INDIANA INTEGRATED RESOURCE PLANNING REPORT

to the:

Indiana Utility Regulatory Commission

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List of Acronyms

Acronym	Definition
ACI	Activated Carbon Injection
AD	Aeroderivative Turbine
ADMS	Advanced Distribution Management System
AEG	AEP Generating Company
AEIC	Association of Edison Illuminating Companies
AEO	Annual Energy Outlook
AEPSC	American Electric Power Service Corporation
AMI	Advanced Metering Infrastructure
ARRA	American Recovery and Reinvestment Act Of 2009
ASTM	American Society for Testing And Materials
AUCAP	Average Accredited Unforced Capacity
BCA	Benefit-Cost Analysis
BCR	Benefit-Cost Ratio
BRA	Base Residual Auction
C&I	Commercial & Industrial
CAA	Clean Air Act
CAGR	Compound Annual Growth Rate
CCR	Coal Combustion Residual
CCS	Carbon Capture and Sequestration
CIFP	Critical Issue Fast Path
CO_2	Carbon Dioxide
CSAPR	Cross-State Air Pollution Rule
CVR	Conservation Voltage Reduction
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DLC	Direct Load Control
DOE	U. S. Department Of Energy
DR	Demand Response
DSI	Dry Sorbent Injection
DSM	Demand-Side Management
DY	Delivery Year
EE	Energy Efficiency
EECO	Electric Energy Consumption Optimization
EER	Enhanced Environmental Regulation

EIA	Energy Information Administration
EIEA2008	Energy Improvement and Extension Act Of 2008
EISA	Energy Independence and Security Act Of 2007
ELCC	Effective Load Carrying Capacity
EPA	Environmental Protection Agency
EPAct	Energy Policy Act Of 2005
ESP	Electrostatic Precipitator
FERC	Federal Energy Regulatory Commission
FPR	Forecast Pool Requirement
FRB	Federal Reserve Board
FRR	Fixed Resource Requirement
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GW	Gigawatt
HSL	Hyperscaler Load
I&M	Indiana Michigan Power Company
IDEM	Indiana Department of Environmental Management
IRA 2022	Inflation Reduction Act Of 2022
IRM	Installed Reserve Margin
ITC	Investment Tax Credit
IURC	Indiana Utility Regulatory Commission
Li-ion	Lithium-Ion
LOA	Letter Of Agreement
LSE	Load Serving Entity
MAP	Maximum Achievable Potential
MATS	Mercury And Air Toxics Standards
MDM	Meter Data Management System
MECS	Manufacturing Energy Consumption Survey
MISO	Midcontinent Independent System Operator
MMBtu	Million British Thermal Unit
MPS	Market Potential Study
MSAs	Master Services Agreements
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NGCC	Natural Gas Combined-Cycle
NGCT	Natural Gas Combustion Turbine
NOx	Nitrogen Oxide
NPV	Net Present Value

NPVRR	Net Present Value Revenue Requirement
NRC	Nuclear Regulatory Committee
NREL	National Renewable Energy Laboratory
NSR	New Source Review
NTG	Net-To-Gross-Like
NWAs	Non-Wires Alternatives
NYISO	New York Independent System Operator
O&M	Operation and Maintenance
OVEC	Ohio Valley Electric Corporation
PJM	PJM Interconnection LLC
PM	Particulate Matter
PRB	Powder River Basin
PTC	Production Tax Credits
PV	Photovoltaic
RAA	The Reliability Assurance Agreement
RAP	Realistic Achievable Potential
REC	Renewable Energy Credit
RFC	ReliabilityFirst Corporation
RFP	Request For Proposal
RICE	Reciprocating Internal Combustion Engines
RPM	Reliability Pricing Model
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
RTP	Real Time Pricing
SAE	Statistically Adjusted End-Use
SLR	Subsequent License Renewal
SMR	Small Modular Reactors
SO_2	Sulfur Dioxide
T&D	Transmission & Distribution
TOU	Time-Of-Use
TRM	Technical Reference Manual
TVA	Tennessee Valley Authority
UCAP	Unforced Capacity
UCT	Utility Cost Test
UF6	Uranium Hexafluoride

Executive Summary

Overview

This Report presents Indiana Michigan Power Company's (I&M or Company) 2024 Integrated Resource Plan for its Indiana jurisdiction (2024 IN IRP or Report). This Report includes descriptions of assumptions, study parameters, and methodologies used to evaluate the integration of supply- and demand-side resources to meet future customer demand in a way that balances the Five Pillars of Indiana energy policy[1].

I&M is in the midst of a transformation in terms of forecasted load growth, customer composition and changes to the generation resources that are needed to serve customers. I&M is forecasting electric load growth by the end of 2030 that will more than double I&M's peak load from its 2023 levels. The load growth is primarily associated with hyperscale (HSL) business development, which includes large data center development with electric capacity requirements exceeding 500 megawatts (MW). By the end of 2030, HSL customers are forecasted to represent approximately 60% of I&M's Indiana Jurisdiction peak load. I&M is also experiencing a shift in the generation resource composition as Rockport Unit 1 is obligated to retire by the end of 2028. This coal-fired resource represents nearly one-fifth of the Company's existing generation fleet. In addition, a key consideration in this Integrated Resource Plan (IRP) was the evaluation of a Subsequent License Renewal (SLR) of the Cook Nuclear Plant Units 1 and 2 that would extend the operating license of each unit 20 years, from 2034 and 2037 to 2054 and 2057, respectively. The magnitude of future demand for electricity is unprecedented and will require substantial expansion of supply- and demand-side resources, especially when considering generation resource retirements coinciding with significant load growth.

At the core of this transformation is the Five Pillars of Indiana energy policy, which guides how I&M generates and supplies electricity to balance the consideration of Reliability, Affordability, Resiliency, Grid Stability, and Environmental Sustainability. As a result, the 2024 IN IRP established and utilized Portfolio Performance Indicators associated with each of the Five Pillars. These indicators allowed I&M to assess and compare the scenarios and sensitivities modeled and ultimately inform I&M's Preferred Portfolio.

The goal of the 2024 IN IRP process is to develop a Preferred Portfolio that contains a near-term plan, representing years 2025-2030, and a long-term-indicative plan, representing years 2031-2044. The Preferred Portfolio identifies the amount, timing, and type of resources required to supply capacity and energy as part of the Company's obligation to ensure a safe, reliable and economical power supply to its Indiana customers. The near-term plan has the least uncertainty and is inclusive of the Company's Short-Term Action Plan described herein which includes the activities the

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[1] Ind. Code § 8-1-2-0.6. (2023). *GENERAL ADMINISTRATIVE ORDER OF THE INDIANA UTILITY REGULATORY COMMISSION.* Retrieved from https://www.in.gov/iurc/files/GAO-2023-04_ORDER_06-28-2023.pdf

Company plans to undertake during the 2025-2027 period to acquire the resource additions that will be necessary to meet the Company's capacity obligations.

This 2024 IN IRP is submitted based on the best information available at the time the load forecast and other modeling assumptions were developed. However, changes that affect this 2024 IN IRP can occur without notice and may not be reflected in this report due to the timing of the changes. Therefore, this 2024 IN IRP is not a firm commitment to specific resource additions or other courses of action over the period of the plan, as the future is uncertain. Accordingly, this 2024 IN IRP and the action items described herein are subject to change as new information becomes available or as circumstances warrant.

Background

An IRP explains how an electric utility company plans to meet the forecasted capacity and energy requirements of its customers. I&M is required to provide an IRP that encompasses a 20-year forecast planning horizon (in this 2024 IN IRP, 2025-2044). The 2024 IN IRP uses the Company's current long-term assumptions for:

- customer load requirements – peak demand and hourly energy;
- commodity prices – fuel, capacity, energy, and emission prices;
- existing planned supply-side resource retirement options;
- supply-side alternative costs and performance characteristics – including natural gas, nuclear, and renewable generation along with storage resources;
- transmission and distribution planning; and
- energy efficiency and demand-side management program costs and impacts.

The 2024 IN IRP load forecast included significant load growth from HSL customers. In addition, I&M's existing long-term wholesale contracts were assumed to continue through their current contractual terms. These load assumptions were included in the customer load requirements above.

In addition to the assumptions noted above, I&M considered the impact of the existing and proposed Greenhouse Gas regulations under the Environmental Protection Agency's (EPA) Section 111(b)(d). The Company's IRP modeling assessed these regulations, and ultimately considered the regulations in its Preferred Portfolio, in an effort to better position I&M for future compliance with Greenhouse Gas regulations.

I&M operates within the PJM Interconnection, L.L.C. (PJM) Regional Transmission Organization (RTO), while most Indiana utilities operate in the Midcontinent Independent System Operator, Inc. (MISO) RTO. As expected, each RTO has its own capacity planning process that results in different resource planning criteria and assumptions. Specifically in the 2024 IN IRP, the Company adhered to PJM's resource adequacy planning processes.

To meet its customers' future capacity and energy requirements, I&M made assumptions regarding the continued operation of its existing fleet of generation resources in the 2024 IN IRP. Specifically, the two units at the Cook Nuclear Plant (Cook) are assumed to operate through the remainder of their current license periods (Unit 1 – 2034 and Unit 2 – 2037). As noted above, the SLR for both units were included as a resource option available for economic selection compared to other supply and demand-side resources. Rockport Unit 1 is assumed to operate through its committed retirement date of December 31, 2028. Supply-side resources under long-term contracts are assumed to continue through the end date of the respective contracts.

I&M analyzed 15 total scenarios and sensitivities that provided adequate supply and demand-side resources to meet its capacity and energy need while reducing or minimizing costs to its customers over the planning horizon (2025 to 2044).

Key Changes from 2021 IRP

The 2024 IN IRP includes changes from the Company's last IRP that impact the Report in its entirety, the capacity and energy assumptions, supply-side resource options, and demand-side resource options.

The following changes impacted all aspects of the 2024 IN IRP:

- I&M is transitioning to a state-specific IRP. This change will allow I&M to tailor its future resource plans and decisions to the needs 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.
- The 2024 IN IRP incorporated recommendations from the Indiana Utility Regulatory Commission (IURC or Commission) in the "Final Director's Report for Indiana Michigan Power Company's 2021 Integrated Resource Plan," issued on February 12, 2024.
- The Company engaged 1898 & Co., a part of Burns & McDonnell, to provide their own unique expertise and perspective along with facilitating the Public Advisory Process.

The following changes impacted the capacity and energy assumptions:

- I&M included the significant load forecast driven by new HSL business development.
- I&M included updated PJM resource adequacy changes, which impacted the capacity accreditation of all existing and modeled resources.
- The company included a capacity contingency in addition to the forecasted PJM load obligation.

The following changes impacted the supply-side resource options and assumptions:

- As noted above, the 2024 IN IRP resource options included a 20-year Cook SLR, or relicensing, for Cook Units 1 and 2.
- The 2024 IN IRP resource options included relicensing for the Elkhart Hydroelectric Plant in 2030, and the Mottville Hydroelectric Plant in 2033.
- The Company included a wider range of resource options, including existing natural gas resources available for procurement.
- Parallel to the 2024 IN IRP process, I&M issued four RFPs for generation resources to meet projected capacity and energy needs. The results from these RFPs were used to confirm and adjust the installed costs and build limits for supply-side resources and ultimately inform the Preferred Portfolio.

The following change impacted the demand-side resource options and assumptions:

The 2024 IN IRP process considered an array of new demand-side resource options through an updated Market Potential Study (MPS) that was completed in 2024. This study was conducted by GDS Associates and evaluated the potential for future energy efficiency (EE), demand response (DR) and distributed energy resources (DER) resources to support the IRP and demand-side management (DSM) planning processes.

IRP Process

The 2024 IN IRP process and associated modeling comply with the Indiana Guidelines for Resource Planning and reliability requirements while also quantifying risks introduced by the market and regulatory environments, and the risk of over-reliance on energy market imports and/or exports. The 2024 IN IRP process is structured around the following five (5) steps:

Step 1: Define IRP Objectives: The initial step in the 2024 IN IRP Process is to define the IRP Objectives that will be used to evaluate the modeling results.

Step 2: Modeling Inputs and Key Assumptions: The second step in the 2024 IN IRP process is to collect modeling inputs. These inputs include the following:

- Load Forecast;
- Fundamental Forecast of PJM Energy, Capacity, and Commodity Prices;
- Current resource evaluation;
- Capacity and Energy needs assessment; and
- Supply- and Demand-side resource options.

Step 3: Define and Optimize I&M Resource Portfolios: The third step in the 2024 IN IRP process is to create a set of optimized portfolios. This step can be iterative based on stakeholder feedback throughout the 2024 IN IRP process.

Step 4: Perform Scenario-Based Risk Analysis: The fourth step in the 2024 IN IRP process is to conduct analysis to determine cost and performance metrics for each portfolio.

Step 5: Identify Preferred Portfolio: In the final step of the 2024 IN IRP Process, portfolio results are presented through the Portfolio Performance Indicators matrix, incorporating each of the IRP Objectives. The result of Step 5 is the selection of a Preferred Portfolio.

The IRP Objectives of the 2024 IN IRP process aligned with the Five Pillars of Indiana energy policy, Reliability, Affordability, Resiliency, Stability, and Environmental Sustainability. Portfolio Performance Indicators related to IRP Objectives were defined and used to evaluate different portfolios in the 2024 IN IRP process, and ultimately identify a Preferred Portfolio. The Portfolio Performance Indicators are noted in Table 1.

Table 1. Portfolio Performance Indicators

IURC Pillar	IRP Objective	Performance Indicator
Reliability	Maintain capacity reserve margin and the consideration of reliance on the market for the benefit of customers.	Energy Market Exposure – Purchases
		Energy Market Exposure – Sales
		Planning Reserves
Affordability	Maintain focus on power supply cost and risks to customers	Net Present Value Revenue Requirement (NPVRR)
		Near-Term Power Supply Cost Impacts (CAGR)
		Portfolio Resilience
Resiliency	Maintain diversity of resources and fleet dispatchability	Resource Diversity
		Fleet Resiliency
(Grid) Stability	Maintain fleet of flexible and dispatchable resources	
Environmental Sustainability	Maintain focus on portfolio environmental sustainability benefits and compliance costs	Emissions Change
		Net Present Value Revenue Requirement (NPVRR)

The electric utility industry is changing rapidly and is subject to a significant number of external factors that are largely outside its control. The business development opportunities for data centers supporting advanced technologies is driving significant load growth across the United States at a time when some baseload generation resources are scheduled to retire. The result is increased economic pressures for new and existing resources to support the capacity and energy needs for utilities and RTO’s experiencing the load growth. While some of these factors have been modeled in the 2024 IN IRP, the Company expects continuous improvement in incorporating these dynamic and uncertain factors in future IRPs.

Public Advisory Process

For the 2024 IN IRP, I&M conducted an extensive and thorough Public Advisory Process. I&M considered multiple sources of input and feedback, including comments in the "Final Director's Report for Indiana Michigan Power Company's 2021 Integrated Resource Plan," issued on February 12, 2024, stakeholder feedback, and internal suggestions. Care was taken to promote stakeholder engagement with a focus on transparency in the 2024 IN IRP process, encouraging questions and feedback along the way, and converting feedback to actionable suggestions to incorporate into the 2024 IN IRP process.

At the core of the process was a series of five (5) public Stakeholder Meeting Workshops. Figure 1 below lists the topics covered in each workshop.

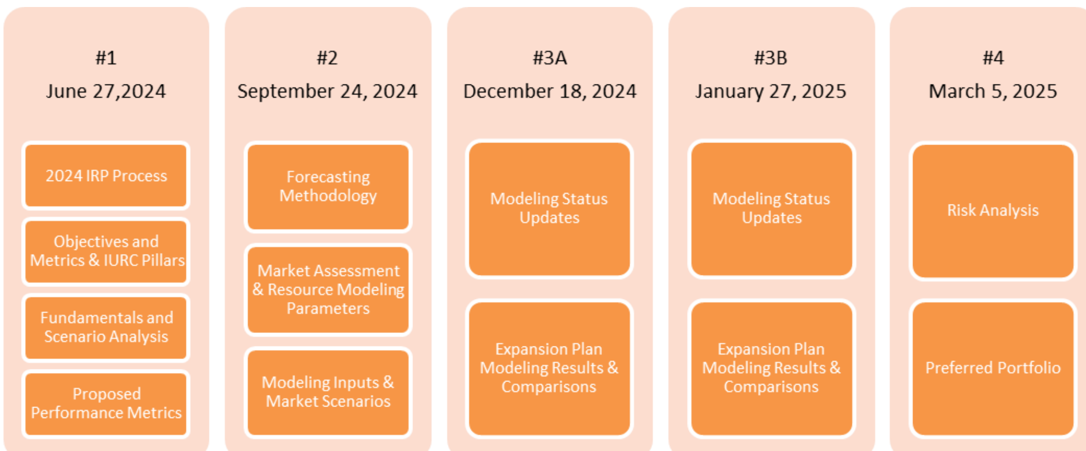

Figure 1. Stakeholder Meeting Workshops

The 2024 IN IRP had an average attendance of nearly 50 stakeholder participants at each of the five Stakeholder Meeting Workshops. Stakeholder participants represented a diverse mix of I&M residential, commercial and industrial customers, regulators, customer advocacy groups, environmental advocacy groups, fuel suppliers, advocacy groups, and elected officials. Meeting materials of each workshop can be found in Appendix Volume 4 and at 2024 IRP - Indiana Stakeholder Engagement Process. All workshops were held via webinar utilizing the Microsoft Teams meeting tool.

Concurrent with the Stakeholder Meeting Workshops described above, the Company managed an IRP website where stakeholders had an opportunity to submit questions and directly provide feedback to I&M for further consideration throughout the process. This provided stakeholders an ongoing and continuous opportunity to engage with I&M during the 2024 IN IRP process.

In addition to the core Stakeholder Meeting Workshops, a separate engagement process was developed for "Technical Stakeholders" who desired to examine the underlying analysis performed during the IRP process. I&M held two (2) technical conferences for Technical Stakeholders who, after signing non-disclosure agreements, were presented with details around portfolio modeling. In addition, I&M held five (5) meetings designated as “office hours” to address Technical Stakeholder modeling questions.

I&M’s Existing Resources and Going-In Positions

To establish a base from which to develop resource portfolios, I&M developed its current outlook for capacity and energy positions over the planning horizon. This outlook reflects the forecasted Indiana jurisdictional share of capacity and energy from I&M’s existing and planned resources (resources approved by the Commission that will provide capacity and energy in future years) compared to Indiana’s forecasted PJM load obligation and a capacity contingency, to calculate capacity and energy needs throughout the planning horizon.

I&M’s existing supply-side resource portfolio includes a mix of nuclear, wind, solar, hydro, and fossil-fired resources. I&M has also recently obtained approval by the Commission for a diverse set of resources including solar, wind, and natural gas (capacity-only) resources that have resulted from multiple competitive procurement processes. Table 2 represents Indiana’s share of the capacity associated with both the existing and recently approved resources.

Table 2. I&M Supply-Side Resources as of September 2024

Unit Name	Location	Fuel Type	C.O.D. [1] or Contract Start Date	Retirement or Contract Expiration Date [2]	PJM Nameplate Capacity (MW) [3]	
Clifty Creek 1-6	Madison, IN	Coal	1956	2039/40	62	(5)
Kyger Creek 1-5	Cheshire, OH	Coal	1955	2039/40	61	(5)
Rockport 1	Rockport, IN	Coal	1984	2027/28	1,079	
Lawrenceburg	Lawrenceburg, IN	Gas	2028	2033/34	697	(4)
Montpelier	West Poneto, IN	Gas	2027	2033/34	172	(4)
Berrien Springs 1-12	Berrien Springs, MI	Hydro	1908	2035/36	5	
Buchanan 1-10	Buchanan, MI	Hydro	1919	2035/36	2	
Constantine 1-4	Constantine, MI	Hydro	1921	2052/53	1	
Elkhart 1-3	Elkhart, IN	Hydro	1913	2029/30	2	
Mottville 1-4	White Pigeon, MI	Hydro	1923	2032/33	1	
Twin Branch 1-8	Mishawaka, IN	Hydro	1904	2035/36	5	
Cook 1	Bridgman, MI	Nuclear	1975	2033/34	830	
Cook 2	Bridgman, MI	Nuclear	1978	2036/37	956	
Deer Creek	Grant County, IN	Solar	2015	2034/35	2	
Elkhart	Elkhart, IN	Solar	2026	2055/56	83	(4)
Hoosier Line	White County, IN	Solar	2027	2056/57	150	(4)
Lake Trout	Blackford County, IN	Solar	2028	2062/63	201	
Mayapple	Elkhart, IN	Solar	2028	2062/63	183	
Olive	St. Joseph County, IN	Solar	2016	2035/36	4	
St. Joseph Solar	St. Joseph County, IN	Solar	2021	2050/51	16	
Twin Branch Solar	St. Joseph County, IN	Solar	2016	2035/36	2	
Watervliet	Berrien County, MI	Solar	2016	2035/36	4	
Fowler Ridge 1	Benton County, IN	Wind	2008	2027/28	83	(4)
Fowler Ridge 2	Benton County, IN	Wind	2009	2028/29	42	(4)
Headwaters	Randolph County, IN	Wind	2014	2033/34	166	(4)
Meadow Lake	Chalmers, IN	Wind	2026	2045/46	83	(4)
Wildcat	Madison County, IN	Wind	2014	2031/32	82	(4)
					4,974	

(1) Commercial operation date.
(2) Retirement or Contract Expiration dates represent the PJM Delivery Year and are assumptions for IRP planning purposes. Cook units 1 and 2, Elkhart Hydro, and Mottville Hydro Retirement dates represent license expiration dates.
(3) Represents Indiana's share of these resources
(4) Represents capacity from Power Purchase Agreements (PPAs) or Capacity Purchase Agreements (CPAs)
(5) Represents Indiana's share of the OVEC capacity under the ICPA

Figure 2 below shows Indiana's Going-In Capacity Position through 2044.

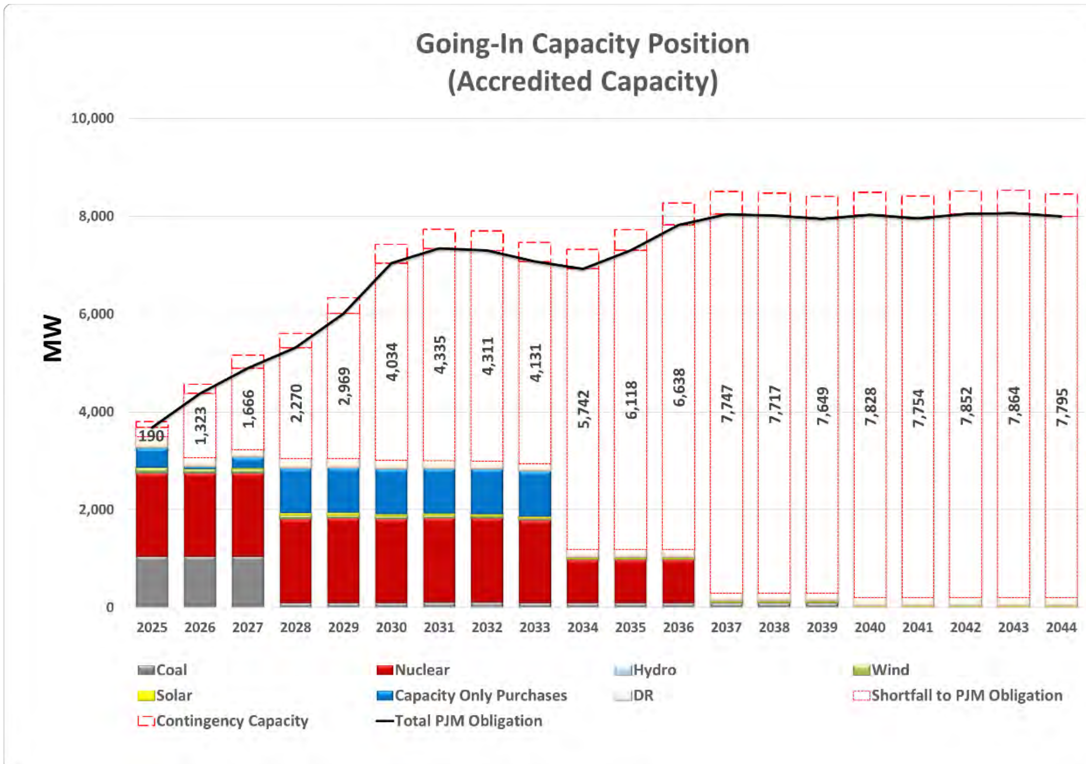

Figure 2. I&M Indiana Going-In Capacity Position

The capacity shortfall begins immediately in 2025 and rapidly increases over the planning horizon due primarily to the significant HSL growth, the expiration of capacity only purchases, and the going-in assumption that Cook Nuclear operates through its current license period. In the near-term, the Company will require a considerable amount of resources to meet the forecasted PJM load obligation. Over the long-term, the forecasted PJM load obligation more than doubles compared to the 2025 level.

I&M also developed a Going-In Energy Position, which is shown in Figure 3 below.

