000 | 1,880 | 73 | 0 |
| 2042 | 1,200 | 0 | 0 | 1,030 | 3,600 | 0 | 2,000 | 1,880 | 65 | 0 |
| 2043 | 1,000 | 0 | 0 | 1,030 | 3,600 | 0 | 2,000 | 1,880 | 58 | 0 |
| 2044 | 1,000 | 0 | 0 | 1,030 | 3,600 | 0 | 2,000 | 1,880 | 53 | 0 |

**Purpose of Scenario:**

- Evaluating the most economical solution to meet capacity and energy needs considering base modeling parameters and assumptions with Low Load forecast scenario

**Observations through 2030:**

- Wind and gas resources selected in 2028 in response to load growth by 2030
- Selected all available existing CC's by 2030 and existing CT's were selected to meet capacity obligation
- Unlike the reference scenario, less short term capacity and no solar or storage are selected

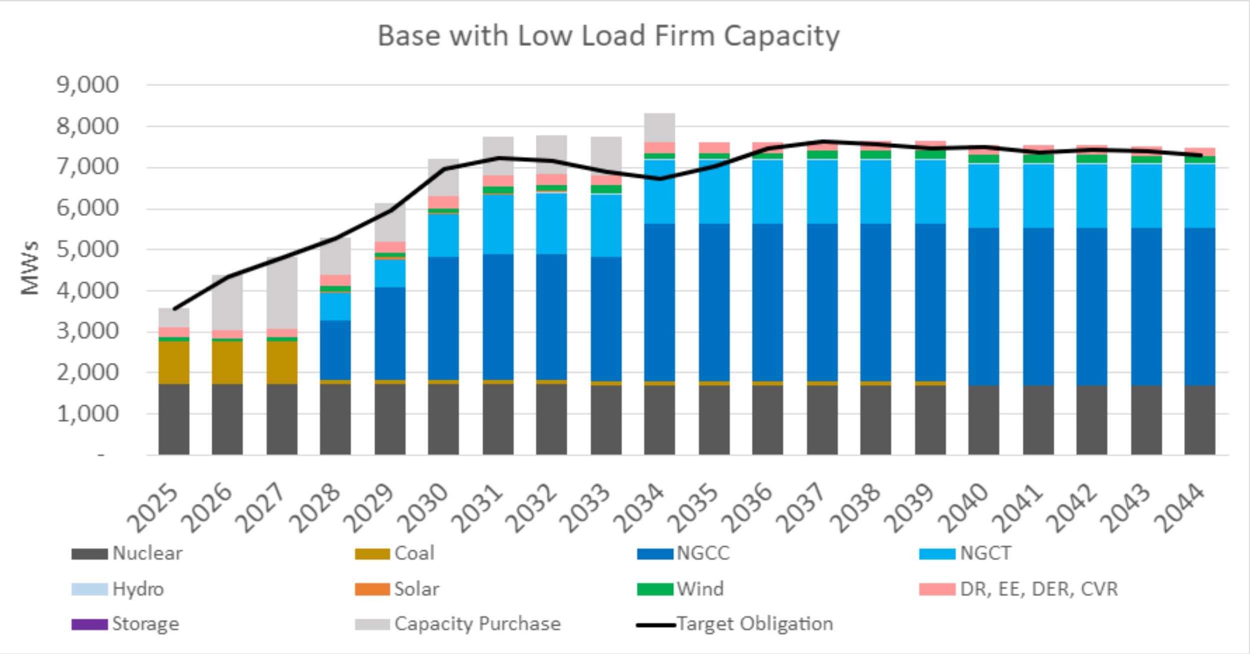
**Observations for 2031+:**

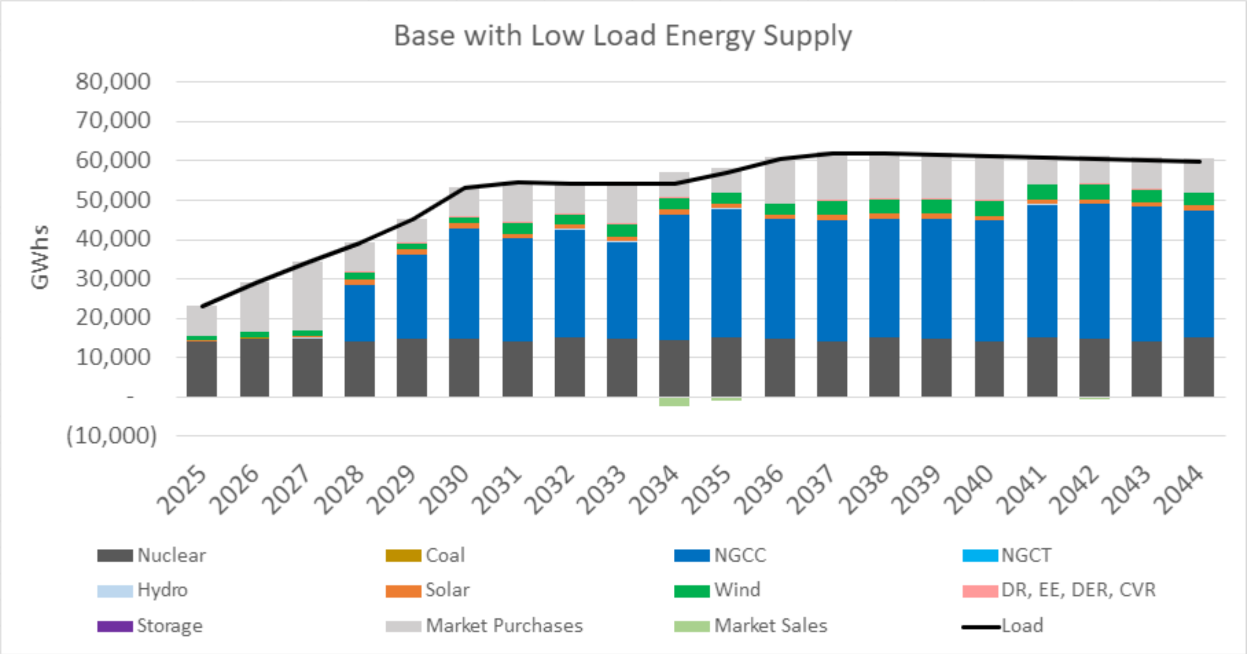
- New CC built in 2034 and additional wind resources built to meet the load growth in the same period and the expiration of existing capacity purchase agreements
- Cook SLR selected in 2035 and 2038



*Nuclear includes Cook SLR

# Base with Low Load Portfolio




**Observations:**

- Nuclear resources provide consistent Carbon-free capacity and energy
- Natural gas resources are generally the most economic options to meet the growing capacity obligations and needed energy supply
- Capacity additions in 2031-2035 built in preparation of load increases that occur from 2034-2037



*Nuclear includes Cook SLR

# High Technology Cost Sensitivity Assumptions

| Technology | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Wind** | 4% | 6% | 8% | 9% | 11% | 13% | 13% | 14% | 14% | 15% | 15% | 16% | 16% | 17% | 17% | 18% | 18% | 19% | 19% | 20% |
| **Solar** | 3% | 5% | 6% | 8% | 11% | 13% | 16% | 19% | 22% | 26% | 31% | 30% | 30% | 30% | 30% | 30% | 30% | 29% | 29% | 29% |
| **Nuclear Small Modular Reactor** | | | | | | 25% | 29% | 32% | 37% | 41% | 46% | 47% | 48% | 50% | 51% | 52% | 53% | 54% | 54% | 55% |
| **NG Combustion Turbine** | 48% | 48% | 48% | 48% | 48% | 48% | 48% | 48% | 48% | 48% | 48% | 48% | 48% | 48% | 48% | 48% | 48% | 48% | 48% | 48% |
| **NG Combined Cycle** | 41% | 41% | 41% | 41% | 41% | 41% | 41% | 41% | 41% | 41% | 41% | 41% | 41% | 41% | 41% | 41% | 41% | 41% | 41% | 41% |
| **Storage (4-Hour)** | 28% | 27% | 27% | 26% | 25% | 24% | 25% | 26% | 27% | 29% | 30% | 31% | 32% | 34% | 35% | 37% | 38% | 40% | 41% | 43% |
| **Storage (6-Hour)** | 28% | 28% | 27% | 27% | 26% | 26% | 27% | 28% | 29% | 31% | 32% | 33% | 35% | 36% | 38% | 40% | 41% | 43% | 45% | 47% |
| **Storage (8-Hour)** | 29% | 28% | 28% | 27% | 27% | 26% | 28% | 29% | 30% | 32% | 33% | 35% | 36% | 38% | 39% | 41% | 43% | 45% | 47% | 49% |

- For the High Technology Cost sensitivity, the installed costs for resource options are modified by the above percentages relative to the reference scenario

- Combustion Turbine and Combined Cycle percentage increase are for existing and new resource options

- Solar with Storage options are a weighted average of the cost changes for Solar and Storage technologies
    - (75% weight on Solar and 25% weight on Storage)

- Increases were sourced from NREL ATB and recent market intelligence

# High Technology Cost Portfolio

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 325 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 28 | 1,500 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 59 | 1,875 |
| 2028 | 200 | 599 | 450 | 0 | 1,800 | 0 | 1,000 | 0 | 94 | 0 |
| 2029 | 200 | 596 | 450 | 0 | 2,700 | 0 | 1,000 | 0 | 100 | 0 |
| 2030 | 200 | 593 | 450 | 0 | 3,600 | 0 | 1,500 | 0 | 97 | 0 |
| 2031 | 200 | 590 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 96 | 0 |
| 2032 | 200 | 587 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 115 | 0 |
| 2033 | 200 | 584 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 131 | 0 |
| 2034 | 200 | 581 | 450 | 1,030 | 3,600 | 0 | 2,000 | 0 | 144 | 0 |
| 2035 | 200 | 578 | 450 | 1,030 | 3,600 | 0 | 2,000 | 888 | 156 | 0 |
| 2036 | 200 | 575 | 450 | 2,060 | 3,600 | 0 | 2,000 | 888 | 169 | 0 |
| 2037 | 200 | 572 | 450 | 2,060 | 3,600 | 0 | 2,000 | 888 | 177 | 0 |
| 2038 | 200 | 569 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 185 | 0 |
| 2039 | 200 | 566 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 193 | 0 |
| 2040 | 200 | 563 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 201 | 0 |
| 2041 | 200 | 560 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 207 | 0 |
| 2042 | 200 | 557 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 211 | 0 |
| 2043 | 0 | 554 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 213 | 0 |
| 2044 | 0 | 551 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 220 | 0 |

**Purpose of Scenario:**

- Evaluating the most economical solution to meet capacity and energy needs considering base modeling parameters and assumptions with increased resource installed costs

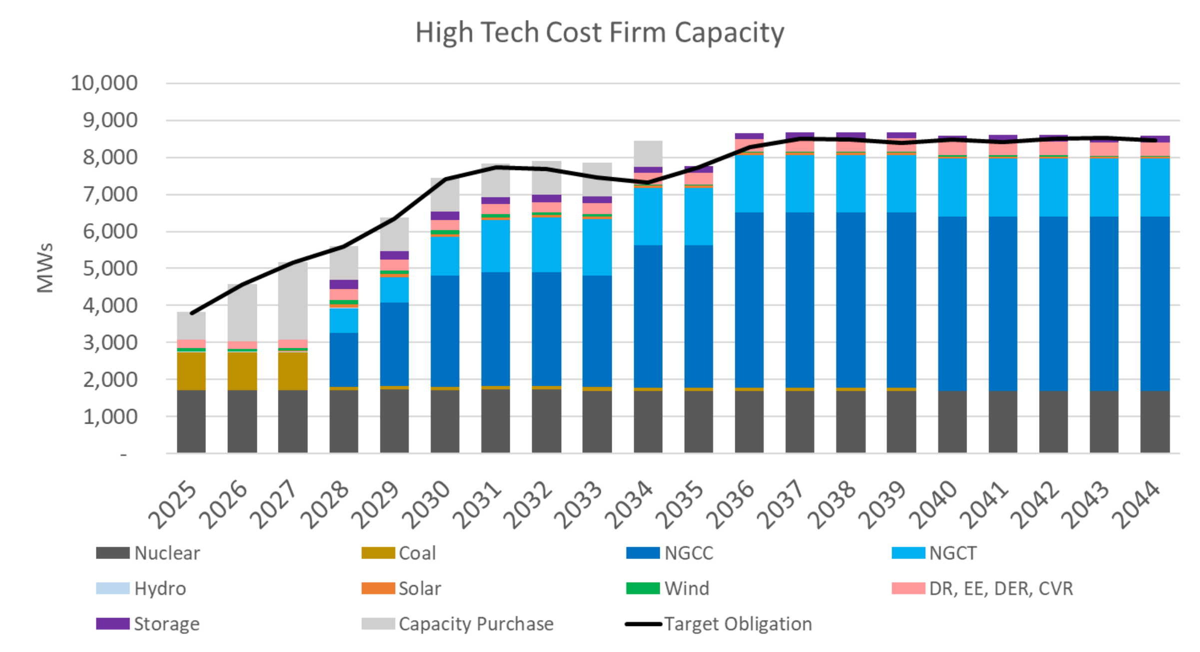
**Observations through 2030:**

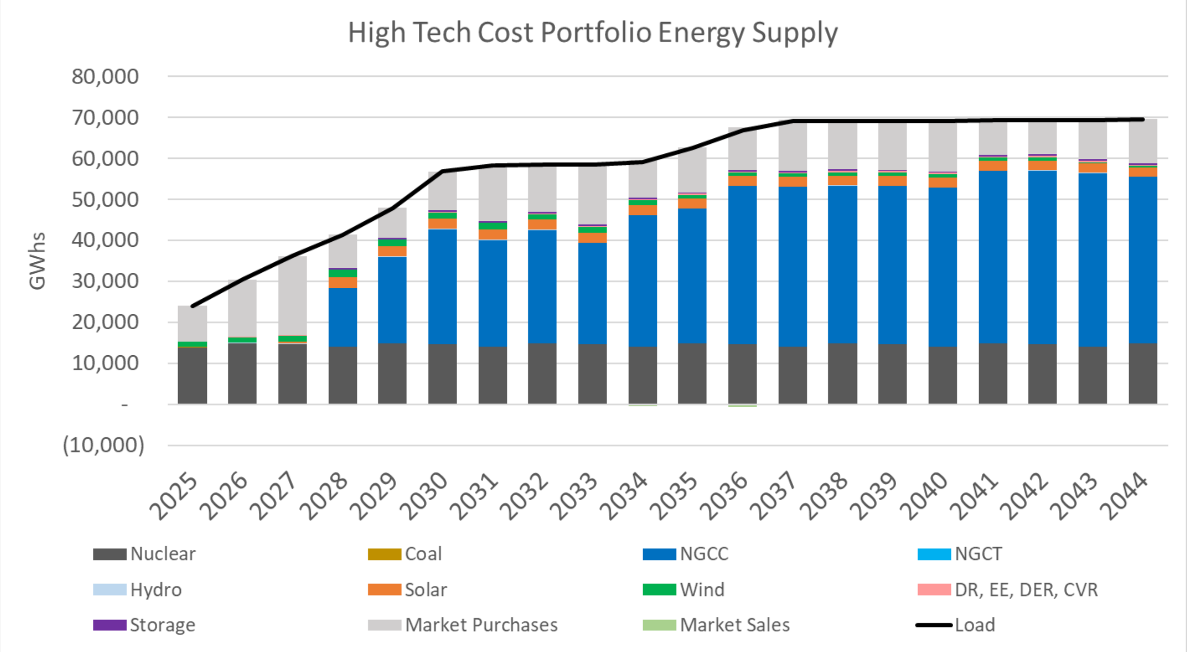
- Resources selected are identical to the reference case starting in 2025 and for the remainder of the planning horizon
- Solar, wind, storage, and gas resources selected in 2028 to meet the capacity and energy obligations are not impacted by the higher cost assumptions
- Selected all available existing CC's by 2030 and existing CT's were selected to meet capacity obligation

**Observations for 2031+:**

- New CC built in 2034 and 2036 to meet the capacity and energy obligations are not impacted by the higher cost assumptions
- Cook SLR selected in 2035 and 2038

# High Technology Cost Portfolio




**Observations:**

- Resources selected are identical to the reference case starting in 2025 and for the remainder of the planning horizon

# 10 Minute Break

# Rockport Unit 1 Retires 2025 Portfolio

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1,250 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 28 | 2,425 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 59 | 2,825 |
| 2028 | 200 | 599 | 450 | 0 | 1,800 | 0 | 1,000 | 0 | 94 | 0 |
| 2029 | 200 | 596 | 450 | 0 | 2,700 | 0 | 1,000 | 0 | 100 | 0 |
| 2030 | 200 | 593 | 450 | 0 | 3,600 | 0 | 1,500 | 0 | 97 | 0 |
| 2031 | 200 | 590 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 96 | 0 |
| 2032 | 200 | 587 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 115 | 0 |
| 2033 | 200 | 584 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 131 | 0 |
| 2034 | 200 | 581 | 450 | 1,030 | 3,600 | 0 | 2,000 | 0 | 144 | 0 |
| 2035 | 200 | 578 | 450 | 1,030 | 3,600 | 0 | 2,000 | 888 | 156 | 0 |
| 2036 | 200 | 575 | 450 | 2,060 | 3,600 | 0 | 2,000 | 888 | 169 | 0 |
| 2037 | 200 | 572 | 450 | 2,060 | 3,600 | 0 | 2,000 | 888 | 177 | 0 |
| 2038 | 200 | 569 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 185 | 0 |
| 2039 | 200 | 566 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 193 | 0 |
| 2040 | 200 | 563 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 201 | 0 |
| 2041 | 200 | 560 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 207 | 0 |
| 2042 | 200 | 557 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 211 | 0 |
| 2043 | 0 | 554 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 213 | 0 |
| 2044 | 0 | 551 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 220 | 0 |

**Purpose of Scenario**:**

- Evaluating the most economical solution to meet capacity and energy needs considering base modeling parameters and assumptions of Rockport retiring 5/31/2025

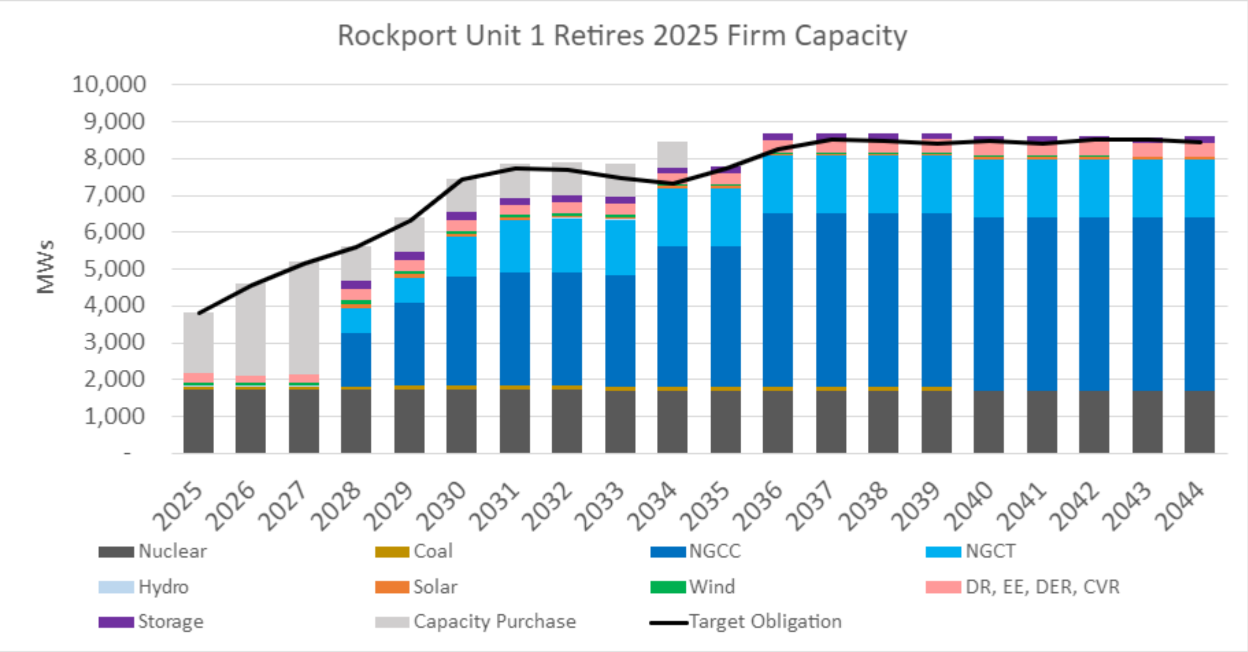
**Observations through Planning Horizon:**

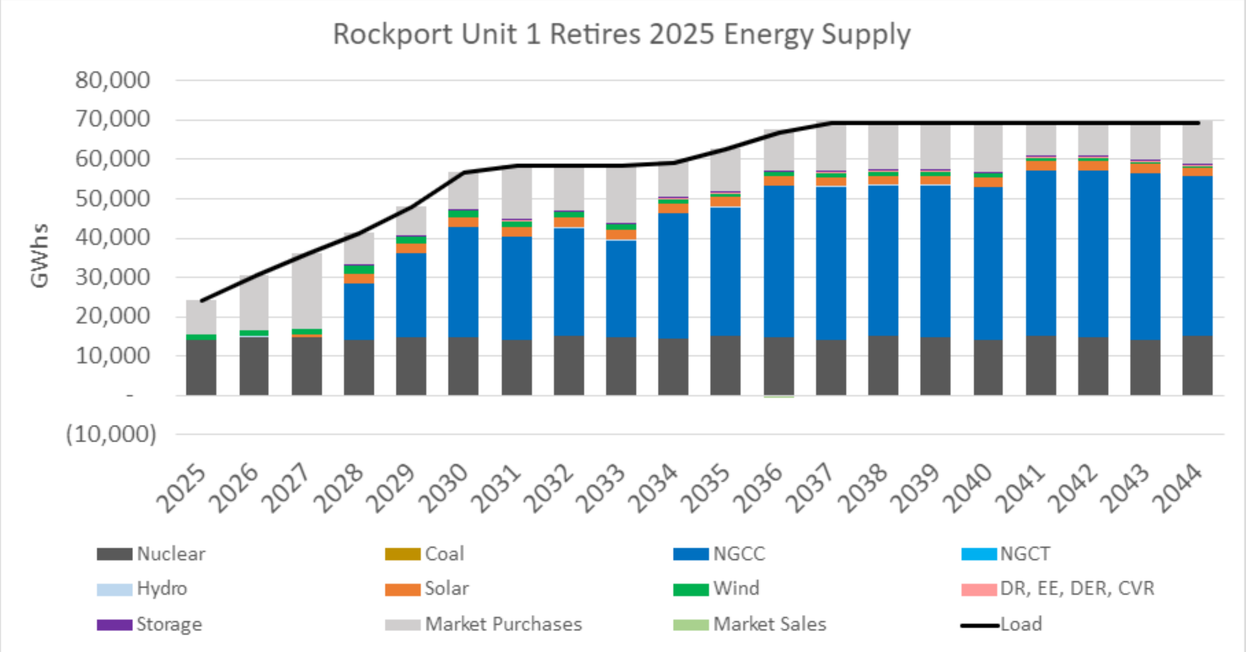
- Additional Short Term Capacity purchases compared to the reference case until new resources become available in 2028
- Resources selected are identical to the reference case starting in 2028 and for the remainder of the planning horizon

*Nuclear includes Cook SLR

** Required per Cause No. 45546

# Rockport Unit 1 Retires 2025 Portfolio




**Observations:**

- Resources selected are identical to the reference case starting in 2028 and for the remainder of the planning horizon



*Nuclear includes Cook SLR

# Rockport Unit 1 Retires 2026 Portfolio

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 325 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 28 | 2,425 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 59 | 2,825 |
| 2028 | 200 | 599 | 450 | 0 | 1,800 | 0 | 1,000 | 0 | 94 | 0 |
| 2029 | 200 | 596 | 450 | 0 | 2,700 | 0 | 1,000 | 0 | 100 | 0 |
| 2030 | 200 | 593 | 450 | 0 | 3,600 | 0 | 1,500 | 0 | 97 | 0 |
| 2031 | 200 | 590 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 96 | 0 |
| 2032 | 200 | 587 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 115 | 0 |
| 2033 | 200 | 584 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 131 | 0 |
| 2034 | 200 | 581 | 450 | 1,030 | 3,600 | 0 | 2,000 | 0 | 144 | 0 |
| 2035 | 200 | 578 | 450 | 1,030 | 3,600 | 0 | 2,000 | 888 | 156 | 0 |
| 2036 | 200 | 575 | 450 | 2,060 | 3,600 | 0 | 2,000 | 888 | 169 | 0 |
| 2037 | 200 | 572 | 450 | 2,060 | 3,600 | 0 | 2,000 | 888 | 177 | 0 |
| 2038 | 200 | 569 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 185 | 0 |
| 2039 | 200 | 566 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 193 | 0 |
| 2040 | 200 | 563 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 201 | 0 |
| 2041 | 200 | 560 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 207 | 0 |
| 2042 | 200 | 557 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 211 | 0 |
| 2043 | 0 | 554 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 213 | 0 |
| 2044 | 0 | 551 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 220 | 0 |

**Purpose of Scenario**:**

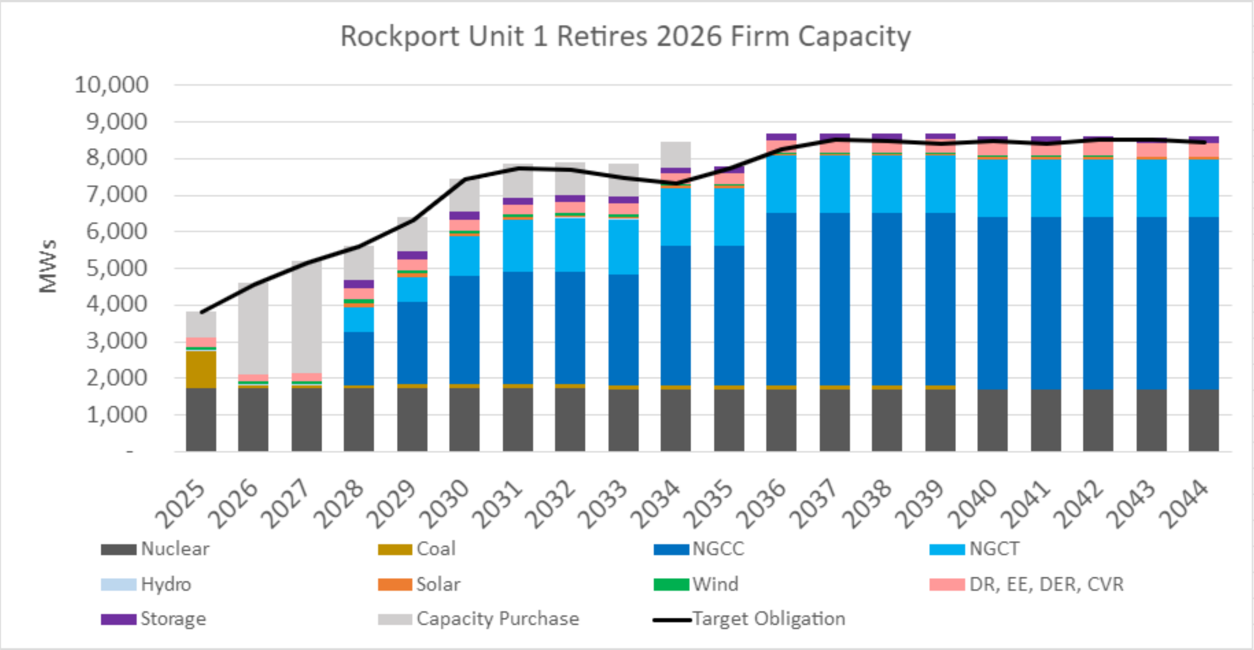
- Evaluating the most economical solution to meet capacity and energy needs considering base modeling parameters and assumptions of Rockport retiring 5/31/2026

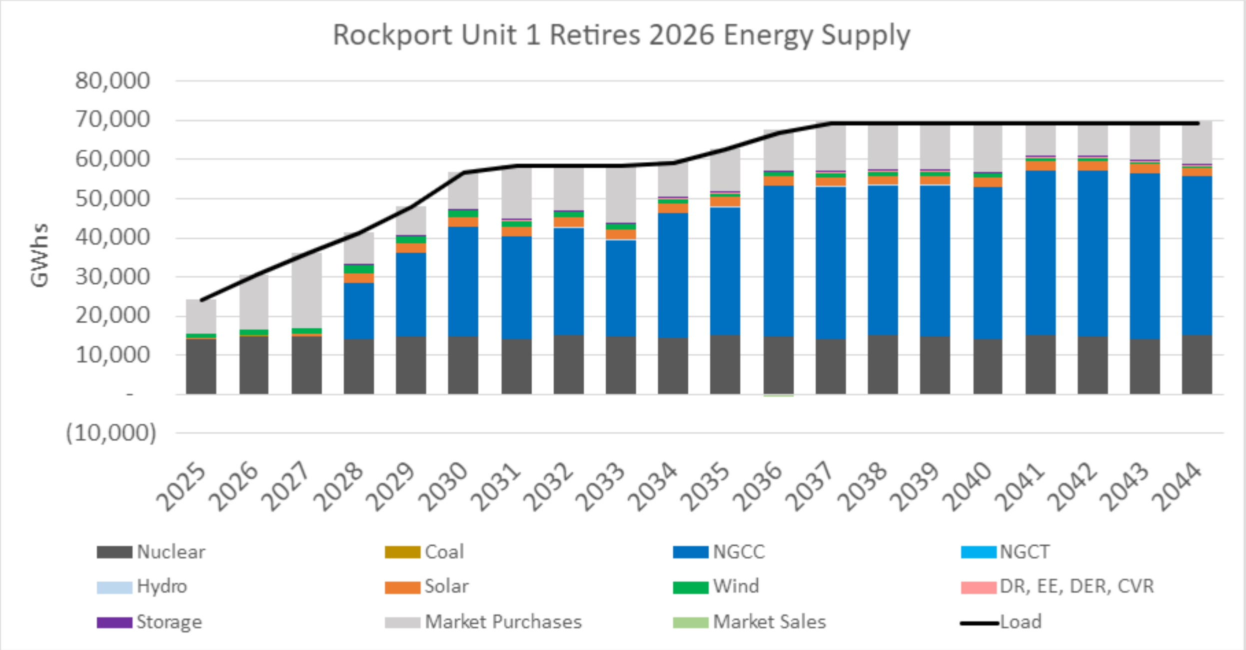
**Observations through Planning Horizon:**

- Additional Short Term Capacity purchases compared to the reference case until new resources become available in 2028
- Resources selected are identical to the reference case starting in 2028 and for the remainder of the planning horizon

*Nuclear includes Cook SLR
** Required per Cause No. 45546

# Rockport Unit 1 Retires 2026 Portfolio




**Observations:**

- Resources selected are identical to the reference case starting in 2028 and for the remainder of the planning horizon



*Nuclear includes Cook SLR

# Exit OVEC ICPA in 2030 Portfolio

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 325 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 28 | 1,500 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 59 | 1,875 |
| 2028 | 200 | 599 | 450 | 0 | 1,800 | 0 | 1,000 | 0 | 94 | 0 |
| 2029 | 200 | 596 | 450 | 0 | 1,800 | 0 | 2,000 | 0 | 119 | 0 |
| 2030 | 200 | 593 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 135 | 0 |
| 2031 | 200 | 590 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 151 | 0 |
| 2032 | 200 | 587 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 173 | 0 |
| 2033 | 200 | 584 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 190 | 0 |
| 2034 | 200 | 581 | 450 | 1,030 | 3,600 | 0 | 2,000 | 0 | 204 | 0 |
| 2035 | 200 | 578 | 450 | 1,030 | 3,600 | 0 | 2,000 | 888 | 221 | 0 |
| 2036 | 200 | 575 | 450 | 2,060 | 3,600 | 0 | 2,000 | 888 | 237 | 0 |
| 2037 | 200 | 572 | 450 | 2,060 | 3,600 | 0 | 2,000 | 888 | 250 | 0 |
| 2038 | 200 | 569 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 261 | 0 |
| 2039 | 200 | 566 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 270 | 0 |
| 2040 | 200 | 563 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 279 | 0 |
| 2041 | 200 | 560 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 286 | 0 |
| 2042 | 200 | 557 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 292 | 0 |
| 2043 | 0 | 554 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 298 | 0 |
| 2044 | 0 | 551 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 302 | 0 |

**Purpose of Scenario**:**

- Evaluating the most economical solution to meet capacity and energy needs considering base modeling parameters and assumptions of the termination of operation of the Ohio Valley Electric Corporation (OVEC) units under the Intercompany Power Agreement (ICPA) by the end of 2030

**Observations through 2030:**

- Resources selected are substantially similar to the reference case for 2028+
- Solar, wind, storage, and gas resources selected in 2028 in response to load growth by 2030
- Selected all available existing CC's by 2030 and existing CT's were selected to meet capacity obligation
- Additional DR, EE, DER, CVR selected compared to reference scenario

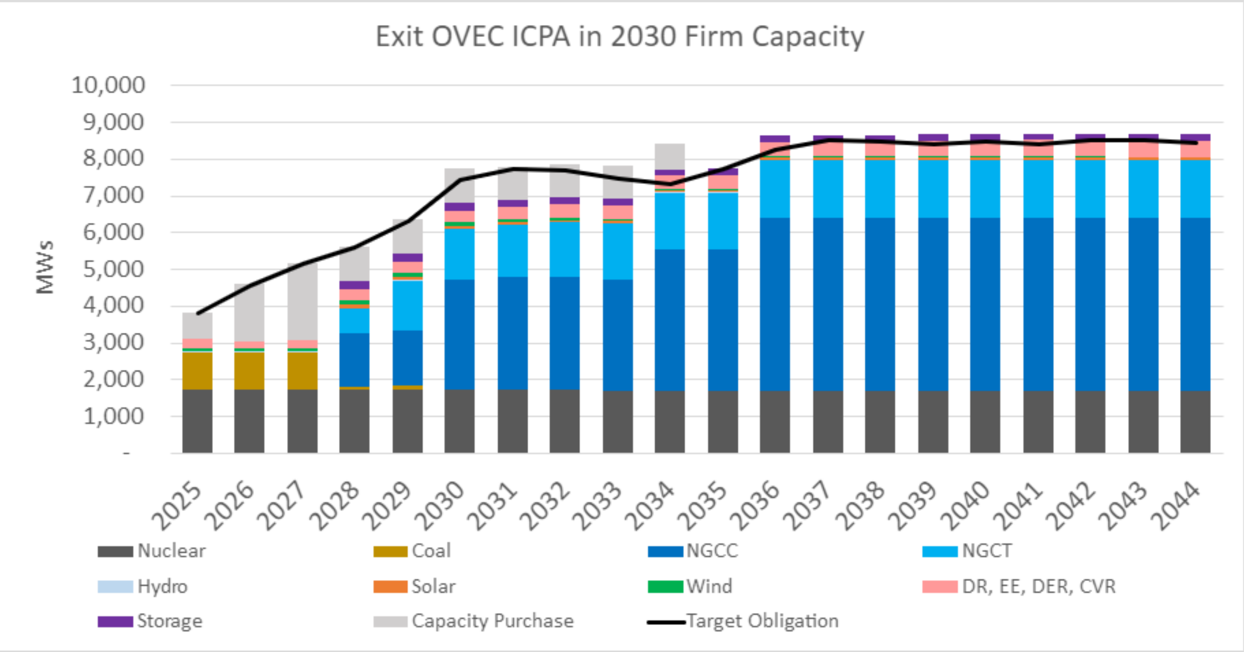
**Observations for 2031+:**

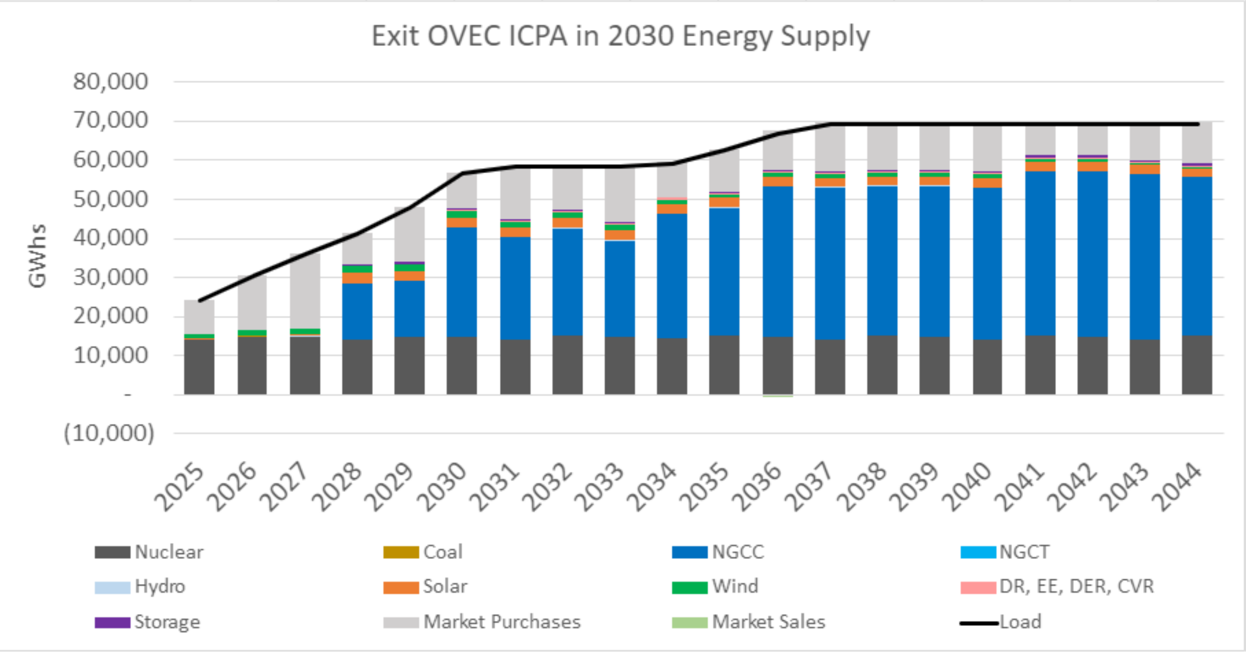
- New CC built in 2034 and 2036 to meet the load growth in the same period and the expiration of existing capacity purchase agreements
- Cook SLR selected in 2035 and 2038

*Nuclear includes Cook SLR

** Required per Cause No. 45546. The ICPA does not have any provision for early termination by one or more of the Sponsoring Companies.

# Exit OVEC ICPA in 2030 Portfolio



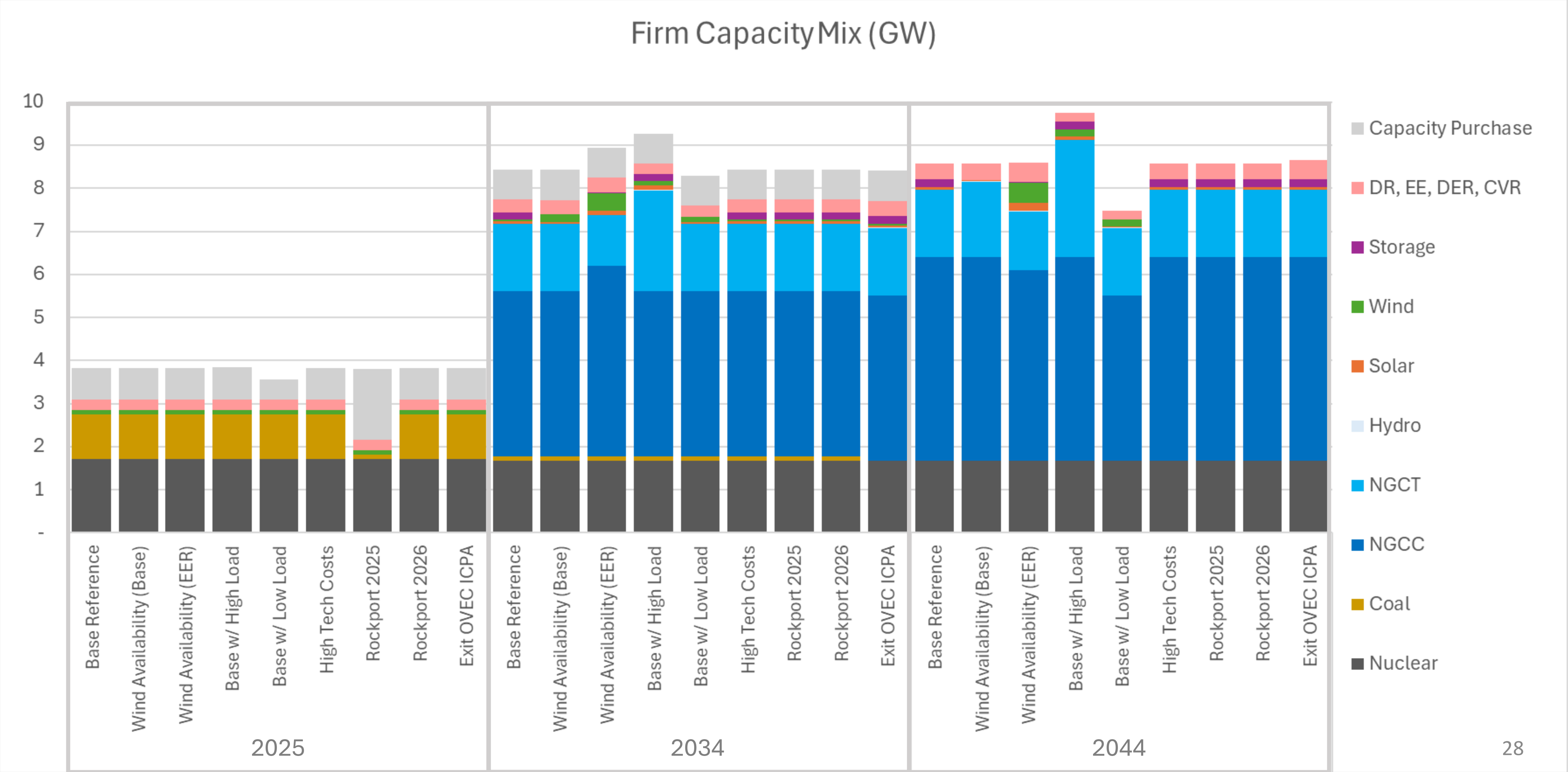

**Observations:**

- Resources selected are substantially similar to the reference case for 2028+

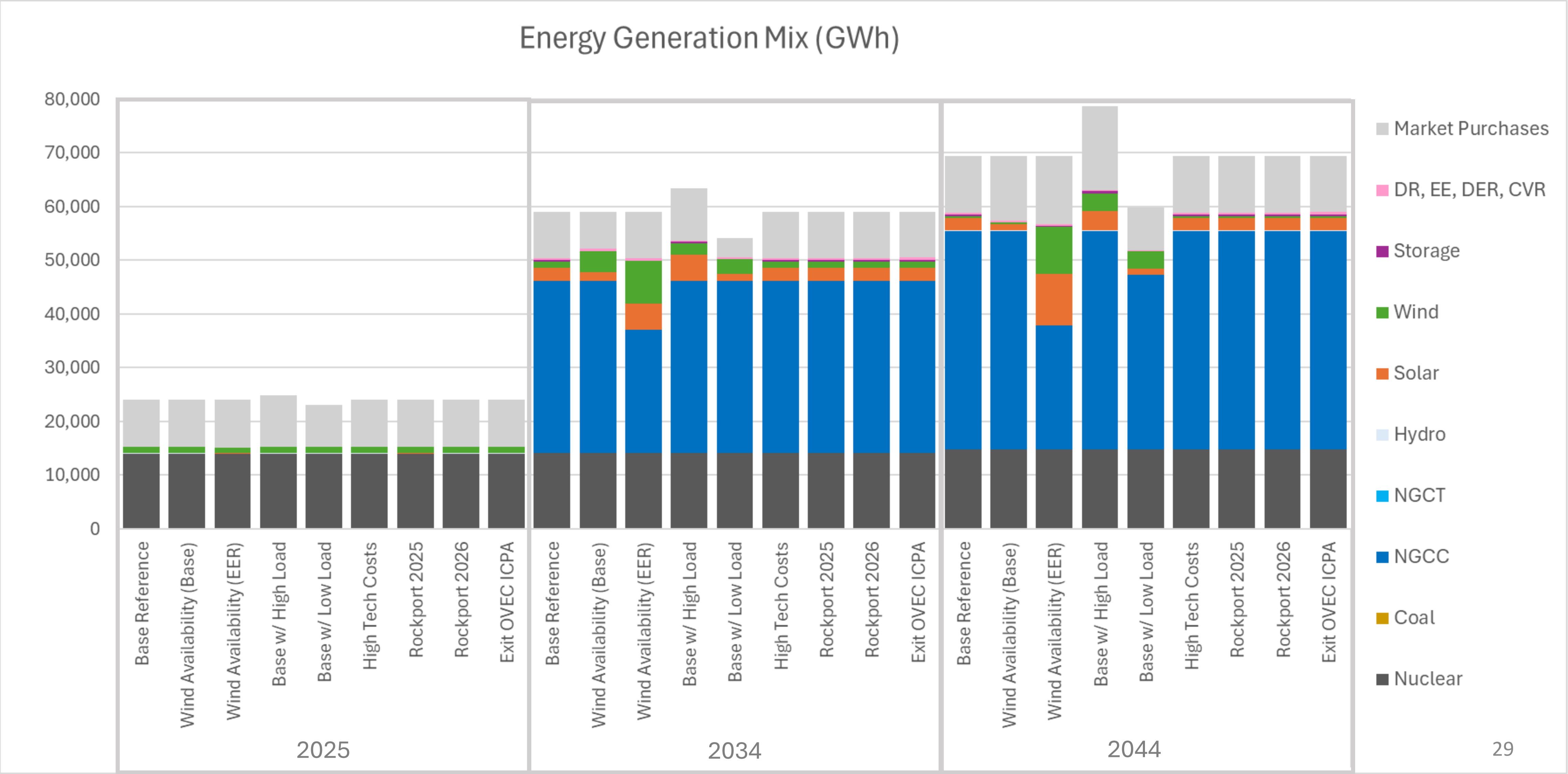


*Nuclear includes Cook SLR

# Results Summary Comparison



# Results Summary Comparison



# Resource Selection Results Summary Comparison

| Portfolio | 2034 Nameplate Capacity Additions (MW) | | | | | | | | 2044 Nameplate Capacity Additions (MW) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | NGCT | NGCC | Nuclear* | DR, EE, DER, CVR** | **Total Additions** | Wind | Solar | Storage | NGCT | NGCC | Nuclear* | DR, EE, DER, CVR** | **Total Additions** |
| **Base Reference** | 200 | 581 | 450 | 2,000 | 4,630 | 0 | 144 | **8,005** | 0 | 551 | 450 | 2,000 | 5,660 | 1,880 | 220 | **10,761** |
| **Expanded Wind Availability (Base)** | 1,200 | 145 | 0 | 2,000 | 4,630 | 0 | 168 | **8,143** | 0 | 0 | 0 | 2,230 | 5,660 | 1,880 | 229 | **9,999** |
| **Expanded Wind Availability (EER)** | 2,600 | 1,775 | 50 | 1,500 | 5,400 | 0 | 196 | **11,521** | 3,000 | 4,145 | 50 | 1,730 | 5,400 | 1,880 | 290 | **16,495** |
| **Base with High Load** | 600 | 1,742 | 451 | 3,000 | 4,630 | 0 | 88 | **10,511** | 1,000 | 1,251 | 451 | 3,460 | 5,660 | 1,880 | 55 | **13,757** |
| **Base with Low Load** | 800 | 0 | 0 | 2,000 | 4,630 | 0 | 100 | **7,530** | 1,000 | 0 | 0 | 2,000 | 4,630 | 1,880 | 53 | **9,563** |
| **High Technology Cost** | 200 | 581 | 450 | 2,000 | 4,630 | 0 | 144 | **8,005** | 0 | 551 | 450 | 2,000 | 5,660 | 1,880 | 220 | **10,761** |
| **Rockport Unit 1 Retires 2025** | 200 | 581 | 450 | 2,000 | 4,630 | 0 | 144 | **8,005** | 0 | 551 | 450 | 2,000 | 5,660 | 1,880 | 220 | **10,761** |
| **Rockport Unit 1 Retires 2026** | 200 | 581 | 450 | 2,000 | 4,630 | 0 | 144 | **8,005** | 0 | 551 | 450 | 2,000 | 5,660 | 1,880 | 220 | **10,761** |
| **Exit OVEC ICPA in 2030** | 200 | 581 | 450 | 2,000 | 4,630 | 0 | 204 | **8,065** | 0 | 551 | 450 | 2,000 | 5,660 | 1,880 | 302 | **10,843** |

*Nuclear includes Cook SLR

**DR, EE, DER, CVR values are accredited

# Portfolio Performance Indicators

| IURC Pillar | IRP Objective | Performance Indicator | Metric Description |
|---|---|---|---|
| Reliability | Maintain capacity reserve margin and the consideration of reliance on the market for the benefit of customers. | Energy Market Exposure – Purchases | NPV of market purchases and average volume exposure of market purchases (Costs and MWhs % of Internal Load) over 10 and 20 years. Lower values are better. |
| | | Energy Market Exposure – Sales | NPV of market sales and average volume exposure of market sales (Revenues and MWhs % of Internal Load) over 10 and 20 years. Lower values are better. |
| | | Planning Reserves | Average Target Reserve Margin over 10 and 20 years. Closest value to the % Target. |
| Affordability | Maintain focus on power supply cost and risks to customers | Net Present Value Revenue Requirement (NPVRR) | Portfolio 30yr NPVRR (power supply costs). Lower values are better. |
| | | Near-Term Power Supply Cost Impacts (CAGR) | 7-year CAGR of Annual Power Supply Cost. Lower values are better. |
| | | Portfolio Resilience | Range of Portfolio NPVRR (power supply costs) dispatched across all Scenarios. Lower values are better. |
| Resiliency | Maintain diversity of resources and fleet dispatchability | Resource Diversity | Percent change in Diversity Index inclusive of Capacity and Energy Diversity in years 2034 and 2044. Higher values are better. |
| (Grid) Stability | Maintain fleet of flexible and dispatchable resources | Fleet Resiliency | Average % dispatchable capacity of company peak load over 10 and 20 years. Higher values are better. |
| Environmental Sustainability | Maintain focus on portfolio environmental sustainability benefits and compliance costs | Emissions Change | $CO_2$, NOx, $SO_2$ emissions change compared to 2005 levels in years 2034 and 2044. Higher values are better. |
| | | Net Present Value Revenue Requirement (NPVRR) | Considered under Affordability Pillar above |

# Draft Portfolio Performance Comparison

| Pillar | Affordability | | | Environmental Sustainability | | |
|---|---|---|---|---|---|---|
| ***Performance Indicators and Metrics*** | ***Short Term*** *7-yr Rate CAGR* Power Supply $/MWh | ***Long Term*** *Supply Portfolio NPVRR Power Supply Costs* | ***Portfolio Resilience:*** *High Minus Low Scenario Range, Portfolio NPVRR* | ***Emissions Analysis:*** *% Change from 2005 Baseline* | | |
| Year Ref. | 2024-2031 | 2025-2044 | 2025-2044 | 2034 \| 2044 | | |
| Units | % | $B | $B | % Change $CO_2$ | % Change NOx | % Change $SO_2$ |
| **Base Reference** | -0.5% | $32.0 | [to be developed] | 2034: -39%<br>2044: -24% | 2034: -94%<br>2044: -93% | 2034: -100%<br>2044: -100% |
| **Expanded Wind Availability (Base)** | -0.5% | $31.8 | [to be developed] | 2034: -39%<br>2044: -24% | 2034: -94%<br>2044: -93% | 2034: -100%<br>2044: -100% |
| **Expanded Wind Availability (EER)** | 0.5% | $32.8 | [to be developed] | 2034: -56%<br>2044: -55% | 2034: -95%<br>2044: -95% | 2034: -100%<br>2044: -100% |
| **Base with High Load** | -0.1% | $34.9 | [to be developed] | 2034: -39%<br>2044: -24% | 2034: -94%<br>2044: -93% | 2034: -100%<br>2044: -100% |
| **Base with Low Load** | -0.7% | $28.3 | [to be developed] | 2034: -39%<br>2044: -39% | 2034: -94%<br>2044: -94% | 2034: -100%<br>2044: -100% |
| **High Technology Costs** | 0.7% | $34.8 | [to be developed] | 2034: -39%<br>2044: -24% | 2034: -94%<br>2044: -93% | 2034: -100%<br>2044: -100% |
| **Rockport Unit 1 Retires 2025** | -0.5% | $32.6 | [to be developed] | 2034: -39%<br>2044: -24% | 2034: -94%<br>2044: -93% | 2034: -100%<br>2044: -100% |
| **Rockport Unit 1 Retires 2026** | -0.5% | $32.4 | [to be developed] | 2034: -39%<br>2044: -24% | 2034: -94%<br>2044: -93% | 2034: -100%<br>2044: -100% |
| **Exit OVEC ICPA in 2030** | -0.4% | $32.1 | [to be developed] | 2034: -39%<br>2044: -24% | 2034: -94%<br>2044: -93% | 2034: -100%<br>2044: -100% |

# Draft Portfolio Performance Comparison

| Pillar | Reliability | | | Reliability/ Resiliency | Grid Stability Resiliency |
|---|---|---|---|---|---|
| ***Performance Indicators and Metrics*** | ***Energy Market Risk*** *Purchases* | ***Energy Market Risk*** *Sales* | ***Planning Reserves*** *% Reserve Margin* | ***Resource Diversity*** | ***Fleet Resiliency:*** *Dispatchable Capacity* |
| Year Ref. | 10 years \| 20 years | 10 years \| 20 years | 10 years \| 20 years | 10 years \| 20 years | 10 years \| 20 years |
| Units | NPV of Market Purchases & MWhs % of Total Demand | NPV of Market Sales & MWhs % of Total Demand | Average of Annual PRM % | Portfolio Index Percent Change from 2025 | Dispatchable Nameplate MW/ % of Company Peak Demand |
| **Base Reference** | 10 Years: $2.6B (27%)<br>20 Years: $4.3B (22%) | 10 Years: $0.0B (0.1%)<br>20 Years: $0.1B (0.3%) | 10 Years: -0.7%<br>20 Years: -3.4% | Capacity: 31% \| 19%<br>Energy: 173% \| 139% | 10 Years: 90%<br>20 Years: 97% |
| **Expanded Wind Availability (Base)** | 10 Years: $2.4B (25%)<br>20 Years: $3.9B (20%) | 10 Years: $0.0B (0.2%)<br>20 Years: $0.1B (0.6%) | 10 Years: -0.6%<br>20 Years: -3.4% | Capacity: 28% \| 12%<br>Energy: 188% \| 114% | 10 Years: 86%<br>20 Years: 93% |
| **Expanded Wind Availability (EER)** | 10 Years: $3.1B (31%)<br>20 Years: $5.4B (27%) | 10 Years: $0.5B (3.5%)<br>20 Years: $1.3B (5.2%) | 10 Years: 5.1%<br>20 Years: -0.6% | Capacity: 31% \| 34%<br>Energy: 296% \| 318% | 10 Years: 92%<br>20 Years: 92% |
| **Base with High Load** | 10 Years: $2.8B (28%)<br>20 Years: $4.9B (23%) | 10 Years: $0.0B (0.3%)<br>20 Years: $0.1B (0.3%) | 10 Years: 0.8%<br>20 Years: -2.6% | Capacity: 34% \| 25%<br>Energy: 208% \| 189% | 10 Years: 92%<br>20 Years: 98% |
| **Base with Low Load** | 10 Years: $2.1B (24%)<br>20 Years: $3.6B (20%) | 10 Years: $0.1B (0.5%)<br>20 Years: $0.1B (0.7%) | 10 Years: 2.3%<br>20 Years: -1.9% | Capacity: 24% \| 19%<br>Energy: 170% \| 172% | 10 Years: 92%<br>20 Years: 96% |
| **High Technology Costs** | 10 Years: $2.6B (27%)<br>20 Years: $4.3B (22%) | 10 Years: $0.0B (0.1%)<br>20 Years: $0.1B (0.3%) | 10 Years: -0.7%<br>20 Years: -3.4% | Capacity: 31% \| 19%<br>Energy: 173% \| 139% | 10 Years: 90%<br>20 Years: 97% |
| **Rockport Unit 1 Retires 2025** | 10 Years: $2.6B (27%)<br>20 Years: $4.3B (22%) | 10 Years: $0.0B (0.1%)<br>20 Years: $0.1B (0.3%) | 10 Years: -0.7%<br>20 Years: -3.4% | Capacity: 80% \| 64%<br>Energy: 183% \| 148% | 10 Years: 84%<br>20 Years: 95% |
| **Rockport Unit 1 Retires 2026** | 10 Years: $2.6B (27%)<br>20 Years: $4.3B (22%) | 10 Years: $0.0B (0.1%)<br>20 Years: $0.1B (0.3%) | 10 Years: -0.6%<br>20 Years: -3.4% | Capacity: 31% \| 19%<br>Energy: 173% \| 139% | 10 Years: 86%<br>20 Years: 95% |
| **Exit OVEC ICPA in 2030** | 10 Years: $2.8B (28%)<br>20 Years: $4.4B (22%) | 10 Years: $0.0B (0.1%)<br>20 Years: $0.1B (0.3%) | 10 Years: -0.6%<br>20 Years: -3.2% | Capacity: 27% \| 21%<br>Energy: 177% \| 142% | 10 Years: 90%<br>20 Years: 97% |

# Remaining Modeling and Next Steps

## Stakeholder Meeting 3B

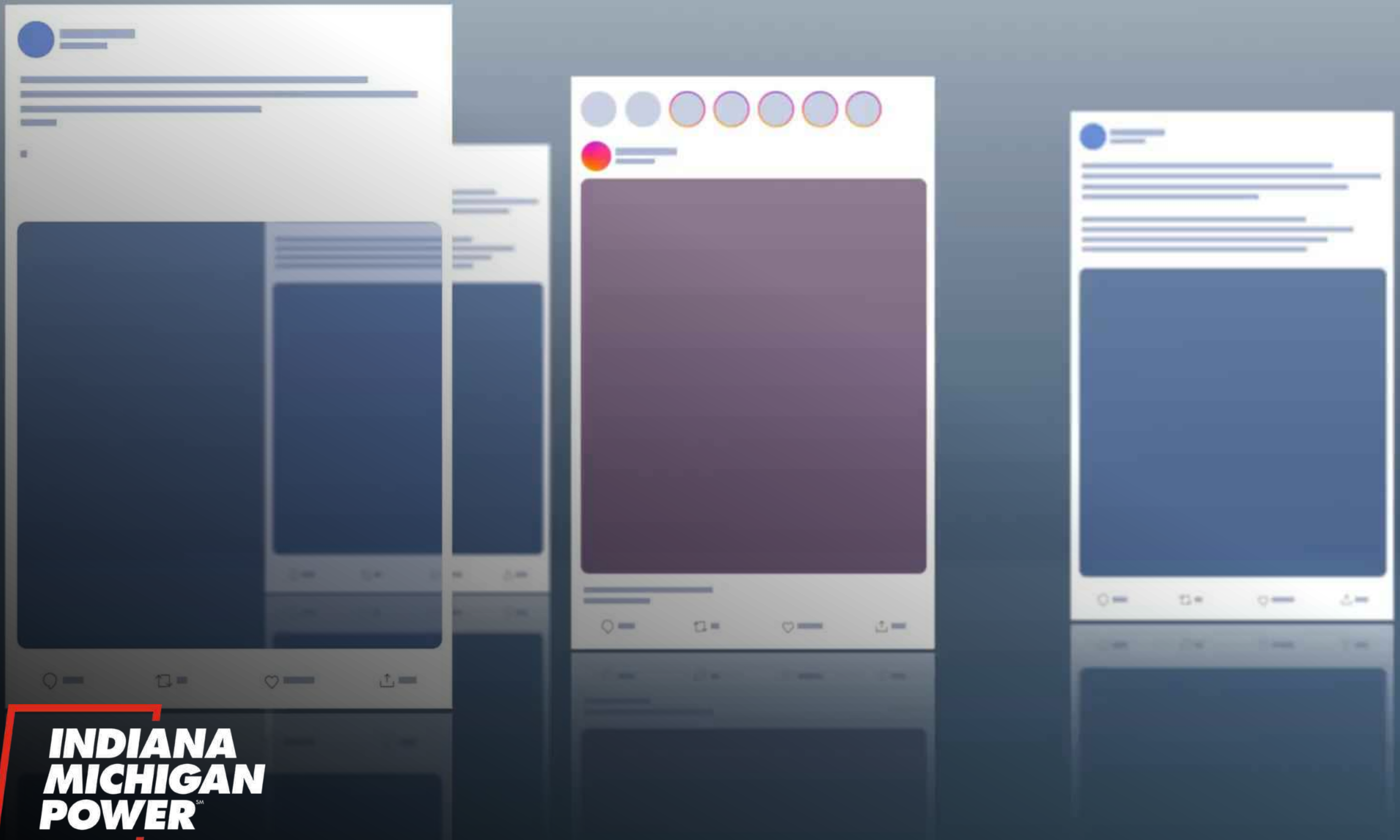
- Meeting Minutes will be posted on February 11, 2025

## Stakeholder Meeting 4: March 5, 2025

- Risk Analysis: Stochastics
- Preferred Plan

## Submit IRP: March 28, 2025

# Feedback and Discussion



INDIANA MICHIGAN POWER
An AEP Company

# Resource Modeling Parameters (Baseload Resources)

| Base Load (New Resources) | | | | | |
|---|---|---|---|---|---|
| **Resource Type** | **First Year Available** | **Annual Build Limit (MW)** | **Cumulative Build Limit through 2030 (MW)** | **Total Cumulative Build Limit Through Planning Horizon (MW)** | **Installed Cost[1] $/kW** |
| NUCLEAR SMALL MODULAR REACTOR | 2037 | 600 | N/A | 5,100 | $11,700 |
| NEW NG COMBINED CYCLE (2x1) | 2031 | 1,030 | N/A | 5,600 | $1,800 |
| NEW NG COMBINED CYCLE (1x1) | 2031 | 420 | N/A | | $2,000 |
| NEW NG COMBINED CYCLE W/CARBON CAPTURE SYSTEM (CCS) | 2035 | 380 | N/A | 3,800 | $4,300 |

| Base Load (Existing Resources) | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Resource Type** | **First Year Available** | **Last Year Available** | **Annual Build Limit (MW)** | **Cumulative Build Limit through 2030 (MW)** | **Total Cumulative Build Limit Through Planning Horizon (MW)** | **Installed Cost[1] $/kW** | **Installed Cost[1] $/MW-D** |
| EXISTING NG COMBINED CYCLE (5 YEAR) | 2028 | 2031 | 1,800 | 3,600 | 5,400 | N/A | ~~$485~~ $680 |
| EXISTING NG COMBINED CYCLE (10 YEAR) | 2028 | 2031 | | | | | |
| EXISTING NG COMBINED CYCLE (20 YEAR) | 2028 | 2031 | | | | $1,100 | N/A |

Note 1: Costs represent nominal dollars in the first year that the resource is available

# Resource Modeling Parameters (Peaking Resources)

## Peaking (New Resources)

| Resource Type | First Year Available | Annual Build Limit (MW) | Cumulative Build Limit through 2030 (MW) | Total Cumulative Build Limit Through Planning Horizon (MW) | Installed Cost[1] $/kW |
|---|---|---|---|---|---|
| NEW COMBUSTION TURBINE | 2030 | 920 | 920 | 6,670 | $1,500 |
| COMBUSTION TURBINES AERODERIVATIVE | 2031 | 330 | N/A | 1,320 | $2,020 |
| RECIPROCATING INTERNAL COMBUSTION ENGINES (RICE) | 2031 | 100 | N/A | 400 | $3,300 |

## Peaking (Existing Resources)

| Resource Type | First Year Available | Last Year Available | Annual Build Limit (MW) | Cumulative Build Limit through 2030 (MW) | Total Cumulative Build Limit Through Planning Horizon (MW) | Installed Cost[1] $/kW | Installed Cost[1] $/MW-D |
|---|---|---|---|---|---|---|---|
| EXISTING NG COMBUSTION TURBINE (5 YEAR) | 2028 | 2031 | 1,000 | 3,000 | 4,000 | N/A | ~~$320~~ $493 |
| EXISTING NG COMBUSTION TURBINE (10 YEAR) | 2028 | 2031 | | | | | |
| EXISTING NG COMBUSTION TURBINE (20 YEAR) | 2028 | 2031 | | | | ~~$540~~ $644 | N/A |

Note 1: Costs represent nominal dollars in the first year that the resource is available

# Resource Modeling Parameters (Intermittent Resources)

## Intermittent (Wind & Solar)

| Resource Type | First Year Available | Annual Build Limit (MW) | Cumulative Build Limit through 2030 (MW) | Total Cumulative Build Limit Through Planning Horizon (MW) | Installed Cost[1] $/kW | Installed Cost[1] $/MWh |
|---|---|---|---|---|---|---|
| WIND (15 YEAR) | ~~2029~~ 2028 | ~~600~~ 200 | ~~800~~ 400 | ~~3200~~ 4000 | N/A | $86 |
| WIND (30 YEAR) | 2031 | 400 | N/A | | $3,000 | N/A |
| SOLAR (15 YEAR) | 2028 | 600 | 1,200 | 4,800 | N/A | $85 |
| SOLAR (35 YEAR)[2] | 2028 | 600 | 1,200 | 4,800 | $2,500 | N/A |
| SOLAR w/STORAGE (4-HOUR) | 2028 | 600 | 750 | 1,350 | $3,100 | N/A |

## Intermittent (Storage)

| Resource Type | First Year Available | Annual Build Limit (MW) | Cumulative Build Limit through 2030 (MW) | Total Cumulative Build Limit Through Planning Horizon (MW) | Installed Cost[1] $/kW |
|---|---|---|---|---|---|
| NEW STORAGE (4-HOUR) | 2028 | 250 | 500 | 3,000 | $2,000 |
| NEW STORAGE (6-HOUR) | 2029 | 150 | 300 | 1,800 | $3,000 |
| NEW STORAGE (8-HOUR) | 2029 | 100 | 200 | 1,200 | $4,000 |
| NEW STORAGE (100-HOUR) | 2032 | 40 | N/A | 240 | $2,800 |

Note 1: Costs represent nominal dollars in the first year that the resource is available

# Preliminary PJM ELCC and FPR Forecasts

| ELCC Class | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|
| Onshore Wind | 35% | 33% | 28% | 25% | 23% | 21% | 19% | 17% | 15% |
| Offshore Wind | 61% | 56% | 47% | 44% | 38% | 37% | 33% | 27% | 20% |
| Fixed-Tilt Solar | 7% | 6% | 5% | 5% | 4% | 4% | 4% | 4% | 3% |
| Tracking Solar | 11% | 8% | 7% | 7% | 6% | 5% | 5% | 5% | 4% |
| Landfill Intermittent | 54% | 55% | 55% | 56% | 56% | 56% | 56% | 56% | 54% |
| Hydro Intermittent | 38% | 40% | 37% | 37% | 37% | 37% | 39% | 38% | 38% |
| 4-hr Storage | 56% | 52% | 55% | 51% | 49% | 42% | 42% | 40% | 38% |
| 6-hr Storage | 64% | 61% | 65% | 61% | 61% | 54% | 54% | 53% | 52% |
| 8-hr Storage | 67% | 64% | 67% | 64% | 65% | 60% | 60% | 60% | 60% |
| 10-hr Storage | 76% | 73% | 75% | 72% | 73% | 68% | 69% | 70% | 70% |
| Demand Resource | 70% | 66% | 65% | 63% | 60% | 56% | 55% | 53% | 51% |
| Nuclear | 95% | 95% | 95% | 96% | 95% | 96% | 96% | 94% | 93% |
| Coal | 84% | 84% | 84% | 85% | 85% | 86% | 86% | 83% | 79% |
| Gas Combined Cycle | 79% | 80% | 81% | 83% | 83% | 85% | 85% | 84% | 82% |
| Gas Combustion Turbine | 61% | 63% | 66% | 68% | 70% | 71% | 74% | 76% | 78% |
| Gas Combustion Turbine Dual Fuel | 79% | 79% | 80% | 80% | 81% | 82% | 83% | 83% | 83% |
| Diesel Utility | 92% | 92% | 92% | 92% | 92% | 93% | 93% | 93% | 92% |
| Steam | 74% | 73% | 74% | 75% | 74% | 75% | 76% | 74% | 73% |

https://www.pjm.com/-/media/planning/res-adeq/elcc/preliminary-elcc-class-ratings-for-period-2026-2027-through-2034-2035.ashx

| Delivery Year | Forecast Pool Requirement (% of Peak Load) |
|---|---|
| **2026/27** | 93.67% |
| **2027/28** | 92.69% |
| **2028/29** | 92.75% |
| **2029/30** | 93.47% |
| **2030/31** | 92.96% |
| **2031/32** | 92.72% |
| **2032/33** | 92.10% |
| **2033/34** | 89.99% |
| **2034/35** | 87.09% |

- I&M's forecasted capacity need is influenced by the accredited capacity PJM recognizes for I&M's resources (i.e., ELCC Class values) as well as by the load requirement PJM sets (i.e., the "FPR" or Forecast Pool Requirement)
- PJM's forecasted decline in ELCC class values for resources such as wind, solar, and storage is offset, in part, by a lower forecasted peak load requirement (i.e., a lower FPR)

# Affordability

The Affordability indicators compare the cost to customers under Base Case market scenario conditions over the short- and long-term and the Portfolio cost range when evaluated across the different market scenarios.

| Performance Indicator | Metric | Description |
|---|---|---|
| Near-term | 7-year Power Supply Cost CAGR under the Base Case (2024-2031) | • I&M measures and considers the expected Compound Annual Growth Rate (“CAGR”) of expected power supply costs for the years 2024-2031 as the metric for the short-term performance indicator<br>• A lower number is better, indicating slower growth in power supply costs |
| Long-term | Portfolio NPVRR under the Base Case (2025-2044) | • I&M measures and considers the growth in Net Present Value Revenue Requirement (power supply costs) over 20 years as the long-term metric<br>• NPVRR represents total long-term cost paid by I&M related to power supply. This includes plant O&M costs, fuel costs, environmental costs, net purchases and sales of energy and capacity, property and income taxes, and the return on capital<br>• A lower number is better, indicating lower costs to supply customers with power |
| Portfolio Resilience | High Minus Low Scenario Range 20-yr NPVRR (2025-2044) | • I&M measures and considers the range of 20-yr NPVRR reported by each portfolio across all PJM market scenarios. This metric reports the difference between the highest and lowest cost scenarios reported by the candidate portfolio on an NPVRR<br>• A lower number is better, indicating a tighter grouping of expected customer costs across a wide range of long-term market conditions |

# Reliability

The Reliability indicators compare the amount of excess reserves and the reliance on market resources to serve customers across candidate portfolios.

| Performance Indicator | Metric | Description |
|---|---|---|
| Planning Reserves | Reserve Margin % | • I&M measures and considers the average amount of firm capacity in each candidate portfolio over 10 and 20 years<br>• A higher number is better, indicating more reserves are available to meet PJM requirements |
| Energy Market Risk | Portfolio Cost Range of market purchases, MWhs as % of internal Load | • I&M measures and considers the reliance of each candidate portfolio on market purchases to balance seasonal generation with customer load<br>• The metric reports the NPV of the cost of market purchases and the average MWhs as a % of internal load over 10 and 20 years<br>• A lower number indicates less reliance on the market to meet customer needs |
| | Portfolio Revenue Range of market sales, MWhs as % of internal Load | • I&M measures and considers the reliance of each candidate portfolio on market sales to balance seasonal generation with customer load<br>• The metric reports the NPV of the cost of market sales and the average MWhs as a % of internal load over 10 and 20 years<br>• A lower number indicates less reliance on the market to meet customer needs |

# Resiliency

The Resiliency indicators compare the amount of dispatchable capacity in the fleet and the technology diversity for capacity and energy of the Indiana generating mix across candidate portfolios.

| Performance Indicator | Metric | Description |
|---|---|---|
| Resource Diversity | Percent Change of the Capacity and Energy Diversity Index in 2034 and 2044 | • I&M measures and considers the capacity and energy diversity of new technologies added to its portfolio when comparing candidate portfolios<br>• The metric will use the Shannon-Weiner Index to measure the number of different technologies and their respective contribution to the portfolio totals for both capacity and energy diversity for each Portfolio. A percent change from 2025 is calculated in year 2034 and 2044<br>• A higher number is better. A portfolio that includes diverse resources for both capacity and energy delivery mitigates customers' performance risk when conditions for that technology are unfavorable |
| Fleet Resiliency | Nameplate MW of dispatchable units in 2034 and 2044 | • I&M measures and considers the average amount of dispatchable units added to the portfolio over 10 and 20 years<br>• The metric for this indicator is the average of total Nameplate MW of dispatchable units as a percent of company peak demand<br>• A higher number is better, indicating greater ability to ramp generation up or down to react to market conditions and follow load |

# (Grid) Stability

The Grid Stability indicator compares the amount of dispatchable capacity in the fleet, and the technology diversity of the Indiana generating mix across candidate portfolios.

| Performance Indicator | Metric | Description |
|---|---|---|
| Fleet Resiliency | Nameplate MW of dispatchable units in 2034 and 2044 | • I&M measures and considers the average amount of dispatchable units added to the portfolio over 10 and 20 years<br>• The metric for this indicator is the average of total Nameplate MW of dispatchable units as a percent of company peak demand<br>• A higher number is better, indicating greater ability to ramp generation up or down to react to market conditions and follow load |

# Sustainability

I&M also considered a Sustainability indicator to compare portfolio performance towards meeting corporate sustainability targets.

| Performance Indicator | Metric | Description |
|---|---|---|
| $CO_2$, NOx, $SO_2$, Emissions | 2034 & 2044 % Change from 2005 Baseline | • I&M measures and considers the total amount of expected $CO_2$, NOx and $SO_2$ emissions of each candidate portfolio.<br>• This metric compares the forecasted emissions of candidate portfolios in 2034 and 2044 under Reference Case market conditions with actual historical emissions from the year 2005.<br>• A higher number indicates greater levels of emissions reductions have been achieved and customers are less exposed to potential future $CO_2$ costs. |

# Indiana Michigan Power Company's 2024 Indiana Integrated Resource Plan

## Stakeholder Workshop #3B

## January 27, 2025

Table of Contents

# Welcome & Introductions

*Kayla Zellers covered Slide 1.*

Kayla Zellers, Director of Resource Planning at American Electric Power Service Corporation (AEPSC), called the meeting to order at 1:00 PM on January 27, 2025. Kayla welcomed participants to Stakeholder Workshop 3B for I&M's 2024 Indiana Integrated Resource Plan and introduced Andrew Williamson, Indiana Michigan Power Company (I&M) Director of Regulatory Services.