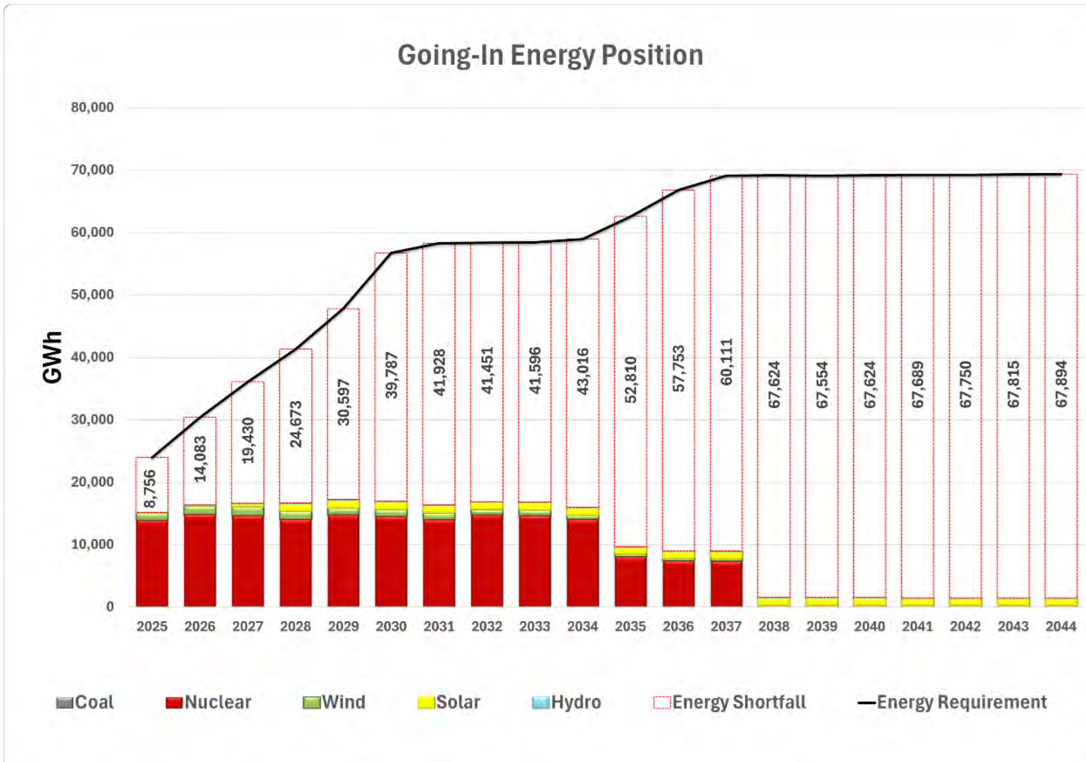

Figure 3. I&M Indiana Going-In Energy Position

Similar to the Going-In Capacity Position, the energy shortfall begins immediately in 2025, growing rapidly by 2030 and to nearly tripling by the end of the planning horizon. The energy shortfall is primarily due to HSL growth and the going-in assumption that Cook Nuclear operates through its current license period.

Summary of I&M's Preferred Portfolio Development

To assess how modeled portfolios would perform under various market and regulatory conditions I&M developed four (4) distinct scenarios, including the (1) Base Reference Case, (2) an Enhanced Environmental Regulations (EER) Case, reflecting existing and proposed regulations under EPA Section 111(b)(d), (3) a High Economic Growth Case and (4) a Low Economic Growth Case. Additionally, I&M developed 11 sensitivities that test how portfolios are impacted by specific changes to base assumptions. Each scenario and sensitivity was assessed using the Portfolio Performance Indicators.

A common theme that resulted from modeling all the scenarios and sensitivities was that similar amounts of natural gas resources were selected to meet Indiana's future capacity needs. This remained true even in the sensitivities where I&M evaluated an expedited transition to a low carbon resource portfolio. Another common theme was that all scenarios and sensitivities economically selected the Cook Nuclear Plant Unit 1 and Unit 2 SLR opportunities, maintaining Cook as a foundation of I&M's future generation portfolio.

Based on the Portfolio Performance Indicators, three Candidate Portfolios were selected for further evaluation: (1) Base Reference Case; (2) Low Carbon: Transition to Objective; and (3) Expanded Wind Availability (EER). A comprehensive risk analysis was conducted on these Candidate Portfolios using a stochastic modeling approach. The modeling analyzed the variability of key output metrics, including Net Present Value (NPV) and percent of energy market purchases and sales compared to total load.

After reviewing both the Portfolio Performance Indicators and the results of the risk analysis for the Candidate Portfolios, a Preferred Portfolio was developed. I&M developed the Preferred Portfolio primarily based on modifications to the Expanded Wind Availability (EER) Case. This case was selected as the basis for the Preferred Portfolio for the following reasons:

- The case better positions I&M for compliance with existing and future Greenhouse Gas regulations based on the current and proposed EPA Section 111(b)(d) rules and the potential for regulations to occur in some form during the planning horizon.
- The case leverages a mix of resource types that support reliability and stability, while increasing resource diversity and expanding the renewable and clean energy portfolio.
- The case leverages existing natural gas resources which allows I&M to better manage the remaining life of its generation portfolio and associated risks, mitigates the impact of development risks associated with new generation, and lowers the additionality impacts of natural gas on I&M's customers and the PJM system.
- The case resulted in less variability in future cost risk as compared to the Base Reference Case in the risk analysis results.
- The case reflects up to date market conditions on resource availability based on results from the four (4) separate RFPs issued in 2024.

The Preferred Portfolio takes advantage of cost savings opportunities and other benefits associated with redevelopment of the Rockport site with future NGCTs and SMR technology. New NGCTs were included in the Preferred Portfolio in 2030, reflecting 690 MW of nameplate capacity. These new NGCTs reflect estimated cost reductions of approximately 15% compared to the generic new NGCT resource price. These cost reductions were included to reflect the cost savings associated with the reuse of the Rockport interconnection and existing facilities and the opportunity to leverage favorable equipment pricing associated with AEP multi-unit supply chain opportunities. In addition, SMRs were included in the Preferred Portfolio in 2036 and 2037, reflecting a total 600 MW of nameplate capacity. These SMRs reflect estimated cost reductions of approximately 30% compared to the generic SMR resource price. These cost reductions were included to reflect the cost savings associated with the reuse of the Rockport interconnection and existing facilities, energy community bonus ITCs, federal grant opportunities, customer participation, and leveraging fast follower savings opportunities. The Rockport facility qualifies as an energy community under the Inflation Reduction Act of 2022.

The Preferred Portfolio capacity additions are shown in Table 3.

Table 3. Preferred Portfolio Cumulative Nameplate Capacity Additions

Year	Nameplate MW								Accredited MW	
	Wind	Solar	Storage	New Acro	Existing NGCC	New NGCT	Existing NGCT	Nuclear Cook SLR & SMR	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

The Preferred Portfolio represents a balanced plan that supports I&M's IRP Objectives and provides a sound planning basis for the Company's near-term plan, 2025 through 2030, and long-term-indicative plan, 2031 through 2044. The Preferred Portfolio reflects a diverse mix of wind, solar, storage, natural gas, nuclear and demand-side resources that is maintained throughout the planning horizon, including taking advantage of near-term expanded wind availability based on market intelligence gained from I&M's 2024 RFPs. This diverse mix of resources represents an all-of-the-above approach to considering Indiana's Five Pillars of energy policy. Existing natural gas combined cycle (NGCC) and combustion turbine (NGCT) resources are leveraged to better position for future environmental compliance while also providing the benefit of lowering costs, mitigating development risk and reducing additionality. The Preferred Portfolio maintains nuclear power as a key foundation to Indiana's future capacity and energy resource diversity by selecting the SLR for both Cook Unit 1 and 2 and also including 600 MW of new SMR technology that takes advantage of redevelopment opportunities at I&M's Rockport site. The Preferred Portfolio also reflects the relicensing of the Elkhart and Mottville Hydro resources in 2030 and 2033, respectively, which will be further evaluated as part of I&M's Short-Term Action Plan.

Figure 4 and Figure 5 below show the Preferred Portfolio's accredited capacity and energy results by resource type.

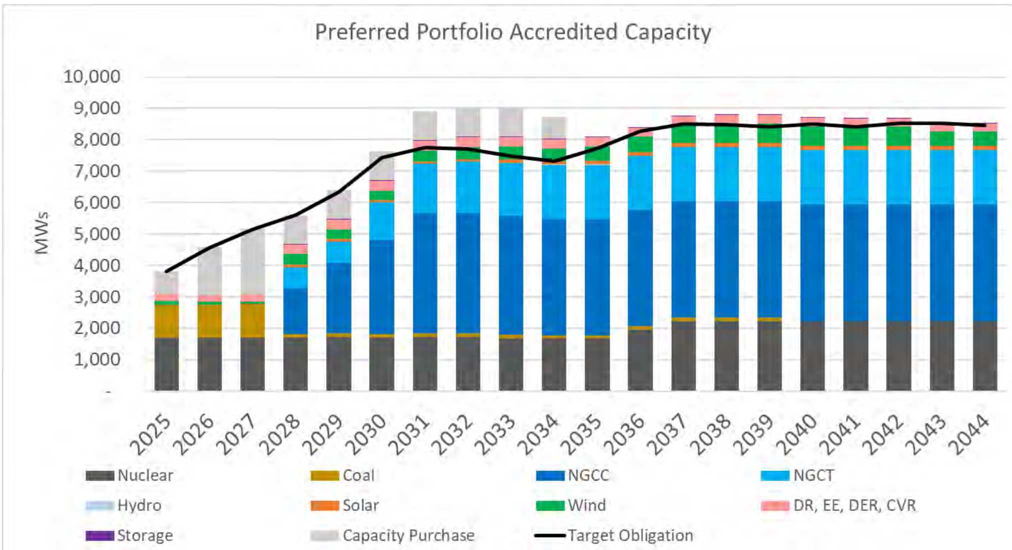

Figure 4. Preferred Portfolio Accredited Capacity by Resource Type

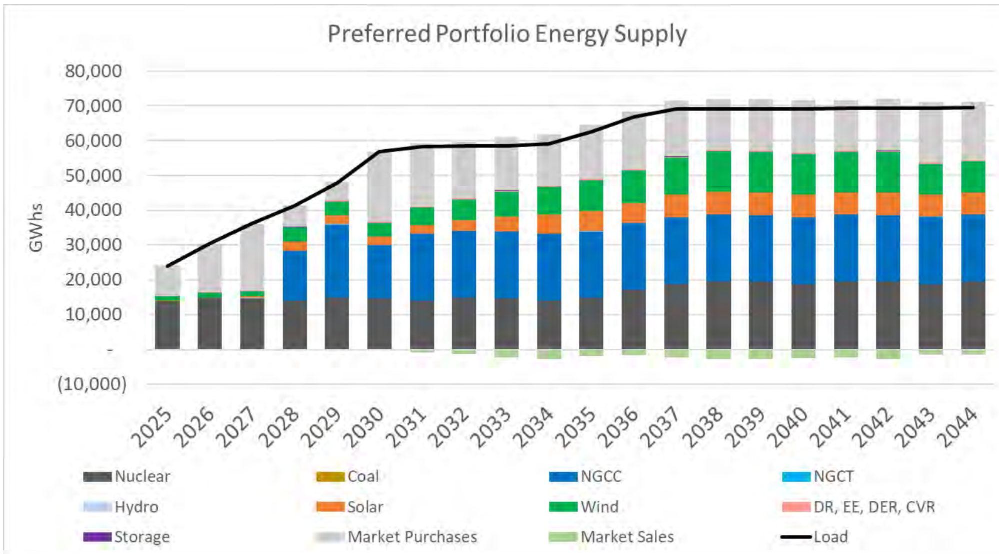

Figure 5. Preferred Portfolio Energy by Resource Type

As seen in the figures above, the Preferred Portfolio relies on significant capacity contributions from nuclear, NGCC, and NGCT resources due to their higher accredited capacity values, while wind and solar resources contribute less capacity due to the lower accredited values. As noted above, this was a common theme amongst all scenario and sensitivity results. From an energy perspective, wind and solar resources provide approximately 25% of the energy generated from 2034 to 2044 and nuclear resources provide approximately 28% of the energy generated from 2036 to 2044, leading to greater energy diversity within the Preferred Portfolio.

Conclusions and Short-Term Action Plan

The Company's 2024 IN IRP is the result of a Public Advisory Process and extensive modeling that evaluated numerous scenarios and sensitivities using the best available industry and market intelligence available at the time to inform resource assumptions. I&M's IRP Objectives and Portfolio Performance Indicators were designed to align with Indiana's Five Pillars of energy policy. The Preferred Portfolio represents a balanced consideration of the Five Pillars and an all-of-the-above resource plan to meet the future energy and capacity needs of I&M's Indiana retail customers and will be used as a guide for the resource decisions I&M undertakes as its business transforms in the future to serve the unprecedented load growth forecasted. The Preferred Portfolio leverages key opportunities to significantly expand I&M's resource diversity, taking advantage of existing and new generation resources, to support ongoing safety, reliability, and resiliency of the grid. The Preferred Portfolio also positions I&M to significantly expand clean energy resources and prepare for potential future environmental regulation, thereby supporting an environmentally sustainable future. Collectively, the benefits of the Preferred Portfolio support I&M's IRP Objectives while mitigating potential cost risks to customers in the event future market conditions change.

Steps that I&M has taken, or will take, as part of its Short-term Action Plan include:

DSM Programs: Continue the planning and regulatory actions necessary to implement an ongoing cost-effective portfolio of DSM programs in Indiana consistent with this IRP.

Rockport Retirement: Continue to take the steps necessary to support a transition of the Rockport Coal facility, including proceeding with necessary actions to support the ongoing development and commissioning of new resources from I&M's 2022 and 2023 All-Source RFPs that have been approved by the Commission to replace Rockport.

Near Term Capacity Needs: Use bilateral capacity purchases to obtain the capacity needed for future PJM Delivery Years that cannot be met through long-term resources.

2024 Competitive Procurement Activities: Complete selection of resources from the 2024 RFP and other competitive procurement activities undertaken by I&M that reflect the market conditions at the time the procurement activities are conducted. Seek approval of resources that are reasonably consistent with the Preferred Portfolio resource selections.

Rockport CT: Complete competitive procurement process, secure 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 Competitive Procurement Activities: Continue to issue future generation RFPs or utilize other competitive procurement methods, as necessary, to meet I&M's capacity and energy needs.

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 opportunities reflected in the Preferred Portfolio.

Adjust for the Future: Adjust this action plan and future IRPs to reflect changing circumstances, as necessary.

Since the Company's last IRP, I&M accomplishments towards the 2021 Short-Term Action Plan include:

- Complied with the modeling and other IRP-related commitments as set forth in the Settlement Agreements in Cause Nos. 45546 and 45933.
- Conducted All-Source RFPs in 2022 and 2023 to acquire the generation resources necessary to replace the energy and capacity needs associated with the Rockport retirement obligation in December 2028. The Commission approved the related resources in Cause Nos. 45868, 45869, 46083, 46085, and 46088.
- The Company completed an updated Market Potential Study in 2024 assessing the potential for future energy efficiency (EE), demand response (DR) and distributed energy resources (DER) resources.
- The Company issued four RFPs in September 2024 targeting approximately 4,000 MW of solar, wind, storage, thermal and supplemental capacity resources.
- The Company has notified PJM of its intention to continue as a Fixed Resource Requirement (FRR) entity through the 2025/2026 PJM Delivery Year ending May 31, 2026.
- The Company continues to monitor and support PJM's Capacity Interconnection Rights (CIR) Transfer Efficiency proposal that would support an expedited process for reusing I&M's existing interconnection rights at the Rockport site for future generation resource development.

1 Introduction

1.1 Overview

This Report presents the Indiana Michigan Power Company's (I&M or Company) 2024 Indiana Integrated Resource Plan (2024 IN IRP or Report) for its Indiana jurisdiction. This Report includes descriptions of assumptions, study parameters, and methodologies. The 2024 IN IRP process for the Company resulted in an integration of supply- and demand-side resources.

The goal of the 2024 IN IRP process is to develop a near-term plan (including a Short-Term Action Plan) and a long-term-indicative plan identifying the amount, timing, and type of resources required to supply capacity and energy as part of the Company's obligation to ensure a reliable and economical power supply to its Indiana customers.

In addition to developing plans for achieving reserve margin requirements as set forth by PJM Interconnection LLC (PJM) and meeting I&M's obligation to ensure reliable and economical power supply to its customers, resource planning also impacts I&M's capital expenditure requirements, regulatory planning, environmental compliance, and other planning processes.

This Report covers the processes, assumptions, results, and recommendations required to develop the Company's IRP. It reflects the best information reasonably available at the time of preparation. I&M notes that changes that may affect the results and conclusions contained herein can, and do, occur. Therefore, commitments to specific resources and actions remain subject to further review and consideration.

Beginning with the 2024 IN IRP, I&M is transitioning to a state-specific integrated resource planning model. The change will allow I&M to tailor its future resource plans and decisions to the capacity and energy needs 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.

1.2 Introduction to I&M

I&M is a multi-jurisdictional company serving both retail and wholesale customers located in the states of Indiana and Michigan (see Figure 6). The peak load requirement of I&M's total retail and wholesale customers is seasonal in nature, with distinctive peaks occurring in the summer and winter seasons. In the state of Indiana, I&M serves approximately 482,000 retail customers. For Indiana, I&M's all-time highest recorded peak demand was 3,976 MW, which occurred in July 2011; and the highest recorded winter peak was 3,318 MW, which occurred in January 2014. The most recent (summer 2024 and winter 2023/24) actual Indiana summer and winter peak demands at the time this 2024 IN IRP process began were 3,270 MW and 2,954 MW, occurring on August 27, 2024, and January 17, 2024, respectively.

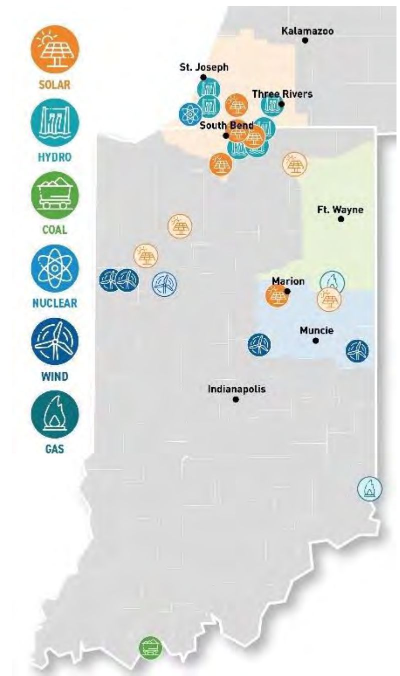

Figure 6. I&M Service Territory and Generating Locations

2 I&M's 2024 IN IRP Process

2.1 Overview of the 2024 IN IRP Process

The purpose of the 2024 IN IRP is to develop a set of supply-side and demand-side resources (Preferred Portfolio) that provides a well-balanced consideration of the Five Pillars of Indiana energy policy. These pillars guide how I&M generates and supplies electricity in a way that balances Reliability, Affordability, Resiliency, Grid Stability, and Environmental Sustainability and they are discussed in Section 2.2.

To prepare for the 2024 IN IRP, I&M reviewed the comments and feedback outlined by the Indiana Utility Regulatory Commission (IURC or Commission) in the "Final Director's Report for Indiana Michigan Power Company's 2021 Integrated Resource Plan," issued on February 12, 2024 (Director's Report). In response, I&M took steps to incorporate the Director's suggestions. Table 4 summarizes the comments and feedback from the Director's Report that have been addressed in this Report.

Table 4. Director's Report Feedback Addressed

Category	2021 IRP Feedback	2024 IN IRP Improvements
Load Forecast	All portfolios were based on the base load forecast. No optimized scenarios were based on a high- or low-load forecast.	The Company modeled four portfolios using load forecasts other than the base load forecast. These portfolios are noted in Section 9.
	The level and share of future load is subject to considerable uncertainty.	The Company used a capacity planning risk model to quantify a Capacity Contingency value based on variability in the load forecast, in addition to variability in other attributes. This risk model is noted in Section 7.
Demand-Side Management	The load forecasting methodology was not consistent with the Net-To-Gross-like (NTG) approach used for EE resources.	The Company now models Demand Side Management (DSM) as an explanatory variable in the residential and commercial models. This is noted in Section 4.
	Demand Response (DR) resources were modeled as nonoptimized resources.	The Company modeled DR and all Demand-Side resources (including EE, DER, and CVR) as optimized resources beginning in 2026. This is noted in Section 8.
Scenario/Risk Analysis	I&M did not examine how the focused six portfolios would perform under scenarios they were not derived from.	The Company modeled four portfolios using load forecasts other than the base load forecast. These portfolios are noted in Section 9. I&M also completed stochastic risk analysis prior to selection of the Preferred Portfolio.
	The IRP did not consider ownership structure for supply-side resource options.	I&M modeled several proxy ownership types of supply-side resources with varying availability and build limits based on PJM market intelligence. Additional details are noted in Section 8.
	There is a disconnect between the regional and the I&M specific capacity expansion modeling.	I&M included an Energy Market Risk metric in its Portfolio Performance Indicators matrix to quantify the reliance on the PJM energy market between portfolios and can be noted in Section 2.
	The resource diversity metric included in the IRP can be misleading.	A new resource diversity metric was included in the 2024 IN IRP and can be noted in Section 2.
Planning Improvements	EVs and DERs have the potential to impact the amount of energy consumed but will also cause changes in the load shape across the day and year, impacting economics of resource choices.	The Company incorporated EV and Distributed Generation (DG) in the load forecast. This can be noted in Section 4.
Stakeholder Comments	I&M should focus on seasonal and even hourly ability of resource portfolios to meet energy requirements across a wide range of circumstances. This process has started with the PJM filing at FERC to enhance PJM's resource adequacy risk modeling and capacity accreditation processes (Docket No. ER24-99-000).	I&M used the PJM capacity accreditation methodology in the 2024 IN IRP and incorporated a metric regarding the planning reserve margin in the Reliability pillar for comparison amongst Cases. An annual energy import and export constraint was applied in all Cases and can be noted in Section 9.
	I&M should provide the annual revenue requirement of Candidate Portfolios for each year of the planning horizon, both in nominal dollars and real dollars.	The annual Power Supply Costs of all Cases for each year of the planning horizon in both nominal and real dollars is included in Appendix Volume 1.

The 2024 IN IRP process, associated modeling, and development of the Preferred Portfolio complies with the Indiana Guidelines for Resource Planning and reliability requirements, while also quantifying risks introduced by the market and regulatory environments, and the risk of over-reliance on imports and/or exports. The steps followed in the development of the Preferred Portfolio are illustrated in Figure 7 and are described in more detail below.

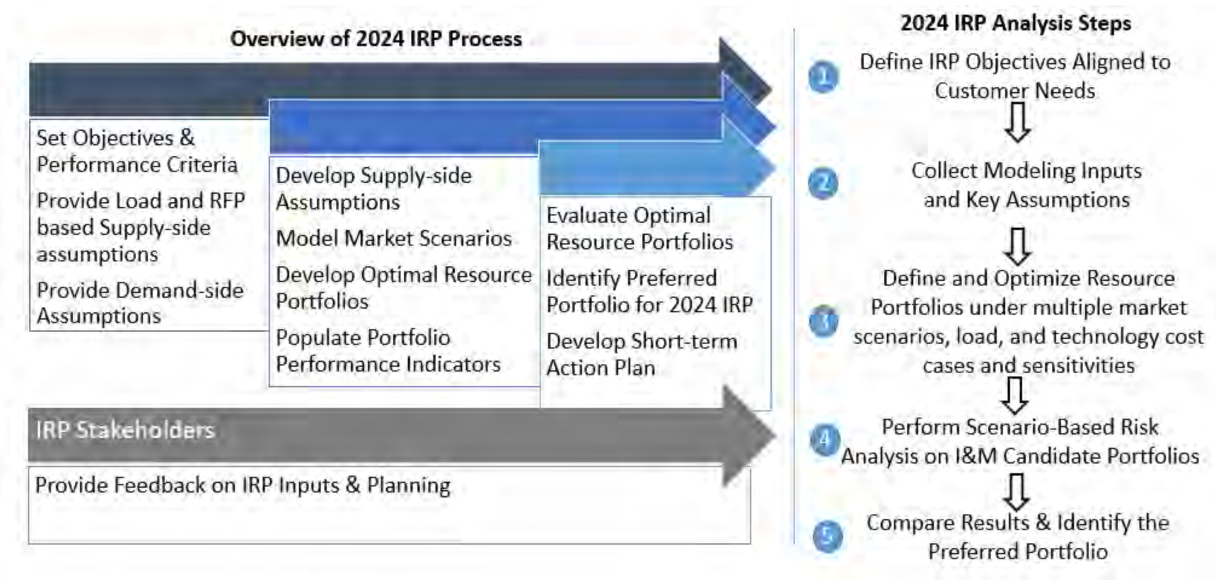

Figure 7. I&M 2024 IN IRP Process

Step 1: Define IRP Objectives: The initial step in the 2024 IN IRP Process is to define the IRP Objectives that will be used to evaluate the various portfolios aligned to customer needs. Portfolios are evaluated in terms of Reliability, Affordability, Resiliency, Grid Stability, and Environmental Sustainability in alignment with the Five Pillars.

Step 2: Modeling Inputs and Key Assumptions: The second step in the 2024 IN IRP process is to collect modeling inputs. These inputs include the following:

- Load Forecast (Section 4);
- Fundamental Forecast of PJM Energy, Capacity, and Commodity Prices (Section 5);
- Current resource evaluation (Section 6);
- Capacity and Energy needs assessment (Section 7); and
- Supply- and Demand-side resource options (Section 8).

Step 3: Define and Optimize I&M Resource Portfolios: The third step in the 2024 IN IRP process is to create a set of optimized portfolios under multiple market scenarios, load, and technology cost cases and sensitivities. This step can be iterative based on stakeholder feedback throughout the 2024 IN IRP process.

Step 4: Perform Scenario-Based Risk Analysis: The fourth step in the 2024 IN IRP process is to conduct scenario-based analysis to determine cost and performance metrics for each portfolio, including a risk analysis. As part of the 2024 IM IRP, the primary tool for portfolio risk analysis was a probabilistic (stochastic) analysis.

Step 5: Identify Preferred Portfolio: In the final step of the 2024 IN IRP Process, detailed portfolio results are presented through the Portfolio Performance Indicators matrix. The Portfolio Performance Indicators matrix incorporates each of the IRP Objectives and measures through a process that considers attributes in accordance with Stakeholder needs, economic and load growth projections, as well as I&M input. The result of Step 5 is the selection of a Preferred Portfolio.

The 2024 IN IRP process considered an array of new demand-side resource options through an updated Market Potential Study that was completed in 2024. This study was conducted by GDS Associates to evaluate the potential for future energy efficiency (EE), demand response (DR) and distributed energy resources (DER) resources to support the IRP and demand-side management (DSM) planning processes. The updated MPS analyzed and developed the following inputs into the IRP process which are further discussed in Section 8.2 and 8.3:

- An update of EE, DR and DER program costs and savings potential specific to I&M Indiana service area over a 20-year time horizon.
- An update to estimates of technical, economic, and achievable potential from primary market research, industry best-practice research, codes and standards research and a comprehensive review of current programs, historical savings, and projected energy savings opportunities.

The supply-side resources were informed through the Energy Information Administration's (EIA) Annual Energy Outlook, National Renewable Energy Laboratory's (NREL) Annual Technology Baseline (ATB) and market-based intelligence through I&M's experience with recent requests for proposals (RFP). These supply-side resources include natural gas resources, renewable energy resources such as storage, solar, and wind, and small modular reactors. Parallel to the 2024 IN IRP process, I&M issued four RFPs for generation resources to meet projected energy and capacity needs. These separate RFPs allowed for a targeted approach addressing intermittent resources, non-intermittent resources, battery energy storage and supplemental capacity resources. The four separate RFPs were designed to allow for an open, competitive solicitation process which included market-based pricing. The results from these RFPs were used to confirm and adjust the installed costs and build limit supply-side resource parameters, and ultimately inform the Preferred Portfolio.

2.2 2024 IN IRP Objectives

The 2024 IN IRP process is structured to enable a systematic and holistic planning analysis to identify the Preferred Portfolio that best meets all its objectives and design requirements over a wide range of market futures. The 2024 IN IRP Process is a time-tested five-step process, which results in a reliable and efficient approach to identifying future resource needs to meet the energy and capacity needs for I&M customers.

The 2024 IN IRP process was also designed so that its objectives align with the Five Pillars of Indiana energy policy, as codified in Indiana Code 8-1-2-0.6. The Five Pillars guiding Indiana utilities are Reliability, Affordability, Resiliency, Stability, and Environmental Sustainability. The definitions for each of the pillars are below and are to be considered in decisions concerning generation resource mix, energy infrastructure and electric service ratemaking constructs.

(1) Reliability, including:

(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:

(i) scheduled; and

(ii) reasonably expected unscheduled;

outages of system elements; and

(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.

(2) Affordability, including ratemaking constructs that result in retail electric utility service that is affordable and competitive across residential, commercial, and industrial customer classes.

(3) Resiliency, including the ability of the electric system or its components to:

(A) adapt to changing conditions; and

(B) withstand and rapidly recover from disruptions or off-nominal events.

(4) Stability, including the ability of the electric system to:

(A) maintain a state of equilibrium during:

(i) normal and abnormal conditions; or

(ii) disturbances; and

(B) deliver a stable source of electricity, in which frequency and voltage are maintained within defined parameters, consistent with industry standards.

(5) Environmental sustainability, including:

(A) the impact of environmental regulations on the cost of providing electric utility service; and

(B) demand from consumers for environmentally sustainable sources of electric generation.

The resulting least cost portfolios developed by the 2024 IN IRP process reflect a combination of market, regulatory and technology specified conditions. While least cost is an important objective, and a driver of the optimization routine, it is not the only objective that is important to this process. I&M considered each objective for the development of the 2024 IN IRP and Preferred Portfolio.

2.3 Portfolio Performance Indicators

To allow for the comparison of portfolio performance across diverse scenarios and sensitivities, and to ultimately identify a Preferred Portfolio, Portfolio Performance Indicators related to IRP Objectives were defined and used to evaluate different portfolios and planning strategies in the 2024 IN IRP process. There are eleven (11) Portfolio Performance Indicators, with each indicator having defined metrics. These metrics align with Indiana's Five Pillars and provide objective assessments of critical factors of each of the portfolios under different market conditions. I&M's 2024 IN IRP objectives, Portfolio Performance Indicators, and metrics are discussed in more detail below by each pillar.

2.3.1 Reliability

The objective for Reliability is to consider reliance on the energy market for purchase and sales and to maintain capacity reserve margin. Three performance indicators were selected to measure progress towards maintaining reliability. The performance indicators for Reliability along with associated metrics are summarized in Table 5.

Table 5. Reliability Performance Indicators

Performance Indicator	Metric Description
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.

As a member of PJM, the Company can leverage market energy for the benefit of its customers. Under normal conditions, this is of high value to ensure access to reliable and lower cost energy. Energy markets, however, include risks around reliance on both purchases and sales during periods of high price volatility. Measuring the total portion of customer energy served by the market, or conversely, the reliance on market energy sales in periods of excess generation will provide insight into potential market risks of each portfolio. By measuring planning reserves performance, the Company can evaluate the exposure of different resource portfolios towards meeting planning reserve margin requirements.

2.3.2 Affordability

The objective of Affordability is to maintain focus on costs to customers and the resilience of resource portfolios to changing market conditions. The affordability metrics utilized consider the generation component of Power Supply Costs only and do not represent the total costs of electric service which will apply to customers. Power Supply Costs represent the annualized capital associated with resources selected, operation and maintenance (O&M) costs, fuel costs, environmental costs, net purchases and sales of energy and capacity, property and income taxes, and the return on capital. The performance indicators for Affordability along with associated metrics are summarized in Table 6.

Table 6. Affordability Performance Indicators

Performance Indicator	Metric Description
Near-Term Rate Impacts (CAGR)	7-year Compound Annual Growth Rate (CAGR) of Annual Power Supply Costs. Lower values are better.
Net Present Value Revenue Requirement (NPVRR)	Portfolio 20-year NPVRR of Power Supply Costs. Lower values are better.
Portfolio Resilience	Range of Portfolio NPVRR (Power Supply Costs) dispatched across all Cases. Lower values are better.

The Affordability metrics above measure each portfolio's ability to provide low-cost capacity and energy in the short- and long-term while meeting the constraints applied for each Case. Both short- and long-term metrics are intended to demonstrate anticipated costs that will impact I&M and its commercial, industrial, and residential customers. As these financial metrics indicate a crucial component of the costs being incurred, lower values for each indicate better portfolio performance under the Affordability Pillar.

The Portfolio Resilience is also considered under the Affordability objective and is measured as the difference between the 10th and 90th percentile NPVRRs obtained from stochastic risk analysis, indicating the financial impact that economic uncertainties could have on portfolio results.

2.3.3 Resiliency

The objective of Resiliency is to maintain diversity of resources and fleet dispatchability. The performance indicators for Resiliency along with associated metrics are summarized in Table 7.

Table 7. Resiliency Performance Indicators

Performance Indicator	Metric Description
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.

I&M is interested in selecting a diverse set of resources for maintaining Resiliency for its customers. Increased diversity of resources can ensure a generation fleet that is more resilient to disruptions ensuring that if one type of resource is unavailable, other types of resources are available to maintain capacity and energy obligations. This performance indicator will allow the Company to assess the overall diversity within portfolios considered. Resource Diversity is measured based on the Shannon-Weiner Diversity Index[2] that considers the number of different types of resources and their respective contributions to the portfolio total with respect to capacity and energy. This metric is an improvement from the 2021 I&M IRP as it considers the respective contributions of each resource, in addition to the number of different types of resources. Whereas the 2021 I&M IRP only considered the number of unique generations and fuel types in its diversity metrics.

The Fleet Resiliency performance indicator allows the Company to evaluate the amount of dispatchable capacity as a percentage of peak load.

2.3.4 (Grid) Stability

The objective of Grid Stability is to maintain a fleet of flexible and dispatchable resources. The performance indicator for Grid Stability is Fleet Resiliency, which is measured by dispatchable capacity as a percentage of peak load.

2.3.5 Environmental Sustainability

The objective of Environmental Sustainability is to maintain focus on portfolio environmental sustainability benefits and compliance costs. The performance indicators for Environmental Sustainability along with associated metrics are summarized in Table 8.

Table 8. Environmental Sustainability Performance Indicators

Performance Indicator	Metric Description
Emissions Change	CO_2, NOx, and 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 the Affordability Pillar above

[1] Bobbitt, Z. (2021, 03 29). *Shannon diversity index: Definition & example*. Statology. Retrieved from https://www.statology.org/shannon-diversity-index/

I&M is interested in understanding how each portfolio's resource selections will impact Environmental Sustainability as measured by emissions reduction. Environmental performance is measured by quantifying the percentage change from the 2005 baseline levels of carbon dioxide (CO_2), nitrogen oxide (NOx), and sulfur dioxide (SO_2). The Company understands that environmental sustainability can come at a cost and will additionally consider NPVRR under the Affordability objective when discussing the Environmental Sustainability objective.

3 Public Advisory Process

3.1 Public Participation Process

For the 2024 IN IRP, I&M conducted an extensive and thorough Public Participation Process. I&M considered multiple sources of feedback, including comments in the "Final Director's Report for Indiana Michigan Power Company's 2021 Integrated Resource Plan," issued on February 12, 2024, Stakeholder feedback, and internal suggestions. I&M was assisted in the management of the public advisory process by 1898 & Co., a part of Burns & McDonnell. Care was taken to promote Stakeholder engagement with a focus on promoting transparency in the 2024 IN IRP process, encouraging questions and feedback along the way, and converting feedback to actionable suggestions that could be used to inform the 2024 IN IRP process.

As a result, stakeholders have had the opportunity to provide feedback on virtually all areas of the 2024 IN IRP, including but not limited to the following:

- Establishing objectives of the 2024 IN IRP;
- Identification of metrics to be used in evaluating IRP Objectives;
- Review of inputs and key assumptions;
- Identification of alternative scenarios and sensitivities to generate a diverse range of potential Candidate Portfolios;
- Analysis of the Candidate Portfolios through risk analysis; and
- Creation of the Preferred Portfolio.

I&M's objectives for Stakeholder engagement included:

- **Listen:** Understand concerns and objectives by providing a forum for Stakeholder feedback at key points in the 2024 IN IRP to inform I&M's decision making.
- **Inform:** Increase Stakeholder understanding of the 2024 IN IRP process, key assumptions, and the challenges facing I&M and the electric utility industry through discussion, answering, and asking questions and being transparent in the process.
- **Consider:** Review all Stakeholder input and carefully consider this feedback at key points in the 2024 IN IRP process to inform I&M's decision making.

The 2024 IN IRP stakeholders included, but were not limited to, I&M residential, commercial, and industrial customers, regulators, customer advocacy groups, environmental advocacy groups, fuel suppliers, advocacy groups, and elected officials.

3.2 2024 IN IRP Public Stakeholder Meeting Workshops

At the core of the process was a series of five (5) public Stakeholder Meeting Workshops. Figure 8 below lists the topics covered in each workshop.

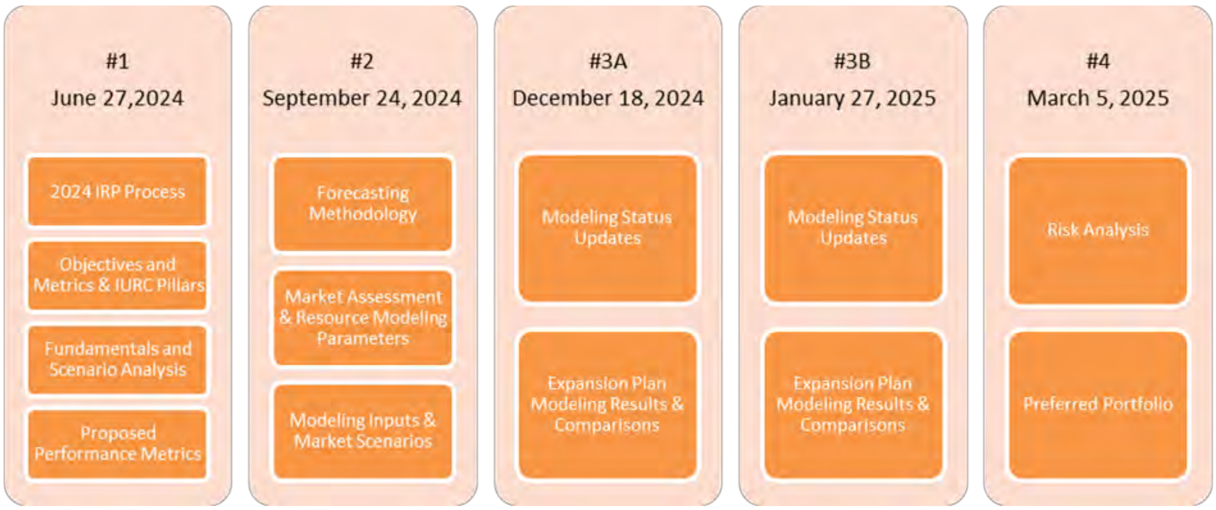

Figure 8. Stakeholder Meeting Workshops

Meeting materials of each workshop can be found in Appendix Volume 4 and at 2024 IRP - Indiana Stakeholder Engagement Process. All workshops were held via webinar utilizing the Microsoft Teams meeting tool.

Concurrent with the workshops described above, the Company managed an IRP website where stakeholders had an opportunity to submit questions and directly provide feedback to I&M for further consideration throughout the process. This provided stakeholders an ongoing and continuous opportunity to engage with I&M during the 2024 IN IRP process. Any feedback or questions submitted along with I&M's responses were posted on the IRP website. A summary of the Stakeholder Meeting Workshops described above are found in Appendix Volume 4, including the presentations, meeting minutes and a full list of the written stakeholder questions responded to by the Company.

The 2024 IN IRP had an average attendance of nearly 50 stakeholder participants at each of the five Stakeholder Meeting Workshops. Each workshop followed the same format.

- Introduction by I&M leadership
- Review of guidelines for the meeting and opportunities for stakeholder engagement
- Focus Topics (different for each Stakeholder Meeting Workshop)
- Plans for Stakeholder Meeting Workshops and Data Provisioning
- Questions and feedback at the end of each focus topic area
- Concluding remarks by I&M leadership

I&M structured the 2024 IN IRP process to provide an open forum for stakeholders to voice questions/concerns and make suggestions on the 2024 IN IRP inputs and analysis. During each workshop, all participants could use the Microsoft Teams chat and “Q&A” tools to submit written questions or feedback. Participants were also able to ask questions or give feedback orally. The results of these question and feedback sessions are included in each Stakeholder Meeting Workshop minutes.

It is important to note that all feedback and suggestions were reviewed by both the 2024 IN IRP working team as well as I&M leadership. Throughout the process, I&M worked on including many of the suggestions discussed in Stakeholder Meeting Workshops into the 2024 IN IRP process, analysis, and results.

3.3 Stakeholder Input Leveraged in the 2024 IN IRP

In addition to the input leveraged from the Director’s Report noted in Table 4, I&M implemented several stakeholder requests and feedback into the 2024 IN IRP process, analysis, and results. Table 9 below summarizes the stakeholder feedback incorporated into the 2024 IN IRP along with the Report sections where more details can be found.

Table 9. Stakeholder Feedback Addressed

Category	Stakeholder Feedback	2024 IN IRP Inclusion
Reserve Margin Obligation Contingency	Stakeholders recommended including additional supporting analyses that was undertaken to develop the 5% Capacity Contingency 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.	I&M has included a description of the analysis to develop the 5% Capacity Contingency in Section 7 and Appendix Volume 3. Details on the results for the 5% Capacity Contingency are included in Appendix Volume 1.
Bonus Investment Tax Credit (Energy Community Bonus)	Stakeholders recommended that I&M consider the 10% additional energy communities bonus tax credit in its modeling.	I&M has taken this feedback into consideration and is modeling a subset of the solar resources that have capital costs with deductions to reflect the energy community tax credit bonus in addition to the Investment Tax Credit (ITC). Details can be found in Section 8.
IRA Tax Credits	Stakeholders recommended that I&M assume the Inflation Reduction Act of 2022 federal tax credits are available at the current value through the end of the planning horizon.	I&M assumed the IRA federal tax credits were available that their current value through the end of the planning horizon for the two Low Carbon sensitivities. Details can be found in Section 9.
Thermal Resource Pricing Assumptions	Stakeholders requested I&M further consider the cost assumptions associated with existing thermal resources due to the expectation of increased competition of resources.	I&M continuously re-evaluated all resource pricing through the 2024 IN IRP modeling process. The Company updated pricing information on the existing thermal resources in Stakeholder Meeting Workshop 3A to better align with the market-based intelligence available at the time. In addition, I&M modeled a High Technology Cost sensitivity to reflect the future competition stakeholders noted for all resources. Details can be found in Section 9.
Build Limits	In summary, stakeholders requested I&M re-evaluate their build limits for all the supply-side resources.	I&M continuously re-evaluated the resource build limits throughout the 2024 IN IRP modeling process. The company utilized updated market information from its 2024 RFPs to refine build limits during its IRP Process. This occurred during Stakeholder Meeting Workshops 3A and 3B. Updated build limits for the wind resources were noted in Stakeholder Meeting Workshop 3A to better align with the market-based intelligence available at the time. Between Stakeholder Meeting Workshop 3A and 3B, I&M modeled two additional sensitivities called Expanded Wind Availability. Details can be found in Section 9.

In addition to stakeholder feedback collected through the 2024 IN IRP process, feedback was collected and included from the 2024 MPS. The Company included stakeholder feedback on how to bundle EE resources, consistent with the Settlement Agreement approved by the IURC in Cause No. 45933.

3.4 2024 IN IRP Technical Stakeholders

In addition to the core Stakeholder Meeting Workshops, a separate engagement process was developed for the “Technical Stakeholders” who desired to examine in more detail the underlying analysis performed during the 2024 IN IRP process. Technical Stakeholders include independent individuals or entities with knowledge in developing IRP scenarios and sensitivity analyses, modeling supply and demand resources, and forecasting inputs such as fuel prices, wholesale market prices, and load forecasts.

To facilitate the engagement of the Technical Stakeholders, consistent with the Settlement Agreement approved by the IURC in Cause No. 45933, I&M engaged with Energy Exemplar to provide three executable PLEXOS modeling licenses for the stakeholders' use. Throughout the 2024 IN IRP process, these stakeholders were invited to meet outside of formal public advisory sessions and were granted access to I&M’s IRP modeling team. The inaugural technical stakeholder meeting took place on September 9, 2024, serving as a collaborative workshop to discuss modeling software, methodologies, and assumptions. Following this, I&M organized technical "Office Hours" to address modeling-related inquiries. The Office Hours were scheduled as follows:

- October 24, 2024
- November 21, 2024
- December 12, 2024
- January 23, 2025
- February 13, 2025

Additionally, I&M established a file-sharing database that contained models executed for various scenarios and sensitivities. This database provided Technical Stakeholders with essential information for conducting model runs, including:

- Commodity forecasts
- Cook operating data and fixed costs
- Elkhart and Mottville operating data, fixed costs and generation
- Existing resource operating parameters
- New resource options operating parameters
- New resource options fixed costs
- Demand-side resource energy and costs
- Production Tax Credit values
- Renewable Energy Credit (REC) values
- Emission Free Energy Credit values

As scenarios and sensitivities were finalized, I&M ensured that technical stakeholders were kept informed as new modeling information was added to the file-sharing database.

4 Load Forecast

4.1 Summary of I&M Load Forecast

The I&M load forecast was developed by AEP's Economic and Supply Forecasting organization and completed in September 2024.[3] The final load forecast is the culmination of a series of underlying forecasts that build on each other. The economic forecast provided by Moody's Analytics (sometimes referred to herein as "Moody's") was used to develop the customer forecast which was then used to develop the sales forecast which was ultimately used to develop the peak load and internal energy requirements forecast.

Over the next 20-year period (2025-2044), I&M's Indiana service territory is expected to see population and non-farm employment growth of 0.0% and 0.1% per year, respectively. I&M is projected to see customer count growth at a similar rate of 0.1% per year. Over the same forecast period, I&M's retail sales are projected to grow at 6.4% per year with stronger growth expected from the commercial and industrial classes (+9.8% and 1.0% per year, respectively) while the residential class experiences 0.2% compound annual growth rate (CAGR). The commercial sector growth is spearheaded by data center development from hyperscale customers (HSL), which includes large data center development with electric capacity requirements exceeding 500 MW. Anticipated large customer additions contribute to industrial growth. Finally, I&M's Indiana internal energy and peak demand are expected to increase at an average rate of 5.7% and 4.8% per year, respectively, through 2044.

4.2 Forecast Assumptions

4.2.1 Economic Assumptions

The load forecasts for I&M and the other operating companies in the AEP System incorporate a forecast of U.S. and regional economic growth provided by Moody's Analytics. The load forecasts utilized Moody's Analytics economic forecast issued in May 2024. Moody's Analytics projects moderate U.S. economic growth during the 2025-2044 forecast period, characterized by a 2.1% annual rise in real Gross Domestic Product (GDP), and moderate inflation, with the implicit GDP price deflator expected to rise by 2.0% per year. Industrial output, as measured by the Federal Reserve Board's (FRB) index of industrial production, is expected to grow at 1.6% per year during the same period. Moody's projects regional employment growth of 0.1% per year during the forecast period and real regional income per-capita annual growth of 1.5% for the I&M service area.

[2] The load forecasts in this report show the internal load, which is the load directly connected to the utility's system, provided with both generation and transmission services. This internal load is used for planning how much generation will be required. Internal load is a subset of connected load, which also includes directly connected load where the utility only provides transmission services. Connected load serves as the starting point for the load forecasts used for transmission planning.

4.2.2 Price Assumptions

The Company utilizes an internally developed service area electricity price forecast. This forecast incorporates information from the Company's financial plan for the near term and the Company's fundamental forecast for the East-North-Central Census Region for the longer term. These price forecasts are incorporated into the Company's energy sales models, where appropriate.

4.2.3 Specific Large Customer Assumptions

I&M's customer service engineers frequently communicate with industrial and commercial customers about their needs and activities. From these discussions, expected load additions or deletions are relayed to the Company. The Company requires a Letter of Agreement (LOA) prior to including a customer's planned load addition in the load forecast.

4.2.4 Weather Assumptions

Where appropriate, the Company includes weather as an explanatory variable in its energy sales models. These models reflect historical weather for the model estimation period and normal weather for the forecast period.

4.2.5 Energy Efficiency and Demand Side Management Assumptions

The Company's long term load forecast models account for trends in Energy Efficiency (EE) both in implicit historical data as well as the forecasted trends in appliance saturations resulting from various legislated appliance efficiency standards (Energy Policy Act of 2005, or EPAct, Energy Independence and Security Act of 2007, or EISA, etc.) modeled by the Department of Energy's (DOE) EIA. In addition to general trends in appliance efficiencies, the Company also administers and implements multiple demand-side management (DSM) programs that the IURC approves as part of its DSM portfolio. The load forecast utilizes the most current DSM programs, which either have been previously approved by or are pending before the IURC at the time the load forecast is created, to adjust for the impact of these programs. For the 2024 IN IRP, DSM programs through 2025 have been embedded into the load forecast.

4.3 Overview of Forecast Methodology

I&M's load forecasts reflect the use of econometric and time-series analyses. This is helpful when analyzing future scenarios and developing confidence bands in addition to objective model verification by using standard statistical criteria.

I&M utilizes two sets of econometric models: 1) a set of monthly short-term models which extend for approximately 24 months, and 2) a set of monthly long-term models which extends for approximately 40 years. The forecast methodology leverages the relative analytical strengths of both the short- and long-term methods to produce a reasonable and reliable forecast that is used for various planning purposes.

The short-term models are regression models with time series errors which analyze the latest sales and weather data to better capture the monthly variation in energy sales for short-term applications like capital budgeting and resource allocation. While these models produce extremely accurate forecasts in the short run, without logical ties to economic factors, they are less capable of capturing structural trends in electricity consumption that are more important for longer-term resource planning applications.

The long-term models are econometric and statistically adjusted end-use models which are specifically equipped to account for structural changes in the economy as well as changes in customer consumption due to increased EE. The long-term forecast models incorporate regional economic forecast data for income, employment, households, gross regional output, and population.

The long-term forecasts are used at least on an annual basis for all customer classes. For typically weather sensitive classes (i.e., residential and commercial), the short-term models are leveraged to develop a monthly pattern for the annual sales forecast developed in the long-term models. This process is used as the short-term models are perceived to provide additional insight into monthly sales patterns and their relationship with heating and cooling degree days. The class level sales are then summed and adjusted for losses to produce monthly net internal energy sales for the system. The demand forecast model utilizes a series of algorithms to allocate the monthly net internal energy to hourly demand. The inputs into forecasting hourly demand are internal energy, weather, 24-hour load profiles and calendar information.

A flow chart depicting the sequence of models used in projecting I&M's electric load requirements as well as the major inputs and assumptions that are used in the development of the load forecast is shown in Figure 9.

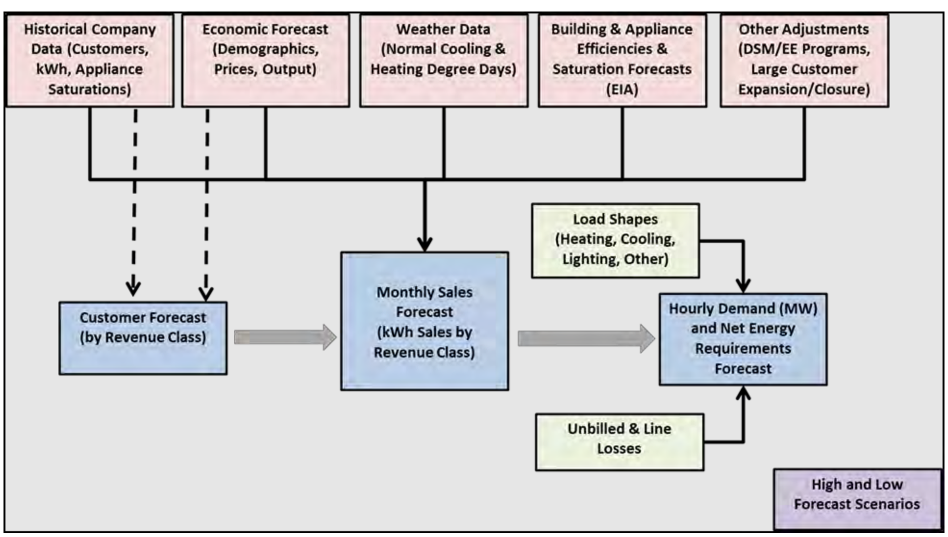

Figure 9. I&M Internal Energy Requirements and Peak Demand Forecasting Method

4.4 Detailed Explanation of Load Forecast

4.4.1 General

This section provides a more detailed description of the short- and long-term models employed in producing the forecasts for I&M's energy consumption by customer class. Conceptually, the difference between short- and long-term energy consumption relates to changes in the stock of electricity-using equipment and economic influences, rather than the passage of time. In the short-term, electric energy consumption is considered to be a function of an essentially fixed stock of equipment. For residential and commercial customers, the most significant factor influencing the short-term is weather. For industrial customers, economic forces that determine inventory levels and factory orders also influence short-term utilization rates. The short-term models recognize these relationships and use weather and recent load growth trends as the primary variables in forecasting monthly energy sales.