*Andrew Williamson covered Slide 2.*

Andrew welcomed stakeholders to Stakeholder Workshop 3B. Andrew reiterated that this IRP is a collaboration between I&M and its stakeholders and that feedback, questions and comments are encouraged during this meeting and at any time during the process.

Andrew then introduced the remainder of the I&M Leadership team present at the meeting before introducing Josh Burkholder, Managing Director of Resource Planning for AEPSC.

Josh introduced the remainder of the Resource Planning Team and the Infrastructure Development Team, who would be available to answer any questions about market condition assumptions. Finally, Josh introduced 1898 & Co., a consulting firm assisting I&M with coordinating stakeholder engagement and conducting technical portfolio analysis.

Josh reminded stakeholders that this is a continuation of Stakeholder Workshop 3A and presented an overview of the meeting's contents. Eight scenarios and sensitivity results are being presented.

Josh reintroduced Kayla, who walked through the agenda for Stakeholder Workshop 3B and welcomed Brian Despard, Senior Project Manager at 1898 & Co.

*Brian Despard Covered Slides 4-5.*

Brian discussed stakeholder participation - questions would be allowed anytime during the presentation via Microsoft Teams' "Raise Hand" and "Q&A" functions. Any questions regarding the Indiana IRP can be submitted to I&MIRP@aep.com anytime. All questions and answers recorded during this meeting (or shortly after, via email) have been provided within these minutes.

Finally, Brian presented guidelines for constructive participation.

## Review of Stakeholder Meeting 3A

*Kayla Zellers covered Slide 6.*

Kayla reestablished which scenarios and sensitivities have already been discussed in Workshop 3A and provided an overview of the sensitivities being presented in Workshop 3B.

Kayla called special attention to the two additional Expanded Wind Availability Cases modeled under Base and Enhanced Environmental Regulations (EER) assumptions. These cases were added due to new information received by I&M regarding the market availability of wind. In addition to these cases, I&M analyzed cases representing small adjustments to the Base Reference Case. As such, many of the results presented during this meeting show strong similarity to the Base Reference Case. All four (4) scenarios and eleven (11) sensitivities presented in Stakeholder Workshops 3A and 3B will inform the Preferred Plan.

Kayla welcomed Mohamed Abukaram, Director of Resource Planning at AEPSC to present expansion plan modeling results.

## Expansion Plan Modeling Results

*Mohamed Abukaram covered slides 7-27.*

### ***Base Reference Case Portfolio Review***

Mohamed revisited the results of the Base Reference Case. This scenario was designed to project the optimal mix of resources to meet capacity and energy requirements under base load and commodity prices. This case is a reference for all scenarios and sensitivities for this IRP.

Mohamed reacquainted stakeholders with the nameplate capacity table for Base Reference results. The capacity table shows market purchases to fill short-term (2025-2027) capacity needs before selecting natural gas and renewable resources in 2028 to meet capacity and energy requirements. Wind, solar, and storage are also selected to provide energy and capacity value. Consistent with the cases presented in Workshop 3A, the D.C. Cook Nuclear plant was selected to be relicensed in every case presented in Workshop 3B.

### *Expanded Wind Availability (Base) Portfolio*

Mohamed reviewed the changes made in the two Expanded Wind Availability Cases. In these cases, wind availability was expanded annually and cumulatively from 2028 to 2030 due to new market intelligence gathered by I&M. The Expanded Wind Availability Portfolios had increased annual build limits for the 15-year wind resource class from 200 MW to 1,200 MW annually and a cumulative build limit increase from 400 MW to 1,200 MW. These modified assumptions were used to create a new case under Base assumptions and a new case under EER assumptions.

Mohamed presented the Expanded Wind Availability results under Base Reference Case assumptions. In this case, the maximum of 1,200 MW of wind first available in 2028 was selected. Even with this increased wind, natural gas resources were still selected to meet capacity and energy needs in the same years and amounts as in the Base Reference Case. Due to the increased wind capacity selected, less solar and no storage capacity is selected compared to the Base Reference Case.

Mohamed reintroduced stakeholders with the firm capacity and energy supply charts used to present results. For all cases, the firm capacity chart shows existing capacity provided by D.C. Cook, Rockport, hydro, and renewable assets supplemented with short-term capacity purchases to meet immediate (3-year) capacity obligations. The model also optimized the license extension of Elkhart and Mottville hydro resources, selecting these units for renewal in each case. Throughout the study period, nuclear and gas resources provide the majority of firm capacity due to their high-capacity accreditation values. Existing renewables offer smaller amounts of firm capacity due to the lower capacity accreditation value assigned by PJM for wind and solar. Results show a significant increase in total firm capacity beginning in 2034 due to capacity purchase expirations and load increases from 2034 to 2037.

The energy supply graph shows the first few years' energy being sourced mainly from D.C. Cook and the energy market. Throughout the forecast period, most of the energy needs are met by natural gas combined cycles (CCs), with a higher contribution of wind than in the Base Reference Case. On average, 30% of load is served by market purchases through 2030, which drops to 16% from 2031 onwards.

## *Expanded Wind Availability (EER) Portfolio*

In the Expanded Wind Availability (EER) Case, compared to the EER Case presented in Meeting 3A, far more wind is selected when first available in 2028. Even with this sharp increase in wind, large amounts of natural gas resources were still selected to cost-effectively meet capacity and energy needs. The substantial wind additions result in less solar and storage resources being selected in this case.

In the Expanded Wind Availability (EER) Case, 1,000 MW of wind was selected in 2028 - slightly lower than the 1,200 MW selected in 2028 in the Expanded Wind (Base) Case. This smaller selection is interpreted as the model pacing itself to not exceed a 4,000 MW cumulative build limit met by the Expanded Wind Availability (EER) Case in 2038.

The firm capacity chart for this case shows an increased contribution from wind, particularly due to the expanded wind build-out. Model results also show an increase in demand-side resources. Capacity additions from 2031 to 2034 are necessary for I&M to abide by market import limits and meet load increases from 2034 to 2037.

The energy mix chart displays a higher contribution from wind and solar additions compared to the Base Reference Case, resulting in decreased natural gas energy contribution. Wind contribution increases because of the increased wind build in this case due to the expanded wind availability.

## *Base with High Load Portfolio*

Mohamed introduced the Base with High Load and Base with Low Load Sensitivities, driven by changes in load under base commodity prices. No change in hyperscaler load was assumed for these sensitivities.

Increased capacity and load requirements under base commodity price assumptions drive the Base with High Load Sensitivity. In this case, the annual wind build-out limit is 200 MW in 2028, the same as the Base Reference Case, resulting in more solar and wind being selected to meet the growing energy needs compared to the Base Reference Case

Increased combustion turbine (CT) capacity was selected in this case compared to the Base Reference Case because of the increased capacity obligation that comes with the higher load assumption.

The firm capacity chart is similar to the Base Reference Case, with most of the capacity provided by gas resources. Additionally, 700 MW of nameplate solar was selected for its energy contribution, but these solar additions do not provide a significant amount of accredited capacity due to low ELCC value. However, solar does provide some energy contribution.

The energy supply chart shows a less proportional contribution from natural gas resources than in the Base Reference Case. Higher contributions from wind and solar resources are shown due to the increased build-out of renewables needed to meet the additional load.

### *Base with Low Load Portfolio*

The Base with Low Load Portfolio aimed to form a portfolio of resources to meet lower capacity and energy needs, using base commodity price assumptions.

In this case, no solar or storage capacity was selected, and less CC capacity was selected compared to the Base Reference Case due to the lower energy needs and capacity obligations. More wind resources were selected relative to the Base Reference Case to offset these decreased needs.

The capacity and energy charts show that contributions from nuclear and gas resources account for most of I&M's load and capacity obligation requirements.

### *High Technology Cost Portfolio*

Mohamed presented drivers for the High Technology Cost Sensitivity, designed to evaluate the impacts of increased technology costs under base load and commodity prices. Cost increases assumed in this sensitivity are summarized in the table on Slide 18. Wind, solar, nuclear, and storage cost percent increases are based on cost spreads observed between the moderate and conservative scenarios in the 2024 NREL Annual Technology Baseline publication. Natural gas CC and CT cost increases are reflective of I&M market intelligence.

For the High Technology Cost Sensitivity, the resource selection is the same as the Base Reference Case because large capacity and energy needs require the selection of CCs, CTs, and wind regardless of the higher costs. Solar and storage are also selected in the same manner as the Base Reference Case.

Firm capacity and energy supply are unchanged from the Base Reference Case, so the two graphs on slide 20 match those presented for the Base Reference Portfolio.

### *Rockport Unit 1 Retires 2025 Portfolio*

Two cases were run evaluating the early retirement of Rockport Unit 1. The Rockport Unit 1 Retires 2025 Sensitivity aims to evaluate the most optimal solution under base assumptions with Rockport Unit 1 retiring on May 31, 2025. The only change from the Base Reference Case for this sensitivity was the addition of short-term capacity purchased in 2025 through 2027 to replace Rockport Unit 1 capacity lost through early retirement.

### *Rockport Unit 1 Retires 2026 Portfolio*

This case evaluates the optimal solution under base assumptions, with the retirement of Rockport Unit 1 by May 31, 2026, a year later than the previous sensitivity.

Model results show additional short-term capacity purchased in 2026 and 2027 to fill the capacity void left by the Rockport Unit 1 retirement.

The removal of Rockport capacity for 2026 and 2027 is offset by increasing capacity purchases, as shown on the firm capacity chart.

### *Exit OVEC ICPA in 2030 Portfolio*

The Exit Ohio Valley Electric Corporation (OVEC) Intercompany Power Agreement (ICPA) in 2030 Sensitivity evaluates the most economical solution under base assumptions, with the OVEC units terminating operation at the end of 2030.

Compared to the Base Reference Case, this portfolio shows changes in timing to existing CT and CC selections. These selections converge with the Base Reference Case by 2031.

This case also has increased demand-side build-out to support the deficit caused by exiting the OVEC ICPA.

## Q&A Related to Expansion Plan Modeling Results

**Question 1**

1. You mentioned that there is not a lot of variation in the resources being added and operated across some of these scenarios, including the different load cases. This is not surprising because the difference between the low and high load forecasts is 10,000 GWh by 2030, and the lowest increase in energy requirements from today's energy requirements to 2030 is 30,000 GWh over and is above about the 20,000 that you have right now so even in the low load forecast there is quite a jump. I wonder if

another sensitivity needs to be run for the purpose of understanding the rate impacts of hyperscaler loads to do a case that's much closer to the level of energy requirements that you have right now. I say that in part because of the activity in the stock market today related to the announcement from a Chinese AI model that uses significantly less energy than USA models appear to. I'm wondering if you can talk through how those load forecasts relate to assumptions about the energy that the customers will need as opposed to the energy that they have contracted for.

a. I&M does not anticipate the recent developments surrounding AI (DeepSeek) in China as having a material impact on our contracted data center load or energy assumptions. The projects associated with I&M's hyperscale activity are at the forefront of this infrastructure development and are anticipated to support both cloud and AI services. What is more, hyperscale customers in other AEP jurisdictions have demonstrated the ability to switch from cloud to AI and back again with minimal interruption to service. Hyperscale customers have also re-emphasized on recent earnings calls that there will be a continued rapid increase in the need for computing power, regardless of whether that's being used for cloud or AI services.

## Results Comparison and Draft Portfolio Performance Indicators

*Kayla Zellers covered Slides 28-33.*

Kayla discussed the results comparison slides, which have the same information as the individual case slides for firm capacity, energy generation, and resource selection, but displayed as a comparison between cases. Kayla stated that, similar to meeting 3A, I&M wanted to display a comparison of these metrics for stakeholder awareness.

The firm capacity comparison chart shows a more than 100% increase in capacity between 2025 and 2034, the first ten years of the study period. Notable differences from the Base Reference Case capacity position can be observed over time in the Expanded Wind Availability (EER) Case, Base with High Load Case, and Base with Low Load Case. The Rockport Retirement and OVEC Exit Cases closely match Base Reference Case. Key observations include the similarity of all cases in 2025, the reliance on natural gas in 2034 and 2044, and the comparatively higher amounts of accredited wind capacity in the Wind Availability Cases.

The generation mix chart, similar to firm capacity chart, shows the most variation over the study period in the Expanded Wind Availability (EER) Case, with other cases, such as Rockport Retirement, High Technology Cost and OVEC Cases showing little difference from the Base Reference Case. Key observations include the similarity of all cases in 2025, increased energy contribution from natural gas resources in 2034 and 2044, and a substantially higher amount of wind and solar energy in the Expanded Wind Availability (EER) Case compared to Base Reference Case.

The resource selection table on slide 30 shows significant similarities in many cases, with the primary exception being in the Expanded Wind Availability (EER) Case. This case shows similar capacity additions to the EER case presented in Stakeholder Meeting 3A. Another key observation is the similarity of Rockport Unit 1 Retirement and Exit OVEC ICPA Cases to the Base Reference Case.

Kayla shifted the discussion to portfolio performance indicators on slide 31. Kayla noted that these metrics have not changed since they were presented during Stakeholder Meeting 3A. Kayla walked through each of the IURC Five Pillars and the criteria representing each in the IRP case evaluation.

Reliability is measured by market purchases and sales, average target reserve margin over 10 and 20-year periods, and resource diversity. Affordability is measured on 20-year Net Present Value of Revenue Requirements (NPVRR) and 7-year Compound Annual Growth Rate (CAGR) of Power Supply Costs. Portfolios for which risk analysis is conducted will carry a third component of affordability to be presented in Stakeholder Meeting 4: portfolio resilience will be shown as the difference between high and low NPVRR for each case. Resiliency is measured by resource diversity and fleet resiliency, represented by the percentage of dispatchable capacity available to serve peak load over 10- and 20-year intervals. Grid Stability is also measured by fleet resiliency. Finally, Environmental Sustainability is measured by the percent reduction of specific emissions compared to 2005 baseline levels, presented for 2034 and 2044.

Kayla walked through the draft portfolio performance of the presented cases on slides 32 and 33, reiterating that certain cases' results are very similar to the Base Reference Case. Key observations for the Affordability pillar included relatively high CAGRs for the Expanded Wind Availability (EER) and High Technology Cost Cases and slightly higher

NPVRRs for Rockport Unit 1 Retirement and OVEC Cases due to increased market purchases. The Base with High Load and Base with Low Load Cases show the highest and lowest NPVRRs, respectively, while Expanded Wind Availability (EER) shows a higher NPVRR to the Base Reference Case, along with a higher CAGR.

Evaluation under the Environmental Sustainability pillar showed similar results for all cases, as the energy generation mix differed little between cases. $CO_2$ emissions differ slightly as a function of renewables selected per portfolio, resulting in cases such as Expanded Wind Availability (EER) showing a greater decrease in emissions. Finally, all portfolios perform well under NOx and $SO_2$ standards.

On slide 33, the Reliability metrics show similar market sales for each portfolio but differences in market purchases. The Wind Availability (Base) Case carries lower market purchase risk than Base Reference Case, while the Exit OVEC ICPA Sensitivity results in greater need for market purchases. Kayla shared I&M's observation that there is a direct correlation between the energy market risk associated with sales and the amount of renewable capacity selected in each portfolio. This observation is reflected in elevated market sales for the Expanded Wind Availability (EER) Case. The planning reserve metric under reliability aims to meet the Reserve Margin targets of -3% and -5.5% for 10- and 20-year averages, respectively. The Base Reference Case shows the lowest average planning reserves, while other cases show little variation for 10-year and 20-year outlooks.

The resource diversity metric for Reliability and Resiliency shows a 10% and 20% change from the 2025 diversity indexes. All cases show an improvement in energy and capacity diversity, with these indexes most impacted by adding renewables. The Expanded Wind Availability (EER) Case shows the greatest increase in energy diversity - over 300% in 20 years.

Finally, the Grid Stability and Resiliency metrics show significant dispatchable capacity due to the relicensing of D.C. Cook and the selection of natural gas resources in all cases. For the first 10 years, Expanded Wind Availability (EER) has the highest dispatchable capacity percentage due to incremental natural gas selections. For the 20-year evaluation, Base, Base with High Load, Base with Low Load, and Exit OVEC Cases have the highest dispatchable capacity percentage value, with the lowest value across all portfolios being 92%. Although the Expanded Wind Availability (EER) Case had the lowest dispatchable capacity percentage in the 20-year period, 92% of dispatchable resources compared to peak demand remains a good resiliency value.

## Q&A Related to Results Comparison and Draft Portfolio Performance Indicators

**Questions 2-4**

2. If new load growth customers demand higher percentages of no-carbon energy and capacity, how would you adjust your buildout scenarios without reducing the demand that exists already in your area from various entities for that kind of power and capacity?

    a. I&M ran two cases called the Low Carbon Cases that address exactly your point. Results for these cases were presented in Stakeholder Meeting 3A. I would recommend that you look at the build-out plans associated with those two sensitivities. The Stakeholder Meeting 3A presentation is posted on the I&M Indiana Resource Planning Portal along with the meeting minutes associated with Stakeholder Meeting 3A. If there is any additional discussion or questions you have about the resource build-out plan, do not hesitate to reach out. Our goal as we evaluate all the various model runs and start working towards a Preferred Portfolio is to develop a resource plan that would balance the various needs of our customers and stakeholders, whether it be environmental requirements, energy policies, or our I&M goals around balancing this transition to a clean energy future. To the extent any of I&M' customers would have an interest in further developing or expanding clean energy resources, there are opportunities to do that outside of I&M. There may also be opportunities for us to partner with our customers on low carbon options in a way that can deliver additional resource benefits that help offset the costs of those resources to make them economic for the entire customer base. So, it is certainly something that's front of mind for us. We are always happy and willing to work with our customers on evaluating low carbon opportunities.

3. Do industrial and hyperscaler customers particularly have the ability to obtain resources outside of I&M that would lower your load growth as well?

    a. Yes, as the resources relate to environmental attributes including renewable energy credits. It is pretty common in the marketplace for large industrial commercial customers to enter into what's called virtual PPAs where essentially, they enter into an agreement with a developer, or owner of a generation resource to acquire the clean or renewable attributes off that facility. It does not change the service that they're receiving from I&M, but it is a way for customers to acquire additional renewable attributes beyond what I&M's service and resources are able to provide.

4. On Slide 32, where a percent decrease in the cost of power supply was presented, is that inclusive of existing generation resources that are in operation today?
    a. What you are referencing is the compound annual growth rate under the affordability pillar. Yes, that includes our existing generation resources that are in operation today. It includes not only existing generation resources but also all the new resources that are selected as part of the build-out plan.

## Remaining Modeling and Next Steps

*Kayla Zellers covered Slide 34.*

Kayla discussed the remaining timeline for the Indiana IRP process. The next stakeholder workshop, Meeting 4, is to be held on March 5, 2025 and will cover stochastic risk analysis and Preferred Portfolio selection. I&M will publish its 2024 Indiana IRP no later than March 28, 2025. Kayla invited Andrew Williamson to provide further remarks.

Andrew discussed initial considerations for Preferred Portfolio selection, including the impact of modeling results and stakeholder feedback. Andrew mentioned I&M's specific attention to the Expanded Wind Availability (EER) Case due to its leveraging of near-term wind resource opportunities and other favorable attributes to support IURC's Five Pillars. Andrew also discussed I&M's consideration of PJM interconnection rights and the value added to the re-development of existing resource sites.

Andrew also provided that I&M holds a strong interest in the use of Small Modular Reactor (SMR) technology in the Preferred Portfolio, referring to an application that AEP submitted seeking a grant from the United States Department of Energy to support permitting to reduce project costs and support the development of SMR, potentially on what is currently the Rockport Coal Plant site. Several I&M customers have expressed an interest in SMR technology, and the Indiana State Legislature is actively considering bills that would support SMR development.

## Q&A Related to Remaining Modeling and Next Steps

**Question 5**

5. In the modeling results, my interpretation is that none of them select SMRs as a cost-effective part of your portfolio for at least the next 20 years. Do I have that correct?
    a. The Low Carbon Sensitivities selected SMRs. So, in a scenario where you place value upon achieving a certain amount of low carbon generation for your portfolio, an SMR is selected. That is based on our assumptions around resource costs. As we consider the potential for an SMR project in the future, we are certainly going to take steps to gain as much support as we can from all areas to reduce that cost and make a SMR as economical as possible.

# Open Discussion

I&M staff thanked stakeholders for their participation. Any additional questions or feedback can be submitted to the IRP Email address at I&MIRP@aep.com. Staff fielded all remaining stakeholder questions and adjourned the meeting at 2:14 PM.

Appendix 4, Exhibit E: Workshop #4 March 5, 2025

Meeting Presentation

Meeting Minutes

Indiana Michigan Power Company

# INDIANA IRP STAKEHOLDER MEETING #4

March 5, 2025

INDIANA MICHIGAN POWER

An AEP Company

# Welcome & Introductions

## I&M Leadership Team

David Lucas | Vice President, Regulatory and Finance

Andrew Williamson | Director, Regulatory Services

Ed Locigno | Regulatory Analysis & Case Manager

Regiana Sistevaris | Manager, Regulatory Services

Jon Walter | Regulatory Innovations Manager

Austin DeNeff| Regulatory Consultant Senior

## I&M Resource Planning

Kayla Zellers | Director, Resource Planning

Mohamed Abukaram | Director, Resource Planning

Mark Sklar-Chik | Staff Analyst, Resource Planning

## 1898 & Co.

Brian Despard| Senior Project Manager

## I&M Infrastructure Development

Tim Gaul | Director, Regulated Infrastructure Development

Justin Dehan | Manager, Regulated Infrastructure Development

## I&M Load Forecasting

Trenton Feasel | Manager, Economic Forecasting

# Agenda

| Time (EST) | Agenda Topic | Lead |
|---|---|---|
| *1:00-1:05* | **Welcome & Introductions** | **Andrew Williamson<br>Kayla Zellers<br>Brian Despard** |
| *1:05-1:15* | **IRP Framework and Journey to Preferred Portfolio** | **Kayla Zellers** |
| *1:15-1:30* | **Candidate Portfolio Review** | **Kayla Zellers** |
| *1:30-1:45* | **Risk Analysis** | **Mohamed Abukaram** |
| *1:45-2:00* | **Preferred Portfolio** | **Andrew Williamson** |
| *2:00-2:15* | **Results Comparison and Portfolio Performance Indicators** | **Kayla Zellers<br>Mohamed Abukaram** |
| *2:15-2:30* | **Short-Term Action Plan** | **Andrew Williamson** |
| *2:30-3:00* | **Open Discussion**<br>• Feedback From Stakeholders | **Andrew Williamson** |

# Participation

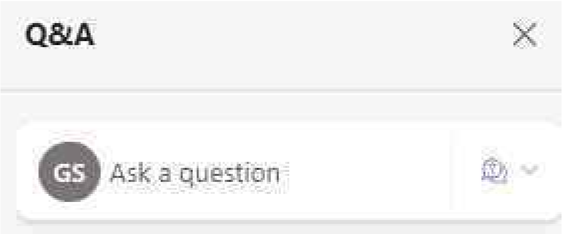
Participants joining today's meeting will be in a "listen-only" mode. Please use the "Raise" function to be recognized and unmuted.

During the presentation, please enter questions at any time into the Teams Q&A feature. Questions will be addressed after each section. At the end of the presentation, we will open up the floor for additional questions, thoughts,  ideas, and suggestions.

All questions and answers will be logged and provided on the IRP website.  Any questions not answered during the meeting will be answered after the meeting and provided in the Q&A log posted to the IRP website.

Questions, thoughts, ideas, and suggestion related to Stakeholder Meeting 4 can be provided to I&MIRP@aep.com following this meeting.


Click the Q&A feature at the top of the Teams screen



# Guidelines

- Please focus questions, thoughts, ideas, and suggestions to the IRP process and the content being discussed in this meeting. Time will be taken during this meeting to respond to questions.
- Please respect other participants and their views by not addressing other participants directly and not commenting on the views expressed by others.
- This meeting will not be recorded or transcribed.
- Any further questions or comments can be provided to I&MIRP@aep.com.

# 2024 IRP Process

## Overview of 2024 IRP Process

Set Objectives & Performance Criteria

Provide Load and RFP based Supply-side assumptions

Provide Demand-side Assumptions

Develop Supply-side Assumptions

Model Market Scenarios

Develop Optimal Resource Portfolios

Populate Portfolio Performance Indicators

Evaluate Optimal Resource Portfolios

Identify Preferred Portfolio for 2024 IRP

Develop Short-term Action Plan

IRP Stakeholders

Provide Feedback on IRP Inputs & Planning

## 2024 IRP Analysis Steps

1. Define IRP Objectives Aligned to Customer Needs
2. Collect Modeling Inputs and Key Assumptions
3. Define and Optimize Resource Portfolios under multiple market scenarios, load, and technology cost cases and sensitivities
4. Perform Scenario-Based Risk Analysis on I&M Candidate Portfolios
5. Compare Results & Identify the Preferred Portfolio

# Stakeholder Engagement Timeline

June | July | Aug | Sept | Oct | Nov | Dec | Jan | Feb | Mar

**June Technical Planning**

Technical Conferences held with key stakeholders with IRP Plexos licenses for modeling application

**June 27 Stakeholder Meeting 1**

- IRP Objectives
- Assumptions
- Estimated Resource Needs
- Scenarios
- Proposed Portfolio Metrics

**August 8 Hyperscale Customers Conference**

- Like Stakeholder Meeting 1 with focused group

**September 9 Technical Conference**

- More detailed review of assumptions
- Demand-Side Management assumptions
- Coordination of modeling data release

**September 24 Stakeholder Meeting 2**

- Review stakeholder feedback
- New resource parameters
- Key modeling assumptions
- Planned Scenarios and Sensitivities

**December 18 Stakeholder Meeting 3A**

- Review stakeholder feedback
- Updates to data and assumptions
- Modeling results to-date
- Preliminary portfolio metrics

**January 27 Stakeholder Meeting 3B**

- Review stakeholder feedback
- Remaining modeling results
- Remaining portfolio metrics

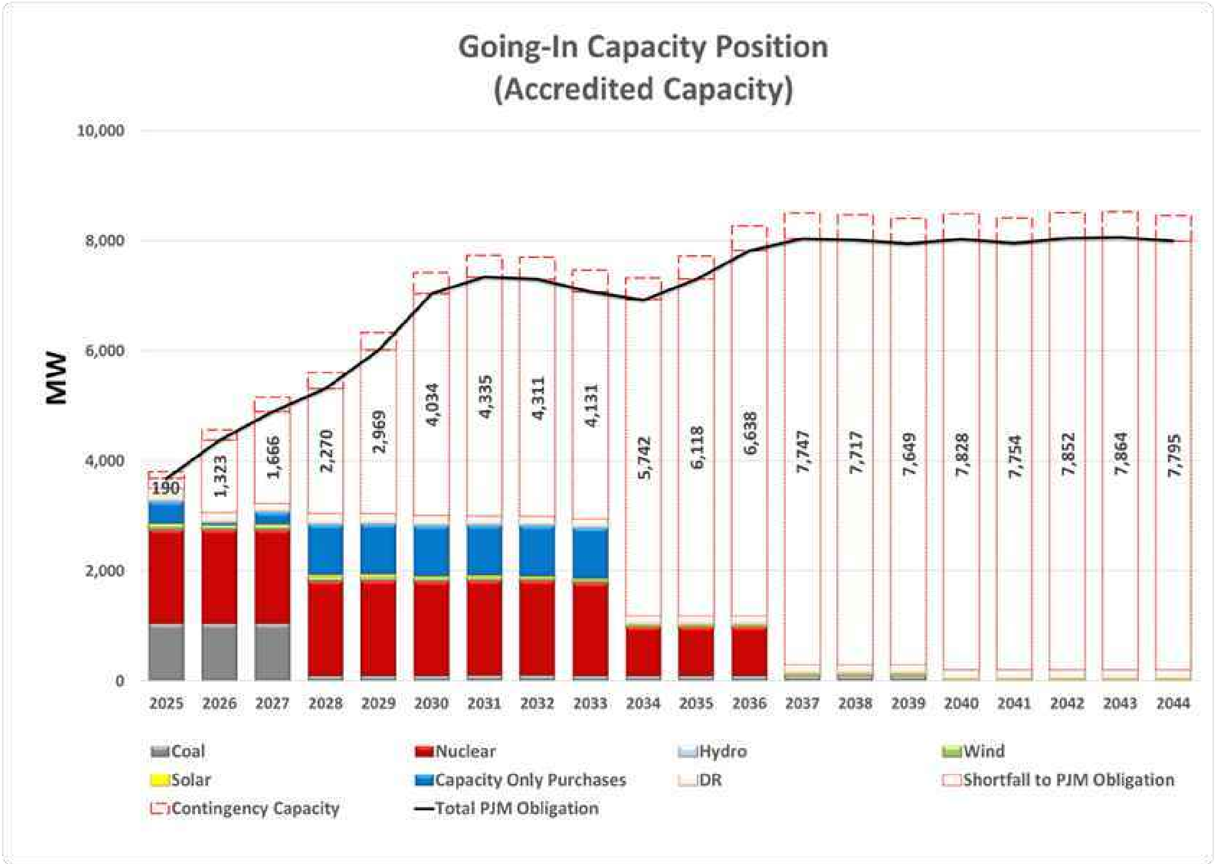
**March 5 Stakeholder Meeting 4**

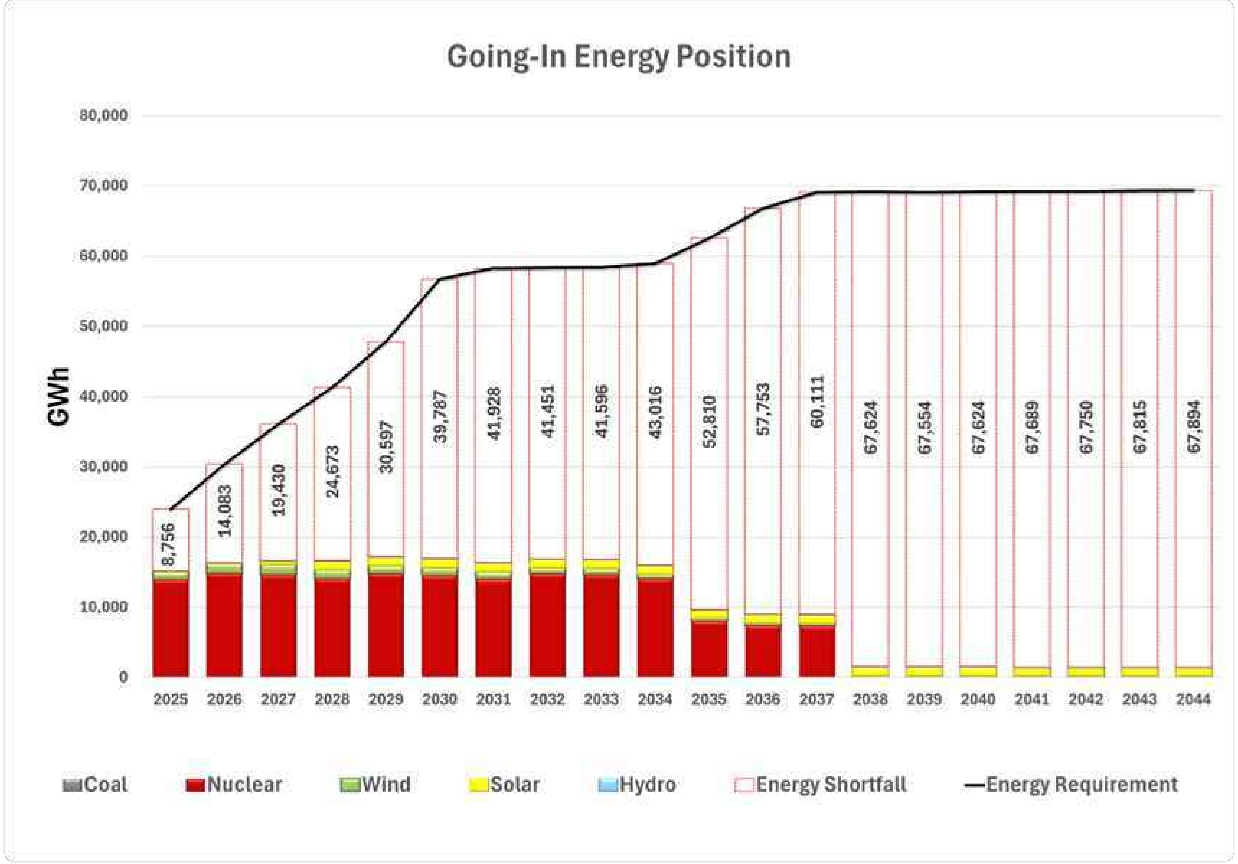
- Review Stakeholder feedback
- Risk Analysis
- Preferred Plan
- Review IRP