Over time, demographic and economic factors such as population, employment, income, and technology influence the nature of the stock of electricity-using equipment, both in size and composition. Long-term forecasting models recognize the importance of these variables and include all or most of them in the formulation of long-term energy forecasts.

4.4.2 Relative Energy Prices Impact on Electricity Consumption

One important difference between the short- and long-term forecasting models is their treatment of energy prices, which are only included in long-term forecasts. This approach makes sense because although consumers may suffer sticker shock from energy price fluctuations, there is little they can do to affect them in the short-term. They already own a refrigerator, furnace, or industrial equipment that may not be the most energy-efficient model available. In the long term, however, these constraints are lessened as durable equipment is replaced and as price expectations come to fully reflect price changes.

4.4.3 Customer Forecast Models

The Company utilizes long-term models to develop the final customer count forecast. The long-term residential customer forecasting models are monthly and extend for 40 years. Explanatory jurisdictional economic and demographic variables may include gross regional product, employment, population, real personal income, and households used in various combinations. In addition to the economic explanatory variables, the long-term customer models employ a lagged dependent variable to capture the adjustment of customer growth to changes in the economy. There are also binary variables to capture monthly variations in customers, unusual data points and special occurrences.

The long-term customer forecasts were used as a primary input into both short- and long-term usage forecast models.

4.4.4 Short-term Forecasting Models

The goal of I&M's short-term forecasting models is to produce an accurate load forecast for the first full year in the future. To that end, the short-term forecasting models generally employ a combination of monthly and seasonal binaries, time trends, and monthly heating cooling degree-days in their formulation. The heating and cooling degree-days are measured at weather stations in the Company's service area. The forecasts relied on Autoregressive Integrated Moving Average (ARIMA) models.

The estimation period for the short-term models was January 2015 through May 2024. There are models for residential and commercial sectors. Off-system sales and/or sales of opportunity are not relevant to the net energy requirements forecast as they are not part of requirements load and are not relevant to determining capacity and energy requirements in the 2024 IN IRP process.

4.4.5 Long-term Forecasting Models

The goal of the long-term forecasting models is to produce a reasonable load outlook for up to and beyond 40 years into the future. Given that goal, the long-term forecasting models employ a full range of structural economic and demographic variables, electricity and natural gas prices, weather as measured by annual heating and cooling degree-days, and binary variables to produce load forecasts conditioned on the outlook for the U.S. economy, for the I&M service-area economy, and for relative energy prices.

Most of the explanatory variables enter the long-term forecasting models in a straightforward, untransformed manner. In the case of energy prices, however, it is assumed, consistent with economic theory, that the consumption of electricity responds to changes in the price of electricity or substitute fuels with a lag, rather than instantaneously. This lag occurs for reasons having to do with the technical feasibility of quickly changing the level of electricity use even after its relative price has changed, or with the widely accepted belief that consumers make their consumption decisions on the basis of expected prices, which may be perceived as functions of both past and current prices.

There are several techniques, including the use of lagged price or a moving average of price that can be used to introduce the concept of lagged response to price change into an econometric model. Each of these techniques incorporates price information from previous periods to estimate demand in the current period.

The general estimation period for the long-term load forecasting models was 1995-2024, with some variation in the estimation period for the various models. The long-term energy sales forecast is developed by blending the short-term forecast with the long-term forecast. The energy sales forecast is developed by making a billed/unbilled adjustment to derive billed and accrued values, which are consistent with monthly generation.

4.4.6 Supporting Model

In order to produce forecasts of certain independent variables used in the internal energy requirements forecasting models, several supporting models are used, including natural gas price models. These models are discussed below.

4.4.6.1 Consumed Natural Gas Pricing Model

The forecast price of natural gas used in the Company's energy models comes from an internally developed model of natural gas prices. They are first developed for Henry Hub and then on a state-specific basis based on their historical relationship with Henry Hub. Further, they are disaggregated in each state's primary consuming sectors: residential, commercial, and industrial. The natural gas price model is based on historical data for 2000 through 2023.

4.4.6.2 Residential Energy Sales

Residential energy sales for I&M are forecasted using two models, the first of which projects the number of residential customers, and the second of which projects kWh usage per customer. The residential energy sales forecast is calculated as the product of the corresponding customer and usage forecasts.

The residential usage model is estimated using a Statistically Adjusted End-Use (SAE) model, which was developed by Itron, Inc., a consulting firm with expertise in energy modeling. This model assumes that use will fall into one of three categories: heat, cool, and other. The SAE model constructs variables to be used in an econometric equation where residential usage is a function of variables designated as Xheat, Xcool, and Xother.

The Xheat variable is derived by multiplying a heating index variable by a heating use variable. The heating index incorporates information about heating equipment saturation, heating equipment efficiency standards and trends, and thermal integrity and size of homes. The heating use variable is derived from information related to billing days, heating degree-days, household size, personal income, gas prices, and electricity prices.

The Xcool variable is derived by multiplying a cooling index variable by a cooling use variable. The cooling index incorporates information about cooling equipment saturation, cooling equipment efficiency standards and trends, and thermal integrity and size of homes. The cooling use variable is derived from information related to billing days, cooling degree-days, household size, personal income, gas prices and electricity prices.

The Xother variable estimates the non-weather sensitive sales and is similar to the Xheat and Xcool variables. This variable incorporates information on appliance and equipment saturation levels, average number of days in the billing cycle each month, average household size, real personal income, gas prices, and electricity prices.

The appliance saturations are based on historical trends from I&M's residential customer survey. The saturation forecasts are based on EIA forecasts and analysis by Itron. The efficiency trends are based on DOE forecasts and Itron analysis. The thermal integrity and size of homes are for the East North Central Census Region and are based on DOE and Itron data.

The number of billing days is from internal data. Economic and demographic forecasts are from Moody's Analytics and the electricity price forecast is developed internally. The Company uses residential DSM per customer as an explanatory variable in the residential SAE model.

The SAE residential model is estimated using linear regression models. These monthly models are typically for the period January 2000 through May 2024, with some variation on the estimation period for the individual models. It is important to note, as will be discussed later, that this modeling incorporated the reductive effects of the EPAct, EISA, American Recovery and Reinvestment Act of 2009 (ARRA) and Energy Improvement and Extension Act of 2008 (EIEA2008), on the residential (and commercial) energy usage based on analysis by the EIA regarding appliance efficiency trends. The SAE models incorporate other government legislation affecting appliance, equipment and lighting efficiency standards through the Inflation Reduction Act of 2022 (IRA 2022).

The Company now captures the effect of DSM on residential energy load within the SAE model. This is achieved by having DSM usage per customer as an explanatory variable in the residential energy usage model. The long-term residential energy sales forecast is derived from multiplying the long-term customer forecast by the usage forecast from the SAE model.

4.4.6.3 Commercial Energy Sales

Long-term commercial energy sales are also forecasted using an SAE model. These models are similar to the residential SAE models, where commercial usage is a function of Xheat, Xcool and Xother variables.

As with the residential model, Xheat is determined by multiplying a heating index by a heat use variable. The variables incorporate information on heating degree-days, heating equipment saturation, heating equipment operating efficiencies, square footage, average number of days in a billing cycle, commercial output, and electricity price.

The Xcool variable uses measures similar to the Xheat variable, except it uses information on cooling degree-days and cooling equipment rather than those items related to heating load.

The Xother variable measures the non-weather sensitive commercial load. It uses non-weather sensitive equipment saturations and efficiencies, as well as billing days, commercial output, and electricity price information.

The saturation, square footage, and efficiency measures are from the Itron base of DOE data and forecasts. The saturations and related items are from EIA's *2023 Annual Energy Outlook*. Billing days and electricity prices are developed internally. The commercial output measure is either service gross regional product, service area real personal income per capita or service area commercial employment from Moody's Analytics. The equipment stock and square footage information are for the East North Central Census Region.

The SAE is a linear regression for the period, which is typically January 2000 through May 2024. As with the residential SAE model, the effects of EPAct, EISA, ARRA and EIEA2008, other legislation through IRA 2022 are captured in this model.

The Company uses commercial DSM as an explanatory variable in the Commercial SAE model.

The Company now evaluates commercial load for HSL customers and other commercial customers. The load for other commercial customers reflects the Company's more traditional commercial base. The forecast for the other commercial customers is derived from the commercial energy sales model. The forecast for the commercial HSL is developed from existing HSL and expected HSL additions. The HSL additions reflect the intentions of customers that have signed an LOA with the Company through 2030. Beyond 2030, the Company included planned loads that are anticipated after additional transmission capacity is available.

4.4.6.4 Industrial Energy Sales

The Company uses combinations of the following economic and pricing explanatory variables: service area gross regional product manufacturing; service area manufacturing employment; FRB industrial production indexes; and service area industrial electricity prices. In addition, binary variables for months and special occurrences are incorporated into the models. Based on information from customer service engineers, there may be load added or subtracted from the model results to reflect plant openings, closures or load adjustments. The last actual data point for the industrial energy sales models is May 2024.

4.4.6.5 All Other Energy Sales

The forecast of public-street and highway lighting relates energy sales to the service area employment or service area population and binary variables.

The Company has three wholesale customers in Indiana, i.e. City of Auburn, Indiana Municipal Power Association, and Wabash Valley Power Association. Wholesale energy sales are modeled relating energy sales to economic variables such as service area gross regional product, industrial production indexes, energy prices, heating and cooling degree-days, and binary variables. Binary variables are necessary to account for discrete changes in energy sales that result from events such as the addition or deletion of new customers.

4.4.7 Internal Energy Forecast

4.4.7.1 Blending Short and Long-Term Sales

The annual energy forecasts are derived from the long-term model projections. For the typically weather sensitive classes, monthly patterns are developed using the X-11 procedure[4]. The monthly patterns for the other classes are derived from the respective forecast models. In this analysis the weather sensitive classes were defined as residential and commercial.

4.4.7.2 Large Customer Changes

The Company's customer service engineers frequently are in touch with large commercial and industrial customers about their needs for electric service. These customers relay information about load additions and reductions. This information will be compared with the load forecast to determine if the industrial or commercial models are adequately reflecting these changes. If the changes are different from the model results, additional factors may be used to reflect those large changes that are different from the forecast models' output.

4.4.7.3 Losses and Unaccounted-For Energy

Energy is lost in the transmission and distribution of electricity. This loss of energy from the source of production to consumption at the delivery point is measured as the average ratio of all Federal Energy Regulatory Commission (FERC) revenue class energy sales measured at the premise meters to the net internal energy requirements metered at the source. In modeling, Company loss study results are applied to the final blended sales forecast by revenue class and summed to arrive at the final internal energy requirements forecast.

4.4.8 Forecast Methodology for Seasonal Peak Internal Demand

The demand forecast model is a series of algorithms for allocating the monthly internal energy sales forecast to hourly demands. The inputs into forecasting hourly demand are blended revenue class sales, energy loss multipliers, weather, 24-hour load profiles, and calendar information.

The weather profiles are developed from representative weather stations in the service area. Twelve monthly profiles of average daily temperature that best represent the cooling and heating degree-days of the specific geography are taken from the last 30 years of historical values. The consistency of these profiles ensures the appropriate diversity of the company loads.

The 24-hour load profiles are developed from historical hourly Company or jurisdictional load and end-use or revenue class hourly load profiles. The load profiles were developed from segregating,

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[3] SAS Institute Inc. (2014). *X-11 seasonal adjustment. SAS*. Retrieved from https://support.sas.com/documentation/onlinedoc/ets/132/x11.pdf

This document provides detailed instructions on the X11 procedure for seasonal adjustment in time series analysis.

indexing and averaging hourly profiles by season, day types (weekend, midweek and Monday/Friday) and average daily temperature ranges.

In the end, the profiles are benchmarked to the aggregate energy and seasonal peaks through the adjustments to the hourly load duration curves of the annual 8,760 hourly values. These 8,760 hourly values per year are the forecast load of I&M Indiana and the individual companies of AEP that can be aggregated by hour to represent load across the spectrum from end-use or revenue classes to total AEP-East, AEP-West, or total AEP System. Net internal energy requirements are the sum of these hourly values on a total company energy need basis. Company peak demand is the maximum of the hourly values from a stated period (month, season, or year).

4.5 Load Forecast Results and Issues

All tables referenced in this section can be found in Appendix Volume 1 Exhibit A. The load forecast includes the forecast impact of customers opting for alternative generation suppliers. This is consistent with the Company's requirement to include such customers' load in its capacity planning in PJM.

4.5.1 Load Forecast

Exhibit A-1 presents I&M Indiana's annual internal energy requirements, disaggregated by major category (residential, commercial, industrial, other internal sales, and losses) on an actual basis for 2014 through the first nine months of 2024 and on a forecasted basis for the last three months of 2024 through 2044. Exhibit A-1 also shows average annual growth rates for both the historical and forecast periods. Exhibit A-2 provides the composition of other internal sales forecasted from 2025 to 2044. Figure 10 below provides a graphical depiction of weather normalized history and forecast for the Company's Indiana residential, commercial, and industrial sales for 2002 through 2044.

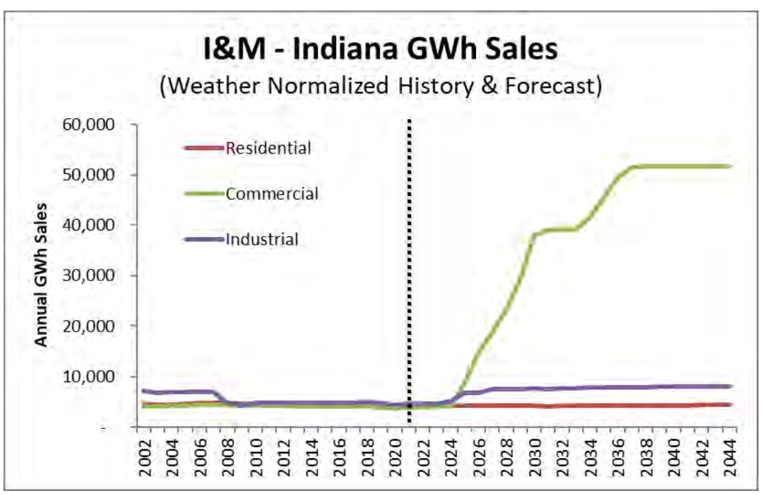

Figure 10. I&M Indiana GWh Retail Sales

4.5.2 Peak Demand and Load Factor

Exhibit A-3 provides the following details for I&M's Indiana service territory:

- Seasonal peak demands;
- annual peak demand;
- internal energy requirements;
- annual load factor; and
- annual growth rates.

This data is shown on an actual basis for the years 2014-2023 and on a forecast basis for the years 2025-2044. For the year 2024, data represents nine months on an actual basis and three months on a forecast basis.

Figure 11 presents actual, weather normal and forecast I&M peak demand for the period 2014 through 2044.

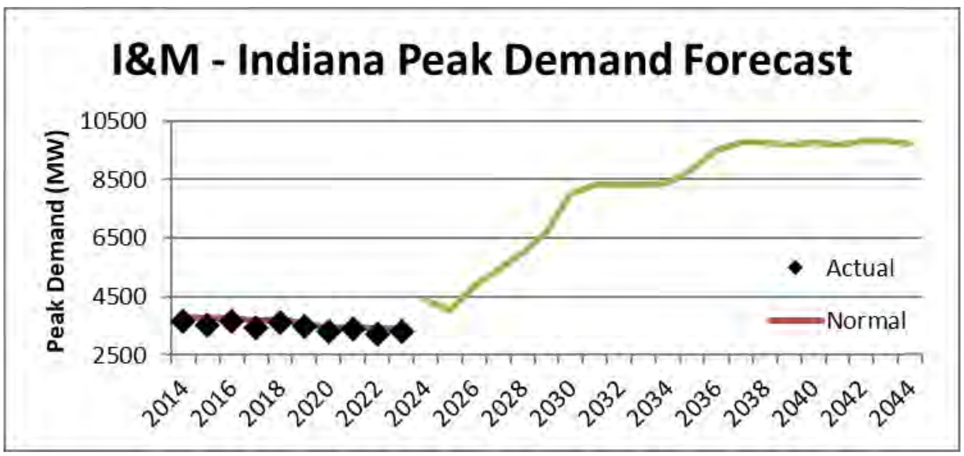

Figure 11. I&M Peak Demand Forecast

4.5.3 Performance of Past Forecasts

The performance of the Company's past load forecasts are reflected in Exhibit A-4, which displays, in graphical form, annual internal energy requirements and summer peak demands experienced since 2006, along with the corresponding forecasts made in 2011, 2013, 2015, 2019, 2021, and 2024 (the current forecast). Exhibit A-4 reflects the uncertainty inherent in the forecasting process and demonstrates the changing perceptions of the future.

4.5.4 Historical and Projected Load Profiles

Exhibits A-5 through A-8 display various historical and forecasted load profiles pertinent to the planning process. Exhibit A-5 shows profiles of monthly peak internal demands for I&M on an actual basis for the years 2015 and 2020, and on a forecasted basis for 2025, 2035 and 2044. Exhibit A-6 shows, for the winter-peak month and summer-peak month for the years 2019 and 2024, respectively, I&M's average daily internal load shape for each day of the week, along with the peak-day load shape. Exhibit A-7 displays, for the forecast years 2025 and 2035, I&M Indiana's daily internal load shapes for a simulated week in the winter-peak month (January) and summer-peak month (August). In both cases, a weekday is assumed to represent the day of the monthly (and seasonal) peak. Such load shapes were developed for use in integrated resource planning analyses.

The Company maintains an on-going load research program consisting of samples of each major rate class in each jurisdiction. Exhibit A-8 displays I&M's Indiana jurisdictional residential, commercial, and industrial customer class summer and winter 2024 load shape information derived from these samples.

4.5.5 Weather Normalization

The load forecast presented in this Report assumes normal weather. To the extent that weather is included as an explanatory variable in various short- and long-term models, the weather drivers are assumed to be normal for the forecast period.

Exhibit A-9 compares the recorded (i.e., actual) and weather-normalized summer and winter peak internal demands and annual internal energy requirements for I&M and I&M Indiana for the last 10 years, 2014-2023.

Peak normalization is a fundamental process of evaluating annual or monthly peaks over time, without the impact of "abnormal" weather events and load curtailment events. The limited number of true annual or monthly peaks over time makes it difficult to use traditional regression analysis. Thus, a regression model is used to determine statistical relationships among a set of daily observations that are similar to annual/monthly peaks and weather conditions. Any load curtailment or significant outage events are added back to the daily observations. The peak normalization demand model is replicated numerous times in a Monte Carlo (stochastic) simulation model. This approach derives probability distributions for both the dependent variable (peak) and independent variables (weather). Multiple estimates for peak are obtained over time that ultimately produces a weather normalized peak.

Similarly, for each year, the weather-normalized internal energy requirements were determined by applying, to each month of the year, an adjustment related to heating or cooling degree-days, as appropriate, to each sector of the recorded internal energy requirements. The adjustment for each sector was obtained as the product of (1) the difference between the service area's expected (or "normal") heating or cooling-degree-days for the month and the actual heating or cooling degree-days for that month and (2) a weather-sensitivity factor (in MWh per heating or cooling degree-day), which was estimated by regressing over the past years monthly sectoral energy requirements against heating or cooling degree-days for the month. The normalized monthly energy requirements thus determined for each sector were then added for all sectors across all 12 months to obtain the net total weather-normalized energy requirements for the year.

4.5.6 Data Sources

The data used in developing I&M Indiana's load forecast comes from both internal and external sources. The external sources are varied and include state and federal agencies, as well as Moody's Analytics. Exhibit A-10 identifies the data series and associated sources, along with notes on adjustments made to the data before incorporation into the load forecast.

4.6 Load Forecast Trends & Issues

4.6.1 Changing Usage Patterns

Over the past decade, there has been a significant change in the trend for electricity usage from prior decades. Figure 12 below presents I&M Indiana's historical and forecasted residential and commercial usage per customer between 1991 and 2030. During the first decade shown (1991-2000), residential usage per customer grew at an average rate of 0.5% per year, while commercial usage also grew by 0.5% per year. Over the next decade (2001-2010), growth in residential usage was at 0.4% per year while the commercial class usage decreased by 0.6% per year. In the next decade shown (2011-2020) residential usage declined at a rate of 1.2% per year while the commercial usage decreased by an average of 1.6% per year. Efficiency gains are expected to continue over the next 10 years (2021-2030) resulting in a projected residential usage decline of 0.2% per year. While the base commercial load will continue to see efficiency gains, this will be greatly offset by customers with significant energy needs (i.e. HSL customers). Commercial usage per customer is projected to increase by 28.7% per year for the 2021-2023 period.

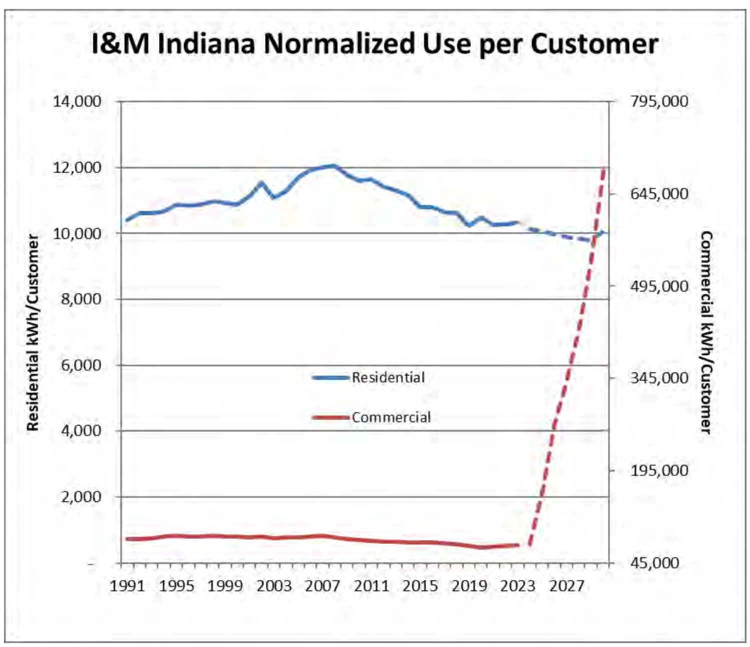

Figure 12. I&M Normalized Use per Customer (kWh)

The SAE models are designed to account for changes in the saturations and efficiencies of the various end-use appliances. Every 3 to 4 years, the Company conducts a Residential Appliance Saturation Survey to monitor the saturation and age of the various appliances in homes. This information is then matched with the saturation and efficiency projections from the EIA which includes the projected impacts from various enacted federal policies mentioned earlier.

The result of this is a base load forecast that already includes some significant reductions in usage as a result of projected EE. For example, Figure 13 below shows the assumed cooling efficiencies embedded in the statistically adjusted end-use models for cooling loads. It shows that the average Seasonal Energy Efficiency Ratio for central air conditioning is projected to increase from 11.9 in 2010 to nearly 15.4 by 2040. The chart shows a similar trend in projected cooling efficiencies for heat pump cooling as well as room air conditioning units.

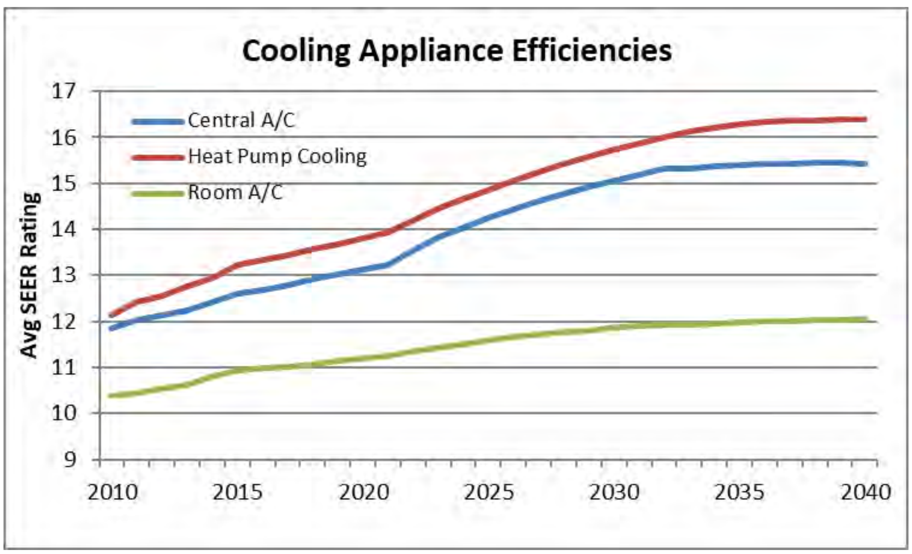

Figure 13. Projected Changes in Cooling Efficiencies, 2010-2040

Figure 14 shows the impact of appliance, equipment, and lighting efficiencies on the Company's weather normal residential usage per customer. There are not many additional efficiency gains expected from lighting for residential customers, as consumers have adopted the newer technologies and moved away from incandescent lighting.

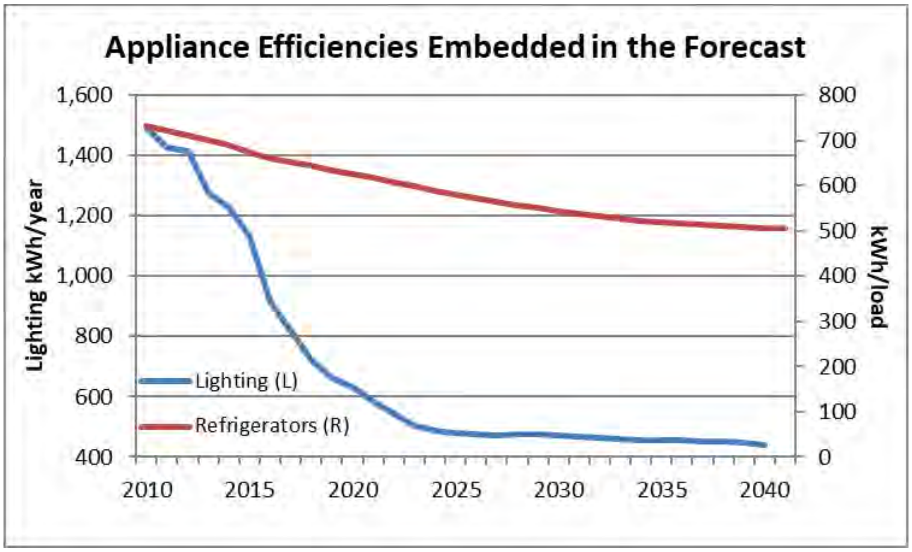

Figure 14. Projected Changes in Lighting & Clothes Washer Efficiencies, 2010-2040

Figure 15 provides weather normalized residential energy per customer and an estimate of the effects of efficiencies on usage. In addition, historical and forecast I&M Indiana residential customers are provided.

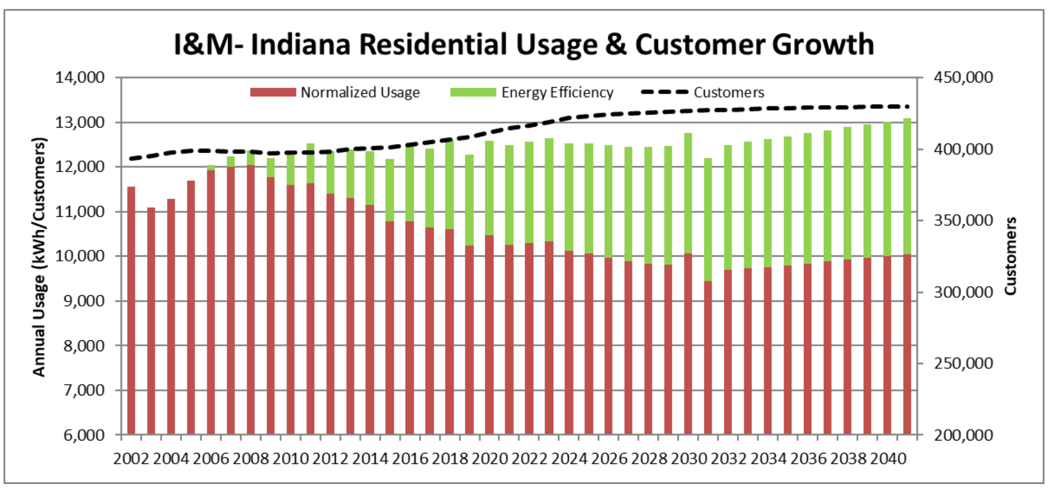

Figure 15. Residential Usage & Customer Growth

4.6.2 Demand-Side Management Impacts on the Load Forecast

The end-use load forecasting models account for changing trends and saturations of energy efficient technologies throughout the forecast horizon. In addition, the Company is also actively engaged in implementing various Commission approved DSM and EE programs which would further accelerate the adoption of energy efficient technology within its service territory. Itron's SAE model relies on the

EIA) to account for future appliance efficiencies. EIA AEO documentation[5] specifically states its forecast data (used by Itron in the SAE) "...accounts for the effects of utility-level EE programs designed to stimulate investment in more efficient equipment for space heating, air conditioning, lighting, and other select appliances." As a result, the Company applies a Supplemental Efficiency Adjustment (SEA) to prevent double counting the impacts from the Company-sponsored EE programs in the load forecast.

For the near-term horizon (through 2025), the load forecast applies energy and demand savings impact assumptions from the current DSM programs. For the years beyond 2025, the 2024 IN IRP model selected optimal levels of incremental economic EE. These levels may differ from the levels currently being implemented based on projections of future market conditions, the future expected costs of available supply resources, and the level of available incremental EE. Since the initial base load forecast accounts for the evolution of market and industry efficiency standards, the energy savings for each specific EE program are adjusted over the expected life of the program. Exhibit A-11 details the impacts of the approved EE programs included in the load forecast, which represent the cumulative adjusted value of EE program impacts throughout the forecast period that were applied to the load forecast. While the 2024 IN IRP optimization process selects the optimal incremental economic EE, the resulting total annual 2024 IN IRP EE program savings contains both the ongoing impacts from current programs and the optimized levels of EE from the 2024 IN IRP process.

Exhibit A-11 provides the DSM/EE impacts incorporated in I&M's Indiana load forecast provided in this Report. Annual energy and seasonal peak demand impacts are provided for I&M Indiana.

4.6.3 Interruptible Load

The Company has six customers with interruptible provisions in their contracts. These customers have a combined interruptible contract capacity of 41 MW. However, these customers are expected to have only 37 MW available for interruption for winter and summer peaks. An additional 153 customers have 303 MW available for interruption in emergency situations in DR agreements. The load forecast does not reflect any load reductions for these customers. Rather, the interruptible load is seen as a resource when the Company's load is peaking. As such, estimates for DR resource impacts are reflected by I&M in determination of PJM-required resource adequacy (i.e., Indiana's going-in capacity position).

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[4] U.S. Energy Information Administration. (2022, 03). *Assumptions to the annual energy outlook 2025: Residential sector demand module*. Retrieved from https://www.eia.gov/outlooks/aeo/assumptions/pdf/residential.pdf

4.6.4 Blended Load Forecast

In the typical non-weather sensitive classes, the long-term forecast is used for the entire forecast horizon. However, in order to capture the strengths of each modeling process as discussed above, elements of both the short- and long-term forecasts are used and blended together for the typical weather sensitive classes. This is accomplished by using the X-11 procedure which breaks down each forecast into trend and seasonal components.

For the weather sensitive classes, the trend component from the long-term forecast is always used to ensure structural economic changes are captured. Since the short-term forecast better captures the monthly usage patterns, a relative ratio of the seasonal components is developed and applied to the long-term seasonal component for each month. This adjusted, long-term seasonal component is then added to the long-term trend component to arrive at a final forecast. Although a small rounding error can occur, the final forecast for the weather sensitive classes will match the original long-term forecast on an annual basis. By limiting the change to the seasonal component on a relative basis, only the monthly usage pattern is altered, with some months adjusted higher and others lowered by an equal amount of energy.

4.6.5 Wholesale Customer Contracts

Company representatives are in continual contact with wholesale customer representatives about their contractual needs. The forecast included in the 2024 IN IRP does not assume the automatic renewal of expiring wholesale contracts. This assumption results in significant load drops in the 2030s.

4.6.6 Large Customer Changes

The Company's customer service engineers are in continual contact with the Company's large commercial and industrial customers about their needs for electric service. These customers will relay information about load additions and reductions. This information will be compared with the load forecast to determine if the industrial or commercial models are adequately reflecting these changes. If the changes are different from the model results, then additional factors may be used to reflect those large changes that differ from the forecast models' output. The Company's goal is to accurately and prudently reflect the large customer load additions. The Company will include the load addition if it has received a signed LOA. Beyond 2030, the Company included planned loads that are anticipated after additional transmission capacity is available.

4.7 Load Forecast Model Documentation

Displays of model equations, including the results of various statistical tests, along with data sets, are provided in the Appendices Volume 1-Exhibit F and Volume 2.

4.8 Changes in Forecasting Methodology

Opportunities to enhance forecasting methods are explored by I&M and AEP on a continuing basis. Since the last IRP filing, the Company changed the residential and commercial forecast methodology to incorporate DSM as an explanatory variable. Also, the Company is now forecasting the impacts of electric vehicles and distributed generation and including the impacts in the load forecast.

4.9 Load-Related Customer Surveys

A residential customer survey was last conducted in the fall of 2021 in which data on end-use appliance penetration and end-use saturation rates were obtained. Beginning in 1980, in intervals of approximately three to four years, the Company has regularly surveyed residential customers to monitor customers' demographic characteristics, appliance ownership, penetration of new energy use products and services, and conservation efforts.

The Company has not conducted its own industrial and/or commercial customer end-use surveys because of the significant cost considerations involved. The Company relies on the EIA for this information which is collected in their Commercial Buildings Energy Consumption Survey and Manufacturing Energy Consumption Survey. I&M also monitors its industrial and commercial (and residential) customer end-use consumption patterns through its ongoing load research program.

4.10 Load Research Class Interval Usage Estimation Methodology

AEP is a participating member of the Association of Edison Illuminating Companies (AEIC) Load Research Committee and was a significant contributor to the AEIC Load Research Manual. AEP uses the procedures set forth in that manual as a guide for load research practices. AEP maintains an on-going load research program in each retail rate jurisdiction which enables class hourly usage estimates to be derived from metered period data for each rate class for each hour of each day. The use of actual period metered data results in the effective capture of weather events and economic factors in the representation of historical usage.

For each rate class in which customer maximum demand is normally less than 1 MW, a statistical random sample is designed and selected to provide at least 10% precision at the 90% confidence level at times of Company monthly peak demand. In the sample design process, billing usage for each customer in the class is utilized in conjunction with any available class interval data to determine the optimal stratified sample design using Model Based Statistical Sampling. Model Based Allocation is used to determine the necessary number of sample customers in each stratum. All active customers with the requisite data available in the rate class population are included in the sample selection process, which uses a random systematic process to select primary sample points and backup sample points for each primary point.

For selected sample sites that reside within an Advanced Metering Infrastructure (AMI) area, the interval data is extracted from the Meter Data Management System (MDM) and stored in Hadoop or imported into the ITRON MV90 System. For selected sample sites that reside outside of an AMI area, each location undergoes field review and subsequent installation of an interval data recorder. The recorder is normally set to record usage in 15-minute intervals. For rate classes in which customer maximum demand is normally 1 MW or greater, each customer in the class is interval metered, and these are referred to as 100% sampled classes. The interval data is retrieved at least monthly, validated through use of the ITRON MV90 System or the MDM, edited or estimated as necessary, and stored for analytical purposes. The status of each sample point undergoes on-going review and backup sample points replace primary sample points as facilities close, change significant parameters such as rate class, or become unable to provide required information due to safety considerations. This on-going sample maintenance process ensures reasonable sample results are continuously available, and samples are periodically refreshed through a completely new sample design and selection process to capture new building stock and when necessary to capture rate class structure changes.

Prior to analysis, as an additional verification that all interval data is correct, interval data for each customer is summed on a billing month basis and the resulting total energy and maximum demand are compared to billing quantities. Any significant discrepancies between the interval data and the billing quantities are further investigated and corrected, as needed. Rate class analysis is then performed through the Load Research Analysis System. The sample interval data is post-stratified and weighted to represent the sampled class populations, and total class hourly load estimates are developed. The analysis provides hourly load estimates at both the stratum and class levels, and standard summary statistics, including non-coincident peaks, coincident peaks, coincidence factors, and load factors, at the class, stratum, and sample point levels.

The resulting class hourly load estimates are examined through various graphical approaches, the summary statistics are reviewed for consistency across time, and the monthly sample class energy results are compared against billed and booked billed and accrued values. Any anomalies are investigated, and a rate class analysis may be re-worked if the investigation shows that is necessary. When analysis and review of all rate classes is completed, losses are applied to the hourly rate class estimates, the class values are aggregated, and the resulting total estimate is compared to the Company hourly load derived from the system interchange and generation metering. Any significant differences between the customer level load research derived numbers and the system level numbers are investigated, and class results may be re-analyzed, if necessary.

Rate classes are often comprised of combinations of commercial and industrial customers. Separate commercial and industrial hourly load estimates are developed after rate class analysis is completed. Monthly billing usage for each commercial and industrial customer is acquired from the customer information system and is imported into the Load Research Analysis System, along with the sample point interval data available from the rate class random and 100% samples. The sample interval data is post-stratified and weighted to represent the commercial and industrial class populations, and total class hourly load estimates are developed. Losses are then applied to the resulting commercial and industrial class estimates, the values are combined with the residential class hourly load estimates from the rate class analysis, the class values are aggregated, and the resulting total estimate is compared to the Company hourly load derived from the system interchange and generation metering. Any significant differences between the load research derived numbers and the system level numbers are investigated, and class results may be re-analyzed, if necessary. Final residential, commercial, and industrial class hourly load estimates are provided to the forecasting organization for use in the long-term forecasting and planning process.

4.11 Customer Self-Generation

I&M customers that install renewable energy resource self-generation facilities are typically served through either I&M's Net Metering Service Rider, Excess Distributed Generation Rider, or Cogeneration and/or Small Production Service Tariff.

Through December 2023, 1,617 I&M Indiana customers had installed net metering and or co-generation qualifying customer-generation facilities which are interconnected and/or net metered with a total nameplate capacity of approximately 21.5 MW.

In comparison to I&M's total system load, current levels of customer self-generation (net metering and co-generation) are not overly impactful.

Since the prior IRP, the number of connected qualifying customer-generation facilities in the I&M Indiana service territory has grown by 125%, and the total nameplate capacity has grown by 134%. This indicates more customers installed self-generation over the past few years and the average nameplate size of systems is increasing.

The Company's load forecast includes the energy impacts of generation by residential and commercial customers. The Company developed econometric models to evaluate the activity. The Company adds the incremental impacts of these activities to the residential and commercial energy forecasts. The incremental impacts are utilized to avoid double counting of previous activities.

For the 2024 IN IRP, the Company completed a 2024 MPS that assessed the future increased potential for DER to be connected to I&M's energy delivery system, incremental to the DER levels included in the load forecast. Specifically, the 2024 MPS developed increased DER potential for residential and commercial customer-owned solar and solar plus battery driven by utility sponsored customer incentive programs. This review was performed by GDS, an MPS industry consultant, and culminated in a forecast for incremental customer-owned solar and solar plus battery capacity and energy which was then included in 2024 IN IRP resource optimization.

4.12 Load Forecast Scenarios

The Base Reference Case load forecast is the probable path for load growth that the Company uses for planning. There are a number of known and unknown potentials that could drive load growth to be different from the Base Reference Case. While potential scenarios could be quantified at varying levels of assumptions and preciseness, the Company has chosen to frame the possible outcomes around the Base Reference Case. The Company recognizes the potential desire for a more exact quantification of outcomes, but the reality is if all possible outcomes were known with a degree of certainty, then they would become part of the Base Reference Case.

Forecast scenarios have been established which are tied to respective High and Low Economic Growth Scenarios. The High and Low Economic Growth Scenarios are consistent with scenarios laid out in the EIA's 2023 Annual Outlook. While other factors may affect load growth, this analysis only considered high and low economic growth. The economy is seen as a crucial factor affecting future load growth. The High and Low Economic Growth Scenarios includes reasonable bounds around the Base Reference Case load forecast with these bounds representing probable changes in the economy. HSL load will be subject to long-term contractual commitments, thus the HSL load forecasts were based on the best forecasted load ramp information available at the time and are consistent in each scenario and are not increased or decreased in the High or Low Economic Growth Scenarios. The low-case, base-case and high-case forecasts of summer and winter peak demands and total internal energy requirements for I&M Indiana are tabulated in Exhibit A-12.

For Indiana, the low-case and high-case energy and peak demand forecasts for the last forecast year, 2044, represent deviations of about 13.8% below and 13.3% above, respectively, the Base Reference Case forecast. During the load forecasting process, the Company developed various other scenarios. Figure 16 provides a graphical depiction of the scenarios developed in conjunction with the load provided in this Report.

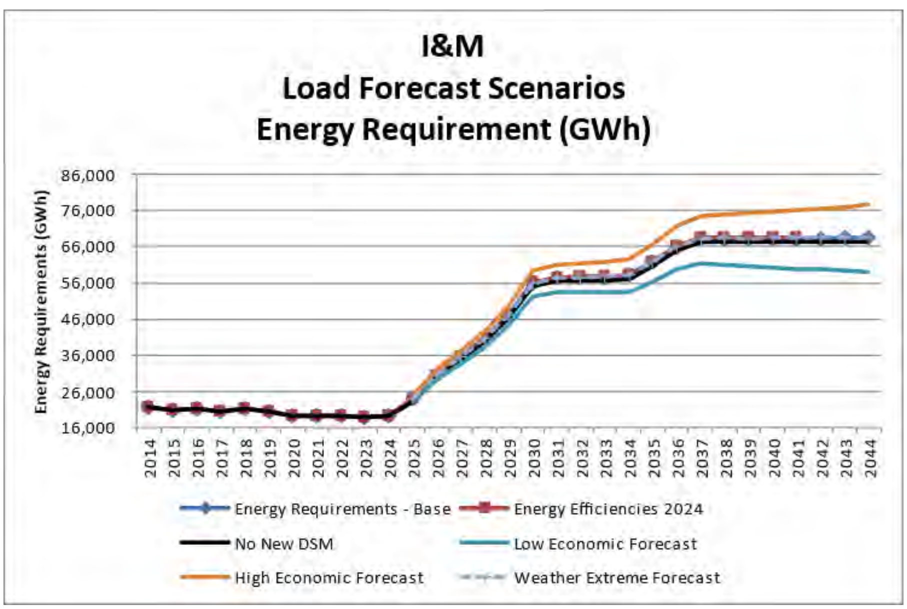

Figure 16. Load Forecast Scenarios

The “no new DSM” scenario extracts the DSM included in the load forecast and provides what load would be without the increased DSM activity. The energy efficiencies 2024 scenario keeps energy efficiencies at 2024 levels for the residential and commercial equipment. Both of these scenarios result in a load forecast greater than the Base Reference Case forecast.

The weather extreme forecast assumes increased average daily temperatures for both the winter and summer seasons which results in diminished heating degree-days in the winter and increased cooling degree days in the summer. This analysis is based on a potential impact of climate change developed by Purdue University. This scenario results in increased load in the summer and diminished load in the winter, with the net result being higher energy requirements forecast. Exhibit A-13 provides graphical displays of the range of forecasts of summer and winter peak demand for I&M Indiana along with the impacts of the weather scenario for each season.

All these alternative scenarios fall within the boundary of the Company’s high and low economic scenario forecasts. The Company’s expectations are that any reasonable scenario developed will fall within this range of forecasts.

The Company adjusted the load forecast for the incremental impact of the increased adoption of electric vehicles. In addition, the Company has also developed high, low and base scenarios on adoption in the service area through 2044. These scenarios are presented graphically in Figure 17.

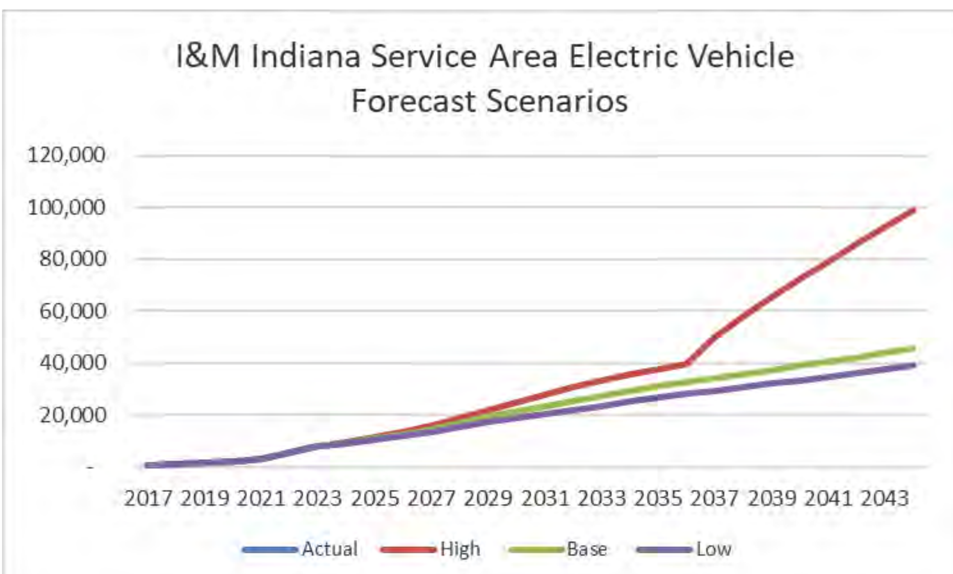

Figure 17. Electric Vehicle Scenarios

The electric vehicle forecast and scenarios are developed internally by the Company using econometric models.

4.13 Directors Report Feedback on Prior Load Forecast Considered

4.13.1 Normal Weather

The Director's Report asked about the impacts of weather. At the time of the 2021 IRP, the Company was using a 30-year weather norm. The Company recently analyzed an alternative number of years for producing a more accurate weather normalization and weather norms. As a result of that analysis, the Company now uses a 20-year weather norm for load forecasting.

4.13.2 Electrification and Distributed Generation

The Company developed internal forecasts for the impacts of electric vehicles and distributed generation. These are econometric based models. The forecasts for electric vehicles are provided in Figure 17. The forecast for distributed generation is provided on Exhibit A-14. The incremental impacts on the load for electric vehicles and distributed generation is provided on Exhibit A-15.

4.13.3 Pricing and Service Options

The Director's Report expressed concerns about how customers will respond to various prices and service options that may be provided in the future. The load forecast models incorporate electricity prices as explanatory variables. The price elasticity reflected in these models will indicate the customer's responsiveness to price changes.

4.13.4 Load Uncertainty

The Director's Report summary stated concerns about uncertainty for future loads. The Company addresses that with the high and low economic growth scenarios. The Company attempts to provide forecast scenarios within a reasonable spread. However, there are times when load additions may occur outside of that range. The Company is experiencing such a change with the 2024 IN IRP and scale of load additions that would not have reasonably been expected in the previous IRP. The Company will continue to be vigilant on potential load additions and evaluate methods to address future uncertainty.

4.13.5 AMI Metering Update

At the time the load forecast was developed (September 2024), the Company was still in the process of deploying AMI metering in the Indiana service area. The Company did not have an adequate amount of history from those customers with AMI meters available to develop class level load shapes. The Company anticipates being able to develop class level load shapes from AMI data in the next IRP filing.

5 Fundamental Forecast

5.1 Fundamental Forecast Process

AEP's Fundamental Forecast was developed by the AEP Economic and Supply Forecasting organization. The forecast, which covers markets within the Eastern Interconnect, is a long-term commodity market forecast completed July 2023. The Fundamental Forecast is used by several organizations in AEP, including AEP operating companies, to support resource planning, capital improvement analyses, fixed asset impairment accounting, and other applications. The forecast includes (in both nominal and real dollars): 1) hourly, monthly, and annual regional power prices; 2) prices for various types of coals; 3) monthly and annual locational natural gas prices, including the benchmark Henry Hub; 4) nuclear fuel prices; 5) sulfur dioxide, nitrogen oxides, and carbon dioxide emission prices; 6) locational implied heat rates; 7) electric generation capacity values; 8) renewable energy subsidies; and 9) inflation factors. Table 10 below describes the source of the Fundamental Forecast components.

Table 10. Fundamentals Forecast Components

Category	Forecast Component	Source
Fuel	Natural gas forecast; Henry Hub	AEP Economic and Supply Forecast
Fuel	Natural gas locational values	AEP Economic and Supply Forecast
Fuel	Oil price, WTI	AEP Economic and Supply Forecast regression model
Fuel	Uranium prices	AEP Economic and Supply Forecast regression model
Fuel	Coal	Wood MacKenzie Coal Forecast
Load	Load Forecast and hourly shapes	AEP Economic and Load Forecasting
Generation	New unit costs/Technology Learning Curves	EIA AEO Build Costs/NREL
Generation	New, low or zero-carbon dispatchable technology	AEP Engineering
Generation	Solar/Wind production shapes by area	NREL
Generation	Generating Reserve Margins	RTO Requirements
Generation	Announced new generation units	Velocity Suite
Generation	Existing generation units	Velocity Suite (EIA 860 and 923 data)
Policy	State-mandated Renewable Portfolio Standards	AEP Economic and Supply Forecast; AEP Environmental
Credits	REC's	Evolution Markets and Wood MacKenzie
Credits	PTC's, ITC's	Inflation Reduction Act
Economic	Inflation/GDP deflators/PPI	Moody's Analytics
Emissions	Annual SO_2, Seasonal/Annual NO_x	AEP Commercial Operations
Emissions	CO_2 – RGGI forecast	AEP Commercial Operations and Wood MacKenzie
Emissions	Unit-level emission rates: CO_2, SO_2, NO_x	Velocity Suite (US EPA CEMS data)

Energy Exemplar's Aurora energy market simulation model is the primary tool used to calculate the Fundamental Forecast. The Aurora model iteratively generates zonal (but not company-specific) long-term capacity expansion plans, annual energy dispatch, fuel burns and emission totals from inputs including fuel, load, emissions, and capital costs. The Aurora model is widely used by utilities for integrated resource and transmission planning, power cost analysis, and detailed generator evaluation. The database includes approximately 22,000 electric generating facilities in the contiguous United States, Canada, and Baja Mexico. These generating facilities include wind, solar, biomass, nuclear, coal, natural gas, and oil. A licensed online data provider, ABB Velocity Suite, provides up-to-date information on markets, entities and transactions along with the operating characteristics of each generating facility, which are subsequently exported to the Aurora model.

5.2 Natural Gas Prices

The Fundamental Forecast includes a projection for Henry Hub natural gas prices, which are the basis for regional natural gas price projections. Figure 18 illustrates the monthly Henry Hub natural gas price forecasts that are used to develop natural gas pricing for the PJM market modeling in the Base Reference Case.