**March 28 I&M Submits 2024 IRP**

★ Technical modeling office hours

# Capacity and Energy Needs Assessment



# Portfolios Modeled

| Scenario | Stakeholder Meeting 3A or 3B |
|---|---|
| Base Reference | 3A |
| High Economic Growth | 3A |
| Low Economic Growth | 3A |
| Enhanced Environmental Regulations (EER) | 3A |

| Sensitivities | Stakeholder Meeting 3A or 3B |
|---|---|
| Base under EPA Section 111(b)(d) Requirements | 3A |
| Low Carbon: Transition to Objective | 3A |
| Low Carbon: Expanded Build Limits | 3A |
| Base with High IN Load | 3B |
| Base with Low IN Load | 3B |
| Rockport Unit 1 Retires 2025 | 3B |
| Rockport Unit 1 Retires 2026 | 3B |
| Exit OVEC ICPA in 2030 | 3B |
| High Technology Cost | 3B |
| Expanded Wind Availability (Base) | 3B |
| Expanded Wind Availability (EER) | 3B |

# Candidate Portfolio Selection

| Pillar | Affordability | | | Reliability | | | Reliability/ Resiliency | Grid Stability Resiliency | Environmental Sustainability | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| ***Performance Indicators and Metrics*** | ***Short Term*** *7-yr Rate CAGR* Power Supply $/MWh | ***Long Term*** *Supply Portfolio NPVRR Power Supply Costs* | ***Portfolio Resilience:*** *High Minus Low Scenario Range, Portfolio NPVRR* | ***Energy Market Risk*** *Purchases* | ***Energy Market Risk*** *Sales* | ***Planning Reserves*** *% Reserve Margin* | ***Resource Diversity*** | ***Fleet Resiliency:*** *Dispatchable Capacity* | ***Emissions Analysis:*** *% Change from 2005 Baseline* | | |
| Year Ref. | 2024-2031 | 2025-2044 | 2025-2044 | 10 years \| 20 years | 10 years \| 20 years | 10 years \| 20 years | 10 years \| 20 years | 10 years \| 20 years | 2034 \| 2044 | | |
| Units | % | $B | $B | NPV of Market Purchases & MWhs % of Total Demand | NPV of Market Sales & MWhs % of Total Demand | Average of Annual PRM % | Portfolio Index Percent Change from 2025 | Dispatchable Nameplate MW/ % of Company Peak Demand | % Change $CO_2$ | % Change NOx | % Change $SO_2$ |
| **Base Reference** | -0.5% | $32.0 | [to be developed] | 10 Years: $2.6B (27%)<br>20 Years: $4.3B (22%) | 10 Years: $0.0B (0.1%)<br>20 Years: $0.1B (0.3%) | 10 Years: -0.7%<br>20 Years: -3.4% | Capacity: 31% \| 19%<br>Energy: 173% \| 139% | 10 Years: 90%<br>20 Years: 97% | 2034: -39%<br>2044: -24% | 2034: -94%<br>2044: -93% | 2034: -100%<br>2044: -100% |
| **Low Carbon: Transition** | 1.3% | $39.9 | [to be developed] | 10 Years: $2.7B (27%)<br>20 Years: $4.1B (20%) | 10 Years: $0.2B (1.6%)<br>20 Years: $1.7B (7.7%) | 10 Years: 2.0%<br>20 Years: 0.5% | Capacity: 53% \| 54%<br>Energy: 302% \| 304% | 10 Years: 91%<br>20 Years: 95% | 2034: -65%<br>2044: -65% | 2034: -96%<br>2044: -96% | 2034: -100%<br>2044: -100% |
| **Expanded Wind Availability (EER)** | 0.5% | $32.8 | [to be developed] | 10 Years: $3.1B (31%)<br>20 Years: $5.4B (27%) | 10 Years: $0.5B (3.5%)<br>20 Years: $1.3B (5.2%) | 10 Years: 5.1%<br>20 Years: -0.6% | Capacity: 31% \| 34%<br>Energy: 296% \| 318% | 10 Years: 92%<br>20 Years: 92% | 2034: -56%<br>2044: -55% | 2034: -95%<br>2044: -95% | 2034: -100%<br>2044: -100% |

**Base Reference**

Functions as comparison point for other Candidate Portfolios

**Low Carbon: Transition**

Resource Diversity ✓

Environmental Sustainability ✓

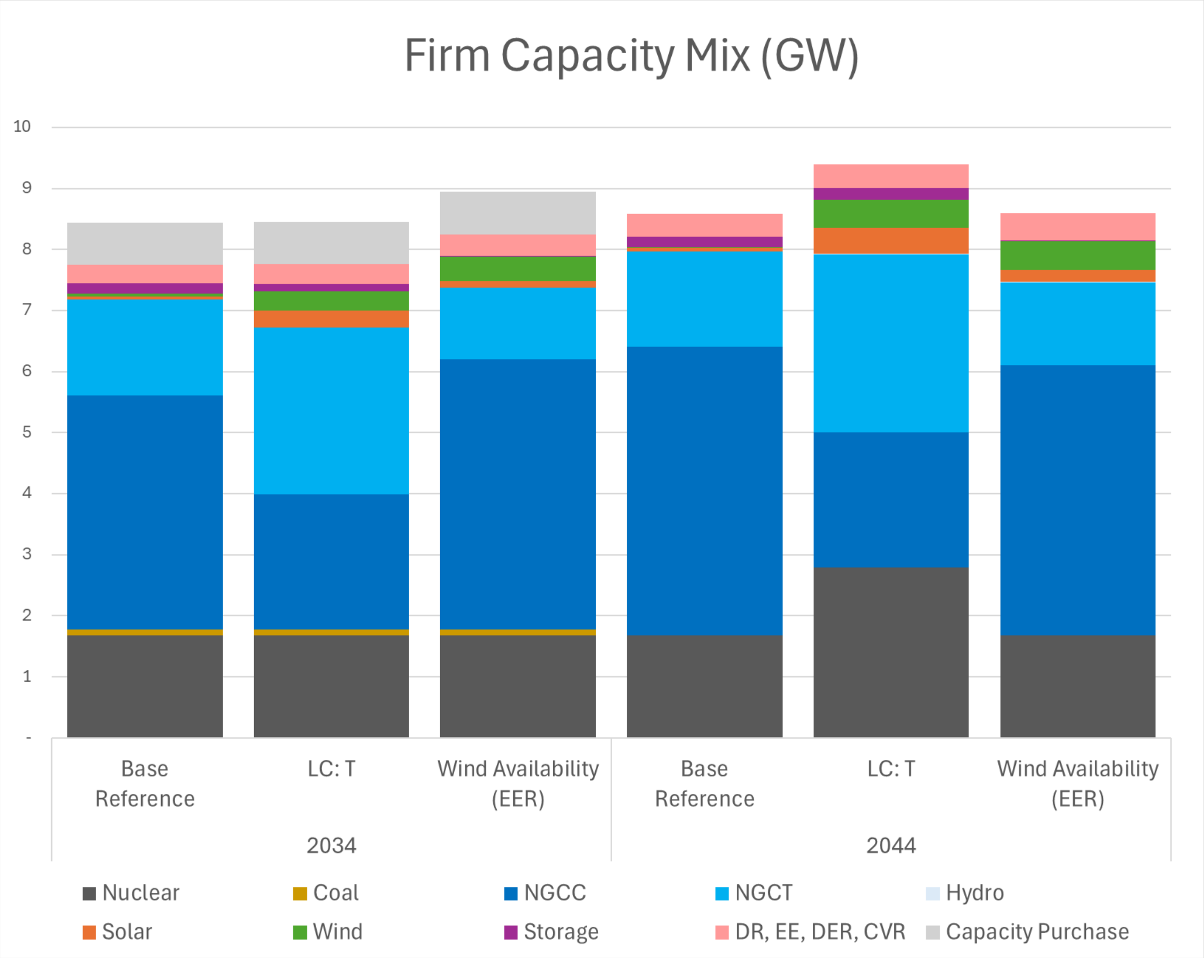
**Expanded Wind Availability (EER)**

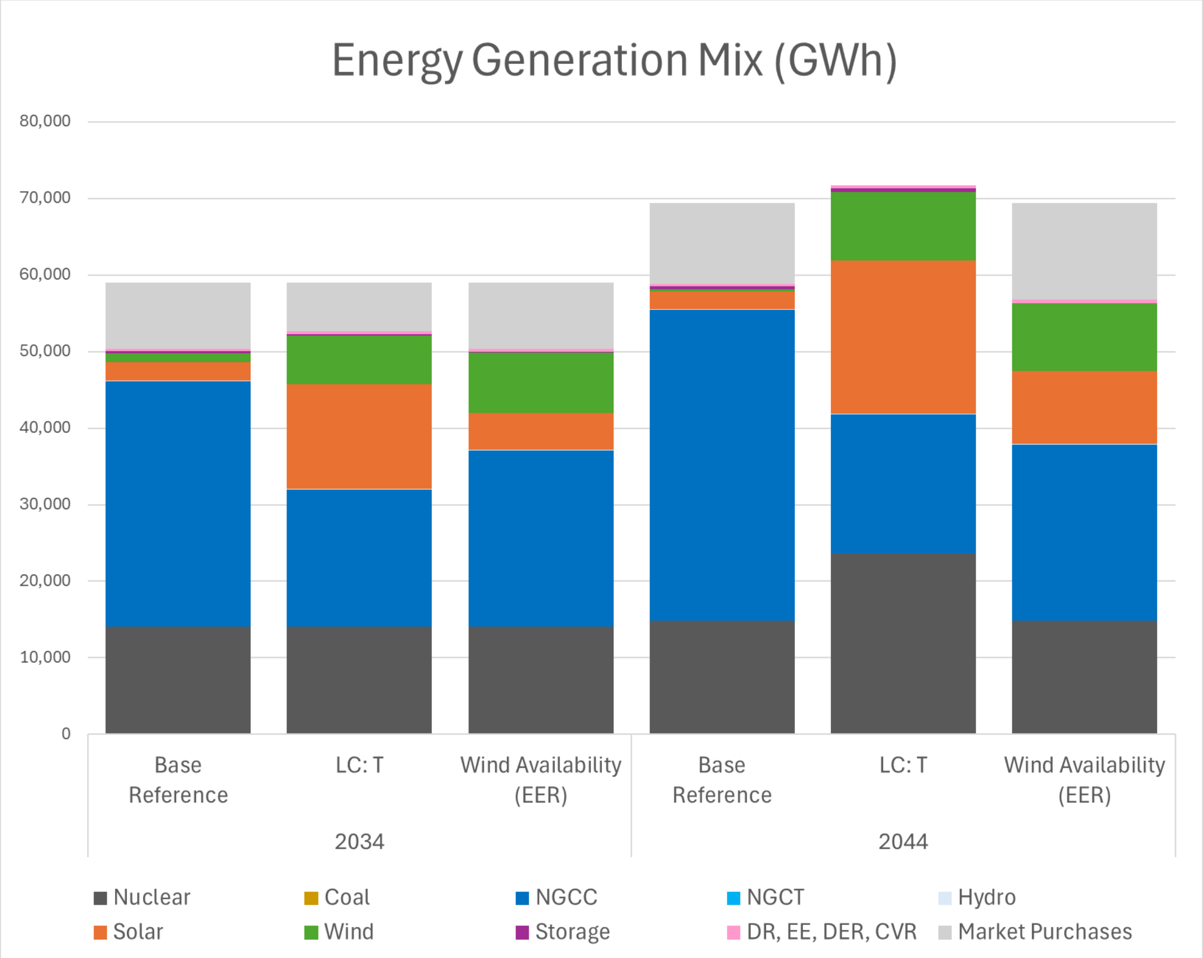
Affordability ✓

Resource Diversity ✓

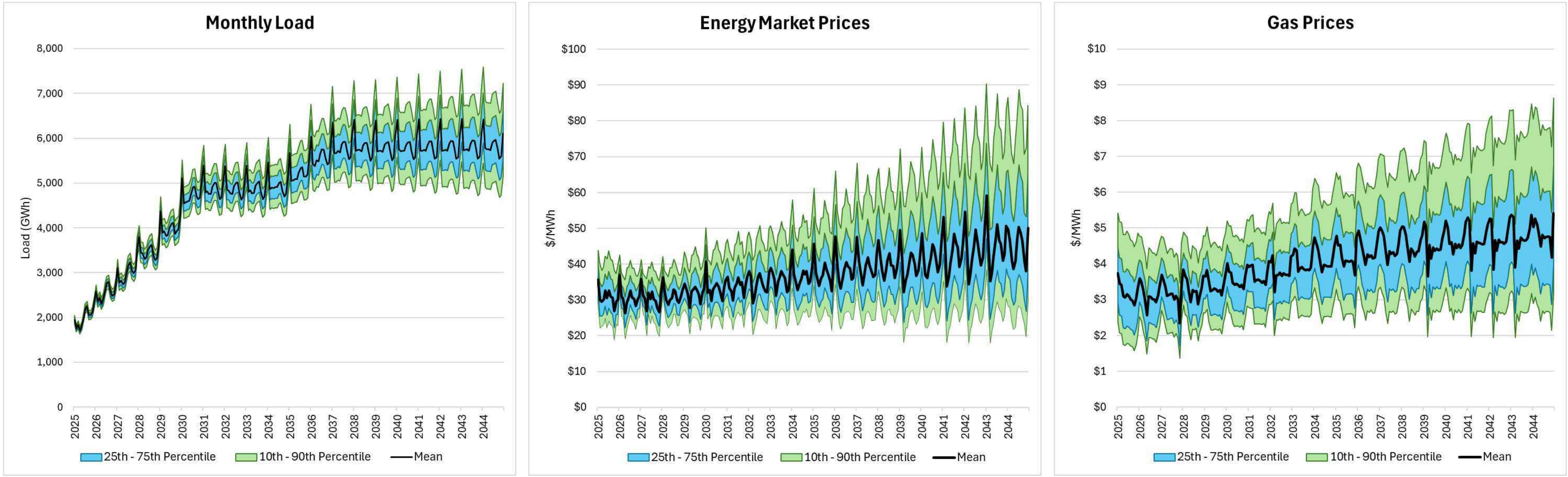
Environmental Sustainability ✓

# Candidate Portfolio Comparison



# Risk Analysis Method and Assumptions



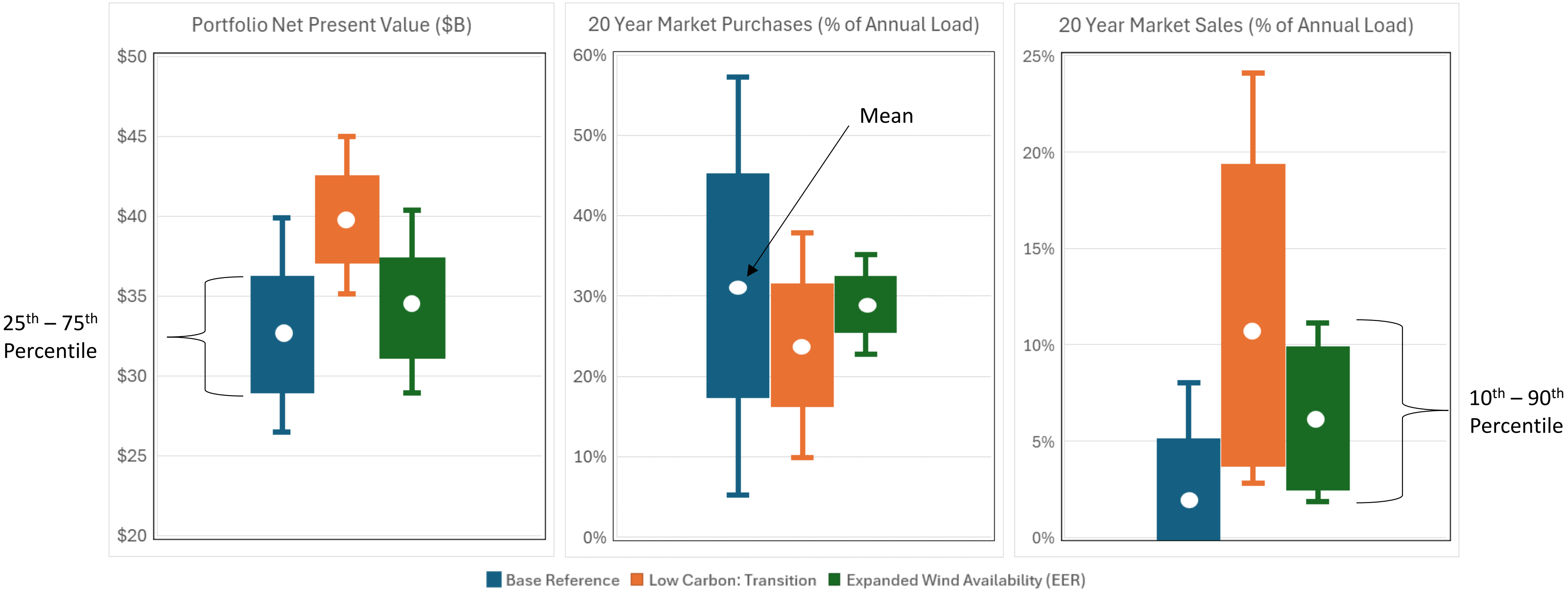

Methodology:

- Introduced uncertainty through Monte Carlo simulation with 100 correlated samples for load, market prices, and gas prices.
- Applied appropriate probability distributions and covariance structures to capture uncertainties and interdependencies among load, market prices, and gas prices.

Observations

- Monthly load and market price uncertainty increases significantly in the later half of the planning horizon.
- Gas prices exhibit moderate growth with periodic fluctuations. However, uncertainty increases after 2035, reflecting greater price unpredictability in the long term.

# Risk Analysis Results




Expanded Wind Availability (EER) and Base Reference case have similar variability. The Low Carbon: Transition case has the least amount of variability but highest average net present value.

Expanded Wind Availability (EER) has the lowest variability due to the gas capacity factor assumption which restricts gas generation during favorable economic conditions.

Low Carbon: Transition has the highest variability due to higher amounts of renewable resources and unrestricted gas capacity factors.

# Preferred Portfolio Development

- Based on modifications to the Expanded Wind Availability Enhanced Environmental Regulations (EER) portfolio
- Supports a balanced consideration of Indiana's Five Pillars of energy policy
  - Positions I&M for compliance with existing and future GHG regulations based on current and proposed rules
  - Leverages a mix of resource types to support reliability and stability, while increasing resource diversity and expanding I&M's renewable and clean energy portfolio
- Reflects up to date market conditions and resource availability based on 2024 RFP
- Includes strategy to leverage cost savings opportunities associated with redevelopment of the Rockport site to include combustion turbines and SMR technologies
  - Rockport CTs reflect estimated cost reductions of ~15% associated with reuse of interconnect and existing facilities while leveraging favorable equipment pricing associated with AEP multi-unit supply chain opportunities
  - Rockport SMRs reflect estimated cost reductions of ~30% associated with reuse of interconnect and existing facilities, energy community bonus ITCs, federal grants, customer participation, and leveraging fast follower savings opportunities
- Selects Cook Subsequent License Renewal maintaining Cook as a foundation of I&M's future generation portfolio

# Preferred Portfolio

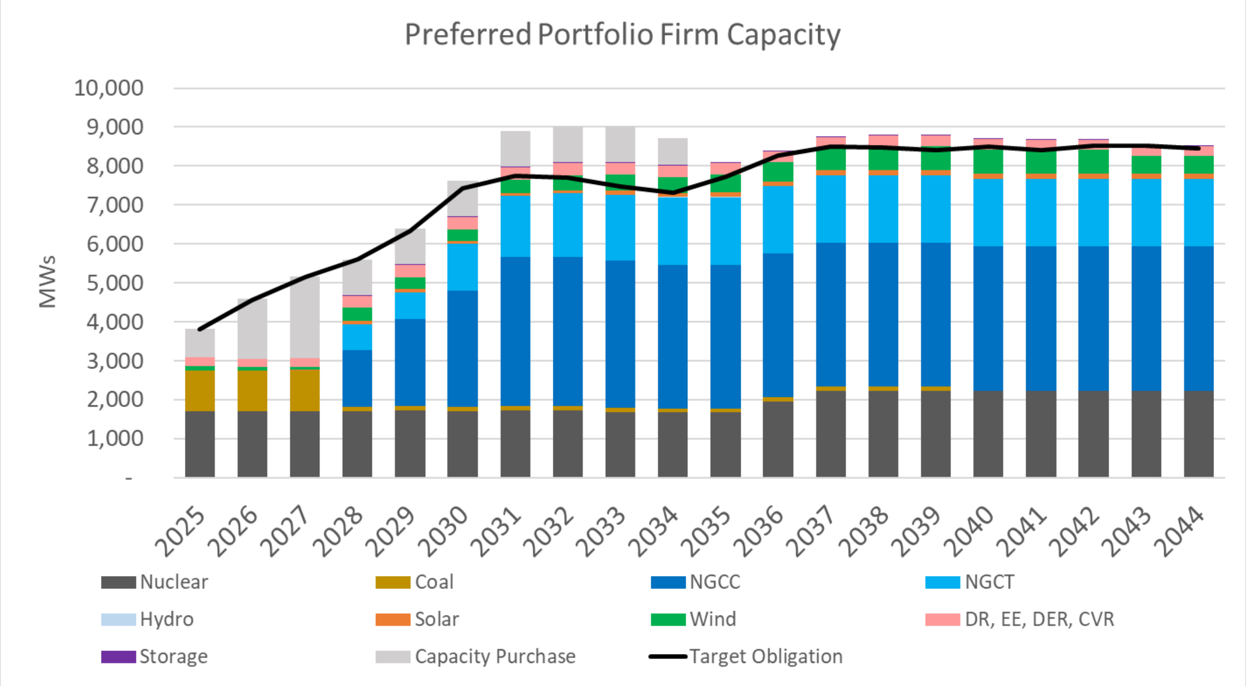
| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT* | Existing CT | Nuclear** | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 325 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 33 | 1,500 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 61 | 1,875 |
| 2028 | 1,000 | 599 | 50 | 0 | 1,800 | 0 | 1,000 | 0 | 92 | 0 |
| 2029 | 1,000 | 596 | 50 | 0 | 2,700 | 0 | 1,000 | 0 | 116 | 0 |
| 2030 | 1,000 | 593 | 50 | 0 | 3,600 | 690 | 1,000 | 0 | 132 | 0 |
| 2031 | 1,400 | 590 | 50 | 0 | 4,500 | 690 | 1,500 | 0 | 148 | 0 |
| 2032 | 1,800 | 886 | 50 | 0 | 4,500 | 690 | 1,500 | 0 | 144 | 0 |
| 2033 | 2,200 | 1,480 | 50 | 0 | 4,500 | 690 | 1,500 | 0 | 138 | 0 |
| 2034 | 2,600 | 2,071 | 50 | 0 | 4,500 | 690 | 1,500 | 0 | 134 | 0 |
| 2035 | 3,000 | 2,210 | 50 | 0 | 4,500 | 690 | 1,500 | 888 | 134 | 0 |
| 2036 | 3,200 | 2,199 | 50 | 0 | 4,500 | 690 | 1,500 | 1,188 | 131 | 0 |
| 2037 | 3,600 | 2,636 | 50 | 0 | 4,500 | 690 | 1,500 | 1,488 | 128 | 0 |
| 2038 | 4,000 | 2,623 | 50 | 0 | 4,500 | 690 | 1,500 | 2,480 | 125 | 0 |
| 2039 | 4,000 | 2,609 | 50 | 0 | 4,500 | 690 | 1,500 | 2,480 | 122 | 0 |
| 2040 | 4,000 | 2,596 | 50 | 0 | 4,500 | 690 | 1,500 | 2,480 | 119 | 0 |
| 2041 | 4,000 | 2,582 | 50 | 0 | 4,500 | 690 | 1,500 | 2,480 | 111 | 0 |
| 2042 | 4,000 | 2,569 | 50 | 0 | 4,500 | 690 | 1,500 | 2,480 | 105 | 0 |
| 2043 | 3,000 | 2,555 | 50 | 0 | 4,500 | 690 | 1,500 | 2,480 | 99 | 0 |
| 2044 | 3,000 | 2,542 | 50 | 0 | 4,500 | 690 | 1,500 | 2,480 | 94 | 0 |

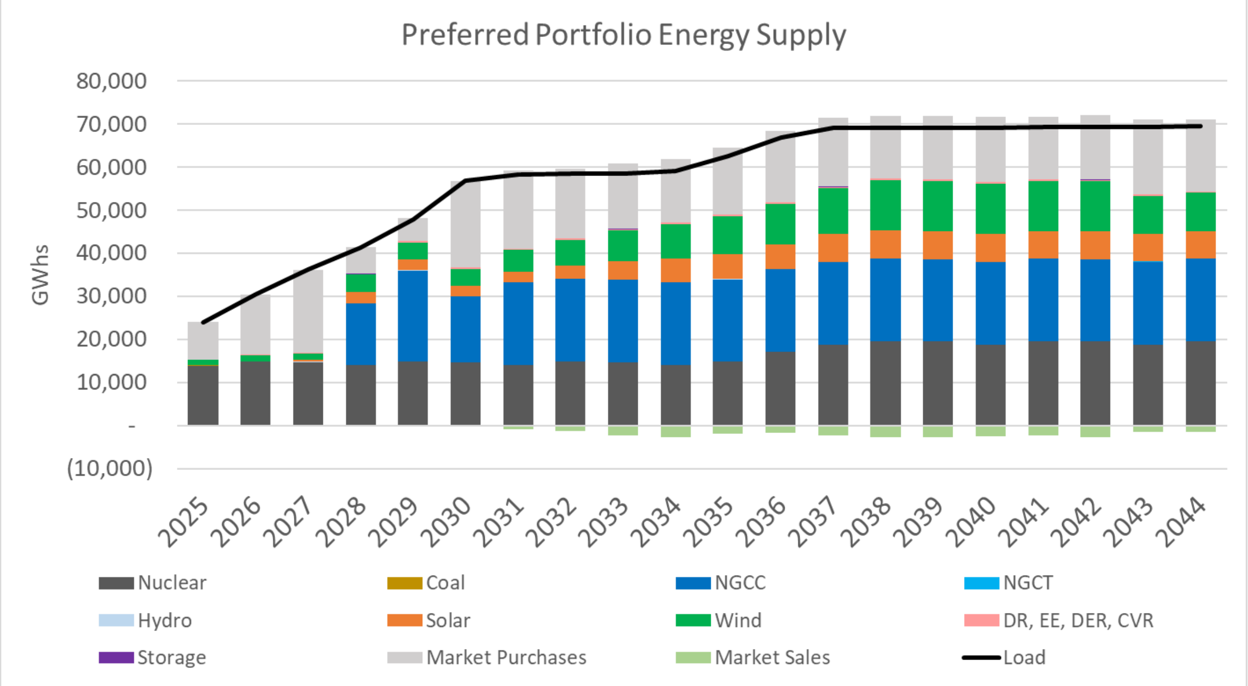
**Observations:**

- Diverse mix of wind, solar, storage, existing CC's and CT's are selected in the first year available to meet the capacity and energy obligation
- Substantial wind, solar, existing CC's, and existing CT's selected over the planning horizon
- Cook SLR selected in 2035 and 2038
- Leverages Rockport redevelopment opportunities with new CT selected in 2030 and 300 MW of SMR's selected in both 2036 and 2037. These resources reduce the need for existing CC's compared to the Expanded Wind Availability (EER) portfolio, adding new capacity to PJM's and I&M's system
- Elkhart and Mottville Hydro relicensing selected in 2030 and 2033, respectively

*The 690 MW New CTs selected in 2030 are assumed to be located at the Rockport site
** Nuclear includes Cook SLR and SMRs. SMRs are assumed to be located at the Rockport site

# Preferred Portfolio

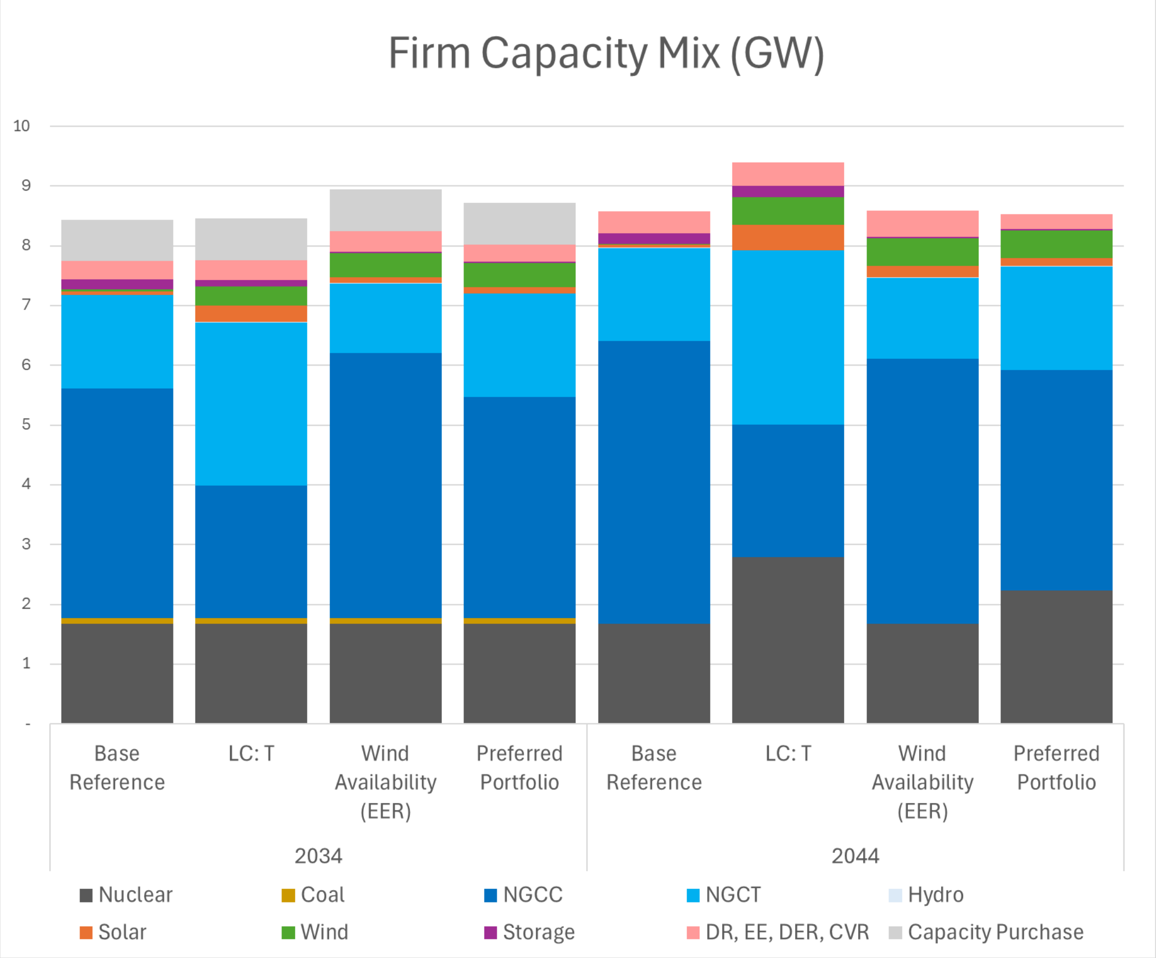


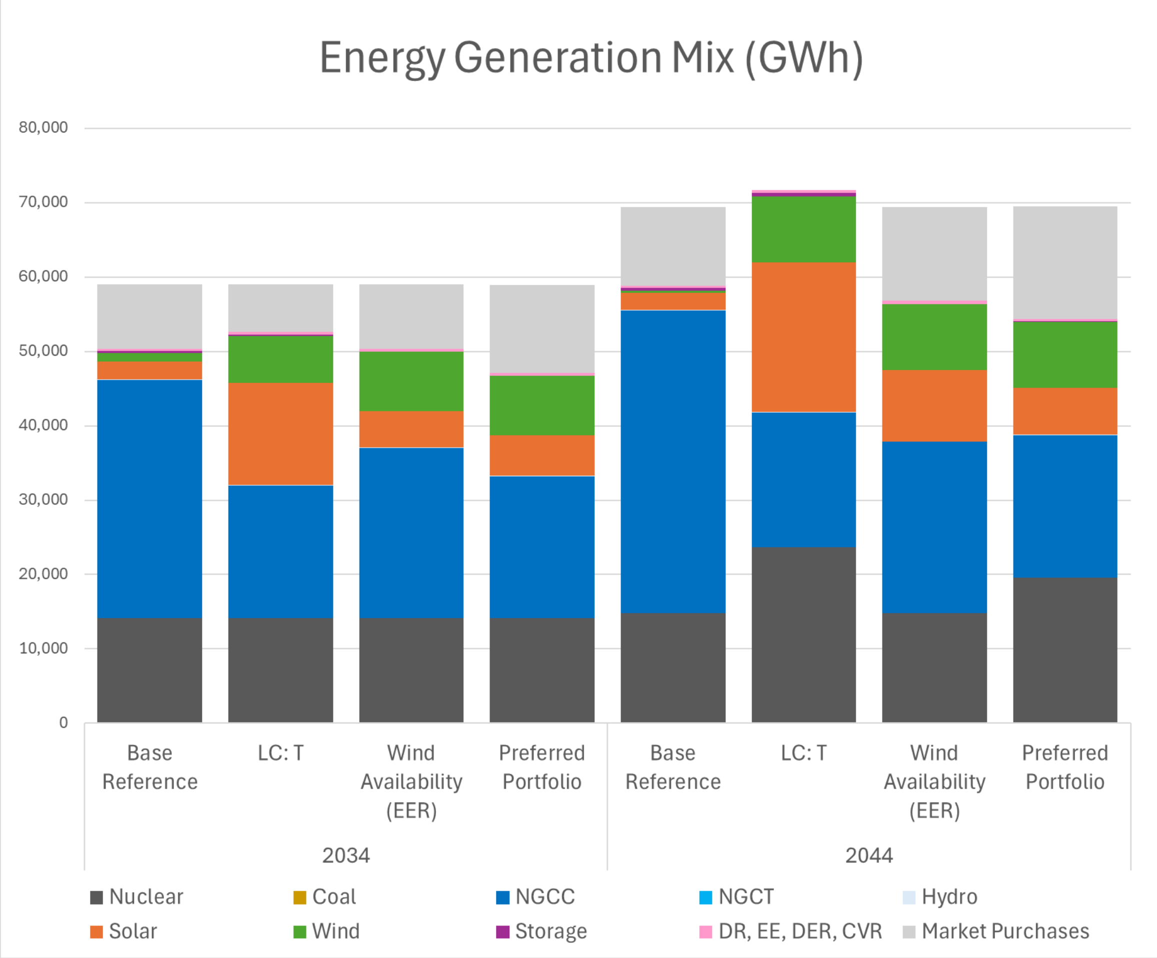




**Observations:**

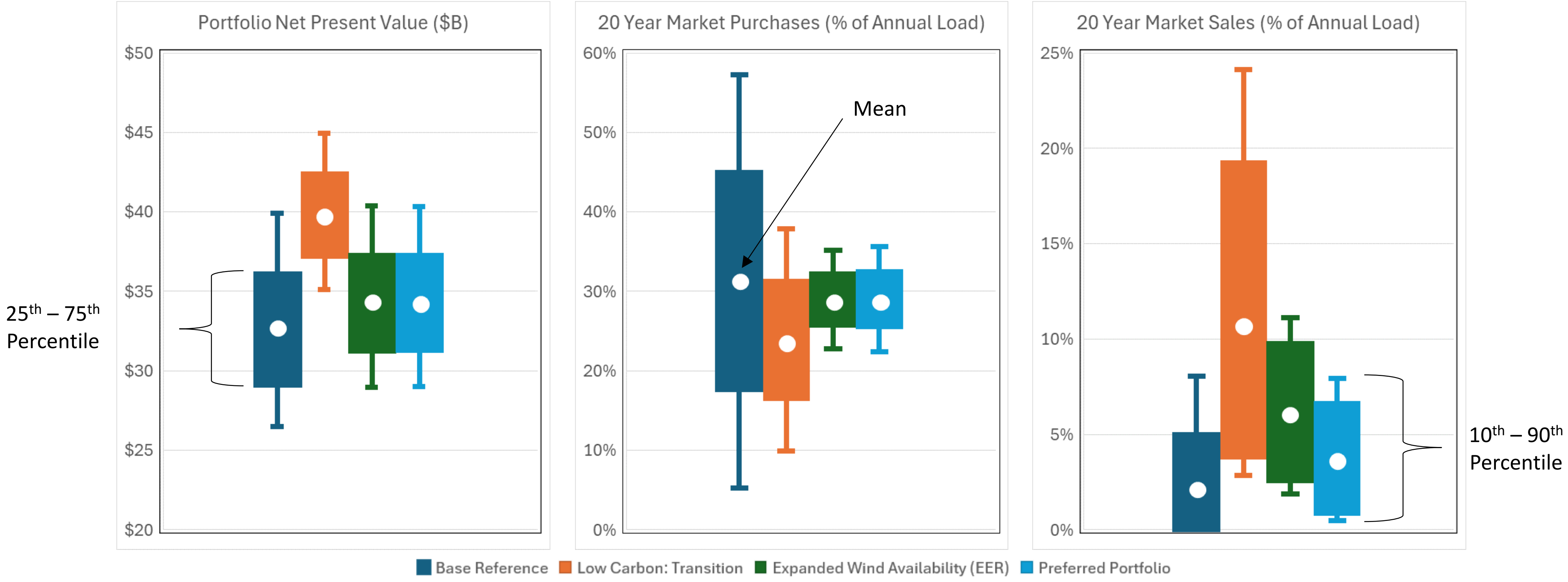
- Expands I&M's wind and solar capacity and energy supply
- Rockport CT's, SMR's, Cook, and other natural gas resources with higher accreditation values support most of I&M's capacity obligation
- Capacity factor limitations associated with EPA Section 111(b)(d) compliance begin in 2030 and result in more energy contributions from other resources
- Capacity additions in 2031-2034 built to provide necessary energy supply and prepare for load increases that occur from 2034-2037
- Renewable resource additions result in higher market energy sales starting in 2031

# Results Summary Comparison



# Preferred Portfolio Risk Analysis Results




Preferred Portfolio variability for net present value is similar to the Expanded Wind Availability (EER) but slightly less. The Preferred Portfolio has less variability in market sales risk and lower average market sales compared to the Expanded Wind Availability (EER).

# Portfolio Performance Indicators

| Pillar | Affordability | | | Environmental Sustainability | | |
|---|---|---|---|---|---|---|
| ***Performance Indicators and Metrics*** | ***Short Term*** *7-yr Rate CAGR* Power Supply $/MWh | ***Long Term*** *Supply Portfolio NPVRR Power Supply Costs* | ***Portfolio Resilience:*** *High Minus Low Scenario Range, Portfolio NPVRR* | ***Emissions Analysis:*** *% Change from 2005 Baseline* | | |
| Year Ref. | 2024-2031 | 2025-2044 | 2025-2044 | 2034 \| 2044 | | |
| Units | % | $B | $B | % Change $CO_2$ | % Change NOx | % Change $SO_2$ |
| **Base Reference** | -0.5% | $32.0 | $13.4 | 2034: -39%<br>2044: -24% | 2034: -94%<br>2044: -93% | 2034: -100%<br>2044: -100% |
| **Low Carbon: Transition** | 1.3% | $39.9 | $9.8 | 2034: -65%<br>2044: -65% | 2034: -96%<br>2044: -96% | 2034: -100%<br>2044: -100% |
| **Expanded Wind Availability (EER)** | 0.5% | $32.8 | $11.4 | 2034: -56%<br>2044: -55% | 2034: -95%<br>2044: -95% | 2034: -100%<br>2044: -100% |
| **Preferred Portfolio** | 0.4% | $33.1 | $11.4 | 2034: -63%<br>2044: -63% | 2034: -96%<br>2044: -96% | 2034: -100%<br>2044: -100% |

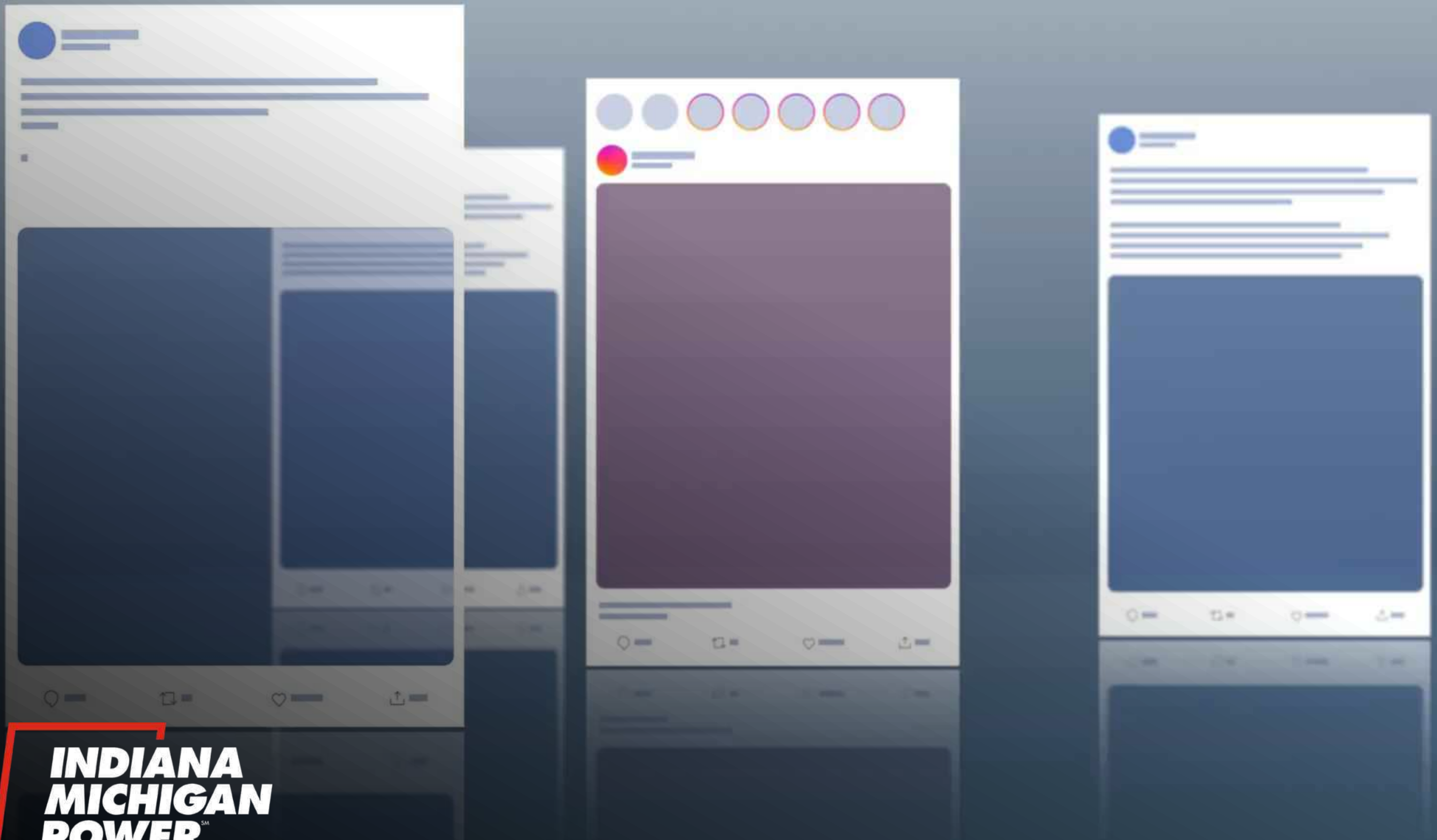
# Portfolio Performance Indicators

| Pillar | Reliability | | | Reliability/ Resiliency | Grid Stability Resiliency |
|---|---|---|---|---|---|
| ***Performance Indicators and Metrics*** | ***Energy Market Risk*** *Purchases* | ***Energy Market Risk*** *Sales* | ***Planning Reserves*** *% Reserve Margin* | ***Resource Diversity*** | ***Fleet Resiliency:*** *Dispatchable Capacity* |
| Year Ref. | 10 years \| 20 years | 10 years \| 20 years | 10 years \| 20 years | 10 years \| 20 years | 10 years \| 20 years |
| Units | NPV of Market Purchases & MWhs % of Total Demand | NPV of Market Sales & MWhs % of Total Demand | Average of Annual PRM % | Portfolio Index Percent Change from 2025 | Dispatchable Nameplate MW/ % of Company Peak Demand |
| **Base Reference** | 10 Years: $2.6B (27%)<br>20 Years: $4.3B (22%) | 10 Years: $0.0B (0.1%)<br>20 Years: $0.1B (0.3%) | 10 Years: -0.7%<br>20 Years: -3.4% | Capacity: 31% \| 19%<br>Energy: 173% \| 139% | 10 Years: 90%<br>20 Years: 97% |
| **Low Carbon: Transition** | 10 Years: $2.7B (27%)<br>20 Years: $4.1B (20%) | 10 Years: $0.2B (1.6%)<br>20 Years: $1.7B (7.7%) | 10 Years: 2.0%<br>20 Years: 0.5% | Capacity: 53% \| 54%<br>Energy: 302% \| 304% | 10 Years: 91%<br>20 Years: 95% |
| **Expanded Wind Availability (EER)** | 10 Years: $3.1B (31%)<br>20 Years: $5.4B (27%) | 10 Years: $0.5B (3.5%)<br>20 Years: $1.3B (5.2%) | 10 Years: 5.1%<br>20 Years: -0.6% | Capacity: 31% \| 34%<br>Energy: 296% \| 318% | 10 Years: 92%<br>20 Years: 92% |
| **Preferred Portfolio** | 10 Years: $3.1B (31%)<br>20 Years: $5.3B (27%) | 10 Years: $0.2B (1.3%)<br>20 Years: $0.5B (2.3%) | 10 Years: 4.2%<br>20 Years: -0.6% | Capacity: 39% \| 35%<br>Energy: 299% \| 299% | 10 Years: 91%<br>20 Years: 93% |

# Short Term Action Plan

| | |
|---|---|
| DSM Programs | Continue the planning and regulatory actions necessary to implement additional cost-effective DSM programs in Indiana consistent with this IRP that identified the potential for increased levels of cost-effective EE. |
| Near Term Capacity Needs | Obtain the capacity needed for PJM Planning Years 2026/2027 through 2027/2028 through Short Term market and bilateral purchases. |
| 2024 RFP | Complete selection of resources from the 2024 RFP. Seek approval of resources consistent with the Preferred Portfolio mix of resources. |
| Rockport CT | Complete competitive procurement process, seek reuse of transmission interconnection and request approval of resource with the commission. |
| Rockport SMR | Initiate early site permit process and continue to evaluate and pursue project development options. |
| Future RFPs | Continue to evaluate the need to issue future generation RFPs to fill the capacity and energy needs, as necessary. |
| Cook SLR | Take the appropriate steps to implement the Cook subsequent license renewal, as supported by the IRP modeling results and Preferred Portfolio. |
| Hydro Relicensing | Take the appropriate steps to finalize the evaluation of the Elkhart and Mottville Hydro operating license renewal opportunity reflected in the Preferred Portfolio. |
| Adjust for the Future | Adjust this action plan and future IRPs to reflect changing circumstances, as necessary. |

# Closing Remarks and Discussion



INDIANA MICHIGAN POWER
An AEP Company

# Portfolio Resource Plans

Appendix

# Base Reference Case Portfolio

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 325 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 28 | 1,500 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 59 | 1,875 |
| 2028 | 200 | 599 | 450 | 0 | 1,800 | 0 | 1,000 | 0 | 94 | 0 |
| 2029 | 200 | 596 | 450 | 0 | 2,700 | 0 | 1,000 | 0 | 100 | 0 |
| 2030 | 200 | 593 | 450 | 0 | 3,600 | 0 | 1,500 | 0 | 97 | 0 |
| 2031 | 200 | 590 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 96 | 0 |
| 2032 | 200 | 587 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 115 | 0 |
| 2033 | 200 | 584 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 131 | 0 |
| 2034 | 200 | 581 | 450 | 1,030 | 3,600 | 0 | 2,000 | 0 | 144 | 0 |
| 2035 | 200 | 578 | 450 | 1,030 | 3,600 | 0 | 2,000 | 888 | 156 | 0 |
| 2036 | 200 | 575 | 450 | 2,060 | 3,600 | 0 | 2,000 | 888 | 169 | 0 |
| 2037 | 200 | 572 | 450 | 2,060 | 3,600 | 0 | 2,000 | 888 | 177 | 0 |
| 2038 | 200 | 569 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 185 | 0 |
| 2039 | 200 | 566 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 193 | 0 |
| 2040 | 200 | 563 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 201 | 0 |
| 2041 | 200 | 560 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 206 | 0 |
| 2042 | 200 | 557 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 211 | 0 |
| 2043 | 0 | 554 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 213 | 0 |
| 2044 | 0 | 551 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 220 | 0 |

*Nuclear includes Cook SLR

**Purpose of Scenario:**

- Evaluating the most economical solution to meet capacity and energy needs considering all base modeling parameters and assumptions; establishes the point of reference for other scenarios and sensitivities

**Observations through 2030:**

- Short Term Capacity purchases until new resources become available in 2028
- Solar, wind, storage, and gas resources selected in 2028 in response to load growth by 2030
- Selected all available existing CC’s by 2030 and existing CT’s were selected to meet capacity obligation
- DR, EE, DER, CVR increase as the load and energy increase with the HSL

**Observations for 2031+:**

- New CC built in 2034 and 2036 to meet the load growth in the same period and the expiration of existing capacity purchase agreements
- Cook SLR selected in 2035 and 2038

# Enhanced Environmental Regulations Case Portfolio

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 325 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 26 | 1,500 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 56 | 1,875 |
| 2028 | 200 | 1,496 | 350 | 0 | 1,800 | 0 | 1,000 | 0 | 88 | 0 |
| 2029 | 200 | 1,489 | 350 | 0 | 2,700 | 0 | 1,000 | 0 | 112 | 0 |
| 2030 | 200 | 1,481 | 350 | 0 | 3,600 | 0 | 1,500 | 0 | 127 | 0 |
| 2031 | 600 | 1,474 | 350 | 0 | 5,400 | 0 | 1,500 | 0 | 142 | 0 |
| 2032 | 1,000 | 2,065 | 350 | 0 | 5,400 | 0 | 1,500 | 0 | 158 | 0 |
| 2033 | 1,400 | 2,653 | 350 | 0 | 5,400 | 0 | 1,500 | 0 | 169 | 0 |
| 2034 | 1,800 | 3,238 | 350 | 0 | 5,400 | 0 | 1,500 | 0 | 178 | 0 |
| 2035 | 2,200 | 3,371 | 350 | 0 | 5,400 | 0 | 1,500 | 888 | 190 | 0 |
| 2036 | 2,600 | 3,952 | 350 | 0 | 5,400 | 0 | 1,500 | 888 | 201 | 0 |
| 2037 | 3,000 | 4,530 | 350 | 0 | 5,400 | 0 | 1,500 | 888 | 208 | 0 |
| 2038 | 3,200 | 4,507 | 350 | 0 | 5,400 | 0 | 1,500 | 1,880 | 215 | 0 |
| 2039 | 3,200 | 4,484 | 350 | 0 | 5,400 | 0 | 1,500 | 1,880 | 220 | 0 |
| 2040 | 3,200 | 4,461 | 350 | 0 | 5,400 | 0 | 1,500 | 1,880 | 224 | 0 |
| 2041 | 3,200 | 4,437 | 350 | 0 | 5,400 | 0 | 1,500 | 1,880 | 227 | 0 |
| 2042 | 3,200 | 4,414 | 350 | 0 | 5,400 | 230 | 1,500 | 1,880 | 230 | 0 |
| 2043 | 3,000 | 4,114 | 350 | 0 | 5,400 | 230 | 1,500 | 1,880 | 232 | 0 |
| 2044 | 3,000 | 4,092 | 350 | 0 | 5,400 | 230 | 1,500 | 1,880 | 233 | 0 |

**Purpose of Scenario:**

- Evaluating the most economical solution to meet capacity and energy needs considering implementation of EPA Section 111(b)(d) greenhouse gas rules and associated market commodity price impacts

**Observations through 2030:**

- Solar, wind, storage, and gas resources selected in 2028 in response to load growth by 2030
- Selected all available existing CC's by 2030 and existing CT's were selected to meet capacity obligation
- Additional solar resources selected due to limited capacity factors on thermal resources
- DR, EE, DER, CVR increase as the load and energy increase with the HSL

**Observations for 2031+:**

- Substantially more wind and solar selected than reference scenario
- Additional existing CC's selected to meet the load growth in the same period and the expiration of existing capacity purchase agreements
- Cook SLR selected in 2035 and 2038
- Additional EE selected compared to reference scenario



*Nuclear includes Cook SLR

# Base Under EPA Section 111(b)(d) Sensitivity

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 325 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 27 | 1,500 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 57 | 1,875 |
| 2028 | 200 | 1,047 | 400 | 0 | 1,800 | 0 | 1,000 | 0 | 90 | 0 |
| 2029 | 200 | 1,042 | 400 | 0 | 2,700 | 0 | 1,000 | 0 | 114 | 0 |
| 2030 | 200 | 1,037 | 400 | 0 | 3,600 | 0 | 1,500 | 0 | 130 | 0 |
| 2031 | 600 | 1,481 | 400 | 0 | 5,400 | 0 | 1,500 | 0 | 146 | 0 |
| 2032 | 1,000 | 2,072 | 400 | 0 | 5,400 | 0 | 1,500 | 0 | 162 | 0 |
| 2033 | 1,400 | 2,660 | 400 | 0 | 5,400 | 0 | 1,500 | 0 | 173 | 0 |
| 2034 | 1,800 | 3,245 | 400 | 0 | 5,400 | 0 | 1,500 | 0 | 182 | 0 |
| 2035 | 2,200 | 3,527 | 400 | 0 | 5,400 | 0 | 1,500 | 888 | 194 | 0 |
| 2036 | 2,600 | 4,108 | 400 | 0 | 5,400 | 0 | 1,500 | 888 | 204 | 0 |
| 2037 | 3,000 | 4,685 | 400 | 0 | 5,400 | 0 | 1,500 | 888 | 212 | 0 |
| 2038 | 3,000 | 4,661 | 400 | 0 | 5,400 | 0 | 1,500 | 1,880 | 218 | 0 |
| 2039 | 3,000 | 4,637 | 400 | 0 | 5,400 | 0 | 1,500 | 1,880 | 223 | 0 |
| 2040 | 3,000 | 4,613 | 400 | 0 | 5,400 | 0 | 1,500 | 1,880 | 228 | 0 |
| 2041 | 3,000 | 4,589 | 400 | 0 | 5,400 | 0 | 1,500 | 1,880 | 231 | 0 |
| 2042 | 3,000 | 4,565 | 400 | 0 | 5,400 | 230 | 1,500 | 1,880 | 233 | 0 |
| 2043 | 2,800 | 4,541 | 400 | 0 | 5,400 | 230 | 1,500 | 1,880 | 235 | 0 |
| 2044 | 2,800 | 4,517 | 400 | 0 | 5,400 | 230 | 1,500 | 1,880 | 236 | 0 |

**Purpose of Scenario:**
- Evaluating the most economical solution to meet capacity and energy needs considering implementation of EPA Section 111(b)(d) greenhouse gas rules and base modeling parameters and assumptions

**Observations through 2030:**
- Solar, wind, storage, and gas resources selected in 2028 in response to load growth by 2030
- Selected all available existing CC's by 2030 and existing CT's were selected to meet capacity obligation
- Additional solar resources selected due to limited capacity factors on thermal resources
- DR, EE, DER, CVR increase as the load and energy increase with the HSL

**Observations for 2031+:**
- Substantially more wind and solar selected than reference scenario
- Additional existing CC's selected to meet the load growth in the same period and the expiration of existing capacity purchase agreements
- Cook SLR selected in 2035 and 2038
- Additional EE selected compared to reference scenario



*Nuclear includes Cook SLR

# Low Carbon Sensitivity: Transition to Objective

| Year | Nameplate MW | | | | | | | | Accredited MW | | Objective Achievement (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity | |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 325 | 100% |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 27 | 1,500 | 100% |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 58 | 1,875 | 95% |
| 2028 | 200 | 1,796 | 300 | 0 | 1,800 | 0 | 1,000 | 0 | 92 | 0 | 92% |
| 2029 | 400 | 2,235 | 300 | 0 | 1,800 | 0 | 2,000 | 0 | 111 | 0 | 79% |
| 2030 | 400 | 2,224 | 300 | 0 | 2,700 | 0 | 2,500 | 0 | 121 | 0 | 60% |
| 2031 | 800 | 2,662 | 300 | 0 | 2,700 | 0 | 3,500 | 0 | 131 | 0 | 62% |
| 2032 | 1,200 | 3,845 | 300 | 0 | 2,700 | 0 | 3,500 | 0 | 149 | 0 | 72% |
| 2033 | 1,600 | 5,023 | 300 | 0 | 2,700 | 0 | 3,500 | 0 | 162 | 0 | 81% |
| 2034 | 2,000 | 6,194 | 300 | 0 | 2,700 | 0 | 3,500 | 0 | 173 | 0 | 82% |
| 2035 | 2,600 | 7,360 | 300 | 0 | 2,700 | 0 | 3,500 | 888 | 185 | 0 | 85% |
| 2036 | 3,200 | 8,968 | 450 | 0 | 2,700 | 230 | 3,500 | 888 | 197 | 0 | 87% |
| 2037 | 3,400 | 10,269 | 500 | 0 | 2,700 | 230 | 3,500 | 1,488 | 205 | 0 | 96% |
| 2038 | 3,400 | 10,217 | 500 | 0 | 2,700 | 230 | 3,500 | 2,780 | 211 | 0 | 100% |
| 2039 | 3,400 | 10,164 | 500 | 0 | 2,700 | 230 | 3,500 | 2,780 | 217 | 0 | 100% |
| 2040 | 3,400 | 10,261 | 500 | 0 | 2,700 | 230 | 3,500 | 2,780 | 223 | 0 | 100% |
| 2041 | 3,400 | 10,208 | 500 | 0 | 2,700 | 230 | 3,500 | 2,780 | 227 | 0 | 100% |
| 2042 | 3,400 | 10,155 | 500 | 0 | 2,700 | 230 | 3,500 | 2,780 | 230 | 0 | 100% |
| 2043 | 3,200 | 9,548 | 500 | 0 | 2,700 | 230 | 3,500 | 3,080 | 233 | 0 | 100% |
| 2044 | 3,000 | 9,359 | 500 | 0 | 2,700 | 230 | 3,500 | 3,080 | 235 | 0 | 100% |

**Purpose of Scenario:**

- Evaluating the most economical solution to achieve the Low Carbon Objective as quickly as possible given the base assumptions for wind and solar build limits

**Observations through 2030:**

- Wind and solar selected near build limits
- Selecting CT’s and CC’s to meet remaining capacity and energy needs
- DR, EE, DER, CVR increase as the load and energy increase with the HSL

**Observations for 2031+:**

- SMR selected in 2037, increasing to 1,200MW by 2043
- Substantially more solar and wind selected to meet the carbon-free objective
- Additional CT’s selected to meet capacity obligation
- Cook SLR selected in 2035 and 2038



*Nuclear includes Cook SLR and SMR

# Low Carbon Sensitivity: Expanded Build Limits

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 325 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 19 | 1,500 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 38 | 1,900 |
| 2028 | 1,200 | 1,347 | 0 | 0 | 1,800 | 0 | 1,000 | 0 | 56 | 0 |
| 2029 | 1,800 | 3,285 | 0 | 0 | 1,800 | 0 | 2,000 | 0 | 69 | 0 |
| 2030 | 3,400 | 5,513 | 300 | 0 | 1,800 | 0 | 3,000 | 0 | 80 | 0 |
| 2031 | 5,000 | 5,485 | 300 | 0 | 1,800 | 0 | 4,000 | 0 | 90 | 0 |
| 2032 | 5,000 | 5,457 | 300 | 0 | 1,800 | 0 | 4,000 | 0 | 108 | 0 |
| 2033 | 5,000 | 5,430 | 300 | 0 | 1,800 | 0 | 4,000 | 0 | 122 | 0 |
| 2034 | 5,000 | 5,701 | 300 | 0 | 1,800 | 0 | 4,000 | 0 | 134 | 0 |
| 2035 | 5,400 | 7,019 | 300 | 0 | 1,800 | 0 | 4,000 | 888 | 147 | 0 |
| 2036 | 6,200 | 8,030 | 300 | 0 | 1,800 | 230 | 4,000 | 888 | 158 | 0 |
| 2037 | 6,200 | 8,438 | 300 | 0 | 1,800 | 230 | 4,000 | 1,188 | 167 | 0 |
| 2038 | 6,200 | 8,394 | 300 | 0 | 1,800 | 230 | 4,000 | 2,180 | 175 | 0 |
| 2039 | 6,200 | 8,351 | 300 | 0 | 1,800 | 230 | 4,000 | 2,180 | 182 | 0 |
| 2040 | 6,200 | 8,457 | 350 | 0 | 1,800 | 230 | 4,000 | 2,180 | 187 | 0 |
| 2041 | 6,200 | 8,412 | 350 | 0 | 1,800 | 230 | 4,000 | 2,180 | 192 | 0 |
| 2042 | 6,200 | 8,368 | 350 | 0 | 1,800 | 230 | 4,000 | 2,180 | 195 | 0 |
| 2043 | 5,000 | 8,047 | 350 | 0 | 1,800 | 230 | 4,000 | 2,780 | 198 | 0 |
| 2044 | 4,600 | 8,222 | 350 | 0 | 1,800 | 230 | 4,000 | 2,780 | 200 | 0 |

**Purpose of Scenario:**
- Evaluating the most economical solution to achieve the Low Carbon Objective starting 2028 with increased wind and solar build limits

**Observations through 2030:**
- Substantial expansion in build limits for wind and solar required to meet the carbon-free objective
- Selecting all available existing CT's by 2030 to meet capacity obligation
- Substantially fewer existing CC's selected compared to reference scenario
- EE, DER, CVR increase as the load and energy increase with the HSL

**Observations for 2031+:**
- SMR selected in 2037 when first made available and again in 2043
- Substantially more solar and wind selected to meet the carbon-free objective
- Additional CT's selected to meet capacity obligation
- Cook SLR selected in 2035 and 2038



*Nuclear includes Cook SLR and SMR

# High Case Portfolio

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage** | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 350 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 28 | 1,650 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 59 | 2,000 |
| 2028 | 200 | 1,796 | 451 | 0 | 1,800 | 0 | 1,000 | 0 | 94 | 200 |
| 2029 | 200 | 1,787 | 451 | 0 | 2,700 | 0 | 2,000 | 0 | 119 | 0 |
| 2030 | 200 | 1,778 | 454 | 0 | 2,700 | 0 | 3,000 | 0 | 135 | 0 |
| 2031 | 600 | 1,769 | 454 | 0 | 3,600 | 0 | 3,500 | 0 | 151 | 0 |
| 2032 | 1,000 | 1,760 | 454 | 0 | 3,600 | 0 | 3,500 | 0 | 167 | 0 |
| 2033 | 1,400 | 1,751 | 454 | 0 | 3,600 | 0 | 3,500 | 0 | 179 | 0 |
| 2034 | 1,800 | 1,891 | 454 | 1,030 | 3,600 | 0 | 3,500 | 0 | 188 | 0 |
| 2035 | 2,000 | 2,480 | 454 | 1,030 | 3,600 | 0 | 3,500 | 888 | 201 | 0 |
| 2036 | 2,400 | 3,066 | 454 | 1,030 | 3,600 | 0 | 3,500 | 888 | 212 | 0 |
| 2037 | 2,800 | 3,648 | 454 | 1,030 | 3,600 | 0 | 3,500 | 888 | 220 | 0 |
| 2038 | 3,200 | 3,630 | 454 | 1,030 | 3,600 | 0 | 3,500 | 1,880 | 226 | 0 |
| 2039 | 3,200 | 3,611 | 454 | 1,030 | 3,600 | 0 | 3,500 | 1,880 | 231 | 0 |
| 2040 | 3,200 | 3,592 | 454 | 1,030 | 3,600 | 0 | 3,500 | 1,880 | 236 | 0 |
| 2041 | 3,200 | 3,573 | 454 | 1,030 | 3,600 | 0 | 3,500 | 1,880 | 239 | 0 |
| 2042 | 3,200 | 3,555 | 454 | 1,030 | 3,600 | 230 | 3,500 | 1,880 | 242 | 0 |
| 2043 | 3,000 | 2,982 | 454 | 1,030 | 3,600 | 230 | 3,500 | 1,880 | 245 | 0 |
| 2044 | 3,000 | 3,266 | 454 | 1,030 | 3,600 | 230 | 3,500 | 1,880 | 246 | 0 |

**Purpose of Scenario:**

- Evaluating the most economical solution to meet capacity and energy needs considering all high economic forecast modeling parameters and assumptions

**Observations through 2030:**

- Solar, wind, storage, and gas resources selected in 2028; significantly more solar than reference scenario
- Selected all available existing CT's by 2030 and existing CC's were selected to meet energy needs
- DR, EE, DER, CVR increase as the load and energy increase with the HSL

**Observations for 2031+:**

- Significantly more wind is selected compared to the reference scenario
- Fewer new CC's selected compared to the reference scenario due to the additional wind and solar selected
- Additional existing CT's selected compared to the reference scenario to meet capacity obligation
- Cook SLR selected in 2035 and 2038
- Additional EE selected compared to reference scenario

*Nuclear includes Cook SLR

** Storage includes Distribution-Sited Storage resources

# Low Case Portfolio

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 75 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 23 | 1,275 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 49 | 1,525 |
| 2028 | 200 | 0 | 0 | 0 | 1,800 | 0 | 1,000 | 0 | 79 | 0 |
| 2029 | 200 | 0 | 0 | 0 | 2,700 | 0 | 1,000 | 0 | 90 | 0 |
| 2030 | 200 | 0 | 0 | 0 | 3,600 | 0 | 1,500 | 0 | 94 | 0 |
| 2031 | 200 | 0 | 0 | 0 | 3,600 | 0 | 1,500 | 0 | 98 | 0 |
| 2032 | 200 | 0 | 0 | 0 | 3,600 | 0 | 1,500 | 0 | 97 | 0 |
| 2033 | 200 | 0 | 0 | 0 | 3,600 | 0 | 1,500 | 0 | 94 | 0 |
| 2034 | 200 | 0 | 0 | 1,030 | 3,600 | 0 | 1,500 | 0 | 92 | 0 |
| 2035 | 200 | 0 | 0 | 1,030 | 3,600 | 0 | 1,500 | 888 | 91 | 0 |
| 2036 | 200 | 0 | 0 | 2,060 | 3,600 | 0 | 1,500 | 888 | 88 | 0 |
| 2037 | 200 | 0 | 0 | 2,060 | 3,600 | 0 | 1,500 | 888 | 85 | 0 |
| 2038 | 200 | 0 | 0 | 2,060 | 3,600 | 0 | 1,500 | 1,880 | 82 | 0 |
| 2039 | 200 | 0 | 0 | 2,060 | 3,600 | 0 | 1,500 | 1,880 | 79 | 0 |
| 2040 | 200 | 0 | 0 | 2,060 | 3,600 | 0 | 1,500 | 1,880 | 78 | 0 |
| 2041 | 200 | 0 | 0 | 2,060 | 3,600 | 0 | 1,500 | 1,880 | 70 | 0 |
| 2042 | 200 | 0 | 0 | 2,060 | 3,600 | 0 | 1,500 | 1,880 | 64 | 0 |
| 2043 | 0 | 0 | 0 | 2,060 | 3,600 | 0 | 1,500 | 1,880 | 57 | 0 |
| 2044 | 200 | 0 | 0 | 2,060 | 3,600 | 0 | 1,500 | 1,880 | 56 | 0 |

**Purpose of Scenario:**
- Evaluating the most economical solution to meet capacity and energy needs considering all low economic forecast modeling parameters and assumptions

**Observations through 2030:**
- Wind and gas resources selected in 2028 in response to load growth by 2030
- Selected all available existing CC's by 2030 and existing CT's were selected to meet capacity obligation
- Fewer DR, EE, DER, CVR are selected compared to reference scenario

**Observations for 2031+:**
- New CC built in 2034 and 2036 to meet the load growth in the same period and the expiration of existing capacity purchase agreements
- Fewer existing CT's selected compared to reference scenario due to lower capacity obligation
- Cook SLR selected in 2035 and 2038