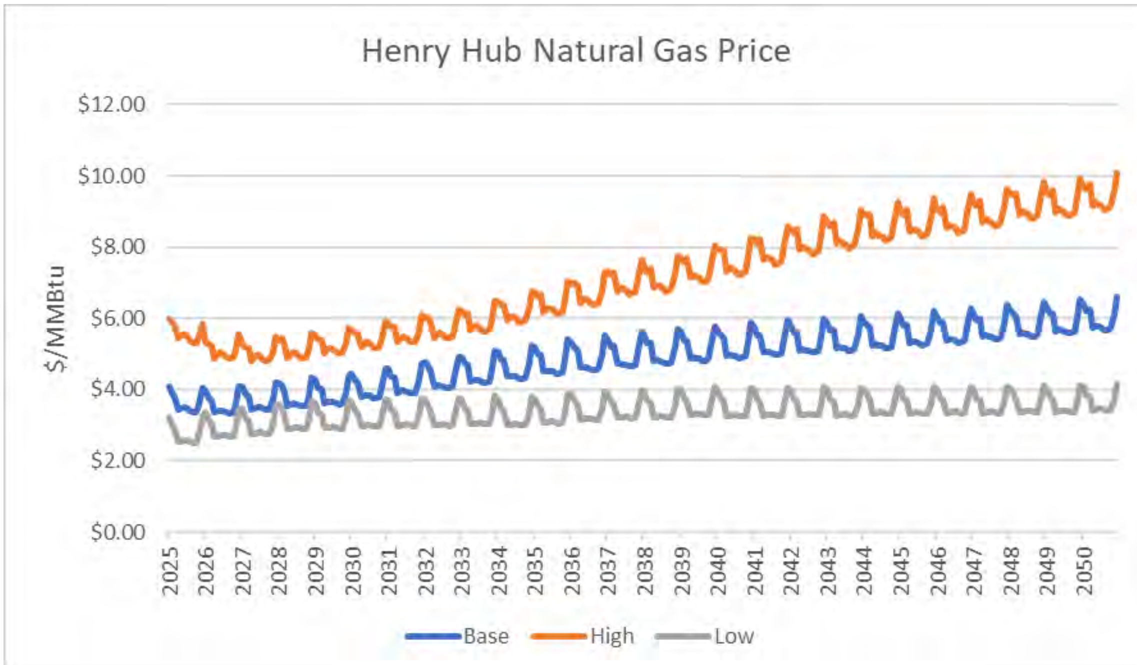

Figure 18. Henry Hub Natural Gas Prices ($/MMBtu)

5.3 Coal Prices

I&M uses Wood MacKenzie's coal price forecast in the 2024 IN IRP. Figure 19 illustrates the monthly forecast of Powder River Basin (PRB) coal prices at the point of purchase (i.e., exclusive of transportation costs) used in the Base Reference Case. While some coal-fired units in PJM burn coals other than PRB, this price reflects the outlook for the type of coal burned at I&M's Rockport facility.

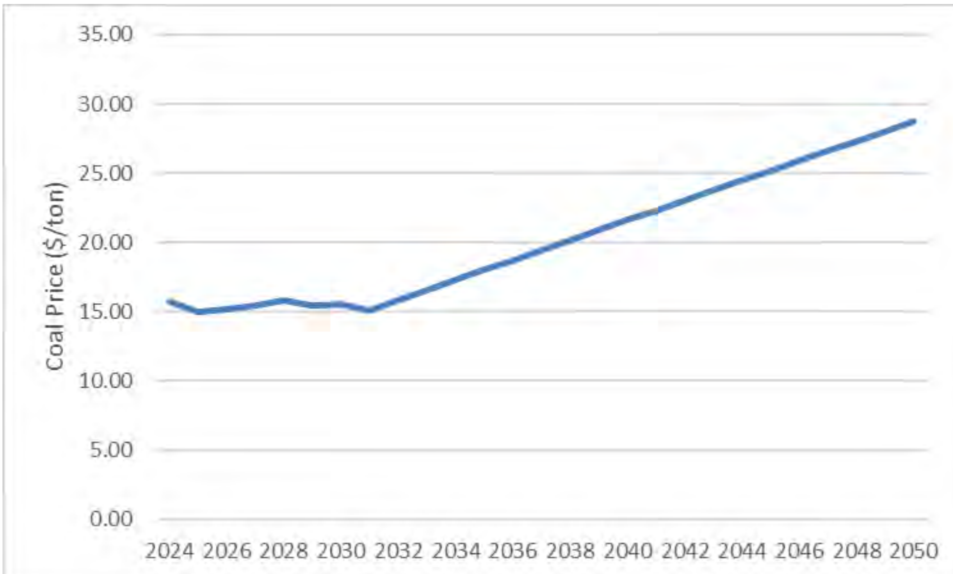

Figure 19. PRB 8,800 Coal Prices ($/ton, FOB origin)

5.4 Fundamental Capacity Expansion Results

AEP used the Aurora long-term capacity expansion model to forecast the least-cost combination of resource additions and retirements in PJM using the assumptions for each market scenario. While the PJM market selections do not directly impact the resources that can be selected for the I&M portfolio, they are informative for describing how different resource types are likely to perform under certain conditions. Figure 20 and Figure 21 illustrate the 2025 and 2044 capacity and generation mix (respectively) across four (4) portfolios reflecting market scenarios. The Base portfolio reflects the Base Reference Case used as the starting point for portfolio analyses. The High and Low portfolios reflect High Economic Growth and Low Economic Growth Cases, which include impacts to market loads and market pricing. The EER portfolio reflects Enhanced Environmental Regulation Case based on Section 111 of the Clean Air Act. Development of these portfolios is discussed in Section 9.2.

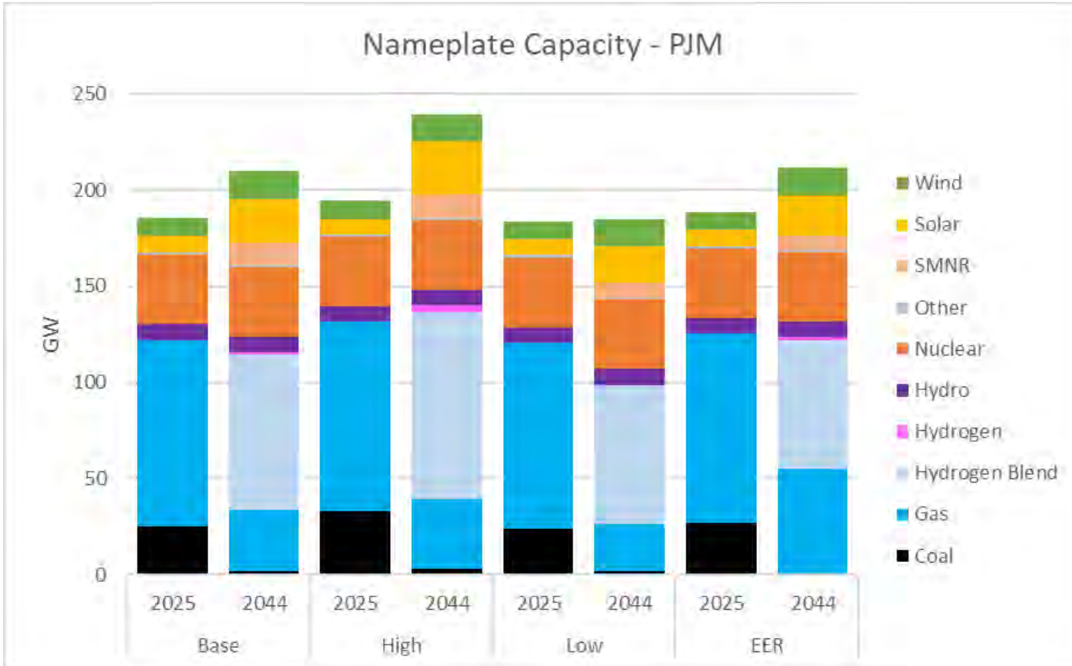

Figure 20. Comparison of 2044 Nameplate Capacity by Technology in PJM w/ 2025 Resource Mix

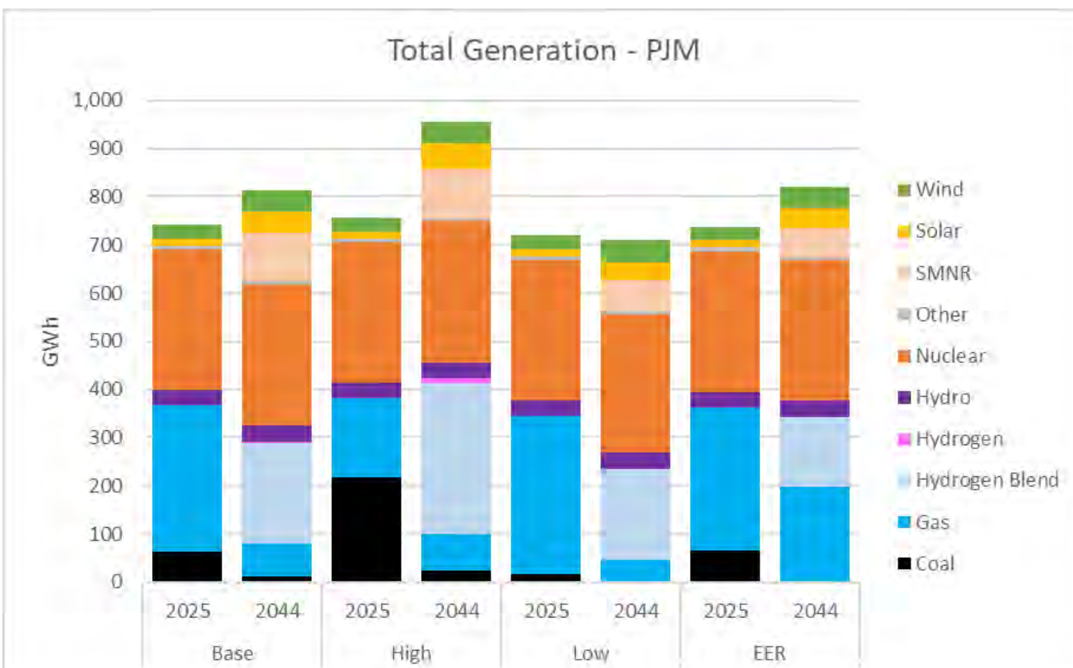

Figure 21. Comparison of 2044 Generation by Technology in PJM w/ 2025 Resource Mix

5.5 Market Price Results

The key market outputs from the scenario modeling process are the power prices illustrated below in Figure 22 for on-peak prices and Figure 23 for off-peak prices. Shown are the four market scenarios modeled in the 2024 IN IRP. These figures illustrate the wide but plausible range of energy prices that emerge from the scenario modeling step that was used to develop and select the Preferred Portfolio.

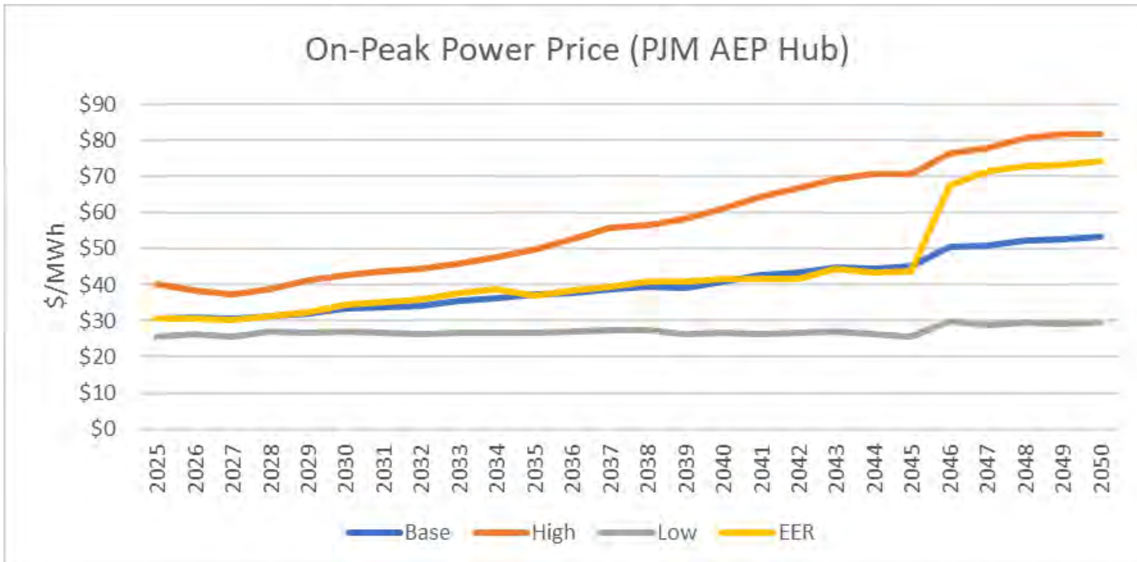

Figure 22. Annual On-Peak PJM AEP Hub Electricity Prices ($/MWh)

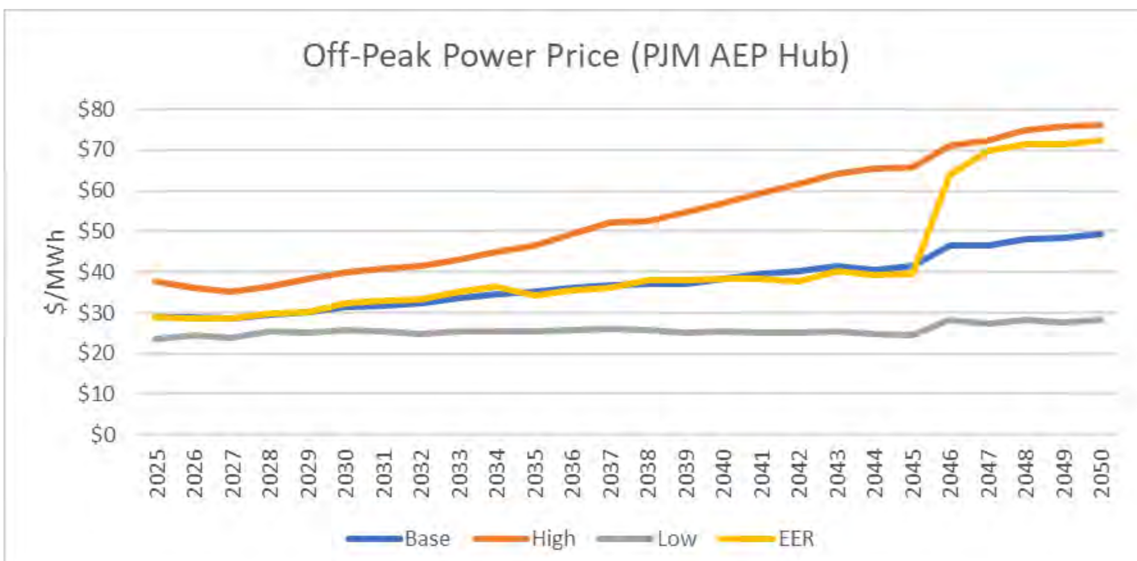

Figure 23. Annual Off-Peak AEP Hub Electricity Prices ($/MWh)

6 Current Resource Evaluation

6.1 Introduction

The next step in the 2024 IN IRP process (see Figure 7) is to evaluate current resources. I&M's resource portfolio comprises a diverse set of supply- and demand-side resources that serve the Company's capacity, energy, and other reliability requirements. The supply-side resources include a mix of nuclear, wind, solar, hydro, and fossil-fired resources. The demand-side resources include active EE, DR, DG, and CVR programs.

6.2 Existing Supply-Side Resources

I&M's existing supply-side resource portfolio includes two large central station resources, the Cook Nuclear Plant located in Bridgman, Michigan and the Rockport Plant, located in southern Indiana. In addition, I&M has power purchase agreements with four wind farms and Ohio Valley Electric Corporation (OVEC), and a suite of relatively small owned solar and run-of-river hydro (hydro) resources. The specific resources are summarized in Table 11. As also shown in Table 11, I&M has also recently obtained approval by the Commission for a diverse set of resources including solar, wind, and natural gas (capacity-only) that have resulted from multiple competitive procurement processes. The approved resources include a mix of Power Purchase Agreements, Capacity Purchase Agreements, and owned resources. Table 11 represents Indiana's share of the capacity associated with both the existing and recently approved resources.

Table 11. I&M Supply-Side Resources as of September 2024

Unit Name	Location	Fuel Type	C.O.D. [1] or Contract Start Date	Retirement or Contract Expiration Date [2]	PJM Nameplate Capacity (MW) [3]	
Clifty Creek 1-6	Madison, IN	Coal	1956	2039/40	62	(5)
Kyger Creek 1-5	Cheshire, OH	Coal	1955	2039/40	61	(5)
Rockport 1	Rockport, IN	Coal	1984	2027/28	1,079	
Lawrenceburg	Lawrenceburg, IN	Gas	2028	2033/34	697	(4)
Montpelier	West Poneto, IN	Gas	2027	2033/34	172	(4)
Berrien Springs 1-12	Berrien Springs, MI	Hydro	1908	2035/36	5	
Buchanan 1-10	Buchanan, MI	Hydro	1919	2035/36	2	
Constantine 1-4	Constantine, MI	Hydro	1921	2052/53	1	
Elkhart 1-3	Elkhart, IN	Hydro	1913	2029/30	2	
Mottville 1-4	White Pigeon, MI	Hydro	1923	2032/33	1	
Twin Branch 1-8	Mishawaka, IN	Hydro	1904	2035/36	5	
Cook 1	Bridgman, MI	Nuclear	1975	2033/34	830	
Cook 2	Bridgman, MI	Nuclear	1978	2036/37	956	
Deer Creek	Grant County, IN	Solar	2015	2034/35	2	
Elkhart	Elkhart, IN	Solar	2026	2055/56	83	(4)
Hoosier Line	White County, IN	Solar	2027	2056/57	150	(4)
Lake Trout	Blackford County, IN	Solar	2028	2062/63	201	
Mayapple	Elkhart, IN	Solar	2028	2062/63	183	
Olive	St. Joseph County, IN	Solar	2016	2035/36	4	
St. Joseph Solar	St. Joseph County, IN	Solar	2021	2050/51	16	
Twin Branch Solar	St. Joseph County, IN	Solar	2016	2035/36	2	
Watervliet	Berrien County, MI	Solar	2016	2035/36	4	
Fowler Ridge 1	Benton County, IN	Wind	2008	2027/28	83	(4)
Fowler Ridge 2	Benton County, IN	Wind	2009	2028/29	42	(4)
Headwaters	Randolph County, IN	Wind	2014	2033/34	166	(4)
Meadow Lake	Chalmers, IN	Wind	2026	2045/46	83	(4)
Wildcat	Madison County, IN	Wind	2014	2031/32	82	(4)
					4,974	

(1) Commercial operation date.
(2) Retirement or Contract Expiration dates represent the PJM Delivery Year and are assumptions for IRP planning purposes. Cook units 1 and 2, Elkhart Hydro, and Mottville Hydro Retirement dates represent license expiration dates.
(3) Represents Indiana's share of these resources
(4) Represents capacity from Power Purchase Agreements (PPAs) or Capacity Purchase Agreements (CPAs)
(5) Represents Indiana's share of the OVEC capacity under the ICPA

I&M's Rockport Unit 1 is a pulverized coal-fired generating unit. I&M has a 50% direct ownership share of Rockport Unit 1. I&M's affiliate AEP Generating Company (AEG) has direct ownership of the remaining 50%. I&M purchases 100% of AEG's portion of the output of Unit 1 through a Unit Power Agreement. Rockport Unit 1 is equipped with: (1) an Electrostatic Precipitator for collection of particulate matter (PM, also referred to as fly ash); (2) low-NOx burners with overfire air to minimize the formation of NOx during combustion; (3) Activated Carbon Injection (ACI) for the capture of mercury emissions; (4) enhanced Dry Sorbent Injection (DSI) for the reduction of acid gases and SO_2 removal; an (5) Selective Catalytic Reduction technology to reduce nitrogen oxide (NOx) emissions. Rockport Unit 1 currently consumes 95% to 100% PRB sub-bituminous coal. This high percentage PRB blend results in lower emission rates of SO_2 and NOx.

The Cook Plant is a two-unit nuclear power plant located along the eastern shore of Lake Michigan. Both units are pressurized water reactors with four-loop Westinghouse nuclear steam supply systems. Unit 1 received its operating license from the Nuclear Regulatory Committee (NRC) in 1974 and began commercial operation in 1975. Unit 2 received its operating license in 1977 and began commercial operation in 1978. The NRC initially granted 40-year licenses to each unit and granted

20-year license extensions in 2005. Unit 1 is currently licensed to operate until 2034, and Unit 2 until 2037. Nuclear power is an important resource in I&M's energy portfolio. Cook provides safe, reliable, low-cost, and carbon-free generation to I&M's customers. Annually, the Cook Plant generates enough electricity to supply approximately 1.5 million homes.

I&M owns five solar facilities located in Indiana and Michigan ranging in size from 2.5 MW to 20 MWs. Together, I&M's owned solar units have an installed capacity of 34.7 MW and provide another renewable energy resource to I&M's generation portfolio, which helps support the Company's environmental sustainability.

The hydro units are power stations situated along the St. Joseph River that utilize the river's flow for generation of power without materially altering the normal course of the river. Consequently, the output of these units is primarily dictated by river flow conditions and varies accordingly. These units are advantageous in that they do not utilize a reservoir for power production and therefore have less of an impact on upstream ecosystems. Additionally, the hydro units are renewable energy resources that help to support I&M's sustainability goals and support Indiana's Environmental Sustainability Pillar.

Future plans surrounding these existing generation resources must consider each unit's useful service life. Unit retirements are incorporated into I&M's plans based upon each unit's in-service date along with the anticipated service life. Retirement dates are periodically reviewed and adjusted with respect to a unit's ability to maintain safe, reliable, and economic operation, as well as external factors such as environmental regulations.

In addition to these long-term resources, I&M currently has short-term contracts to provide 360 MW, representing Indiana's capacity share, during the 2025/2026 delivery year. Based on the assessment of the current resources, planned retirements, peak demand and energy forecasts, a capacity and energy needs assessment can be established. This needs assessment will determine the amount and timing of capacity and energy resources for the 2024 IN IRP. This is discussed further in Section 7.

6.3 Fuel Inventory and Procurement Practices

6.3.1 Fuel Inventory and Procurement Practices – Coal

I&M plans to secure a portfolio of coal supplies for the Rockport Generating Station (Rockport) to meet full-load burn requirements in both the short-term and the long-term. AEP, acting as agent for I&M, is responsible for the procurement and delivery of coal to Rockport, as well as for establishing and managing coal inventory target levels. AEP's primary objective is to assure the availability of a reliable supply of coal at the lowest reasonable delivered cost. Deliveries are arranged so that the coal needed for the generation of electricity is available at Rockport.

6.3.2 Specific Units – Coal

I&M has one coal-fired generating station in Indiana, the Rockport Generating Station (Rockport) located in Spencer County. Rockport Unit 1 is a 1,300 MW nameplate coal fired regulated unit[6]. The New Source Review (NSR) Performance Standard and the U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards (MATS) limit the emissions at Rockport. The NSR limits SO_2 emissions at Rockport to 0.15 lbs. SO_2 per Million British Thermal Unit (MMBtu) on a 30-day rolling average basis with a maximum limit of 10,000 SO_2 tons per year. The MATS rule limits the emissions at Rockport for mercury, acid gases, and other hazardous air pollutants.

I&M complies with the NSR SO_2 emission limit by using a blend of coal consisting primarily of PRB low-sulfur subbituminous coal from Wyoming (≤ .65 lbs. SO_2 per MMBtu) with low-sulfur bituminous coal from Central Appalachian sources. To meet the MATS emission limits, Rockport uses DSI, ACI and an electrostatic precipitator. The DSI system uses sodium bicarbonate to reduce emissions of acid gases. The ACI system uses brominated activated carbon to reduce emissions of mercury. The electrostatic precipitator ensures compliance with hazardous air pollutant limits that are measured via particulate matter emission limits. The use of DSI and ACI technologies to reduce emissions has not required a change in the coal blend utilized at Rockport.

6.3.3 Procurement Process – Coal

I&M's coal purchasing strategy and delivery requirements are determined by considering existing coal inventory, forecasted coal consumption, adjustments for contingencies that necessitate an increase or decrease in coal inventory levels, and current coal market conditions. I&M's total coal requirements are met using a portfolio of long-term arrangements and spot-market purchases that are primarily made through a competitive Request for Proposal process. Long-term contracts (>1 year) support a relatively stable and consistent supply of coal. Spot purchases are used to provide additional flexibility to accommodate changing demand and to meet short term needs.

6.3.4 Contract Descriptions – Coal

Rockport's PRB coal supply needs are met by three long term agreements with Peabody COALSALES, LLC. Rockport's Central Appalachian coal supply needs are being met by one long-term supply agreement with Pocahontas Sales and Logistics LLC. As the existing agreements expire, additional coal supplies will be contracted to maintain a sufficient supply of coal.

6.3.5 Inventory – Coal

I&M has established an inventory target level for Rockport and strives to maintain this inventory target level to minimize operational risks for Rockport. The actual coal inventory at Rockport fluctuates throughout the year due to periods when the consumption of the plant and the deliveries

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[6] Rockport Unit 2 is a 1,122 MW nameplate coal fired resource that operates as a merchant generating unit and participates in the PJM markets as an RPM-only resource.

to the plant are not of equal volumes. Inventory levels build during times when coal consumption is reduced due to low demand and consumption is low. Inventory levels decline during times when consumption is high or during supply disruptions such as river water levels impacting shipping, river lock outages, railroad track outages or maintenance, unloading equipment outages, mine production outages, and rail or barge equipment shortages.

6.3.6 Fuel Inventory and Procurement Practices – Uranium

Uranium inventory for nuclear power is different than traditional inventories such as coal. No uranium is stored or brought to the Donald C. Cook (Cook) nuclear power plant in its raw material form. Uranium in its raw material form (commonly referred to as Yellowcake or U3O8) undergoes multiple processes before arriving on-site as fully fabricated fuel assemblies.

I&M typically purchases the raw material as converted U3O8, formally known as Uranium Hexafluoride (UF6). The purchased UF6 is delivered from the UF6 vendor to I&M's account at the enricher via a book transfer. After the UF6 has been enriched to I&M's specifications, the enriched material is then book transferred from I&M's account at the enricher to I&M's account at the fabricator. The fabricator then fabricates fuel assemblies per I&M's specifications, specifically designed for delivery to each unit. These final fabricated fuel assemblies are then transported to Cook marking the only point that material is in I&M's possession on site. These fuel assemblies are brought on site to be receipt inspected approximately a month prior to a unit's scheduled refueling outage (approximately every 18 months). There are a total of 193 fuel assemblies in each unit's core design. During every refueling outage Cook replaces a batch of fuel assemblies, which consists of approximately 80-88 new fuel assemblies. A batch will remain in the core for up to 54 months depending on the unit's generation schedule.

6.3.7 Specific Units – Uranium

The Cook Nuclear Plant is owned and operated by I&M. At full power, Unit 1 and Unit 2 can generate enough electricity for more than 1.5 million homes. The Unit 1 core holds a total of 193 fabricated fuel assemblies. This unit has a nameplate rating of approximately 1,100 MW. Cook Unit 2 initial criticality was in March 1978 and is currently licensed to operate until December 2037. The Unit 2 core holds a total of 193 fabricated fuel assemblies. This unit has a nameplate rating of approximately 1,200 MW.