*Nuclear includes Cook SLR

# Expanded Wind Availability (Base) Portfolio

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 325 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 27 | 1,500 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 58 | 1,875 |
| 2028 | 1,200 | 150 | 0 | 0 | 1,800 | 0 | 1,000 | 0 | 92 | 0 |
| 2029 | 1,200 | 149 | 0 | 0 | 2,700 | 0 | 1,000 | 0 | 110 | 0 |
| 2030 | 1,200 | 148 | 0 | 0 | 3,600 | 0 | 1,500 | 0 | 120 | 0 |
| 2031 | 1,200 | 147 | 0 | 0 | 3,600 | 0 | 2,000 | 0 | 129 | 0 |
| 2032 | 1,200 | 147 | 0 | 0 | 3,600 | 0 | 2,000 | 0 | 146 | 0 |
| 2033 | 1,200 | 146 | 0 | 0 | 3,600 | 0 | 2,000 | 0 | 158 | 0 |
| 2034 | 1,200 | 145 | 0 | 1,030 | 3,600 | 0 | 2,000 | 0 | 168 | 0 |
| 2035 | 1,200 | 144 | 0 | 1,030 | 3,600 | 0 | 2,000 | 888 | 180 | 0 |
| 2036 | 1,200 | 144 | 0 | 2,060 | 3,600 | 0 | 2,000 | 888 | 191 | 0 |
| 2037 | 1,200 | 143 | 0 | 2,060 | 3,600 | 0 | 2,000 | 888 | 199 | 0 |
| 2038 | 1,200 | 142 | 0 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 206 | 0 |
| 2039 | 1,200 | 141 | 0 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 212 | 0 |
| 2040 | 1,200 | 141 | 0 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 217 | 0 |
| 2041 | 1,200 | 140 | 0 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 221 | 0 |
| 2042 | 1,200 | 139 | 0 | 2,060 | 3,600 | 230 | 2,000 | 1,880 | 225 | 0 |
| 2043 | 0 | 0 | 0 | 2,060 | 3,600 | 230 | 2,000 | 1,880 | 227 | 0 |
| 2044 | 0 | 0 | 0 | 2,060 | 3,600 | 230 | 2,000 | 1,880 | 229 | 0 |

**Purpose of Scenario:**

- Evaluating the most economical solution to meet capacity and energy needs considering all base modeling parameters and additional wind availability through 2030

**Observations through 2030:**

- Additional wind selected by the model reduces solar and storage resources compared to the reference scenario
- Selected all available existing CC's by 2030 and existing CT's were selected to meet capacity obligation similar to the reference scenario

**Observations for 2031+:**

- New CC built in 2034 and 2036 to meet the load growth in the same period and the expiration of existing capacity purchase agreements similar to the reference scenario
- New CT built in 2042 compared to the reference scenario to meet capacity obligation
- Cook SLR selected in 2035 and 2038



*Nuclear includes Cook SLR

# Expanded Wind Availability (EER) Portfolio

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 325 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 27 | 1,500 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 57 | 1,875 |
| 2028 | 1,000 | 599 | 50 | 0 | 1,800 | 0 | 1,000 | 0 | 90 | 0 |
| 2029 | 1,000 | 596 | 50 | 0 | 2,700 | 0 | 1,000 | 0 | 113 | 0 |
| 2030 | 1,000 | 593 | 50 | 0 | 3,600 | 0 | 1,500 | 0 | 129 | 0 |
| 2031 | 1,400 | 590 | 50 | 0 | 5,400 | 0 | 1,500 | 0 | 143 | 0 |
| 2032 | 1,800 | 587 | 50 | 0 | 5,400 | 0 | 1,500 | 0 | 166 | 0 |
| 2033 | 2,200 | 1,182 | 50 | 0 | 5,400 | 0 | 1,500 | 0 | 182 | 0 |
| 2034 | 2,600 | 1,775 | 50 | 0 | 5,400 | 0 | 1,500 | 0 | 196 | 0 |
| 2035 | 2,800 | 2,364 | 50 | 0 | 5,400 | 0 | 1,500 | 888 | 212 | 0 |
| 2036 | 3,200 | 2,951 | 50 | 0 | 5,400 | 0 | 1,500 | 888 | 228 | 0 |
| 2037 | 3,600 | 3,534 | 50 | 0 | 5,400 | 0 | 1,500 | 888 | 240 | 0 |
| 2038 | 4,000 | 3,815 | 50 | 0 | 5,400 | 0 | 1,500 | 1,880 | 251 | 0 |
| 2039 | 4,000 | 3,796 | 50 | 0 | 5,400 | 0 | 1,500 | 1,880 | 260 | 0 |
| 2040 | 4,000 | 3,776 | 50 | 0 | 5,400 | 0 | 1,500 | 1,880 | 269 | 0 |
| 2041 | 4,000 | 3,757 | 50 | 0 | 5,400 | 0 | 1,500 | 1,880 | 276 | 0 |
| 2042 | 4,000 | 3,737 | 50 | 0 | 5,400 | 0 | 1,500 | 1,880 | 281 | 0 |
| 2043 | 3,000 | 4,167 | 50 | 0 | 5,400 | 230 | 1,500 | 1,880 | 286 | 0 |
| 2044 | 3,000 | 4,145 | 50 | 0 | 5,400 | 230 | 1,500 | 1,880 | 290 | 0 |

**Purpose of Scenario:**

- Evaluating the most economical solution to meet capacity and energy needs considering implementation of EPA Section 111(b)(d) greenhouse gas rules and associated market commodity price impacts with the expansion of wind availability through 2030

**Observations through 2030:**

- Additional wind selected by the model reduces solar and storage resources compared to the EER scenario
- All available existing CC's by 2030 and existing CT's were selected to meet capacity obligation

**Observations for 2031+:**

- Similar to the EER scenario, substantial wind, solar, and existing CC's selected to meet the load growth and the expiration of existing capacity purchase agreements
- Cook SLR selected in 2035 and 2038



*Nuclear includes Cook SLR

# Base with High Load Portfolio

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage** | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 350 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 28 | 1,650 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 59 | 2,000 |
| 2028 | 200 | 1,796 | 451 | 0 | 1,800 | 0 | 1,000 | 0 | 94 | 200 |
| 2029 | 200 | 1,787 | 451 | 0 | 2,700 | 0 | 1,500 | 0 | 100 | 0 |
| 2030 | 200 | 1,778 | 451 | 0 | 3,600 | 0 | 2,000 | 0 | 97 | 0 |
| 2031 | 600 | 1,769 | 451 | 0 | 3,600 | 0 | 3,000 | 0 | 96 | 0 |
| 2032 | 600 | 1,760 | 451 | 0 | 3,600 | 0 | 3,000 | 0 | 95 | 0 |
| 2033 | 600 | 1,751 | 451 | 0 | 3,600 | 0 | 3,000 | 0 | 91 | 0 |
| 2034 | 600 | 1,742 | 451 | 1,030 | 3,600 | 0 | 3,000 | 0 | 88 | 0 |
| 2035 | 600 | 1,733 | 451 | 1,030 | 3,600 | 0 | 3,000 | 888 | 86 | 0 |
| 2036 | 600 | 1,724 | 451 | 2,060 | 3,600 | 0 | 3,000 | 888 | 84 | 0 |
| 2037 | 1,000 | 1,715 | 451 | 2,060 | 3,600 | 0 | 3,000 | 888 | 80 | 0 |
| 2038 | 1,200 | 1,706 | 451 | 2,060 | 3,600 | 0 | 3,000 | 1,880 | 76 | 0 |
| 2039 | 1,200 | 1,697 | 451 | 2,060 | 3,600 | 0 | 3,000 | 1,880 | 75 | 0 |
| 2040 | 1,200 | 1,688 | 451 | 2,060 | 3,600 | 0 | 3,000 | 1,880 | 74 | 0 |
| 2041 | 1,200 | 1,679 | 451 | 2,060 | 3,600 | 0 | 3,000 | 1,880 | 68 | 0 |
| 2042 | 1,200 | 1,670 | 451 | 2,060 | 3,600 | 230 | 3,000 | 1,880 | 62 | 0 |
| 2043 | 1,000 | 1,107 | 451 | 2,060 | 3,600 | 460 | 3,000 | 1,880 | 56 | 0 |
| 2044 | 1,000 | 1,251 | 451 | 2,060 | 3,600 | 460 | 3,000 | 1,880 | 55 | 0 |

*Nuclear includes Cook SLR
** Storage includes Distribution-Sited Storage resources

**Purpose of Scenario:**
- Evaluating the most economical solution to meet capacity and energy needs considering base modeling parameters and assumptions with High Load forecast scenario

**Observations through 2030:**
- Solar, wind, storage, and gas resources selected in 2028 in response to load growth by 2030
- Selected all available existing CC's by 2030 and existing CT's were selected to meet capacity obligation
- Increased Short Term Capacity purchased compared to reference scenario due to increased Capacity Obligation due to higher load
- Additional solar and CT resources selected by 2030 in response to higher load compared to reference scenario

**Observations for 2031+:**
- More wind and CT's are selected compared to the reference scenario
- New CC built in 2034 and 2036 to meet the load growth in the same period and the expiration of existing capacity purchase agreements similar to the reference scenario
- Cook SLR selected in 2035 and 2038

# Base with Low Load Portfolio

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 75 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 23 | 1,275 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 49 | 1,525 |
| 2028 | 200 | 0 | 0 | 0 | 1,800 | 0 | 1,000 | 0 | 79 | 0 |
| 2029 | 200 | 0 | 0 | 0 | 2,700 | 0 | 1,000 | 0 | 97 | 0 |
| 2030 | 200 | 0 | 0 | 0 | 3,600 | 0 | 1,500 | 0 | 106 | 0 |
| 2031 | 600 | 0 | 0 | 0 | 3,600 | 0 | 2,000 | 0 | 115 | 0 |
| 2032 | 600 | 0 | 0 | 0 | 3,600 | 0 | 2,000 | 0 | 111 | 0 |
| 2033 | 800 | 0 | 0 | 0 | 3,600 | 0 | 2,000 | 0 | 105 | 0 |
| 2034 | 800 | 0 | 0 | 1,030 | 3,600 | 0 | 2,000 | 0 | 100 | 0 |
| 2035 | 800 | 0 | 0 | 1,030 | 3,600 | 0 | 2,000 | 888 | 99 | 0 |
| 2036 | 800 | 0 | 0 | 1,030 | 3,600 | 0 | 2,000 | 888 | 96 | 0 |
| 2037 | 1,200 | 0 | 0 | 1,030 | 3,600 | 0 | 2,000 | 888 | 92 | 0 |
| 2038 | 1,200 | 0 | 0 | 1,030 | 3,600 | 0 | 2,000 | 1,880 | 87 | 0 |
| 2039 | 1,200 | 0 | 0 | 1,030 | 3,600 | 0 | 2,000 | 1,880 | 84 | 0 |
| 2040 | 1,200 | 0 | 0 | 1,030 | 3,600 | 0 | 2,000 | 1,880 | 81 | 0 |
| 2041 | 1,200 | 0 | 0 | 1,030 | 3,600 | 0 | 2,000 | 1,880 | 73 | 0 |
| 2042 | 1,200 | 0 | 0 | 1,030 | 3,600 | 0 | 2,000 | 1,880 | 65 | 0 |
| 2043 | 1,000 | 0 | 0 | 1,030 | 3,600 | 0 | 2,000 | 1,880 | 58 | 0 |
| 2044 | 1,000 | 0 | 0 | 1,030 | 3,600 | 0 | 2,000 | 1,880 | 53 | 0 |

**Purpose of Scenario:**

- Evaluating the most economical solution to meet capacity and energy needs considering base modeling parameters and assumptions with Low Load forecast scenario

**Observations through 2030:**

- Wind and gas resources selected in 2028 in response to load growth by 2030
- Selected all available existing CC's by 2030 and existing CT's were selected to meet capacity obligation
- Unlike the reference scenario, less short term capacity and no solar or storage are selected

**Observations for 2031+:**

- New CC built in 2034 and additional wind resources built to meet the load growth in the same period and the expiration of existing capacity purchase agreements
- Cook SLR selected in 2035 and 2038



*Nuclear includes Cook SLR

# High Technology Cost Portfolio

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 325 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 28 | 1,500 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 59 | 1,875 |
| 2028 | 200 | 599 | 450 | 0 | 1,800 | 0 | 1,000 | 0 | 94 | 0 |
| 2029 | 200 | 596 | 450 | 0 | 2,700 | 0 | 1,000 | 0 | 100 | 0 |
| 2030 | 200 | 593 | 450 | 0 | 3,600 | 0 | 1,500 | 0 | 97 | 0 |
| 2031 | 200 | 590 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 96 | 0 |
| 2032 | 200 | 587 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 115 | 0 |
| 2033 | 200 | 584 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 131 | 0 |
| 2034 | 200 | 581 | 450 | 1,030 | 3,600 | 0 | 2,000 | 0 | 144 | 0 |
| 2035 | 200 | 578 | 450 | 1,030 | 3,600 | 0 | 2,000 | 888 | 156 | 0 |
| 2036 | 200 | 575 | 450 | 2,060 | 3,600 | 0 | 2,000 | 888 | 169 | 0 |
| 2037 | 200 | 572 | 450 | 2,060 | 3,600 | 0 | 2,000 | 888 | 177 | 0 |
| 2038 | 200 | 569 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 185 | 0 |
| 2039 | 200 | 566 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 193 | 0 |
| 2040 | 200 | 563 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 201 | 0 |
| 2041 | 200 | 560 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 207 | 0 |
| 2042 | 200 | 557 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 211 | 0 |
| 2043 | 0 | 554 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 213 | 0 |
| 2044 | 0 | 551 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 220 | 0 |

**Purpose of Scenario:**

- Evaluating the most economical solution to meet capacity and energy needs considering base modeling parameters and assumptions with increased resource installed costs

**Observations through 2030:**

- Resources selected are identical to the reference case starting in 2025 and for the remainder of the planning horizon
- Solar, wind, storage, and gas resources selected in 2028 to meet the capacity and energy obligations are not impacted by the higher cost assumptions
- Selected all available existing CC's by 2030 and existing CT's were selected to meet capacity obligation

**Observations for 2031+:**

- New CC built in 2034 and 2036 to meet the capacity and energy obligations are not impacted by the higher cost assumptions
- Cook SLR selected in 2035 and 2038

# Rockport Unit 1 Retires 2025 Portfolio

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1,250 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 28 | 2,425 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 59 | 2,825 |
| 2028 | 200 | 599 | 450 | 0 | 1,800 | 0 | 1,000 | 0 | 94 | 0 |
| 2029 | 200 | 596 | 450 | 0 | 2,700 | 0 | 1,000 | 0 | 100 | 0 |
| 2030 | 200 | 593 | 450 | 0 | 3,600 | 0 | 1,500 | 0 | 97 | 0 |
| 2031 | 200 | 590 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 96 | 0 |
| 2032 | 200 | 587 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 115 | 0 |
| 2033 | 200 | 584 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 131 | 0 |
| 2034 | 200 | 581 | 450 | 1,030 | 3,600 | 0 | 2,000 | 0 | 144 | 0 |
| 2035 | 200 | 578 | 450 | 1,030 | 3,600 | 0 | 2,000 | 888 | 156 | 0 |
| 2036 | 200 | 575 | 450 | 2,060 | 3,600 | 0 | 2,000 | 888 | 169 | 0 |
| 2037 | 200 | 572 | 450 | 2,060 | 3,600 | 0 | 2,000 | 888 | 177 | 0 |
| 2038 | 200 | 569 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 185 | 0 |
| 2039 | 200 | 566 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 193 | 0 |
| 2040 | 200 | 563 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 201 | 0 |
| 2041 | 200 | 560 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 207 | 0 |
| 2042 | 200 | 557 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 211 | 0 |
| 2043 | 0 | 554 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 213 | 0 |
| 2044 | 0 | 551 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 220 | 0 |

**Purpose of Scenario**:**
- Evaluating the most economical solution to meet capacity and energy needs considering base modeling parameters and assumptions of Rockport retiring 5/31/2025

**Observations through Planning Horizon:**
- Additional Short Term Capacity purchases compared to the reference case until new resources become available in 2028
- Resources selected are identical to the reference case starting in 2028 and for the remainder of the planning horizon

*Nuclear includes Cook SLR
** Required per Cause No. 45546

# Rockport Unit 1 Retires 2026 Portfolio

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 325 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 28 | 2,425 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 59 | 2,825 |
| 2028 | 200 | 599 | 450 | 0 | 1,800 | 0 | 1,000 | 0 | 94 | 0 |
| 2029 | 200 | 596 | 450 | 0 | 2,700 | 0 | 1,000 | 0 | 100 | 0 |
| 2030 | 200 | 593 | 450 | 0 | 3,600 | 0 | 1,500 | 0 | 97 | 0 |
| 2031 | 200 | 590 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 96 | 0 |
| 2032 | 200 | 587 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 115 | 0 |
| 2033 | 200 | 584 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 131 | 0 |
| 2034 | 200 | 581 | 450 | 1,030 | 3,600 | 0 | 2,000 | 0 | 144 | 0 |
| 2035 | 200 | 578 | 450 | 1,030 | 3,600 | 0 | 2,000 | 888 | 156 | 0 |
| 2036 | 200 | 575 | 450 | 2,060 | 3,600 | 0 | 2,000 | 888 | 169 | 0 |
| 2037 | 200 | 572 | 450 | 2,060 | 3,600 | 0 | 2,000 | 888 | 177 | 0 |
| 2038 | 200 | 569 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 185 | 0 |
| 2039 | 200 | 566 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 193 | 0 |
| 2040 | 200 | 563 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 201 | 0 |
| 2041 | 200 | 560 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 207 | 0 |
| 2042 | 200 | 557 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 211 | 0 |
| 2043 | 0 | 554 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 213 | 0 |
| 2044 | 0 | 551 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 220 | 0 |

**Purpose of Scenario**:**
- Evaluating the most economical solution to meet capacity and energy needs considering base modeling parameters and assumptions of Rockport retiring 5/31/2026

**Observations through Planning Horizon:**
- Additional Short Term Capacity purchases compared to the reference case until new resources become available in 2028
- Resources selected are identical to the reference case starting in 2028 and for the remainder of the planning horizon

*Nuclear includes Cook SLR
** Required per Cause No. 45546

# Exit OVEC ICPA in 2030 Portfolio

| Year | Nameplate MW | | | | | | | | Accredited MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | New CC | Existing CC | New CT | Existing CT | Nuclear* | DR, EE, DER, CVR | Short Term Capacity |
| 2025 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 325 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 28 | 1,500 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 59 | 1,875 |
| 2028 | 200 | 599 | 450 | 0 | 1,800 | 0 | 1,000 | 0 | 94 | 0 |
| 2029 | 200 | 596 | 450 | 0 | 1,800 | 0 | 2,000 | 0 | 119 | 0 |
| 2030 | 200 | 593 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 135 | 0 |
| 2031 | 200 | 590 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 151 | 0 |
| 2032 | 200 | 587 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 173 | 0 |
| 2033 | 200 | 584 | 450 | 0 | 3,600 | 0 | 2,000 | 0 | 190 | 0 |
| 2034 | 200 | 581 | 450 | 1,030 | 3,600 | 0 | 2,000 | 0 | 204 | 0 |
| 2035 | 200 | 578 | 450 | 1,030 | 3,600 | 0 | 2,000 | 888 | 221 | 0 |
| 2036 | 200 | 575 | 450 | 2,060 | 3,600 | 0 | 2,000 | 888 | 237 | 0 |
| 2037 | 200 | 572 | 450 | 2,060 | 3,600 | 0 | 2,000 | 888 | 250 | 0 |
| 2038 | 200 | 569 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 261 | 0 |
| 2039 | 200 | 566 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 270 | 0 |
| 2040 | 200 | 563 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 279 | 0 |
| 2041 | 200 | 560 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 286 | 0 |
| 2042 | 200 | 557 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 292 | 0 |
| 2043 | 0 | 554 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 298 | 0 |
| 2044 | 0 | 551 | 450 | 2,060 | 3,600 | 0 | 2,000 | 1,880 | 302 | 0 |

**Purpose of Scenario**:**
- Evaluating the most economical solution to meet capacity and energy needs considering base modeling parameters and assumptions of the termination of operation of the Ohio Valley Electric Corporation (OVEC) units under the Intercompany Power Agreement (ICPA) by the end of 2030

**Observations through 2030:**
- Resources selected are substantially similar to the reference case for 2028+
- Solar, wind, storage, and gas resources selected in 2028 in response to load growth by 2030
- Selected all available existing CC's by 2030 and existing CT's were selected to meet capacity obligation
- Additional DR, EE, DER, CVR selected compared to reference scenario

**Observations for 2031+:**
- New CC built in 2034 and 2036 to meet the load growth in the same period and the expiration of existing capacity purchase agreements
- Cook SLR selected in 2035 and 2038

*Nuclear includes Cook SLR

** Required per Cause No. 45546. The ICPA does not have any provision for early termination by one or more of the Sponsoring Companies.

# Results Summary Comparison and Portfolio Performance Indicators

Appendix

# Results Summary Comparison

| Portfolio | 2034 Wind | 2034 Solar | 2034 Storage | 2034 NGCT | 2034 NGCC | 2034 Nuclear* | 2034 DR, EE, DER, CVR** | 2034 Total Additions | 2044 Wind | 2044 Solar | 2044 Storage | 2044 NGCT | 2044 NGCC | 2044 Nuclear* | 2044 DR, EE, DER, CVR** | 2044 Total Additions |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Nameplate Capacity Additions (MW) | | | | | | | | Nameplate Capacity Additions (MW) | | | | | | | |
| **Preferred Portfolio** | 2,600 | 2,071 | 50 | 2,190 | 4,500 | 0 | 134 | **11,545** | 3,000 | 2,542 | 50 | 2,190 | 4,500 | 2,480 | 94 | **14,856** |
| **Base Reference** | 200 | 581 | 450 | 2,000 | 4,630 | 0 | 144 | **8,005** | 0 | 551 | 450 | 2,000 | 5,660 | 1,880 | 220 | **10,761** |
| **Enhanced Environmental Regulations** | 1,800 | 3,238 | 350 | 1,500 | 5,400 | 0 | 178 | **12,466** | 3,000 | 4,092 | 350 | 1,730 | 5,400 | 1,880 | 233 | **16,685** |
| **Base Under EPA Section 111(b)(d)** | 1,800 | 3,245 | 400 | 1,500 | 5,400 | 0 | 182 | **12,527** | 2,800 | 4,517 | 400 | 1,730 | 5,400 | 1,880 | 236 | **16,963** |
| **Low Carbon: Transition** | 2,000 | 6,194 | 300 | 3,500 | 2,700 | 0 | 173 | **14,867** | 3,000 | 9,359 | 500 | 3,730 | 2,700 | 3,080 | 235 | **22,604** |
| **Low Carbon: Expanded Build Limits** | 5,000 | 5,701 | 300 | 4,000 | 1,800 | 0 | 134 | **16,935** | 4,600 | 8,222 | 350 | 4,230 | 1,800 | 2780 | 200 | **22,182** |
| **High Growth** | 1,800 | 1,891 | 454 | 3,500 | 4,630 | 0 | 188 | **12,463** | 3,000 | 3,266 | 450 | 3,730 | 4,630 | 1,880 | 246 | **17,202** |
| **Low Growth** | 200 | 0 | 0 | 1,500 | 4,630 | 0 | 92 | **6,422** | 200 | 0 | 0 | 1,500 | 5,660 | 1,880 | 56 | **9,296** |

*Nuclear includes Cook SLR and SMR

**DR, EE, DER, CVR values are accredited

# Results Summary Comparison

| Portfolio | 2034 Nameplate Capacity Additions (MW) | | | | | | | | 2044 Nameplate Capacity Additions (MW) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Wind | Solar | Storage | NGCT | NGCC | Nuclear* | DR, EE, DER, CVR** | **Total Additions** | Wind | Solar | Storage | NGCT | NGCC | Nuclear* | DR, EE, DER, CVR** | **Total Additions** |
| **Base Reference** | 200 | 581 | 450 | 2,000 | 4,630 | 0 | 144 | **8,005** | 0 | 551 | 450 | 2,000 | 5,660 | 1,880 | 220 | **10,761** |
| **Expanded Wind Availability (Base)** | 1,200 | 145 | 0 | 2,000 | 4,630 | 0 | 168 | **8,143** | 0 | 0 | 0 | 2,230 | 5,660 | 1,880 | 229 | **9,999** |
| **Expanded Wind Availability (EER)** | 2,600 | 1,775 | 50 | 1,500 | 5,400 | 0 | 196 | **11,521** | 3,000 | 4,145 | 50 | 1,730 | 5,400 | 1,880 | 290 | **16,495** |
| **Base with High Load** | 600 | 1,742 | 451 | 3,000 | 4,630 | 0 | 88 | **10,511** | 1,000 | 1,251 | 451 | 3,460 | 5,660 | 1,880 | 55 | **13,757** |
| **Base with Low Load** | 800 | 0 | 0 | 2,000 | 4,630 | 0 | 100 | **7,530** | 1,000 | 0 | 0 | 2,000 | 4,630 | 1,880 | 53 | **9,563** |
| **High Technology Cost** | 200 | 581 | 450 | 2,000 | 4,630 | 0 | 144 | **8,005** | 0 | 551 | 450 | 2,000 | 5,660 | 1,880 | 220 | **10,761** |
| **Rockport Unit 1 Retires 2025** | 200 | 581 | 450 | 2,000 | 4,630 | 0 | 144 | **8,005** | 0 | 551 | 450 | 2,000 | 5,660 | 1,880 | 220 | **10,761** |
| **Rockport Unit 1 Retires 2026** | 200 | 581 | 450 | 2,000 | 4,630 | 0 | 144 | **8,005** | 0 | 551 | 450 | 2,000 | 5,660 | 1,880 | 220 | **10,761** |
| **Exit OVEC ICPA in 2030** | 200 | 581 | 450 | 2,000 | 4,630 | 0 | 204 | **8,065** | 0 | 551 | 450 | 2,000 | 5,660 | 1,880 | 302 | **10,843** |

*Nuclear includes Cook SLR and SMR
**DR, EE, DER, CVR values are accredited

# Portfolio Performance Indicators

| IURC Pillar | IRP Objective | Performance Indicator | Metric Description |
| --- | --- | --- | --- |
| Reliability | Maintain capacity reserve margin and the consideration of reliance on the market for the benefit of customers. | Energy Market Exposure – Purchases | NPV of market purchases and average volume exposure of market purchases (Costs and MWhs % of Internal Load) over 10 and 20 years. Lower values are better. |
| | | Energy Market Exposure – Sales | NPV of market sales and average volume exposure of market sales (Revenues and MWhs % of Internal Load) over 10 and 20 years. Lower values are better. |
| | | Planning Reserves | Average Target Reserve Margin over 10 and 20 years. Closest value to the % Target. |
| Affordability | Maintain focus on power supply cost and risks to customers | Net Present Value Revenue Requirement (NPVRR) | Portfolio 30yr NPVRR (power supply costs). Lower values are better. |
| | | Near-Term Power Supply Cost Impacts (CAGR) | 7-year CAGR of Annual Power Supply Cost. Lower values are better. |
| | | Portfolio Resilience | Range of Portfolio NPVRR (power supply costs) dispatched across all Scenarios. Lower values are better. |
| Resiliency | Maintain diversity of resources and fleet dispatchability | Resource Diversity | Percent change in Diversity Index inclusive of Capacity and Energy Diversity in years 2034 and 2044. Higher values are better. |
| | | Fleet Resiliency | Average % dispatchable capacity of company peak load over 10 and 20 years. Higher values are better. |
| (Grid) Stability | Maintain fleet of flexible and dispatchable resources | | |
| Environmental Sustainability | Maintain focus on portfolio environmental sustainability benefits and compliance costs | Emissions Change | $CO_2$, NOx, $SO_2$ emissions change compared to 2005 levels in years 2034 and 2044. Higher values are better. |
| | | Net Present Value Revenue Requirement (NPVRR) | Considered under Affordability Pillar above |

# Portfolio Performance Indicators

| Pillar | Affordability | | | Reliability | | | Reliability/ Resiliency | Grid Stability Resiliency | Environmental Sustainability | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Performance Indicators and Metrics* | ***Short Term*** *7-yr Rate CAGR* Power Supply $/MWh | ***Long Term*** *Supply Portfolio NPVRR Power Supply Costs* | ***Portfolio Resilience:*** *High Minus Low Scenario Range, Portfolio NPVRR* | ***Energy Market Risk*** *Purchases* | ***Energy Market Risk*** *Sales* | ***Planning Reserves*** *% Reserve Margin* | ***Resource Diversity*** | ***Fleet Resiliency:*** *Dispatchable Capacity* | ***Emissions Analysis:*** *% Change from 2005 Baseline* | | |
| Year Ref. | 2024-2031 | 2025-2044 | 2025-2044 | 10 years \| 20 years | 10 years \| 20 years | 10 years \| 20 years | 10 years \| 20 years | 10 years \| 20 years | 2034 \| 2044 | | |
| Units | % | $B | $B | NPV of Market Purchases & MWhs % of Total Demand | NPV of Market Sales & MWhs % of Total Demand | Average of Annual PRM % | Portfolio Index Percent Change from 2025 | Dispatchable Nameplate MW/ % of Company Peak Demand | % Change $CO_2$ | % Change NOx | % Change $SO_2$ |
| **Preferred Portfolio** | 0.4% | $33.1 | $11.4 | 10 Years: $3.1B (31%)<br>20 Years: $5.3B (27%) | 10 Years: $0.2B (1.3%)<br>20 Years: $0.5B (2.3%) | 10 Years: 4.2%<br>20 Years: -0.6% | Capacity: 39% \| 35%<br>Energy: 299% \| 299% | 10 Years: 91%<br>20 Years: 93% | 2034: -63%<br>2044: -63% | 2034: -96%<br>2044: -96% | 2034: -100%<br>2044: -100% |
| **Base Reference** | -0.5% | $32.0 | $13.4 | 10 Years: $2.6B (27%)<br>20 Years: $4.3B (22%) | 10 Years: $0.0B (0.1%)<br>20 Years: $0.1B (0.3%) | 10 Years: -0.7%<br>20 Years: -3.4% | Capacity: 31% \| 19%<br>Energy: 173% \| 139% | 10 Years: 90%<br>20 Years: 97% | 2034: -39%<br>2044: -24% | 2034: -94%<br>2044: -93% | 2034: -100%<br>2044: -100% |
| **Enhanced Environmental Regulations** | 0.7% | $33.2 | N/A | 10 Years: $3.1B (31%)<br>20 Years: $5.5B (28%) | 10 Years: $0.6B (4.2%)<br>20 Years: $1.4B (5.7%) | 10 Years: 5.3%<br>20 Years: -0.3% | Capacity: 35% \| 37%<br>Energy: 306% \| 325% | 10 Years: 95%<br>20 Years: 95% | 2034: -56%<br>2044: -55% | 2034: -95%<br>2044: -95% | 2034: -100%<br>2044: -100% |
| **Base Under EPA Section 111(b)(d)** | 0.7% | $33.3 | N/A | 10 Years: $3.1B (31%)<br>20 Years: $5.5B (28%) | 10 Years: $0.5B (4.0%)<br>20 Years: $1.4B (5.7%) | 10 Years: 5.5%<br>20 Years: -0.2% | Capacity: 36% \| 38%<br>Energy: 281% \| 299% | 10 Years: 96%<br>20 Years: 96% | 2034: -56%<br>2044: -55% | 2034: -95%<br>2044: -95% | 2034: -100%<br>2044: -100% |
| **Low Carbon: Expanded Build Limits** | 4.5% | $41.4 | N/A | 10 Years: $2.1B (22%)<br>20 Years: $3.6B (18%) | 10 Years: $0.4B (3.6%)<br>20 Years: $1.4B (6.0%) | 10 Years: 4.5%<br>20 Years: -0.8% | Capacity: 56% \| 52%<br>Energy: 317% \| 311% | 10 Years: 87%<br>20 Years: 88% | 2034: -77%<br>2044: -77% | 2034: -97%<br>2044: -97% | 2034: -100%<br>2044: -100% |
| **Low Carbon: Transition** | 1.3% | $39.9 | $9.8 | 10 Years: $2.7B (27%)<br>20 Years: $4.1B (20%) | 10 Years: $0.2B (1.6%)<br>20 Years: $1.7B (7.7%) | 10 Years: 2.0%<br>20 Years: 0.5% | Capacity: 53% \| 54%<br>Energy: 302% \| 304% | 10 Years: 91%<br>20 Years: 95% | 2034: -65%<br>2044: -65% | 2034: -96%<br>2044: -96% | 2034: -100%<br>2044: -100% |
| **High Growth** | 1.6% | $39.3 | N/A | 10 Years: $4.0B (30%)<br>20 Years: $6.6B (23%) | 10 Years: $0.1B (0.5%)<br>20 Years: $0.3B (0.9%) | 10 Years: 3.9%<br>20 Years: -0.7% | Capacity: 41% \| 43%<br>Energy: 71% \| 79% | 10 Years: 96%<br>20 Years: 97% | 2034: -46%<br>2044: -34% | 2034: -95%<br>2044: -93% | 2034: -100%<br>2044: -100% |
| **Low Growth** | -2.3% | $25.7 | N/A | 10 Years: $1.8B (24%)<br>20 Years: $2.5B (19%) | 10 Years: $0.0B (0.3%)<br>20 Years: $0.2B (1.9%) | 10 Years: -0.3%<br>20 Years: -1.5% | Capacity: 18% \| 5%<br>Energy: 161% \| 154% | 10 Years: 89%<br>20 Years: 97% | 2034: -35%<br>2044: -35% | 2034: -93%<br>2044: -94% | 2034: -100%<br>2044: -100% |
| **Expanded Wind Availability (Base)** | -0.5% | $31.8 | N/A | 10 Years: $2.4B (25%)<br>20 Years: $3.9B (20%) | 10 Years: $0.0B (0.2%)<br>20 Years: $0.1B (0.6%) | 10 Years: -0.6%<br>20 Years: -3.4% | Capacity: 28% \| 12%<br>Energy: 188% \| 114% | 10 Years: 86%<br>20 Years: 93% | 2034: -39%<br>2044: -24% | 2034: -94%<br>2044: -93% | 2034: -100%<br>2044: -100% |
| **Expanded Wind Availability (EER)** | 0.5% | $32.8 | $11.4 | 10 Years: $3.1B (31%)<br>20 Years: $5.4B (27%) | 10 Years: $0.5B (3.5%)<br>20 Years: $1.3B (5.2%) | 10 Years: 5.1%<br>20 Years: -0.6% | Capacity: 31% \| 34%<br>Energy: 296% \| 318% | 10 Years: 92%<br>20 Years: 92% | 2034: -56%<br>2044: -55% | 2034: -95%<br>2044: -95% | 2034: -100%<br>2044: -100% |

# Portfolio Performance Indicators

| Pillar | Affordability | | | Reliability | | | Reliability/ Resiliency | Grid Stability Resiliency | Environmental Sustainability | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| ***Performance Indicators and Metrics*** | ***Short Term*** *7-yr Rate CAGR* Power Supply $/MWh | ***Long Term*** *Supply Portfolio NPVRR Power Supply Costs* | ***Portfolio Resilience:*** *High Minus Low Scenario Range, Portfolio NPVRR* | ***Energy Market Risk*** *Purchases* | ***Energy Market Risk*** *Sales* | ***Planning Reserves*** *% Reserve Margin* | ***Resource Diversity*** | ***Fleet Resiliency:*** *Dispatchable Capacity* | ***Emissions Analysis:*** *% Change from 2005 Baseline* | | |
| Year Ref. | 2024-2031 | 2025-2044 | 2025-2044 | 10 years \| 20 years | 10 years \| 20 years | 10 years \| 20 years | 10 years \| 20 years | 10 years \| 20 years | 2034 \| 2044 | | |
| Units | % | $B | $B | NPV of Market Purchases & MWhs % of Total Demand | NPV of Market Sales & MWhs % of Total Demand | Average of Annual PRM % | Portfolio Index Percent Change from 2025 | Dispatchable Nameplate MW/ % of Company Peak Demand | % Change $CO_2$ | % Change NOx | % Change $SO_2$ |
| **Base with High Load** | -0.1% | $34.9 | N/A | 10 Years: $2.8B (28%)<br>20 Years: $4.9B (23%) | 10 Years: $0.0B (0.3%)<br>20 Years: $0.1B (0.3%) | 10 Years: 0.8%<br>20 Years: -2.6% | Capacity: 34% \| 25%<br>Energy: 208% \| 189% | 10 Years: 92%<br>20 Years: 98% | 2034: -39%<br>2044: -24% | 2034: -94%<br>2044: -93% | 2034: -100%<br>2044: -100% |
| **Base with Low Load** | -0.7% | $28.3 | N/A | 10 Years: $2.1B (24%)<br>20 Years: $3.6B (20%) | 10 Years: $0.1B (0.5%)<br>20 Years: $0.1B (0.7%) | 10 Years: 2.3%<br>20 Years: -1.9% | Capacity: 24% \| 19%<br>Energy: 170% \| 172% | 10 Years: 92%<br>20 Years: 96% | 2034: -39%<br>2044: -39% | 2034: -94%<br>2044: -94% | 2034: -100%<br>2044: -100% |
| **High Technology Costs** | 0.7% | $34.8 | N/A | 10 Years: $2.6B (27%)<br>20 Years: $4.3B (22%) | 10 Years: $0.0B (0.1%)<br>20 Years: $0.1B (0.3%) | 10 Years: -0.7%<br>20 Years: -3.4% | Capacity: 31% \| 19%<br>Energy: 173% \| 139% | 10 Years: 90%<br>20 Years: 97% | 2034: -39%<br>2044: -24% | 2034: -94%<br>2044: -93% | 2034: -100%<br>2044: -100% |
| **Rockport Unit 1 Retires 2025** | -0.5% | $32.6 | N/A | 10 Years: $2.6B (27%)<br>20 Years: $4.3B (22%) | 10 Years: $0.0B (0.1%)<br>20 Years: $0.1B (0.3%) | 10 Years: -0.7%<br>20 Years: -3.4% | Capacity: 80% \| 64%<br>Energy: 183% \| 148% | 10 Years: 84%<br>20 Years: 95% | 2034: -39%<br>2044: -24% | 2034: -94%<br>2044: -93% | 2034: -100%<br>2044: -100% |
| **Rockport Unit 1 Retires 2026** | -0.5% | $32.4 | N/A | 10 Years: $2.6B (27%)<br>20 Years: $4.3B (22%) | 10 Years: $0.0B (0.1%)<br>20 Years: $0.1B (0.3%) | 10 Years: -0.6%<br>20 Years: -3.4% | Capacity: 31% \| 19%<br>Energy: 173% \| 139% | 10 Years: 86%<br>20 Years: 95% | 2034: -39%<br>2044: -24% | 2034: -94%<br>2044: -93% | 2034: -100%<br>2044: -100% |
| **Exit OVEC ICPA in 2030** | -0.4% | $32.1 | N/A | 10 Years: $2.8B (28%)<br>20 Years: $4.4B (22%) | 10 Years: $0.0B (0.1%)<br>20 Years: $0.1B (0.3%) | 10 Years: -0.6%<br>20 Years: -3.2% | Capacity: 27% \| 21%<br>Energy: 177% \| 142% | 10 Years: 90%<br>20 Years: 97% | 2034: -39%<br>2044: -24% | 2034: -94%<br>2044: -93% | 2034: -100%<br>2044: -100% |

# Affordability

The Affordability indicators compare the cost to customers under Base Case market scenario conditions over the short- and long-term and the Portfolio cost range when evaluated across the different market scenarios.

| Performance Indicator | Metric | Description |
|---|---|---|
| Near-term | 7-year Power Supply Cost CAGR under the Base Case (2024-2031) | • I&M measures and considers the expected Compound Annual Growth Rate ("CAGR") of expected power supply costs for the years 2024-2031 as the metric for the short-term performance indicator<br>• A lower number is better, indicating slower growth in power supply costs |
| Long-term | Portfolio NPVRR under the Base Case (2025-2044) | • I&M measures and considers the growth in Net Present Value Revenue Requirement (power supply costs) over 20 years as the long-term metric<br>• NPVRR represents total long-term cost paid by I&M related to power supply. This includes plant O&M costs, fuel costs, environmental costs, net purchases and sales of energy and capacity, property and income taxes, and the return on capital<br>• A lower number is better, indicating lower costs to supply customers with power |
| Portfolio Resilience | High Minus Low Scenario Range 20-yr NPVRR (2025-2044) | • I&M measures and considers the range of 20-yr NPVRR reported by each portfolio across all PJM market scenarios. This metric reports the difference between the highest and lowest cost scenarios reported by the candidate portfolio on an NPVRR<br>• A lower number is better, indicating a tighter grouping of expected customer costs across a wide range of long-term market conditions |

# Reliability

The Reliability indicators compare the amount of excess reserves and the reliance on market resources to serve customers across candidate portfolios.

| Performance Indicator | Metric | Description |
|---|---|---|
| Planning Reserves | Reserve Margin % | • I&M measures and considers the average amount of firm capacity in each candidate portfolio over 10 and 20 years<br>• A higher number is better, indicating more reserves are available to meet PJM requirements |
| Energy Market Risk | Portfolio Cost Range of market purchases, MWhs as % of internal Load | • I&M measures and considers the reliance of each candidate portfolio on market purchases to balance seasonal generation with customer load<br>• The metric reports the NPV of the cost of market purchases and the average MWhs as a % of internal load over 10 and 20 years<br>• A lower number indicates less reliance on the market to meet customer needs |
| | Portfolio Revenue Range of market sales, MWhs as % of internal Load | • I&M measures and considers the reliance of each candidate portfolio on market sales to balance seasonal generation with customer load<br>• The metric reports the NPV of the cost of market sales and the average MWhs as a % of internal load over 10 and 20 years<br>• A lower number indicates less reliance on the market to meet customer needs |

# Resiliency

The Resiliency indicators compare the amount of dispatchable capacity in the fleet and the technology diversity for capacity and energy of the Indiana generating mix across candidate portfolios.

| Performance Indicator | Metric | Description |
|---|---|---|
| Resource Diversity | Percent Change of the Capacity and Energy Diversity Index in 2034 and 2044 | • I&M measures and considers the capacity and energy diversity of new technologies added to its portfolio when comparing candidate portfolios<br>• The metric will use the Shannon-Weiner Index to measure the number of different technologies and their respective contribution to the portfolio totals for both capacity and energy diversity for each Portfolio. A percent change from 2025 is calculated in year 2034 and 2044<br>• A higher number is better. A portfolio that includes diverse resources for both capacity and energy delivery mitigates customers' performance risk when conditions for that technology are unfavorable |
| Fleet Resiliency | Nameplate MW of dispatchable units in 2034 and 2044 | • I&M measures and considers the average amount of dispatchable units added to the portfolio over 10 and 20 years<br>• The metric for this indicator is the average of total Nameplate MW of dispatchable units as a percent of company peak demand<br>• A higher number is better, indicating greater ability to ramp generation up or down to react to market conditions and follow load |

# (Grid) Stability

The Grid Stability indicator compares the amount of dispatchable capacity in the fleet, and the technology diversity of the Indiana generating mix across candidate portfolios.

| Performance Indicator | Metric | Description |
|---|---|---|
| Fleet Resiliency | Nameplate MW of dispatchable units in 2034 and 2044 | • I&M measures and considers the average amount of dispatchable units added to the portfolio over 10 and 20 years<br>• The metric for this indicator is the average of total Nameplate MW of dispatchable units as a percent of company peak demand<br>• A higher number is better, indicating greater ability to ramp generation up or down to react to market conditions and follow load |

# Sustainability

I&M also considered a Sustainability indicator to compare portfolio performance towards meeting corporate sustainability targets.

| Performance Indicator | Metric | Description |
| --- | --- | --- |
| $CO_2$, NOx, $SO_2$, Emissions | 2034 & 2044 % Change from 2005 Baseline | • I&M measures and considers the total amount of expected $CO_2$, NOx and $SO_2$ emissions of each candidate portfolio.<br>• This metric compares the forecasted emissions of candidate portfolios in 2034 and 2044 under Reference Case market conditions with actual historical emissions from the year 2005.<br>• A higher number indicates greater levels of emissions reductions have been achieved and customers are less exposed to potential future $CO_2$ costs. |

# Indiana Michigan Power Company's 2024 Indiana Integrated Resource Plan

## Stakeholder Workshop #4

## March 5, 2025

## Table of Contents

## Welcome & Introductions

*Kayla Zellers covered Slides 1-2.*

Kayla Zellers, Director of Resource Planning at American Electric Power Company (AEP), called the meeting to order at 1:00 PM on March 5, 2025. Kayla welcomed participants to Stakeholder Workshop 4 for I&M's 2024 Indiana Integrated Resource Plan and introduced AEP and I&M team members on the call.

*Andrew Williamson covered Slide 2.*

Andrew Williamson welcomed stakeholders to Stakeholder Meeting 4. Andrew reiterated that this IRP is a collaboration between I&M and its stakeholders, and that feedback, questions and comments are encouraged during this meeting and at any time during the process.

Andrew then introduced the remainder of the I&M Leadership team present at the meeting before handing it back over to Kayla.

Kayla presented an overview of the meeting's contents, including Candidate Portfolios, Risk Analysis and the Preferred Portfolio development.

Kayla introduced Brian Despard, Senior Project Manager at 1898 & Co.

*Brian Despard Covered Slides 4-5*.

Brian Despard discussed stakeholder participation, stating that questions would be allowed anytime during the presentation via Microsoft Teams' "Raise Hand" and "Chat" functions. Any questions regarding the Indiana IRP can be submitted to I&MIRP@aep.com anytime. All questions and answers recorded during this meeting (or shortly after, via email) have been provided within these minutes.

Finally, Brian presented guidelines for constructive participation.

## Review of 2024 IRP Process

*Kayla Zellers covered Slides 6-9.*

Kayla reviewed the IRP process with the visual presented on slide 6, which was also shared in Stakeholder Meeting 1. She noted that the visual has been slightly adjusted since

Stakeholder Meeting 1 to reflect a more accurate representation of the IRP process. When comparing the presentations, a few small differences can be noticed.

On the right side of the slide, Kayla walked through the steps. In the first stakeholder meeting, the IRP objectives were defined, aligning with the Five Pillars of Indiana Energy policy. In the second meeting, key modeling inputs and assumptions were discussed. During Stakeholder Meetings 3A and 3B, optimized portfolios were reviewed. In the current meeting, steps 4 and 5 will be covered, including a review of the Risk Analysis, the Preferred Portfolio, and the Short-Term Action Plan.

In the lower portion of the slide, Kayla highlighted that the IRP stakeholders have had opportunities throughout the process to provide feedback. Since the first stakeholder meeting roughly seven months ago, the stakeholder group has provided significant input, which has been considered in the IRP.

Kayla presented a timeline of the IRP engagement on slide 7 with the stakeholder group. The timeline includes Stakeholder Meetings, Technical Conferences, and Office Hours which were held for technical stakeholders to ask modeling-specific questions.

The first public stakeholder meeting in June kicked off the IRP, discussing objectives, assumptions, scenarios, and proposed portfolio metrics. Smaller group sessions in August and September with hyperscale customers and the technical stakeholder group provided initial feedback, such as including the Energy Community tax credit bonus alongside the investment tax credit. This feedback was incorporated into the IRP.

The second public stakeholder meeting in September furthered the discussion on inputs and key modeling assumptions. Following this, portfolio modeling efforts began and extensive modeling for different portfolios was completed.

In early October, stakeholder feedback on inputs and assumptions was received, particularly regarding the cost and build limit assumptions for resources. These were re-evaluated and updated in Stakeholder Meeting 3A. Continuous evaluation of build limit assumptions led to updates to near-term build limits for wind resources. This led to two new Expanded Wind Availability Cases, which were covered in Stakeholder Meeting 3B.

Kayla discussed the Indiana-specific capacity and energy positions on slide 8. Although these visuals have been covered in the past, she emphasized their importance in showcasing the need and problem the IRP aims to address with the growing customer base.

The visuals highlight a significant capacity and energy need, specifically in the first 10 years. There is a forecasted 4 GW capacity and a 43,000 GWh energy shortfall. This immense need underpins the significant resource additions seen in all the modeled portfolios throughout the process.

Kayla reviewed with stakeholders the 15 modeled portfolios to understand resource selection under various inputs and assumptions. In all cases, natural gas resources, whether CCs or CTs, were necessary to meet the capacity obligations. However, the energy need could be met with different mixes of renewable natural gas and nuclear resources. As the 15 different cases were reviewed, time was taken to identify key attributes that were important for selecting candidate portfolios for the risk analysis.

## Candidate Portfolio Selection

*Kayla Zellers covered slides 10-11.*

Kayla segued into the selection process of Candidate Portfolios on slide 10. This process included looking at the capacity additions and performance indicator metrics. Three Candidate Portfolios were selected to move on to the next step of Risk Analysis.

The first Candidate Portfolio selected was the Base Reference Case because this portfolio functions as an important comparison point for all the other Candidate Portfolios and the Preferred Portfolio. The Base Reference Case also had one of the lowest costs.

The Low Carbon: Transition to Objective Case was selected because this portfolio had one of the highest resource diversity values and the highest environmental sustainability results. This portfolio selected a large amount of carbon-free resources. Kayla stated that one downside to this portfolio was the affordability metric, as this portfolio showed some of the highest costs in comparison to other portfolios.

The Expanded Wind Availability (EER) was selected because it had a lower net present value and short-term growth rate compared to some of the other portfolios modeled. It had favorable resource diversity values and the second-highest environmental sustainability results. In addition, it was important to complete Risk Analysis on a portfolio that considered the EPA Section 111(b)(d) regulations.

Capacity and energy mixes were also assessed when selecting Candidate Portfolios. Kayla presented visuals showing the firm capacity and energy mixes for the years 2034 and 2044.

Examining the firm capacity mix, the Low Carbon: Transition to Objective and Expanded Wind Availability (EER) Cases have more accredited capacity from renewables compared to the Base Reference Case. However, the amount of accredited capacity from renewables remains small compared to natural gas and nuclear resources due to the low accredited capacity values for renewables assigned by PJM.

In the Expanded Wind Availability (EER) Case, the accredited capacity from natural gas resources is similar to that of the Base Reference Case. However, the energy mix between these two cases differ significantly, primarily due to the additional renewable resources and capacity factor constraints on natural gas resources in the Expanded Wind Availability (EER).

There is greater energy diversity in the Low Carbon: Transition to Objective and Expanded Wind Availability (EER) Cases compared to the Base Reference Case. Resource diversity was important for the development of the Preferred Portfolio.

Kayla welcomed Mohamed Abukaram, Director of Resource Planning at I&M to present expansion plan modeling results.

## Risk Analysis Method

*Mohamed Abukaram covered slides 12-13*

Mohamed introduced the methodology of the risk analysis process on each candidate and Preferred Portfolio. In the Risk Analysis process, uncertainty was calculated for load, energy market prices, and gas prices. This calculation produced 100 samples for each input variable. Probability Distributions for uncertainty input variables were developed and applied along with correlations to capture uncertainties and interdependencies. These variables were injected into the build plans for each portfolio, with the physical resources of these portfolios remaining fixed. Energy market imports, exports and short-term capacity purchases were allowed to fluctuate to assess the cost and market risk of each portfolio.

Mohamed presented a comparison of candidate portfolios using Box and Whisker charts that demonstrate cost and market risks. The charts included Net Present Value (NPV) risk, energy market purchases as a percent of annual load, and energy market sales as a percent of annual load for both 10-year and 20-year time frames. The bottom whisker to the top whiskers in the charts represent the 10th to 90th percentile of outcomes. The thicker portion of each bar shows the 25th to 75th percentile of outcomes. The white dot on each bar represents the mean of the outcomes.

The Expanded Wind Availability (EER) Case showed less variation in cost risk compared to the Base Reference Case, while the Low Carbon: Transition to Objective Case had the least variation but a higher mean cost.

In terms of energy market purchases, the Expanded Wind (EER) Case had significantly less variation due to reduced gas generation risks, driven by capacity factor limitations due to EPA 111(b)(d) policy. The mean of the Expanded Wind Availability (EER) Case was similar to the Base Reference Case but with far less risk. For energy market sales, the Low Carbon: Transition to Objective Case had a higher risk due to increased renewable energy penetration, which affects market sales.

Mohamed concluded that the Expanded Wind Availability (EER) Case offered the best balance of cost risk and market risk. It has a similar mean cost and market purchase risk as the Base Reference Case but with lower risk, and a significantly lower market sales risk as compared to the Low Carbon: Transition to Objective Case.

## Preferred Portfolio Development

*Andrew Williamson covered slides 14-16.*

Andrew explained the development of the Preferred Portfolio, emphasizing that it was a thorough process evaluating various scenarios and sensitivities. The goal was to ensure the Preferred Portfolio balanced the consideration of Indiana's Five Pillars of energy policy. The Portfolio Performance Indicator metrics were used to inform the selection of the Preferred Portfolio. Ultimately, the Expanded Wind Availability (EER) Case was chosen as the primary basis for the Preferred Portfolio development. This case provided a well-rounded, diverse resource plan that better positions I&M for future environmental compliance.

Additionally, the Preferred Portfolio was developed by leveraging I&M’s 2024 RFPs, which offered real-time market intelligence focusing on resource availability in the near-term. This approach allowed for the incorporation of more wind resources into the portfolio than initially expected. I&M also took advantage of opportunities specific to the Rockport site, enabling cost savings associated with Small Modular Reactor (SMR) technology.

Another key consideration for this IRP was the relicensing of the Cook nuclear plant. This resource option was consistently selected in all evaluated scenarios and sensitivities. Thus, it was selected in the Preferred Portfolio.

Andrew presented a summary of the resource capacity additions associated with the Preferred Portfolio from the capacity expansion analysis. The Preferred Portfolio significantly expands I&M's clean energy resources, adding nearly 3,000 MW of wind, solar, and storage over the next five years. The Preferred Portfolio also includes 600 MW of SMR technology to be added between 2036 and 2037.

A key component of the plan is the subsequent license renewal for the Cook nuclear plant, which will maintain Cook as a foundational resource for future electric service. This license renewal will help ensure reliability, resource adequacy, and rate stability for customers. Additionally, the plan selects the relicensing of two hydroelectric facilities evaluated in the IRP. Andrew emphasized that the IRP evaluation is just one of several factors that will be considered in making a final decision about these hydro facilities.

Lastly, the Preferred Portfolio includes a diverse mix of demand-side resources, further enhancing the overall resource plan.

Andrew presented a depiction of the Preferred Portfolio's capacity and energy relative to I&M's obligations. The Preferred Portfolio notably increases the amount of clean energy resources compared to many other scenarios and sensitivities evaluated during the IRP process. Nuclear and natural gas resources remain critical for meeting I&M's future capacity needs, a trend observed consistently throughout the other scenarios and sensitivities modeled. In addition, renewables make a significantly larger contribution to I&M's future energy needs in the Preferred Portfolio.

This Preferred Portfolio provides a balanced mix of dispatchable technologies and nuclear energy while also leveraging the benefits of intermittent renewable resources. The Preferred Portfolio represents a diverse combination of resources to meet I&M's future energy requirements.

## Q&A Related to Preferred Portfolio Development

1. How do Renewables result in higher market energy sales?
    a. Renewables result in higher energy market sales due to the manner in which renewable energy complements dispatchable energy. Renewables provide

intermittent generation energy during specific periods of the day, and when this is aggregated with dispatchable energy, can cause our energy production to exceed loads levels and thus generates market sales.

2. How many MWs of data centers were included in the load forecast behind the Preferred Portfolio?
    a. The load forecast assumptions of the Preferred Portfolio is no different from the load forecast assumptions that were used through all the scenarios and sensitivities, with the exception of the High and Low Economic Growth and Base with High and Low Indiana Load Cases. The load shown in the Preferred Portfolio represents the base load forecast that was evaluated throughout the IRP process.
3. Can you further explain how to interpret the zeros across the board for years 2025-2027 in the table on slide 15? Do the zeros mean there were no resource additions in those years?
    a. Yes, that is correct, and is due to the long-term supply-side resource limitation assumptions used in the IRP. The IRP assumes 2028 would be the earliest year where supply-side resources would be available. Between 2025 and 2028, the IRP could select short-term capacity and demand-side resource options to meet the capacity and energy requirements between 2025-2027.
4. Why does the Expanded Wind Availability (EER) Case reduce solar compared to the Low Carbon: Transition to Objective Case?
    a. In the Expanded Wind Availability (EER) Case, less solar is selected compared to the Low Carbon: Transition to Objective Case because more wind is selected. The increase in wind availability in this case, on a per year and cumulative basis starting in 2028, increases the selection of wind resources and as a result decreases the selection of solar. Alternatively, in the Low Carbon: Transition to Objective Case, the Low Carbon Objective as discussed in Stakeholder Meeting 3A established a low carbon energy requirement that influenced the resource selection. To meet that objective, the model selected more solar in the near term as less wind was available.

5. Why are the accredited MWs declining after 2035 for DR/EE/DER (this question is related to the Preferred Portfolio)?
    a. These are cumulative numbers, and the decrease is due to some of the resources reaching end of life by the middle of the planning horizon.
6. Did you model the expanded OVEC capacity that I&M has proposed shifting from Michigan to Indiana customers?
    a. Not as part of this IRP process. We are addressing that through a separate case that is currently pending the Commission's review.
7. Most plans point to market purchases, especially in the short term to meet demand. How will that impact consumer prices?
    a. It is necessary to utilize short-term capacity to bridge the gap between our load obligation and what our long-term resources are able to provide. This is something that we have done historically and are currently doing. The impact of this is relative to what the cost of short-term capacity is compared to a long-term generation resource. At this time, we are not expecting there to be a significant impact on the cost of providing service to our customers. Most importantly, we do acquire the short-term capacity through competitive solicitations to provide the most economic price available.
8. Why is there so little storage in the Preferred Portfolio?
    a. In the Preferred Portfolio and other portfolios, we allowed for storage to be selected economically. Given the energy and capacity value of storage, the selection of 50 MW of standalone storage is reasonable. The capacity from existing combined cycles and combustion turbines as well as the intermittent energy generated from solar was more economic than building more storage.
9. Is the nuclear on the Michigan State side or projected for Indiana? Is it SMR?
    a. The nuclear column represents two resources. It represents the relicensing of the Cook nuclear plant, which is located in southwest Michigan. However, it does provide service to Indiana retail customers. The values associated with the Cook nuclear plant are Indiana's jurisdictional share of capacity. In addition, nuclear numbers include two SMR units, one in 2036 and one in

2037. These are each 300 MW and would be located at the Rockport facility in Rockport, IN which is in Southeastern Indiana.

10. How are you comparing fairly the three portfolios, as they have very large capacity differences, outlined below?

    - Base Reference - 8,005 MW
    - Low Carbon: Transition to Objective - 14,867 MW
    - Expanded Wind Availability (EER) - 11,521 MW

    a. These three portfolios, and all other portfolios, were compared using the Portfolio Performance Indicator metrics (slides 19 and 20), the Results Summary Comparison (slide 17), and the Risk Analysis (slide 18). Further discussion of these portfolios occurred later in the meeting.

11. What are the biggest hurdles to wind and solar expansion?

    a. New renewable development faces a lot of challenges with zoning and permitting. This is true for several counties in Indiana and AEP has experienced this in many different states and has seen this throughout the country. Additionally, the solar resources are intermittent, and they provide a lower accredited capacity value for I&M's customers. PJM goes through a process of evaluating the capacity value associated with intermittent resources and this is called Effective Load Carrying Capability (ELCC). The capacity value of solar is closer to 10%, and wind is closer to 30% versus dispatchable technology, which will be in the range of 70% or higher. The specific ELCC values over the planning horizon are included in Stakeholder Meeting 2. The modeling recognizes the hurdle around the capacity value and that significantly more renewable resources would have to be selected to achieve a similar capacity value as dispatchable technologies with higher capacity factors, resulting in a more expensive portfolio.

12. Where is the Cook nuclear radioactive waste disposed?

    a. The Cook nuclear plant, similar to other nuclear facilities in the country, is storing spent nuclear fuel on site. They have a very robust nuclear fuel storage program that is highly regulated. We continue to work with the Department of Energy (DOE) on spent nuclear fuel storage, including reimbursement of storage costs, which is likely to continue until the federal government establishes a national repository. More generally, radiological waste from normal plant activities are disposed of utilizing qualified vendors. These vendors contract with licensed disposal sites located in both Texas and Utah.

## Results Summary & Comparison

*Kayla Zellers covered slides 17-18.*

Kayla explained that the Preferred Portfolio was based on the Expanded Wind Availability (EER) Case. She pointed out that the firm capacity chart showed an increase in nuclear capacity from the Cook relicensing and the addition of SMRs in 2036 and 2037, which is a difference between the Preferred Portfolio and the Expanded Wind Availability (EER) Case.

Regarding energy mix, Kayla noted that over both 10- and 20-year periods, the Preferred Portfolio displayed greater diversity in the resource mix compared to the Base Reference Case. By 2044, wind and solar were expected to contribute roughly 25% of the energy needed to serve Indiana's load in the Preferred Portfolio. There is also a reduction in natural gas energy compared to the Expanded Wind Availability (EER) Case, due to the replacement of a natural gas CC with the addition of the Rockport CT and SMRs.

Kayla emphasized that the energy reduction from natural gas was replaced by carbon-free energy from the SMRs. She addressed comparing cases with different capacity additions over the planning horizon, explaining that the visual represented firm, or accredited capacity. She noted that renewable resources generally have a lower accredited capacity value compared to dispatchable resources. In the Low Carbon: Transition to Objective Case, a significant amount of renewables was selected, increasing the nameplate capacity additions. However, when comparing the Expanded Wind Availability (EER) and the Preferred Portfolio from an accredited capacity perspective, the differences were not as pronounced. Kayla stated that the Low Carbon: Transition to Objective Case had higher accredited capacity values because it aimed to serve a specific amount of Indiana's energy needs with carbon-free energy.

Kayla covered the Preferred Portfolio Risk Analysis results in comparison to the Candidate Portfolios. She noted that the slide was similar to what Mohamed had presented earlier, with the addition of the Preferred Portfolio shown in light blue. The Risk Analysis results supported the selection of the Preferred Portfolio and provided insights into how the portfolio would perform under various uncertain futures.

Mohamed had discussed earlier that the input data for the risk analysis, highlighting the variability in load market, energy, and gas prices. The NPV chart showed that the Preferred Portfolio's variability was similar to, but slightly less than, the Expanded Wind Availability (EER) Case. She emphasized the importance of this visual, as NPV uncertainty ranges are included in the Portfolio Performance Indicator matrix.

Based on the 20-year Market Purchases (% of Annual Load), the Preferred Portfolio results were similar to the Expanded Wind Availability (EER), with much less variability compared to the Base Reference Case.

For the 20-year Market Sales (% of Annual Load) chart, Kayla highlighted how the market sales variability and mean value for the Preferred Portfolio were lower compared to the Expanded Wind Availability (EER). This was attributed to the lower number of solar resources in the Preferred Portfolio. The variability seen in the market sales risk is a function of the number of renewables selected in the plan.

The Preferred Portfolio displayed a balanced mix of cost and market energy variability in the risk analysis. Kayla concluded that the Preferred Portfolio's level of variability was similar to the Expanded Wind Availability (EER) and much less than the Base Reference Case.

**Portfolio Performance Indicators**

*Kayla Zellers covered slides 19-20*

Kayla explained that the Preferred Portfolio is about 3% more costly than the Base Reference Case, totaling $33.1 billion expressed as an NPV. However, this additional cost brings several benefits and a more balanced consideration of the Five Pillars, as reflected in the Portfolio Performance Indicators matrix.

One key benefit is the Portfolio Resilience metric, which represents the 10$^{th}$ to 90$^{th}$ percentile range of the NPV from the Risk Analysis (slide 18). While the Base Reference Case has a lower overall cost, it shows a much higher range of NPV, indicating more risk. The Low Carbon: Transition to Objective Case has the least variability but comes with a much higher cost.

In terms of Short-Term Affordability, the Preferred Portfolio shows a slightly lower growth rate compared to the Expanded Wind Availability (EER) Case. This is due to the lower cost assumption for the Rockport CTs compared to the existing CCs. The addition of the Rockport CT and SMR replaced 900 MW of existing CCs, lowering the short-term cost for the Preferred Portfolio.

Another significant benefit of the Preferred Portfolio is in the Environmental Sustainability metrics. In a future where the proposed greenhouse gas rules are implemented, the Preferred Portfolio achieves a similar reduction in carbon emissions compared to the Low Carbon: Transition to Objective Case but at a much more affordable cost. This cost difference is over $6 billion in NPV across the planning horizon, making the Preferred Portfolio a cost-effective option for reducing carbon emissions.

Kayla explained the use of the Shannon Weiner Diversity Index to measure capacity and energy diversity for each case modeled over the planning horizon. This index was computed annually, and the percent change in capacity and energy diversity was analyzed over 10- and 20-year periods starting from 2025. She provided this background for those who might not have attended Stakeholder Meetings 3A and 3B and recommended looking up the Shannon Weiner Index for more details on its calculation.

Kayla emphasized that resource diversity was a crucial metric in developing the Preferred Portfolio. The Preferred Portfolio achieved a much higher capacity and energy diversity metric compared to the Base Reference Case and had similar results to the Expanded Wind Availability (EER). However, the Low Carbon: Transition to Objective Case had higher capacity and energy diversity values but was more costly.

Kayla also highlighted the fleet resiliency metric, noting that all modeled portfolios provided significant dispatchable resources relative to company peak demand. Over the 20-year period, the Preferred Portfolio showed a slight improvement in dispatchable capacity compared to the Expanded Wind Availability (EER). The Preferred Portfolio provided over 90% of dispatchable capacity relative to company peak demand, demonstrating strong fleet resiliency.

Kayla reiterated that the Preferred Portfolio successfully balanced all the different objectives and metrics set out for the IRP, aligning with the Five Pillars.

## Q&A Related to Results Summary

13. What is the reason for the 2034 and 2044 emission values to be the same in the Preferred Portfolio?

    a. The focus of this is the change in resources that emit CO2, NOX, and SO2 between these two time periods. The generation for these emitting resources did not significantly change from 2034 to 2044.

14. Are the portfolio risk analysis results statistically significant (not explainable to chance alone, that they are clearly discernable)? If they are not, how are you able to differentiate the portfolios adequately?

    a. Though we didn't perform formal statistical significance tests, our approach provides a robust basis for portfolio comparison. We injected 100 samples of market prices, load, and gas prices into the runs for each one of these candidate build-out portfolios without allowing the physical resource mix to change as compared to the deterministic run. We also ensured that the correlation between these variables is maintained throughout the forecast, so they are subject to the same variability in the three input parameters. This methodology allows us to draw fair comparisons between portfolios and differentiate them based on their risk profiles.

15. The Low Carbon: Transition to Objective Case appears to be the only portfolio that doesn't have market purchases. Why is it not the Preferred Portfolio?

    a. The chart on slide 17 represents the net market purchases thus it does not represent that there are no energy market purchases for the Low Carbon: Transition to Objective Case in 2044. In 2044, there are more market sales than market purchases. The market purchases were discussed for the Low Carbon: Transition to Objective Case on slide 20. It was not selected as the basis of the Preferred Portfolio due to the high cost. Ultimately what we are seeing is that in 2044, we have more market sales than we do market purchases.

16. Are you satisfied with carbon reduction being unchanged from 2034 to 2044 when there is clearly a need to see reductions of far more by 2050?

    a. The carbon emission results continue to represent significant reductions from 2005 levels. A consistent theme throughout I&M's IRP modeling was that I&M requires a significant amount of natural gas generation to serve its growing load. A benefit of the Preferred Portfolio is that it leverages existing resources which mitigates the additionality impacts of adding carbon to the environment. Every three years I&M has the opportunity to reevaluate carbon emissions as we conduct future Indiana IRPs. This gives us the opportunity to assess changes in technologies and the associated costs and continue to refine our ongoing resource plans.

17. Are the market purchases in the Preferred Portfolio low carbon (are the purchases coming from low carbon resources)? Is that how you accomplish a similar carbon reduction in the Low Carbon: Transition to Objective Case?

    a. We assume that the energy market purchases are coming from the PJM energy market, so we do not have an assumption for what type of energy and whether that is low carbon. To address the second part of the question, in the Low Carbon: Transition to Objective Case the reduction is achieved by reducing the number of natural gas CCs. The Preferred Portfolio achieves a similar carbon reduction due to the capacity factor constraints that is applied to the natural gas CCs and the reduction of the natural gas CCs selected. The capacity factor constraints are aligned with the EPA Section 111(b)(d) regulations. Thus, it is a combination of the reduction of the natural gas CCs in the Preferred Portfolio and the capacity factor constraints that are applied to those natural gas resources. Together, these enable the Preferred Portfolio to meet similar carbon emission reductions.

18. Does I&M use uranium from Canada? If so, have you used the higher uranium cost variables with respect to the tariffs?

    a. I&M contracts for uranium do not specify the country of origin of the uranium so any tariffs due would depend on specific circumstances at the time of delivery. As an example, for 2025, considering the entities we are contracting with, we anticipate that about one-third of a reload is likely sourced from a Canadian supplier A tariff, if any due, would be determined at that time. Based on the tariff information currently available, for 2025 the impact is estimated at $1-2 million, which would remain a lower cost option than purchasing at the current spot market.

19. Since we haven't talked about it in these meetings, I assume they are not part of the IRP filing, but I'm wondering if you have conducted any analysis that would accompany the IRP, e.g., have you conducted a resource adequacy study of the PJM footprint? Have you conducted any transient stability or EMT studies of your new datacenter customers?

    a. AEP requires dynamic modeling data to be submitted for all large load interconnections, including data centers, per the AEP's publicly posted Requirements for Connection of New Facilities or Changes to Existing Facilities Connected to the AEP Transmission System. AEP utilizes the submitted data to perform targeted dynamic/transient stability studies in both time domain (PSSE) and EMT (PSCAD) and mitigates reliability issues identified with the interconnection.

       Public Link to the referenced document:

       AEP Transmission Studies & Requirements

20. What is the key driver for market sales and purchases - the expectation of wholesale power prices?

    a. The key drivers for market sales and purchases are power prices, load and resource generation. When there is not enough generation to meet load, then market purchases are necessary. When there is more than enough generation to meet load and there is incentivization (due to high market prices) to sell excess energy into the market, then this results in market sales. If market prices are low, then this could lead to market purchases because it may be more economically feasible to purchase energy from the market to serve load rather than producing energy.