6.3.8 Procurement Process – Uranium

In developing contracts and making purchases, I&M plans the lead time required to perform each phase of the fuel process. The target date from which decisions are made is the date the fabricated fuel is needed at Cook. Once the target date is established, it is then necessary to identify when the fabricator must have the enriched uranium. I&M continuously monitors the long-term generation schedule to determine any impacts to fuel procurement activities. All material delivered during the procurement process is delivered on the contractually obligated date to the designated facility. This process assures security of supply for refueling the reactors.

6.3.9 Contract Descriptions – Uranium

I&M's procurement needs are broken down into four main categories of contracts based on the procurement process (Raw Material or Uranium, Conversion, Enrichment and Fabrication).

I&M has Master Services Agreements (MSAs) in place with multiple Uranium vendors from across the United States, Canada and Europe for the purchase of Uranium and conversion services. These MSAs provide flexibility to purchase UF6 from multiple vendors from various parts of the world providing I&M a diverse level of supply and creates pricing competition. Per contractual terms, all material must meet the American Society for Testing and Materials (ASTM) "standard specifications for Uranium Hexafluoride for Enrichment for commercial natural UF6" as defined in the current specifications in effect[7]. I&M currently has contracted material to provide Cook with the vast majority of raw material that will be needed based on the current generation forecast through 2027.

I&M currently has one long term contract for enrichment that will cover all needs for both Units at Cook that is extendable through the current end of the plant life. Per contractual terms, all enriched uranium shall conform to the definition of "enriched commercial grade UF6" per the latest ASTM "standard specification for Uranium Hexafluoride Enriched to Less Than 5%".

I&M currently has one long term fabrication contract that will cover all needs for both Units at Cook through the current end of life of the plant. I&M fabricated fuel assemblies comply with the NRC license. This includes an approved Quality Assurance Program that requires the procurement of nuclear fuel from vendors with approved Quality Assurance programs which meet federal regulations. These Quality Assurance Programs are intended to control the design and manufacturing process to assure a product of the highest quality. This contract provides 100% of all final fabricated fuel assemblies needed to refuel the units on an approximately every 18-month basis and is adjusted based on the generation forecast as it is updated.

6.3.10 Excess Inventory - Uranium

Excess inventory (or remaining account balances at the enricher & fabricator) fluctuates depending on the timing of the reload batch to be delivered as well as depending on the availability of material from providers. Natural uranium inventory may be required when market conditions warrant to provide security of supply at the lowest cost to customers needed to operate the units. Any inventory is then used in support of near-term reloads. Also, small amounts of enriched uranium inventory still exist as a result of final detailed fuel cycle and fuel assembly design.

The recent volatility in market pricing and supply availability has changed how and when I&M is able to procure uranium for future reloads. With primary producers limited in their ability to provide uranium material for future years' delivery, I&M began to procure material in 2023 to ensure security

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[6] ASTM International. (2020). *C787 Standard specification for uranium hexafluoride for enrichment*. Retrieved from https://www.astm.org/c0787-20.html

of supply to maintain the reactors at full power at the lowest cost possible for the next several years. The uranium material that has been procured will be held until needed in the reactor.

I&M continually monitors the performance of any vendor who is under contract to assure fulfillment of contractual obligations. By contracting with reliable and proven performers and continuously monitoring their performance, the Company can operate the units with confidence.

6.3.11 Forecasted Fuel Prices

I&M-specific resource forecasted monthly fuel prices, by unit, for the period 2025 through 2044 are displayed in Appendix Volume 3, Exhibit A (Confidential).

6.4 Environmental Issues and Implications

It should be noted that the following discussion of environmental regulations is based on the requirements currently in effect and those compliance options viewed as most likely to be implemented by the Company. Activity including, but not limited to, Presidential Executive Orders, litigation, petitions for review, and Federal EPA proposals may delay the implementation of these rules, or alter the requirements set forth by these regulations. While such activities have the potential to materially change the compliance options available to the Company in the future, all potential outcomes cannot be reasonably foreseen or estimated.

6.4.1 Clean Air Act (CAA) Requirements

The Clean Air Act (CAA) establishes a comprehensive program to protect and improve the nation's air quality and control sources of air emissions. The states implement and administer many of these programs and could impose additional or more stringent requirements. The primary regulatory programs that continue to drive investments in AEP operating companies' existing generating units include: (a) periodic revisions to National Ambient Air Quality Standards (NAAQS) and the development of state implementation plans (SIP) to achieve any more stringent standards, (b) implementation of the regional haze program by the states and the Federal EPA, (c) regulation of hazardous air pollutant emissions under the MATS rule, (d) implementation and review of Cross-State Air Pollution Rule (CSAPR), a federal implementation plan (FIP) designed to eliminate significant contributions from sources in upwind states to non-attainment or maintenance areas in downwind states, and (e) the Federal EPA's regulation of greenhouse gas emissions from fossil fueled electric generating units under Section 111 of the CAA.

Notable developments in significant CAA regulatory requirements affecting the Company's operations are discussed in the following sections.

6.4.2 National Ambient Air Quality Standards (NAAQS)

The Federal EPA periodically reviews and revises the NAAQS for criteria pollutants under the CAA. Revisions tend to increase the stringency of the standards, which in turn may require AEP to make investments in pollution control equipment at existing generating units, or, since most units are already well controlled, to make changes in how units are dispatched and operated. In February 2024, the Federal EPA finalized a new more stringent annual primary PM2.5 standard.

Areas with air quality that does not meet the new standard will be designated by the Federal EPA as "nonattainment," which will trigger an obligation for states to revise their SIPs to include additional requirements, resulting in further emission reductions to ensure that the new standard will be met.

6.4.3 Cross-State Air Pollution Rule (CSAPR)

CSAPR is a regional trading program that the Federal EPA began implementing in 2015, which was originally designed to address interstate transport of emissions that contribute significantly to nonattainment and interfere with maintenance of the 1997 ozone NAAQS and the 1997 and 2006 PM2.5 NAAQS in downwind states. CSAPR relies on SO_2 and NOx allowances and individual state budgets to compel further emission reductions from electric utility generating units. Interstate trading of allowances is allowed on a restricted basis. The Federal EPA has revised, or updated, the CSAPR trading programs several times since they were established.

In January 2021, the Federal EPA finalized a revised CSAPR, which substantially reduced the ozone season NOx budgets for several states, including Indiana, beginning in ozone season 2021. AEP has been able to meet the requirements of the revised rule over the first few years of implementation, and is evaluating its compliance options for later years, when the budgets are further reduced.

In addition, in February 2023, the Federal EPA Administrator finalized the disapproval of interstate transport SIPs submitted by 19 states, including Indiana, addressing the 2015 Ozone NAAQS. The Federal EPA disapproved interstate transport SIPs submitted by additional states soon thereafter. Disapproval of the SIPs provided the Federal EPA with authority to impose a FIP for those states, replacing the SIPs that were disapproved. In August 2023, a FIP (the Good Neighbor Plan) went into effect that further revised the ozone season NOx budgets under the existing CSAPR program in states to which the FIP applies. As a result of several separate legal challenges brought by states and industry parties in various federal courts, implementation of the FIP has been stayed in all of the states in which AEP operates. In October 2024, the Federal EPA issued a final rule to administratively stay the effectiveness of the Good Neighbor Plan's requirements for all sources covered by that rule as promulgated where an administrative stay was not already in place. The administrative stay of the Good Neighbor Plan's effectiveness for power plants and other industrial facilities in each of the 23 states will remain in place until the Supreme Court lifts its order staying enforcement of the Good Neighbor Plan, other courts lift any judicial orders staying the SIP disapproval action as to the state, and the Federal EPA takes subsequent rulemaking action consistent with any judicial rulings on the merits. Management will continue to monitor the outcome of this litigation and the development of SIPs for any potential impact to operations.

6.4.4 Mercury and Other Hazardous Air Pollutants Regulation

In April 2024, the Federal EPA issued a revised MATS rule for power plants. The rule includes a more stringent standard for emissions of filterable PM for coal-fired electric generating units, as well as a new mercury standard for lignite-fired electric generating units. The rule also requires the installation and operation of continuous emissions monitors for PM. Several states and other parties have challenged the rule in the United States Court of Appeals for the District of Columbia Circuit, but management cannot predict the outcome of the litigation. Management is evaluating the impacts of the rule but does not anticipate any significant challenges complying with the rule.

6.4.5 Climate Change, CO_2 Regulation and Energy Policy

In April 2024, the Administrator of the Federal EPA signed new GHG standards and guidelines for new gas units and existing coal and gas steam sources. The rule relies on carbon capture and sequestration/storage and natural gas co-firing as means to reduce carbon dioxide (CO_2) emissions from coal fired plants and carbon capture and sequestration/storage or limited utilization to reduce CO_2 emissions from new gas turbines. The rule also offers early retirement of coal plants in lieu of carbon capture and sequestration/storage as an alternative means of compliance. The Federal EPA deferred the finalization of standards for existing gas turbines until a later date. States must submit a State Implementation Plan to the Federal EPA for approval by May 2026. The Federal EPA has one year to approve the state plan with requirements becoming effective as early as 2030.

AEP is in the early stages of evaluating and identifying the best strategy for complying with this and other new rules, discussed below, while ensuring the adequacy of resources to meet customer needs. The rule has been challenged by 27 states, numerous companies, trade associations and others. AEP has joined with several other utilities to challenge the rule and the appeals have been consolidated. The case has been briefed and argued before the U.S. Court of Appeals for the District of Columbia Circuit. In February 2025, Federal EPA moved the court to hold the case in abeyance while the new administration evaluates the rule, and the court granted that motion to hold the case in abeyance through April 2025.

6.4.6 New Source Review (NSR) Consent Decree Obligations

I&M's Rockport Plant is subject to requirements that stem from a 2007 Consent Decree with the Federal EPA and United States Department of Justice, and several subsequent modifications to that agreement. Pursuant to the Consent Decree, Rockport is subject to annual tonnage limits for SO2 of 10,000 ton per year beginning in calendar year 2021. Rockport Unit 1 is also required to retire by the end of 2028.

6.4.7 Coal Combustion Residual (CCR) Rule

The Federal EPA's CCR Rule regulates the disposal and beneficial re-use of CCR, including fly ash and bottom ash created from coal-fired generating units and FGD gypsum generated at some coal-fired plants. The original rule applied to active and inactive CCR landfills and surface impoundments at facilities of active electric utility or independent power producers. With revisions announced in April 2024, the scope of the rule has expanded significantly, to include inactive impoundments at inactive facilities (legacy CCR surface impoundments) as well as to establish requirements for currently exempt solid waste management units that involve the direct placement of CCR on the land (CCR management units).

The Federal EPA is requiring that owners and operators of legacy surface impoundments comply with all the existing CCR Rule requirements applicable to inactive CCR surface impoundments at active facilities, except for the location restrictions and liner design criteria. The rule establishes compliance deadlines for legacy surface impoundments to meet regulatory requirements, including a requirement to initiate closure within five years after the effective date of the final rule. The rule requires evaluations to be completed at both active facilities and inactive facilities with one or more legacy surface impoundments. Closure may be accomplished by applying an impermeable cover system over the CCR material (closure in place) or the CCR material may be excavated and placed in a compliant landfill (closure by removal). Groundwater monitoring and other analysis over the next three years will provide additional information on the planned closure method.

In April 2020, the Supreme Court issued an opinion regarding whether discharges to groundwater that is hydrologically connected to surface water constitute “point source” discharges that require a permit under the Clean Water Act. According to the Supreme Court, factors including the distance traveled, the length of time to reach the ocean, and other factors can make a discharge to groundwater “functionally equivalent” to a direct discharge from a point source.

Following the Supreme Court’s decision, the Federal EPA issued draft guidance for public comment on applying the outcome of the Supreme Court’s decision and consideration of functionally equivalent factors. To date, Federal EPA has not finalized that guidance. The impact of the Supreme Court’s ruling on CCR units remains to be seen.

6.4.8 Solid Waste Disposal

Ash produced by the Rockport Plant is disposed at the on-site landfill permitted by the Indiana Department of Environmental Management (IDEM). The landfill is underlain with clay and a geosynthetic plastic liner, has a groundwater monitoring well system that is sampled to monitor for potential impacts to groundwater, and storm-water runoff collection and treatment system, with discharge regulated by an IDEM-issued National Pollutant Discharge Elimination System permit. Ash handling and storage is also regulated by the Federal CCR Rule.

Non-hazardous solid wastes generated at the Rockport Plant, as well as the hydro facilities, are disposed at permitted municipal solid waste landfills. Typical solid waste may include general trash, non-hazardous solvents, and hydraulic fluid, which may be recycled or properly disposed of using licensed vendors. These facilities recycle numerous non-hazardous and hazardous waste, including everything from paper and cardboard to batteries and used mercury.

6.4.9 Hazardous Waste Disposal

Rockport is typically a small-quantity generator of hazardous waste, such as parts washer by-products, batteries, light bulbs, and paints. The plant recycles light bulbs and batteries. Rockport has significantly reduced the amount of solvents generated in the parts washers by purchasing its own equipment and processing its own non-hazardous solvents.

6.4.10 Clean Water Act Regulations

The Federal EPA's ELG rule for generating facilities establishes limits for FGD wastewater, fly ash and bottom ash transport water and flue gas mercury control wastewater, which are to be implemented through each facility's wastewater discharge permit. A revision to the ELG rule, published in October 2020, established additional options for reusing and discharging small volumes of bottom ash transport water, provided an exception for retiring units and extended the compliance deadline to a date as soon as possible beginning one year after the rule was published but no later than December 2025. The Rockport Plant opted to file a Notice of Planned Participation, pursuant to which it is not required to install additional controls to meet ELG limits provided it commits to cease coal combustion by December 31, 2028.

6.5 Demand-Side Management Programs

6.5.1 Background

DSM programs collectively include utility programs aimed at influencing both the level of, and timing of, customer use of grid supplied electricity. These types of programs are structured to counter the ongoing need for increased supply resources through customer energy conservation or direct intervention in how customers use electricity. Typically, customer influence is achieved through some form of monetary or product enticement either through utility rebates or electric bill credit payments. Several demand-side programs are available including Energy Efficiency (EE), Demand Response (DR), Conservation Voltage Reduction (CVR) and Distributed Generation (DG). Rate design can also influence customers' energy consumption behaviors.

Generally, EE programs pay rebates directly to customers that are designed to encourage either end-use conservation or energy use reduction through the installation of or upgrade to more efficient end-use technologies. Some EE programs do not pay a cash rebate but instead encourage customers to reduce their annual energy consumption, or better manage their cost of electricity. Other types of EE programs seek to influence the manufacture and supply of more efficient end-use technologies through upstream rebate payments to end-use technology providers that reduce the technology cost to end-use customers. EE programs provide both energy and demand savings. Energy savings are accounted for as an around-the-clock energy reduction impact while demand savings are accounted for in terms of their point-in-time, peak coincident use reduction on an hourly basis.

Generally, DR programs offer electric bill credits through tariff pricing mechanisms to elicit point-in-time energy use reductions (also known as demand, or coincident peak demand reductions). DR programs require specific action to monitor and control electricity use during periods of peak usage. Direct load control (DLC) programs allow utility control over customers' end use loads to achieve the specific peak period use reduction. Other types of DR programs allow customers to reduce use during peak periods on their own accord and receive bill credits based on the actual level of usage during peak period events. DR programs primarily provide peak coincident demand impacts but can provide energy impacts as well depending upon the extent of use reduction that occurs.

DG typically refers to small-scale customer-sited generation located behind the customer meter. Common examples are combined heat and power generation, residential and small commercial solar applications, and even wind. Currently, these resources represent a small component of demand-side resources, even with available federal tax credits and tariffs favorable to such applications. I&M's Indiana retail jurisdiction has an excess distributed generation tariff in place which currently allows excess generation to be credited to customers at the retail rate up to the amount of the customer's monthly bill.

CVR (a.k.a. Electric Energy Consumption Optimization (EECO) or Volt-VAR Optimization) is a process by which the utility systematically reduces voltages in its distribution network through the installation and use of sensors and controllers on the grid, resulting in a proportional reduction of load on the network. This voltage reduction still maintains minimum levels needed by customers but elicits lower energy use from end-use customer appliances without any changes in behavior or changes to appliance efficiencies.

Rate design remains an important element of future utility regulation and resource planning as the industry changes, particularly in the way electricity is supplied and used, as well as the times at which energy is produced. As an example, increasing levels of DERs, EVs, and overall electrification of the economy will have significant and uncertain impacts on electric demand, supply, and use. AMI technology provides useful and necessary information to better evaluate and disaggregate loads and support future rate design changes. In general, the Company's approach to rate design changes is two-fold: 1) test rate design concepts with small scale or limited-scope offerings; and 2) include proposals in its base rate or other proceedings in order to allow other parties, Commission Staff, and Commissioners to evaluate the reasonableness of such proposals. As this area of the business evolves, I&M anticipates incorporating those learnings and developments in future DSM program considerations.

6.5.2 Existing Demand-Side Programs

Included in the load forecast discussed in Section 4 of this Report are the demand and energy impacts associated with I&M's DSM programs approved in Indiana prior to preparation of this 2024 IN IRP. A summary of these include:

- EE: I&M currently has approved EE programs in place in its Indiana service territory. These programs are forecasted to reduce peak demand in 2025 by approximately 18 MW and reduce energy consumption by approximately 108 GWh.
- DR: DR programs are accounted for as a load shape reduction from the load forecast used in the 2024 IN IRP. For the year 2025, I&M anticipates 204 MW of DR reduction. The majority of this DR is achieved through interruptible load agreements. A smaller portion is achieved through direct load control.
- DG: Through November 2024, the Company has 818 customers that have installed net metering and/or co-generation qualifying customer-generation facilities which are interconnected and/or net metered with a total nameplate capacity of approximately 18 MW.
- CVR: I&M currently has 108 distribution circuits with CVR installed in its Indiana service territory.

6.6 AEP-PJM Transmission

6.6.1 General Description

The AEP eastern transmission system (Eastern Zone) consists of the transmission facilities of the 11 eastern AEP operating or Transmission companies including I&M, Appalachian Power Company, Ohio Power Company, Kentucky Power Company, Wheeling Power Company, Kingsport Power Company, AEP Appalachian Transmission Company, AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, and AEP West Virginia Transmission Company. The Eastern Zone is composed of approximately 14,800 miles of circuitry operating at or above 100kV and includes over 2,120 circuit miles of 765kV transmission lines, 96 circuit miles of 500kV transmission lines, 3,575 circuit miles of 345kV transmission lines, and over 9,000 circuit miles of 138kV transmission lines.

The transmission line circuit miles in I&M's Indiana service territory include approximately 610 miles of 765kV, 1,400 miles of 345kV, 1,550 miles of 138kV, 590 miles of 69kV, and 190 miles of 34.5kV lines.

The AEP eastern transmission system is part of the Eastern Interconnection, the most integrated transmission system in North America. The entire AEP Eastern Zone is located within the ReliabilityFirst Corporation (RFC) geographic area. On October 1, 2004, AEP's eastern zone joined the PJM Regional Transmission Organization (RTO) and now participates in PJM regional planning, operations and markets.

The AEP Eastern Zone can be influenced by both internal and external factors due to its geographical location, expanse, and numerous interconnections. Facility outages, load changes, or generation re-dispatch on neighboring companies' systems, in combination with power transactions across the interconnected network, can affect power flows on AEP's transmission facilities. As a result, the AEP Eastern Zone is designed and operated to perform adequately even with the outage of its most critical transmission elements or the unavailability of generation. The Eastern Zone conforms to the North American Electric Reliability Corporation (NERC) Reliability Standards and applicable RFC standards and performance criteria. In addition, transmission modifications may be required to address changes in power flow patterns and changes in local voltage profiles resulting from operation of the PJM and adjacent markets, such as the Midcontinent Independent System Operator (MISO) and the New York Independent System Operator (NYISO).

6.6.2 Transmission Planning Process

AEP and PJM coordinate the planning of the transmission facilities in the AEP Eastern Zone through a "bottom up/top down" approach. AEP will continue to develop transmission expansion plans to meet the applicable reliability criteria in support of PJM's transmission planning process. PJM will incorporate AEP's expansion plans with those of other PJM member utilities and then collectively evaluate the expansion plans as part of its Regional Transmission Expansion Plan (RTEP) process. The PJM RTEP will ensure consistent and coordinated expansion of the overall bulk transmission system within its footprint. In accordance with this process, AEP will continue be the responsible party for the planning of its local transmission system under the provisions of Schedule 6 of the PJM Operating Agreement and Attachment M-3 of the PJM tariff. By way of the RTEP, PJM will ensure that transmission expansion is developed for the entire RTO footprint via a single regional planning process that considers both regional and local needs and solutions, thus ensuring a consistent view of needs and expansion timing while minimizing expenditures. When regional system upgrade requirements are identified under the RTEP, PJM determines the individual member's responsibility as related to construction and costs to implement the expansion. This process identifies the most appropriate, reliable, and economical integrated transmission reinforcement plan for the entire region, while blending the local planning expertise of the transmission owners such as I&M with a regional view and formalized open Stakeholder input.

AEP's transmission planning criteria are consistent with NERC and RFC reliability standards. The AEP planning criteria are filed with FERC annually as part of AEP's FERC Form 715 and these planning criteria are posted on the AEP website.[8] Using the NERC and RFC standards and limitations, constraints and future potential deficiencies on the AEP transmission system are identified. Solutions are identified and budgeted as appropriate to ensure that system enhancements will be timed to address anticipated deficiencies.

PJM also coordinates its regional expansion plan on behalf of the member utilities with neighboring utilities and/or RTOs, including the MISO, to ensure inter-regional reliability. The Joint Operating Agreement between PJM and MISO provides for joint transmission planning.

6.6.3 Evaluation of Adequacy for Load Growth

As part of the on-going near-term/long-term planning process, AEP and PJM use load forecasts along with information on system configuration, generation dispatch, and system transactions to develop models of the AEP transmission system. These models are the foundation for conducting performance appraisal studies based on established criteria to determine the potential for overloads, voltage problems, or other unacceptable operating problems under adverse system conditions. Whenever a potential problem is identified, PJM and AEP seek solutions to avoid the occurrence of the problem. Solutions may include operating procedures or capital transmission project reinforcements. Through this on-going process, AEP works diligently to maintain an adequate transmission system able to meet forecasted loads.

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[7] American Electric Power. (2024). *Transmission planning reliability criteria: AEP/PJM 2024 filing*. Retrieved from https://docs.aep.com/docs/requiredpostings/TransmissionStudies/docs/2024/TransmissionPlanningReliabilityCriteria-AEP_PJM-2024_Filing.pdf

In addition, PJM performs a Load Deliverability assessment on an annual basis using a 90/10[9] load forecast for areas that may need to rely on external resources to meet their demands during an emergency condition.

6.6.4 Evaluation of Generation Interconnections

As a member of PJM, and in compliance with FERC Orders 888 and 889, AEP is obligated to provide sufficient transmission capacity to support the wholesale electric energy market. In this regard, any committed generator interconnections and firm transmission services are taken into consideration under AEP's and PJM's planning processes. In addition to providing reliable electric service to AEP's retail and wholesale customers, PJM will continue to use any available transmission capacity in AEP's Eastern Zone to support the power supply and transmission reliability needs of the entire PJM market.

A number of generation requests have been initiated in the PJM generator interconnection queue. AEP, through its membership in PJM, is obligated to evaluate the impact of these projects and construct the transmission interconnection facilities and system upgrades required to connect any projects that sign an interconnection agreement.

Additionally, AEP in coordination with PJM performs analysis for any planned generation deactivations to determine system impacts. If violations of planning criteria are identified, mitigating solutions are developed that could include operating procedures or transmission upgrades.

A discussion of the AEP Eastern Zone reliability criteria for transmission planning, as well as the assessment practice used, is provided in AEP's 2024 FERC Form 715 Annual Transmission Planning and Evaluation Report Part 4 and 5, which can be found in Appendix Volume 1, Exhibit M. That filing also provides pertinent information on power flow studies and an evaluation and continued adequacy assessment of AEP's Eastern Zone.

6.6.5 Transmission Projects

AEP's eastern transmission system is anticipated to continue to perform reliably for the upcoming peak load seasons. AEP will continue to assess the need to expand its system to ensure adequate reliability for I&M's customers. A listing of certain Indiana transmission projects in the current I&M project portfolio is provided in Appendix Volume 1 Exhibit H. These projects contribute to the robust health and capacity of the overall transmission grid, which benefits all customers. In addition, several other projects beyond the I&M service territory have also been completed or are underway across

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[8] 90% probability that the actual peak load will be lower than the forecasted peak load and 10% probability that the actual peak load will be higher than the forecasted peak load.

the AEP Eastern Zone. While they do not directly impact I&M, such additions contribute to the robust health and capacity of the overall transmission grid, which also benefits Indiana customers.

6.7 Distribution Opportunities – Grid Modernization

On an ongoing basis, I&M engages in electric distribution grid planning to ensure safe, reliable, and secure development and operation of the distribution energy delivery system. As part of Grid Modernization efforts, I&M continues to enhance policies, procedures, and plans to build out the existing energy delivery system to support DER integration and other new technologies. I&M will facilitate integration of customer owned DER and end-use technology for any customer that seeks to interconnect their resources into the distribution energy delivery system in accordance with the Company's interconnection requirements. To this extent, I&M distribution planning efforts include traditional activities, such as system coordination, system adequacy, distribution hardening, and asset sizing. These traditional activities serve as the foundation to enable the grid for technology applications. Distribution automation, AMI, energy storage, micro grids, and DER integration, are being incorporated into, and applied to the foundational activities to advance the future capabilities of the distribution energy delivery system.

In order to ensure a safe, reliable, and secure foundation for the distribution energy delivery system, I&M developed plans to first address the leading causes of outages on its system – including, most importantly, vegetation management, and aging infrastructure, and then layers in distribution automation technology to enhance system capability and operation as part of a Grid Modernization effort. I&M is also in the process of building out an Advanced Distribution Management System (ADMS) with a Distributed Energy Resource Management System (DERMS) module to help with the management of new technologies as well as resources that are interconnected to its system.