21. Relating to the portfolio risk results, have you thought of running a T-Test (as they look normally distributed, I assume you used a normal distribution in your Monte Carlo simulation) or maybe a nonparametric test (e.g. Wilcoxon signed-rank test) for thoroughness, to determine if they are statistically significant, as in they are distinct portfolios that actually perform differently, such that you can select

confidently that the Preferred Portfolio performs actually best among the other portfolios?

a. We implemented several methodological safeguards to ensure our results are robust. We maintained consistency by using the same 100 samples scenarios throughout our modeling. we also implemented quality assurance checks to validate the samples statistical properties. We are happy to investigate the methods mentioned and how they may be used in the future, but for this set of analyses, we did not implement those measures noted in the question.

# Short-Term Action Plan

*Andrew Williamson covered slide 21.*

Andrew explained that I&M will continue to conduct RFPs or other competitive procurement practices as needed, consistent with past practices. Regarding Cook subsequent license renewals, he mentioned that they had discussed this in prior Indiana Utility Regulatory Commission (IURC) proceedings. The plan was to evaluate the opportunity in the IRP, and if selected, they would take the necessary steps to continue to implement the subsequent license renewal process, which takes several years and will be ongoing for I&M following the IRP.

Andrew stated that they would finalize the evaluation of the Elkhart and Mottville Hydro operating license renewal opportunities, as reflected in the Preferred Portfolio. He emphasized that, as with past IRPs, they will continue to check and adjust as they move forward. The IRP serves as a foundation for resource decisions, but they will consider and evaluate the best information available at the time and adjust to changing circumstances as they occur.

## Q&A Related to Performance Indicators & Short-Term Action Plan

22. Do you assume market prices will go up when I&M plans to purchase energy?

    a. We have a fundamental forecast of market energy prices included in the appendix of Stakeholder Meetings 1 and 2 and those market energy prices are from a capacity expansion plan model that is PJM-wide. We do not have an assumption included in the model that would increase the market energy prices as the model is purchasing energy.

23. Where are the expanded wind and solar generation going to be built? Are these projects very likely to come online as they are part of your assumptions?
    a. When we complete modeling related to an IRP, we assume generic non-location specific resources. The updated wind availability assumptions that were used to inform the Preferred Portfolio were driven from the results of our 2024 RFP. This reflects updated market intelligence that there are a number of resources available that would allow us to achieve these levels. The RFP considered both existing facilities as well as new facilities and we have a robust set of non-price criteria that looks at assessing the development risk associated with these.
24. On your Five Pillars there seems to be bias as to some being more important than others? Where are the metrics?
    a. We have a description of all the metrics in the appendix on slide 42 of the presentation. This has a description of what all the different metrics are. In addition, we have included in the appendix the portfolio performance indicators matrix starting on slide 43 for all the different cases that we ran.

# Open Discussion

I&M staff thanked stakeholders for their participation. Any additional questions or feedback can be submitted to the IRP Email address at I&MIRP@aep.com. Staff fielded all remaining stakeholder questions and adjourned the meeting.

## Q&A Related to Open Discussion

25. How did you obtain a -0.5% 7-year CAGR under Base portfolio? Wouldn't adding more capacity always increase affordability cost?
    a. This is something that we covered in Stakeholder Meetings 3A and 3B. This metric specifically is on a $/MWh basis, which is different than the NPV we use for the long-term portfolio Power Supply Costs. It was important to have this metric on a $/MWh basis because of the significant increase in load and revenue over the analysis period, as provides a more relevant comparison

between each of the cases that we had modeled. Meaning, while we see a significant number of resources additions in future, these additions are driven by load growth. As load grows, revenues that I&M will receive will help offset costs. The negative percentage was achieved because the economics of the capacity additions in the Base Reference Case are reducing I&M's average power supply costs over the 7-year period measured.

26. If Section 111(b) is voided, will you be doing remodeling?

    a. Regardless of any of the scenarios or sensitivities that were modeled, there was a similar amount of natural gas resources that were selected by the IRP. The main difference when you consider the Preferred Portfolio is: did it leverage new natural gas opportunities or existing? Assuming the environmental regulations that were used as the basis in the EER cases, it favored existing resources because it lessened the cost of compliance with the current and proposed rules. Those resources are still needed regardless of whether the rules would be enacted or not. If anything, they position I&M to transition more quickly to other technologies that will be available in the future that can further the transition to a clean energy future. We feel that this positions I&M very well on multiple fronts, both with respect to whether the laws or regulations are enacted or if they are not.

27. Since you are locking in substantial gas capacity by 2034, how would future IRPs be able to economically reduce carbon to lower levels by 2050 given the lifetime cost of gas CCs?

    a. In part, that opportunity will come through the actual resources that I&M has in the portfolio. The IRP had to evaluate this through a set of limited assumptions but as we move forward and evaluate the actual options that are available in the market to obtain the resources that are needed, we are going to be evaluating a very diverse set of resource opportunities. Some resource opportunities will have much shorter lives and will provide the opportunity for us to continue to make progress on the transition in the future.

28. It seems like you were talking about 25% or so renewables in the 2044 scenario of this Preferred Portfolio, but those are not guaranteed. It is not like those projects have been approved or they are online yet, so it is a goal, but it is not a guarantee. Those things could still not happen, correct?

    a. That is a fair statement for any of the resources in an IRP because an IRP is a projection of the future that is subject to a lot of variables, some of which are very much outside the control of any utility. While it is true that there is going to be some variability in the future versus what is modeled here, it is also true that we are going to see a lot of the resources that were selected being added in varying quantities. The results for the 2024 RFPs show us that there is a very diverse set of opportunities available for solar, wind, and natural gas that align very well with the Preferred Portfolio. There will be some variability between the IRP and the actual resources we acquire, but we also expect that the diversity will materialize for I&M and its customers.

29. Following up on the CAGR question, if I am understanding it correctly that the load is growing faster than available capacity in 7-years, does that mean that I&M is buying wholesale from the market to meet load before the capacity is available? Hence a negative value, since customers are not yet paying for new capacity.

    a. In terms of buying from the market vs acquiring resources to provide the needed capacity and energy it is going to be a mix of both. We are going to leverage our existing resources, continue to expand our long-term resources through the efforts that we have discussed, and in between we will fill the gaps with purchases of energy or capacity within PJM. This is no different than how all utilities operate. All of those factors are reflected in the compound annual growth rate (CAGR) calculation. It considers the assumptions that were made on purchases of market energy including any market sales, long-term resource costs, and short-term capacity purchases in each of the respective years based on the resource expansion plan that we modeled.

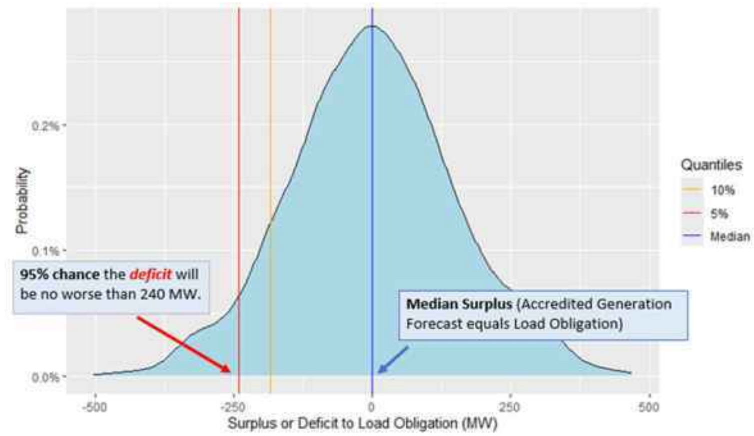
30. Will there be a formal comment period?

    a. Yes, once the IRP is submitted, the IURC will establish a formal comment period. Stakeholders are encouraged and able to provide us feedback directly throughout this process by going to our IRP landing page on the Indiana Michigan Power website. We encourage feedback there as well.

31. When do you anticipate a Certificate of Public Convenience and Necessity (CPCN) filing?
    a. We anticipate beginning to make our resource approval filings as early as April and we would anticipate additional filings being made through the remainder of 2025.
32. Could you please clarify - for 2025, which resources would you seek approval for? We would appreciate the opportunity to comment/stay involved/informed of that process.
    a. That would be primarily the resources related to our 2024 RFPs. We have been evaluating bilateral opportunities because some resources are not able or in a position to participate in an RFP-like process. The resource filings we would expect to make this year would be driven by a combination of those two efforts.

# Appendix 4, Exhibit F: Public Advisory Comments

| 2024 Indiana IRP Stakeholder Comment Summary | | | | |
|---|---|---|---|---|
| | Stakeholder | Topic | Comment | I&M Response |
| CAC, Earthjustice, Vote Solar, and Solar United Neighbors submitted comments on Wednesday, October 2, 2024 | | | | |
| 1. | CAC, Earthjustice, Vote Solar, and Solar United Neighbors | Reserve Margin Obligation Contingency | One of the items discussed during the September 9th meeting was the inclusion of a 5% contingency for the reserve margin obligation, which translated to about 450 MW of additional capacity. Since this is a new concept that I&M is incorporating into the IRP and not one that we have seen used by other utilities, it would be helpful if I&M shared any supporting analyses that were undertaken to develop the 5% contingency. We also ask that I&M show how much of this contingency was assigned to each of the various factors it described during the September 9th and 24th meetings, such as potential changes in accreditation. | It is prudent to plan above the minimum reserve margin obligation to address risks associated with load requirements and capacity accreditation that are largely outside the utilities control. This is particularly important given that I&M is moving from an extended period of having surplus capacity relative to PJM's requirements to the position of needed to add significant new resources to meet PJM's requirements.<br><br>There are many factors that lead to uncertainty in the peak load forecast and the other factors driving uncertainty in the amount of generating capacity that I&M will have accredited in any future planning year. Together, these factors contribute to meaningful risk that the Company's accredited capacity will not meet its load obligation if it is not exceeded. For Indiana, I&M's analysis supports that to have 90% to 95% confidence that the Company will meet its load obligation in a future planning year, it will be necessary to add approximately 5% to the PJM-forecasted load obligation, depending on the types of resources in our portfolio and how distant is the planning year. There is the potential for significant financial risk if I&M is unable to meet its capacity obligation. If deficient, PJM will either a) remove the company from participating in the FRR option (initial demonstration is short) or b) impose a capacity deficiency charge (short within the planning year). For reference, the capacity deficiency charge for planning year 2025/2026 is $452/MW-day. The following graph illustrates an example of the distribution of the demand surplus or deficit compared to the reserve margin obligation for a planning year, if the median accredited capacity equals the reserve margin obligation based on the current load forecast. |

| 2024 Indiana IRP Stakeholder Comment Summary | | | | |
|---|---|---|---|---|
| | Stakeholder | Topic | Comment | I&M Response |
| | | | | <br>If I&M targets a surplus equal to zero, then there would be only 50% confidence (1 out of every 2 years) that the Company will have sufficient capacity. I&M aims for 90% to 95% confidence. In this illustration, the Company would need to target another 200 MW capacity to achieve 90% confidence and 240 MW to achieve 95% confidence.<br>In addition to this response, I&M plans to include a section in its IRP filing that will further detail this analysis. |
| 2. | CAC, Earthjustice, Vote Solar, and Solar United Neighbors | Load Forecast | During the technical stakeholder meeting, we requested to receive access to the supporting information used to develop the load forecast that will be modeled in the IRP, in particular related to loads from new customers. Since the load forecast and assumptions around load growth from new customers will be an important driver of resource decisions in this IRP, we request that I&M provide supporting workbooks with stakeholders.<br>Information that would be beneficial for stakeholders to review include MW additions for new customers, any applicable ramp rates, the customer category (i.e. data center, hydrogen production, manufacturing, etc.), and the 8,760 | I&M provided the following data directly to its IRP technical stakeholders who have executed a non-disclosure agreement (NDA).<br>- 2024 Indiana Load Additions: This included the year and month of the addition, the customer class, the facility type, the MW and MWh additions, and the associated load factor.<br>- Indiana Large Load Shapes: This included the 8760 shape for all new customers. |

| 2024 Indiana IRP Stakeholder Comment Summary | | | | |
|---|---|---|---|---|
| | Stakeholder | Topic | Comment | I&M Response |
| | | | shape. In addition, if I&M is using a process to forecast additional levels of new customer additions above what is already known to them, that would also be beneficial to share with stakeholders. | |
| 3. | CAC, Earthjustice, Vote Solar, and Solar United Neighbors | Bonus Investment Tax Credit | Another topic discussed during the September meeting was assumptions for supply side resources. During the meeting, we recommended that I&M include the 10% additional energy communities bonus tax credit in its modeling. It is our understanding that I&M's position is that the energy communities bonus credit is only important for evaluating the merits of resources responding to I&M's RFP. While we agree that it will be important for evaluation of resources in an RFP, we disagree that it does not hold value for IRP modeling and resource selection. Including this tax credit adder could materially impact the type of supply-side capacity additions selected by the model, as it will affect the relative cost-competitiveness of different capacity options. For its 2024 IRP, Duke Energy Indiana is including assumptions around the energy communities bonus credit for wind, solar, and battery storage resources.[1] We appreciate that I&M has reconsidered its position will include some level of solar resource that is eligible the energy communities bonus credit but we do not yet know what that amount is and whether it is additional to the UPV I&M currently plans to model.<br><br>[1] Duke Energy Indiana 2024 Integrated Resource Plan Public Stakeholder Meeting 1 Presentation, Slide 43. Retrieved from https://www.duke-energy.com/-/media/pdfs/for-your-home/dei-irp/20240222-dei-irp-public- meeting-1-slides.pdf?rev=c4b04eb66fdf4ba7a6f775eb38cc8778 | I&M has taken this feedback into consideration and is modeling a subset of our solar resources that will have capital costs with deductions to reflect the energy community tax credit bonus in addition to the Investment Tax Credit (ITC). Please reference the response to question 27 in the Stakeholder Meeting 2 Meeting Minutes. |

| 2024 Indiana IRP Stakeholder Comment Summary | | | | |
|---|---|---|---|---|
| | Stakeholder | Topic | Comment | I&M Response |
| 4. | CAC, Earthjustice, Vote Solar, and Solar United Neighbors | IRA Tax Credits | I&M plans to assume that the PTC and ITC will reach 75% of their current value in 2037, 50% in 2038, and 0% in 2039. Based on a commencement-of-construction safe harbor assumption,[2] it appears that the underlying premise of this assumption is that nationwide total electric generation greenhouse gas ("GHG") emissions will be reduced by 75% from 2022 levels in 2032.[3] Given the enormous quantities of new load that I&M and many other electric utilities across the country are planning to add, we are extremely skeptical that this nationwide goal is likely to be achieved by 2032. We recommend that I&M instead assume that the federal tax credits are available at current value through the end of the planning period (based on a more likely assumption that nationwide electric sector GHG emissions will not reach 25% of 2022 levels until 2040, which, per statute, would push back the federal tax credit phaseouts accordingly). As a check on this, I&M may want to benchmark its own emissions in 2032 under the simulations it is presumably currently running compared to its 2022 levels. In its last IRP, the Preferred Portfolio did result in a reduction in direct emissions from 2022 levels of about 75%. However, that included the removal of Rockport 2 from I&M's portfolio in 2024, retirement of Rockport 1 in 2028, and no additions of gas capacity through 2032 other than 1,000 MW of peakers. Since I&M plans to add approximately 4,400 MW of new data center load during this time and its proposed renewable and battery storage build limits would prevent its model from selecting adequate quantities of clean energy resources to meet this drastic load increase in that time period, | I&M's modeling is utilizing the most up to date information provided in the Internal Revenue Code, which references that the PTC and ITC can begin to phase out beginning in 2032 if the nationwide goal is met. I&M will keep its current assumption of the IRA Tax Credits for modeling all scenarios and sensitivities. The Company will include the stakeholder requested assumption around tax credit availability throughout the planning period for the Carbon-Free Sensitivity.<br><br>As part of the portfolio performance indicators (scorecard), I&M will complete a comparison of our emissions to the 2005 levels for each scenario and sensitivity modeled. Regarding the availability of new resources, I&M's near-term build limits are informed by our market intelligence. Additional information to support the near-term build limits are noted below in the response to comments 7 and 8. |

| 2024 Indiana IRP Stakeholder Comment Summary | | | | |
|---|---|---|---|---|
| | Stakeholder | Topic | Comment | I&M Response |
| | | | I&M's modeling appears to be forcing in a large increase in its carbon emissions relative to its last IRP.<br><br>[2] 26 U.S.C. §§ 45Y(d)(1), 48E(e)(1).<br>[3] 26 U.S.C. §§ 45Y(d)(3), 48E(e)(3). If 2032 were the "applicable year" as defined in Section 45Y(d)(3), then the 75% tax credit value would obtain for projects commencing construction in 2034, and, based on I&M's remarks at the September 24 stakeholder meeting, we presume I&M is estimating that such 2034 projects would reach completion in 2037. | |
| 5. | CAC, Earthjustice, Vote Solar, and Solar United Neighbors | ICE Report | During the September meetings, I&M discussed that certain resources will be considered for the value they can provide to help avoid interruptions for customers. It would be helpful for stakeholders to understand how the values for this modeling were developed. We ask that I&M provide the parameters that were specified for the Interruption Cost Estimation ("ICE") Calculator so that stakeholders can replicate the values that were developed. | For clarification purposes, the Interruption Cost Estimation (ICE) Calculator that is currently available online was not directly used to develop the estimated avoided customer minutes of interruption (CMI) savings value presented in the Indiana IRP. The avoided CMI savings value from the application of Distribution Storage Resource Options was calculated by multiplying the following three parameters for each proposed option:<br>• The 3 Year (2021-2023) Historical CMI of the benefitting feeder(s).<br>    ○ Whitaker-Elk: 1,631,324<br>    ○ Pleasant-Yoder: 1,072,833<br>• A 30% CMI Reduction Assumption attributed to the proposed distribution storage resource option.<br>• A 0.06 $/CMI avoided cost value which was obtained for residential customers in the Eastern AEP footprint from an analysis performed by the Lawrence Berkley National Lab and Resource Innovations as part of the ICE Calculator 2.0 update project. AEP is one of the Phase 1 sponsoring utilities of that project. More information on the ICE Calculation 2.0 project can be found here: [https://icecalculator.com/recent-updates.](https://icecalculator.com/recent-updates) |
| 6. | CAC, Earthjustice, Vote Solar, and Solar United Neighbors | Data Sharing | As we discussed at the June 27th meeting, we have no meaningful feedback to provide on sensitivities, scenarios, and inputs until we can review the data that will be used. We appreciate the provision of the PLEXOS license, but do not yet have data to review and therefore do not have comments on | I&M provided the referenced data on October 4, 2024, directly to its IRP technical stakeholders who have executed a non-disclosure agreement (NDA). |

| 2024 Indiana IRP Stakeholder Comment Summary | | | | |
|---|---|---|---|---|
| | Stakeholder | Topic | Comment | I&M Response |
| | | | those items at this time. On September 30th, I&M emailed stakeholders to say that the following information would be shared on October 1st:<br><br>• Load shape<br>• Energy market price forecast<br>• Renewable energy shapes<br>• Gas price forecast<br>• Cook operating data<br>• Elkhart and Mottville operating data and generation<br><br>These data, which have not yet been provided, would allow us to only partially comment on the proposed market scenarios and sensitivities presented at last public stakeholder meeting. | |
| 7. | CAC, Earthjustice, Vote Solar, and Solar United Neighbors | New Thermal Resources | As we discussed at the September 24th meeting, we are surprised by the relative low cost of existing thermal assets in I&M's proposed inputs. We would expect to see stiff competition for such resources, driving actual purchase prices for these assets much higher that assumed by I&M. The extraordinary load growth projects from other utilities in Indiana and across PJM are also likely to mean that few existing assets will actually be available to I&M. We request I&M provide additional data to support its cost assumptions and assumptions about the quantity of such capacity that would be available since I&M has never provided stakeholders with even summary data from its last RFP. | I&M provided the following data directly to its IRP technical stakeholders who have executed a non-disclosure agreement (NDA).<br>- Details to support the cost and quantity assumptions for its existing thermal resources.<br><br>I&M does expect to see prices for all resources increase due to the competition for all resources and this view is shared by many market analysts. For example, the industry resource, LevelTen PPA Price Index[1], notes in their Q3 2024 executive summary that there will be increased competition for clean energy supply due to the decarbonization goals of the companies building data centers. The company is modeling a High Technology Cost sensitivity that will reflect the most up to date cost information that the Company is seeing in the marketplace.<br><br>[1]https://www.leveltenenergy.com/ppa |
| 8. | CAC, Earthjustice, | Build Limits | I&M's resource build limits for solar, wind, and battery storage are unreasonably restrictive and | The changes requested by the stakeholders are separated below into additional sections with responses noted for each section. |

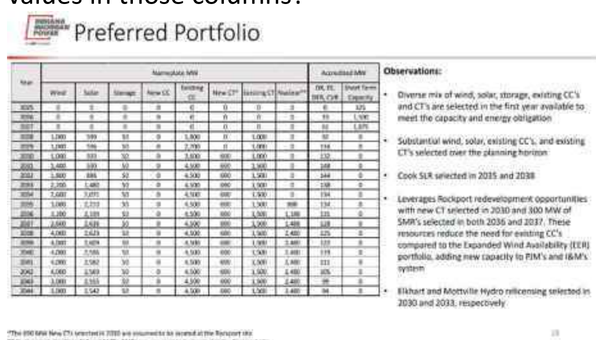
| 2024 Indiana IRP Stakeholder Comment Summary | | | | |
|---|---|---|---|---|
| | Stakeholder | Topic | Comment | I&M Response |
| | Vote Solar, and Solar United Neighbors | | would effectively prevent I&M from meeting a substantial portion of its proposed load growth with clean energy resources. Conversely, I&M has proposed far more relaxed build limits on fossil-fuel-based resources, as well as on speculative, unproven technologies like nuclear SMRs. We request major changes to these build limits so I&M's IRP modeling assumptions does not effectively force an outcome that entails a massive buildout of new fossil-fuel resources.<br><br>I&M has proposed unprecedented load growth of approximately 4.4 GW by the early 2030s, which would net the company about $2.2 billion in additional annual revenues and risk extreme rate increases for customers.[4] With such an unexpected opportunity to massively grow its profits, I&M should have ample financial capacity to invest in a much more ambitious clean energy procurement initiative than it has historically considered feasible. As a part of AEP, one of the largest and most sophisticated utilities and power generation asset owners in the country, I&M should be capable of going to significant lengths to ensure its load growth is met with clean energy solutions. Furthermore, an ambitious load growth strategy will not be consistent with Indiana's Five Pillars, and particularly Environmental Sustainability, if it results in the addition of large quantities of fossil fuel resources to power these facilities, putting existing ratepayers at risk of potentially enormous environmental compliance costs as climate regulations continue to be strengthened.<br><br>We recommend the following changes: | |

| 2024 Indiana IRP Stakeholder Comment Summary | | | | |
|---|---|---|---|---|
| | Stakeholder | Topic | Comment | I&M Response |
| | | | [4] Cause No. 46097, Workpaper AJW-2. | |
| 8.1 | CAC, Earthjustice, Vote Solar, and Solar United Neighbors | Build Limits: For so-called "Base Load (New Resources)" | For so-called "Base Load (New Resources):<br>• Limit nuclear small modular reactor Total Cumulative Build Limit through Planning Horizon to 2,000 MW or less rather than 5,100 MW. This is a new technology that has never been licensed by the NRC or installed in America. I&M's suggestion that it could somehow build 5,100 MW of SMRs while capping wind to only 3,200 MW and 15-year solar to 4,800 MW raises serious concerns about the reasonableness and objectivity of this analysis. It is unclear why I&M is severely constraining proven, existing, cost-effective clean energy resources while allowing a much quicker, larger, and far more speculative SMR build-out in the late 2030s and early 2040s.<br>• The Total Cumulative Build Limit through Planning Horizon for New NG Combined Cycle should be significantly reduced down from 5,600 MW to 1,500 MW or less. Building 5,600 MW of new base load fossil fuel resources beginning in the 2030s is inconsistent with the Environmental Sustainability pillar and would lock in I&M's customers to high levels of climate pollution for decades.<br>• The Total Cumulative Build Limit through Planning Horizon for New NG Combined Cycle w/CCS should be reduced down from 3,800 MW to 1,000 MW. This is a new technology that has not been widely deployed in the power sector to date. Allowing up to 3,800 MW could impose an unreasonable risk on ratepayers and is completely unrealistic in this | I&M stands by its total cumulative build limits through the planning horizon for New Baseload Resources. The Company believes the total cumulative build limits for the planning horizon (through 2059) for both SMR and CC w/ CCS are achievable. The Company is including analysis related to the environmental sustainability pillar by completing a comparison of the company's emissions to the 2005 level for each scenario and sensitivity. The Company is also including analysis related to the affordability pillar by completing rate impact analysis for each scenario and sensitivity. This analysis, in combination with the other portfolio performance indicators (scorecard), will guide the company in its selection of a Preferred Portfolio. The portfolio performance indicators have been shared with stakeholders and can be referenced in the Stakeholder Meeting 1 materials (slide 21)[2].<br><br>[2]https://www.indianamichiganpower.com/lib/docs/community/projects/IM-irp/IM-Stakeholder-Meeting-1-6.27.pdf |

| 2024 Indiana IRP Stakeholder Comment Summary | | | | |
|---|---|---|---|---|
| | Stakeholder | Topic | Comment | I&M Response |
| | | | timeframe given the long lead time, technological complexity, and novel nature of the technology. | |
| 8.2 | CAC, Earthjustice, Vote Solar, and Solar United Neighbors | Build Limits: For the so-called "Base Load (Existing Resources)" | For the so-called "Base Load (Existing Resources)" category:<br>• Reduce the Annual Build Limit to 1,000 MW.<br>• Reduce the Cumulative Build Limit through 2030 from 3,600 MW to 1,000 MW.<br>• Reduce the Total Cumulative Build Limit through Planning Horizon from 5,400 MW to 1,500 MW. Given load growth forecasts, planned resource retirements, and interconnection challenges, there does not appear to be justification for assuming large amounts of existing resources will be available to I&M during the Planning Horizon. | I&M provided the following data directly to its IRP technical stakeholders who have executed a non-disclosure agreement (NDA).<br>- Details to support the annual and cumulative build limits for the so-called "Base Load (Existing Resources)" |
| 8.3 | CAC, Earthjustice, Vote Solar, and Solar United Neighbors | Build Limits: For the so-called "Intermittent (Wind & Solar)" and "Intermittent (Storage)" category of resources | For the so-called "Intermittent (Wind & Solar)" category of resources:<br>- Increase annual build limits for wind and solar to 1,500 MW per year for each subcategory (e.g., Wind (15 year), Wind (30 year), etc.), eliminate the total cumulative build limits through the planning horizon (there is no reason to artificially limit the build out of lower-cost clean energy options beyond an annual build limit), and increase the Cumulative Build Limit through 2030 to 3,000 MW for each subcategory.<br>○ Consider new strategies to significantly increase access to wind capacity, such as utility self-build projects. It is our understanding that one of the main reasons for the low | I&M's cumulative build limits through 2030 for wind, solar, and storage consider multiple variables impacting I&M's ability to contract for new renewable resources, including availability in the PJM queue, local permitting challenges, and other project-specific risks, known opportunities, and resource constraints. Based on PJM's current interconnection queue timeline, projects that were placed in the "Transition Cycle #2" are expected to have executed Generator Interconnection Agreements (GIA) by the end of 2026. As a result of extended lead times for critical high voltage equipment, such as breakers and transformers, current target energization dates are roughly 30 months after execution of the GIA. Under this set of assumptions, projects in the Transition Cycle 2 would expect target energization dates in mid-2029. Typical construction schedules target a Commercial Operation Date (COD) roughly 6 months after the energization date, meaning that the Transition Cycle 2 projects would expect to achieve COD at the end of 2029, which would make them available to I&M for the 2030/31 capacity planning year. Given this logic, cumulative build limits through 2030 for wind, solar, and storage were based on projects in the PJM interconnection queue in or before Transition Cycle 2 located in the states of IN, MI, OH, IL, KY, and WV. |

| 2024 Indiana IRP Stakeholder Comment Summary | | | | |
|---|---|---|---|---|
| | Stakeholder | Topic | Comment | I&M Response |
| | | | availability of wind projects is local siting restrictions prevent private developers from building new facilities. I&M, as a public utility in Indiana, is not subject to having its infrastructure constrained by local siting restrictions that are unreasonable, such as county-wide moratoriums on all new wind projects.<br>- The First Year Available for new solar and storage projects (2028) appears too conservative. It is possible that there is some solar and / or storage capacity available sooner. We recommend modifying this to 2027 or earlier, depending on RFP results.<br>- The Overnight Cost for wind appears to be higher than other cost assumptions we have seen recently. We request that I&M update these cost assumptions if the RFP results suggest adjustments are warranted.<br><br>For the so-called "Intermittent (Storage)" category, we recommend:<br>- Moving up the First Year Available for 6-hour and 8-hour storage to 2028. It is unclear why this year is currently 2029, when 4-hour storage is shown as 2028.<br>- Increasing the Annual Build Limit to at least 2,000 MW for 4-, 6-, and 8-hour storage, respectively.<br>- Increasing the Cumulative Build Limit through 2030 to at least 3,000 MW for 4-, 6-, and 8-hour storage, respectively. | Similarly, I&M's first year availability for wind, solar, and storage consider multiple variables impacting I&M's ability to contract for new renewable resources, including availability in the PJM queue, local permitting challenges, and other project-specific risks, known opportunities, and resource constraints. Based on PJM's current interconnection queue timeline, projects that were placed in the "Expedited Process" (a.k.a "Fast Lane") are expected to have executed GIAs by the end of 2024. Under this set of assumptions, projects in the Expedited Process would expect target energization dates in mid-2027. Typical solar and storage schedules target a COD roughly 6 months after the energization date, meaning that the Expedited Process project would expect to achieve COD at the end of 2027, which would make them available to I&M for the 2028/29 capacity planning year. While there are limited projects that executed GIAs ahead of the Expedited Process, I&M cannot assume that these mature projects remain uncontracted and available to I&M. Even if these projects do bid into I&M's 2024 RFP, developers would likely be required to initiate construction of the facility prior to I&M's receipt of regulatory approval to achieve COD prior to the 2027/28 capacity planning year, which is an unlikely scenario.<br><br>Details regarding the PJM Interconnection Queue have been shared with stakeholders and can be reference in the Stakeholder Meeting 2 materials (slide 17)[3].<br><br>It is also important to note that I&M's preliminary modeling results for its reference case demonstrated the total cumulative build limits for solar and storage are not a constraining factor. I&M updated the total cumulative build limit for wind as it was a constraining factor in the reference case. This was communicated to the IRP technical stakeholders on 10/17/24. I&M will continue to evaluate the build limits as we model different scenarios and sensitivities and adjust the build limits if they become a constraint to meet the load growth.<br><br>Regarding comments on I&M's self-build options, I&M's current focus is to promote and maintain positive working relationships with the local |

| 2024 Indiana IRP Stakeholder Comment Summary | | | | |
|---|---|---|---|---|
| | Stakeholder | Topic | Comment | I&M Response |
| | | | - Eliminating the Total Cumulative Build Limit through Planning Horizon for 4-, 6-, and 8-hour storage and increasing it to at least 1,000 MW for 100-hour storage. | communities that it serves and that it relies upon to host its transmission and generation infrastructure. With that overarching intent, the Company is not actively considering superseding or overruling the siting and permitting decisions of local officials that represent the communities they serve for the purpose of developing new generation resources.<br><br>I&M will update cost assumptions for wind, if warranted, in the High Technology Cost sensitivity. The High Technology sensitivity will reflect the most up to date cost information that the Company is seeing in the marketplace.<br><br>[3]https://www.indianamichiganpower.com/lib/docs/community/projects/IM-irp/IN_Stakeholder_Meeting_2.pdf |
| 9. | CAC, Earthjustice, Vote Solar, and Solar United Neighbors | Power Prices | We are increasingly concerned that the rapid load growth currently envisioned in I&M's service territory and across PJM are not being adequately represented in I&M's modeling. The unprecedented, rapid growth in demand at a time when new supply resources are severely constrained will result in power prices increasing. For instance, a recent ICF analysis found that data center load growth could lead to a 19% increase in U.S. power prices by 2028.[5]<br><br>We therefore request I&M update its power prices based on refreshed analysis that includes this load growth to ensure these power price assumptions are still reasonable. For example, I&M is currently using a projection of the on-peak PJM Market Prices in its Base and EER cases that are between $30-$40/MWh for each year 2025 through approximately 2037 (slide 36, IRP Meeting #2) and below $30/MWh for each year in the Low case for every year through the mid-2040s. The High case | **The Company's portfolio analysis uses load forecasts that include the rapid load growth in development of the preferred plan.**<br><br>**The market price scenarios do not include rapid load growth. These scenarios were created prior to the forecasted rapid load growth. The Company is using load forecasts that include the hyperscale load for the modeling.** The Company's scenarios provide a wide range of power prices used in development and testing of the Preferred Portfolio. The wide range is intended to address any unknown economic factors at the time of scenario development. The Company maintains its position that the range of current scenarios for power prices is sufficiently wide to encapsulate the potential near-term price risk identified by CAC.<br><br>Note: updated bold response on 10/28/2024 |

| 2024 Indiana IRP Stakeholder Comment Summary | | | | |
|---|---|---|---|---|
| | Stakeholder | Topic | Comment | I&M Response |
| | | | has on-peak prices below $50/MWh through 2035. These assumed prices might warrant upward revisions.<br><br>[5] https://www.icf.com/news/2024/09/icf-report-projects-surge-in-us-electricity-demand-by-2028 | |
| 10 | Black Sun Light Sustainability | MPS | I would like to review the Market Potential Study (MPS) models. | I&M issued an NDA that is required to view the MPS models. |
| 11 | CAC | MPS | I notice that the IRP website still has the 2021 MPS. Could you please provide the public 2024 MPS documents? I didn't see those in the Stakeholder Comment document, but let me know if I missed it. | I&M is working on finalizing the public MPS and once finalized will be posted to the I&M website. I&M will notify the requesting the CAC once posted to the I&M website. |
| 12 | Ranger Power | Preferred Portfolio | Can you please clarify the difference between "Existing CC/CT" and "New CC/CT" in the table below? I am not clear on what the zeros mean in the existing columns - shouldn't the existing resources already be generating and thus have values in those columns?<br> | The Preferred Portfolio table, Slide 15, Meeting # 4 presentation, represents a capacity expansion plan for I&M, meaning new resources that I&M would acquire and add to its generation portfolio. The zeros in the table represent years, both previous and current, where no resources in those categories are planned to be added to I&M's generation portfolio. The difference is that the "Existing CC/CT" column is referring to existing CC/CT facilities that are currently operating and are expected to be available in the market and the "New CC/CT" column refers to new development facilities that are not yet operating and would be constructed. For example, in the "Existing CT" column the Preferred Portfolio calls for I&M to acquire 1,000 MW of existing CT in 2028 and acquire an additional 500 MW existing facility in 2031. |
| 13 | Google | Load Forecast | I&M IRP team, could possibly send me the load forecast used for the base case in excel format with annual peak load values? Thank you for your help. | Requested information provided to stakeholder. |