Grid Modernization recognizes the growth potential for third party DER and the increased need for active utility monitoring and controls to manage a more dynamic grid. This includes options for non-wires alternatives (NWAs), as well as I&M's progress in developing a process for screening and developing these NWA solutions. Several NWA solutions were included as resource options in the IRP modeling, and they are noted in Section 8.1.5.2.

The addition of renewables may lead to more distributed storage capacity on the grid. It is anticipated that these storage additions will continue to accelerate as FERC Order 2222 matures. AMI and distribution automation systems offer increased visibility into actual distribution system operation. This evolution coupled with other distribution automation devices which give real-time system information will result in a grid that is more dynamic and inter-dependent and will require active utility monitoring and controls to manage. An ADMS with DERMS functionality will allow the Company to implement a new network architecture across AEP. This new network architecture will expand distribution planning efforts listed above. The distribution planning efforts will be reviewed and updated as necessary as DER becomes more prevalent on the I&M system.

7 Capacity and Energy Needs Assessment

The next step in the 2024 IN IRP process (see Figure 7) is the demonstration of the capacity and energy resource requirements. This aspect of the traditional "needs" assessment must consider projections of:

- Existing capacity and energy resources—current levels and anticipated changes
- Anticipated changes in capability
- Load and peak demand
- Current DR/EE
- PJM capacity reserve margin and reliability criteria

7.1 PJM Capacity Performance Rule Implications

I&M operates in the PJM Interconnection, L.L.C. (PJM) and in ReliabilityFirst Corporation, a Regional Entity of the North American Electric Reliability Corporation (NERC). I&M participates in the PJM energy market. Based on offers placed into this market, the generation resources within the entire PJM regional transmission organization (RTO) are economically dispatched for energy to serve the total PJM load, including I&M's internal load. Separately, PJM has a mandatory capacity market which is called the Reliability Pricing Model (RPM). PJM allows an entity to either participate in a capacity auction (in which PJM functions to procure the capacity) or utilize the Fixed Resource Requirement (FRR) option in which the entity supplies its own capacity resource either through constructing the necessary capacity or through bilateral contracts with existing resources.

PJM requires all FRR entities to make mandatory commitments to meet their capacity reserve requirements by supplying PJM with an FRR plan three years in advance of a Delivery Year (DY). The same three year forward concept holds for entities using the RPM auction process. The Reliability Assurance Agreement (RAA) sets forth the rules of participation in the PJM Capacity Market and establishes capacity obligations of PJM Load Serving Entities.

Currently, I&M, along with other operating companies of AEP in PJM, participates as a PJM FRR entity and is committed to the FRR option through PJM DY 2025/26. The last day to submit FRR election decisions for PJM PY 2026/27 is May 9, 2025. For the 2024 IN IRP, the Company assumes it will continue as an FRR entity within the PJM Capacity planning process. AEP plans to notify PJM of its FRR election decision by the auction election deadlines.

The underlying minimum reserve margin criterion to be utilized in the determination of I&M's capacity need is based on the PJM Installed Reserve Margin (IRM) of 18.6% for 2025/26 Base Residual Auction (BRA). The ultimate reserve margin is determined from the PJM Forecast Pool Requirement (FPR), which considers the IRM and PJM's Pool-Wide Average Accredited Unforced Capacity (AUCAP). The PJM FPR is 0.9367 for the 2026/27 PJM DY. Table 12 below provides PJM's latest estimates of the IRM, AUCAP Factor, and FPR for PJM PY 2027/28 through 2034/35. These estimates are non-binding.

Table 12. PJM Estimated Capacity Measures[10]

Delivery Year	IRM (%)	AUCAP Factor	FPR
2027/28	20.1	0.7718	0.9269
2028/29	21.9	0.7609	0.9275
2029/30	23.9	0.7544	0.9347
2030/31	26.3	0.7360	0.9296
2031/32	28.9	0.7193	0.9272
2032/33	30.8	0.7041	0.9210
2033/34	33.0	0.6766	0.8999
2034/35	35.1	0.6446	0.8709

For planning purposes in the 2024 IN IRP, FPR values are assumed to remain constant from DY 2034/35 to the end of the planning horizon. As discussed earlier, the Company included the Reserve Margin metric in the Portfolio Performance Indicators matrix to ensure that portfolios considered meet the PJM FPR.

7.1.1 PJM Critical Issue Fast Path (CIFP) for Resource Adequacy Issues Implications

On January 30, 2024, FERC issued an order approving PJM's proposed changes to its RAA. These changes include reliability modeling enhancements, implementation of marginal effective load carrying capability (ELCC) for all resources, additional generator testing requirements, modified (lowered) stop-loss to be based on capacity auction revenues and the FRR transition mechanism. On February 6, 2024, FERC issued an order rejecting PJM's proposal to eliminate the physical cure and netting option for FRR participants, modifying eligibility for bonus payments and changes to the Market Seller Offer Cap. The rulemaking is effective with the 2025/2026 PJM DY.

The Company also assumes, consistent with the CIFP reforms, that unit capabilities will be based on the installed capacity times the AUCAP Factor (ELCC Class Rating x Performance Adjustment

[10] PJM Interconnection. (2024). *Supplementary information: ELCC class ratings. Presentation*. Retrieved from https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2024/20240806/20240806-item-08---supplementary-information---elcc-class-ratings.ashx

Factor). The resource ELCCs through 2034 are based on PJM's Preliminary ELCC Class Ratings[11] for period DY 2026/27 through DY 2034/35 and are be noted in Table 13. For planning purposes in the 2024 IN IRP, ELCC values are assumed to remain constant from DY 2034/35 to the end of the planning horizon.

Table 13. PJM Preliminary ELCC Class Ratings

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%

The Performance Adjustment Factors reflect each resource's average historically observed performance, in hours and weather conditions in which the system experiences reliability risk, relative to class average historically observed performance in those same hours and weather conditions. The 2025-2026 BRA Performance Adjustment statistics[12] by ELCC Class are noted below in Table 14.

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[11] PJM Interconnection. (2024). *Preliminary ELCC class ratings for period 2026-2027 through 2034-2035*. Retrieved from https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/preliminary-elcc-class-ratings-for-period-2026-2027-through-2034-2035.pdf

[12] PJM Interconnection. (2024). *Stats performance adjustment*. Retrieved from https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/stats-performance-adjustment.xlsx

Table 14. 2025-2026 BRA Performance Adjustment Statistics

ELCC Class	Min	25%	50%	75%	Max
Coal	0.82	0.97	1.03	1.06	1.10
Diesel Utility	0.84	0.98	1.01	1.04	1.05
Gas Combined Cycle	0.60	0.98	1.01	1.05	1.08
Gas Combustion Turbine	0.47	0.92	1.04	1.14	1.20
Gas Combustion Turbine Dual	0.73	0.95	1.04	1.06	1.09
Hydro Intermittent	0.00	0.57	1.01	1.43	1.80
Landfill Intermittent	0.34	0.91	1.00	1.21	1.51
Nuclear	0.81	1.00	1.02	1.02	1.03
Onshore Wind	0.42	0.82	1.04	1.16	1.40
Solar Fixed	0.27	0.87	0.99	1.09	1.35
Solar Tracking	0.16	0.95	1.02	1.08	1.29
Steam	0.54	1.02	1.06	1.09	1.19

7.2 Capacity Needs Assessment

The next step in the 2024 IN IRP process (see Figure 7) is to develop the capacity needs assessment (Going-In Capacity Position). The Going-In Capacity Position includes existing and planned resources as described in Section 6, the forecasted PJM load obligation, the capacity contingency, and Indiana's expected capacity needs (or capacity shortfall) through the planning horizon. As noted above, the existing and planned resources installed capacity is converted to unforced capacity (UCAP) utilizing the AUCAP Factor. UCAP is defined in the RAA to be the megawatt level of a generating unit's capability after removing the effect of forced outage events. Moving forward in this report, UCAP will be referred to as accredited capacity. Indiana's peak demand, provided through the load forecast, is then multiplied by the FPR noted in Table 12, to calculate the forecasted PJM load obligation. In addition to the forecasted PJM load obligation, the Company included an additional 5% capacity contingency to mitigate risks associated with uncertainty in the load forecast and the other factors driving uncertainty in the amount of generating capacity that Indiana will have accredited in any future DY. Each of the cases modeled in the 2024 IN IRP are optimized to meet a capacity constraint which is defined as the forecasted PJM load obligation and the capacity contingency. Figure 24 shows Indiana's Going-In Capacity Position through 2044.

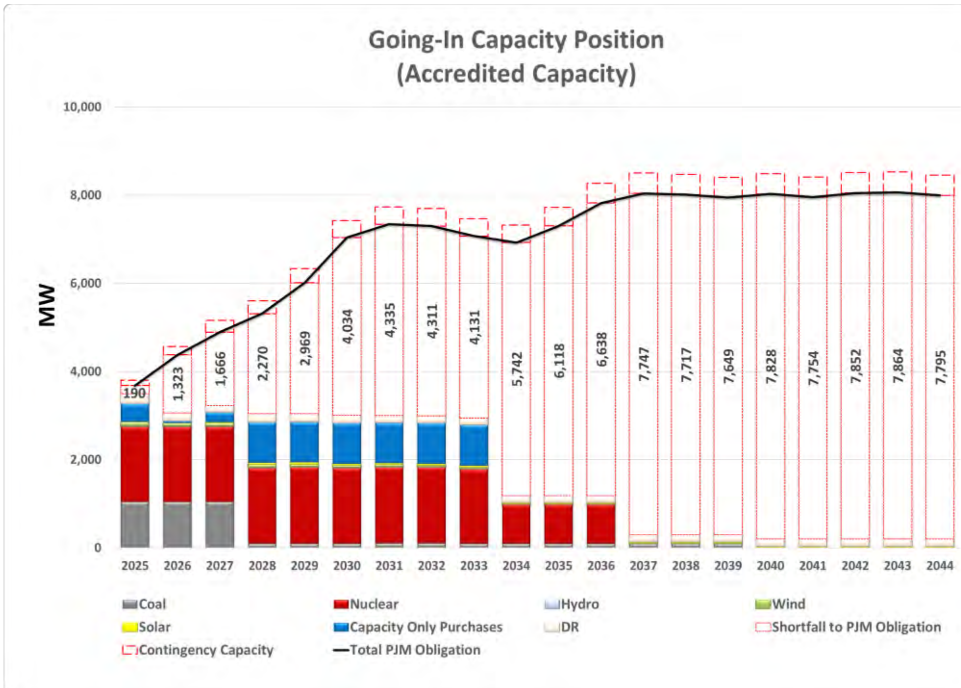

Figure 24. I&M Indiana Going-In Capacity Position

The capacity shortfall begins immediately in 2025 and significantly increases over the planning horizon due to the load growth associated with the HSL customers, reaching a capacity shortfall of nearly 8 GW by the end of the planning horizon. The initial HSL growth from 2025 to 2030 represents 4.4 GW of capacity. The later HSL growth begins in 2034 and continues until 2038, representing a total 6 GW of capacity needs over the planning horizon. In the 2034/35 DY, there is a decrease in the forecasted PJM load obligation. This is due to the expiration of wholesale customer contracts and the decrease in the FPR.

At the end of 2028, Rockport Unit 1 ceases operations and is no longer included in the capacity portfolio for Indiana in the 2028/29 DY. Rockport Unit 1 represents roughly 900 MW of accredited capacity. Capacity purchase contracts to replace the capacity lost from Rockport Unit 1 are included in the 2028/29 DY. These contracts extend until the 2033/34 DY but do not contribute to the energy position. In 2034/35, the capacity purchase contracts expire, and Cook Unit 1 is assumed to cease operations due to its license expiration, further increasing the capacity shortfall by 1.4 GW. Cook Unit 2 is assumed to cease operations in the 2036/37 DY due to its license expiration, increasing the capacity shortfall by 520 MW.

7.2.1 Capacity Contingency

It is prudent to plan above the forecasted PJM load 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 having a significant capacity shortfall and needing to add 4 GW of new resources by 2030.

There are many factors that lead to uncertainty in the peak load forecast and uncertainty in the amount of generating capacity that I&M will have accredited in any future DY. This uncertainty contributes to meaningful risk that the Company's accredited capacity will not meet its load obligation, and as a result be subject to potential significant financial risk. If deficient, PJM will either a) remove the company from participating in the FRR option (if the initial capacity demonstration does not meet the FPR) or b) impose a capacity deficiency charge (if the company is short capacity within the DY). For reference, the capacity deficiency charge for DY 2025/2026 is $452/MW-day. 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 DY, it will be necessary to add approximately 5% to the forecasted PJM load obligation. Figure 25 illustrates a general example of the distribution of the demand surplus or deficit compared to the PJM load obligation for a DY, if the median accredited capacity equals the forecasted PJM load obligation.

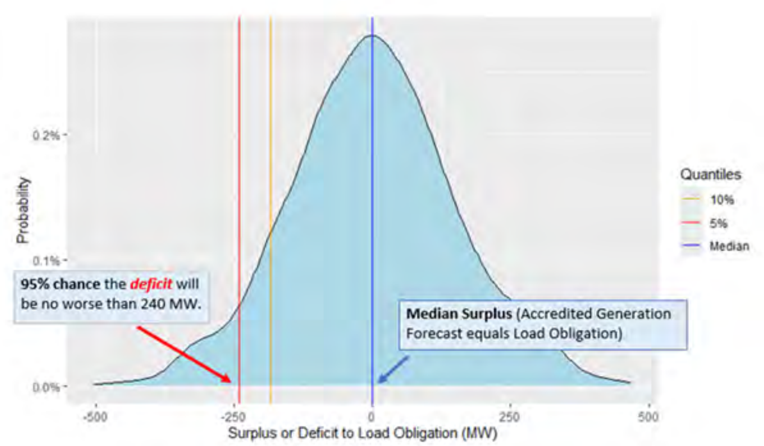

Figure 25. Example of Demand Surplus/Deficit Distribution

If Indiana targets a surplus equal to zero, then the Company only has 50% confidence that it will have sufficient capacity to meet the forecasted PJM load obligation. In this illustration, the Company would need to target another 200 MW of capacity to achieve 90% confidence and 240 MW to achieve 95% confidence. Additional details on the analysis results and methodology can be found in Appendix Volume 1, Exhibit K and Volume 3, Exhibit B, respectively.

7.3 Energy Needs Assessment

In addition to the Going-In Capacity Position, the Company identified the Going-In Energy Position to understand the amount of load that will be served by Indiana's existing or planned resources. Figure 26 illustrates the Going-In Energy Position over the planning horizon.

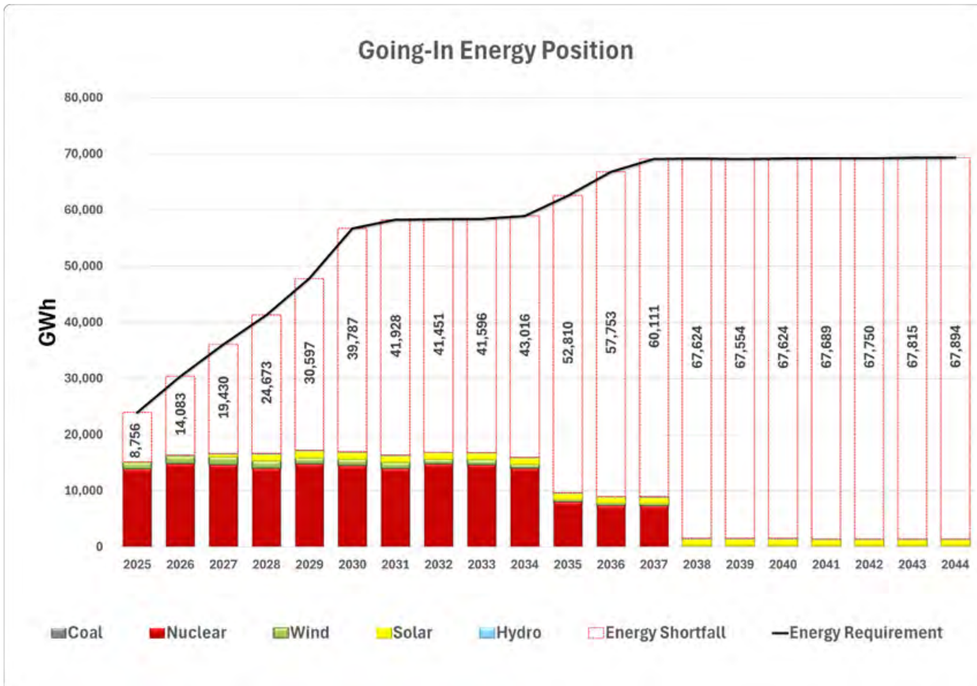

Figure 26. I&M Indiana Going-In Energy Position

Similar to the Going-In Capacity Position, the energy shortfall begins in 2025 and grows to nearly 68,000 GWhs by the end of the planning horizon. The energy shortfall is primarily due to the HSL customer growth. Initially, Cook Units 1 and 2 support the energy requirement producing a combined 14,500 GWh of energy annually. By 2038, both units are assumed to cease operations due to license expirations, furthering the energy shortfall.

In addition to optimizing the model with a capacity constraint, the Company modeled an energy constraint, focusing on the percentage of energy purchases and sales compared to Indiana load. At the beginning of the planning horizon, the Company allowed higher energy market purchases and sales as resources did not become available for selection in the model until 2028. After 2029, the Company reduced the energy market purchases and sales limits, requiring the model to select resources to support the energy need instead of relying on purchases from the PJM energy market.

Risk associated with energy purchases was an important objective the Company wanted to analyze in the 2024 IN IRP. Relying too heavily on energy market purchases could negatively impact Indiana's customers during times of elevated energy market prices. As such, the percentage of market purchases and sales was an element of the Portfolio Performance Indicator matrix and an important consideration in comparing portfolios to identify the Preferred Portfolio.

8 Supply-Side and Demand-Side Resource Options

8.1 Supply-Side Resource Options and Costs

New supply-side capacity alternatives were modeled to represent base/intermediate alternatives, peaking alternatives, renewable alternatives, storage alternatives, and short-term capacity market purchases. These were all considered as part of the 2024 IN IRP. Throughout the 2024 IN IRP, several data sources and generation engineering subject matter expert inputs were considered to develop the supply-side resource assumptions. Table 15 shows a matrix of the supply-side resource parameters and the associated source to develop the parameter.

Table 15. Supply-Side Resource Parameters

Supply-Side Resource Parameter	Source
Installed Costs	EIA Annual Energy Outlook, Market Based Intelligence, NREL's Annual Technology Baseline, Inflation
VOM, FOM, and Operating Parameters	EIA Annual Energy Outlook
First Year Available	PJM Queue Analysis, Infrastructure Development Expertise
Build Limits	Market Based Intelligence, Generation Engineering Expertise

Parallel to the 2024 IN IRP process, I&M issued four (4) requests for proposals (RFPs) for generation resources to meet projected capacity and energy needs. These separate RFPs allowed for a targeted approach addressing intermittent resources, non-intermittent resources, battery energy storage and supplemental capacity resources. The four (4) separate RFPs were designed to allow for an open, competitive solicitation process which included market-based pricing. In the Settlement Agreement approved in IURC Cause No. 45546, I&M committed to using its most recent RFP to inform the 2024 IN IRP analysis. The results from the 2024 RFPs were used to inform, confirm and adjust the installed costs and build limit for the supply-side resources, as necessary.

8.1.1 Assumptions for Multiple Resource Types

8.1.1.1 Resource Cost Assumptions

For the 2024 IN IRP, the cost and performance characteristics of the supply-side resources were informed through a combination of the EIA's 2023 Annual Energy Outlook (AEO)[13], the National Renewable Energy Laboratory's (NREL) 2024 Annual Technology Baseline Report[14], market-based intelligence gained through I&M's experience with recent RFP's, and subject matter expertise from the AEP's Generation Engineering and Infrastructure Development organizations. EIA's AEO report provided the basis for all new resource overnight costs, and market-based adjustments to the overnight costs were applied. The existing resource costs were informed through market-based intelligence and were confirmed by the Company's 2024 RFPs. NREL's AEO report provides long-term forecasts for technologies and is the source of the learning curve applied to annual overnights costs. Additional assumptions were applied to the resource overnight costs, including inflation, financing costs, and transmission network and interconnection costs to calculate installed costs for the resources. Renewable resource and carbon-free technology costs reflect tax credits made available under IRA 2022.

Appendix Volume 1, Exhibit E includes a summary of the performance parameters and resource costs.

8.1.1.2 Supply-Side Resource Build Limits

Modeling parameters used for new resources also include the year a resource is first available, annual build limits, cumulative build limits through 2030, and cumulative build limits through the planning horizon. The new resource build limits used in the 2024 IN IRP modeling were developed based on a review of PJM's Interconnection Queue, market-based intelligence on the near-term availability of existing resources, and generation engineering expertise. The Company's 2024 RFPs confirmed the cumulative build limits through 2030. Table 16 below includes the supply-side resource build assumptions used in the 2024 IN IRP modeling.

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[13] U.S. Energy Information Administration. (2023, 03). *Electricity market module: Assumptions to the annual energy outlook 2025*. Retrieved from https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf

[14] National Renewable Energy Laboratory. (2024). *Electricity data*. Retrieved from https://atb.nrel.gov/electricity/2024/data

Table 16. New Resource Build Assumptions

Resource Type	First Year Available	Last Year Available	Annual Build Limit Through 2030 (MW)	Cumulative Build Limit through 2030 (MW)	Cumulative Build Limit Through Planning Horizon (MW)
Nuclear Small Modular Reactor	2037	N/A	600	N/A	5,100
New NG Combined Cycle (2x1)	2031	N/A	1,030	N/A	5,600
New NG Combined Cycle (1x1)	2031	N/A	420	N/A	
New NG Combined Cycle w/ CCS	2035	N/A	380	N/A	3,800
Existing NG Combined Cycle	2028	2031	1,800	3,600	5,400
New Combustion Turbine	2030	N/A	920	920	6,670
Combustion Turbines Aeroderivative	2031	N/A	330	N/A	1,320
Reciprocating Internal Combustion Engines (RICE)	2031	N/A	100	N/A	400
Existing NG Combustion Turbine	2028	2031	1,000	3,000	4,000
Wind (15 Year)	2028	N/A	200	400	4,000
Wind (30 Year)	2031	N/A	400	N/A	
Solar (15 Year)	2028	N/A	600	1,200	4,800
Solar (35 Year)	2028	N/A	600	1,200	4,800
Co-located Solar and Storage (4-Hour)	2028	N/A	600	750	1,350
New Storage (4-Hour)	2028	N/A	250	500	3,000
New Storage (6-Hour)	2029	N/A	150	300	1,800
New Storage (8-Hour)	2029	N/A	100	200	1,200
New Storage (100-Hour)	2032	N/A	40	N/A	240

8.1.1.3 Resource ELCCs

Resource ELCCs through 2034 are based on PJM's Preliminary ELCC Class Ratings for the Delivery Year 2026/27 through 2034/35, which can be noted in Table 17. For planning purposes in the 2024 IN IRP, ELCC values are assumed to remain constant from Delivery Year 2034/35 to the end of the planning horizon. PJM developed these ELCCs based on a methodology approved by FERC[15].

[15] Approved by FERC on January 30, 2024 in Docket No. ER24-99.

Table 17. PJM Preliminary ELCC Class Ratings

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%

8.1.1.4 IRA 2022 Tax Incentives

Modeling parameters for supply-side resource cost include tax incentives for resources with reduced or no carbon emissions, pursuant to the IRA 2022, which provides for three kinds of tax credits: an Investment Tax Credit (ITC), a Production Tax Credit (PTC), and a Carbon Capture and Storage Tax Credit. The Company modeled the most up to date information provided in the Internal Revenue Code, which references that the incentives from the IRA 2022 can begin to phase out beginning in 2032 if the nationwide carbon emission reduction goal is met.

The ITC, which is applied to the up-front development and construction costs of a new generation resource, was applied to the installed costs for solar, storage, and small modular nuclear reactor technologies. Application of the ITC to the supply-side resources assumed a flat 30% credit to projects selected between 2025 and 2036. The 30% credit assumes that projects meet certain wage and apprenticeship requirements. The 30% credit was reduced to 27.1% for renewable resources and 25.7% for nuclear resources to reasonably account for components assumed not eligible for the ITC and for financing costs associated with monetizing the ITC benefit. The IRA 2022 also provides for a “phase out” period prior to 2036 in which lesser, but still substantial tax credits apply. Tax credits of 22.5% and 15.0% were assumed for projects selected in 2037 and 2038, respectively. Modeling parameters for projects selected in 2039 or later assumed no ITC benefits.

The PTC, which is applied on a dollar per megawatt-hour ($/MWh) to resource generation, was applied to wind resource cost parameters. Application of the PTC to the supply-side resources assumed a range of $40/MWh to $58/MWh tax benefit for the first 10 years of operation of wind resources selected between 2025 and 2036. Similar to the ITC, a “phase out” period assumed a PTC reduction of 25% and 50% for wind resources selected in 2037 and 2038, respectively. No PTC was applied for projects selected in 2039 or later.

Finally, Carbon Capture and Storage Tax Credit, provided for in the IRA 2022, provide incentive to carbon capture and sequestration (CCS) technologies. Cost parameters for natural gas-fired combined-cycle resources (NGCC) with CCS were applied on a $/MWh generation basis as per the IRA 2022. NGCC projects with CCS selected from 2025 to 2036 received a benefit in the range of $29/MWh to $44/MWh for their first 12 years of operation. The benefit was calculated assuming a $85/tonne tax credit, converting to $/MWh and applying inflation throughout the time the tax credit was available (2025-2036). No tax credit was assumed for CCS projects selected in 2037 or later.

8.1.1.5 Network and Interconnection Costs

All new resources included an assumption for additional network and interconnection upgrade costs. For the 2024 IN IRP, a proxy cost of $17/kW was included in the cost of thermal resources, $71/kW was included for wind resources, $51/kW was included for solar resources, and $39/kW was included for storage resources. These costs were informed from responses to AEP RFPs and are used as a proxy for potential network and interconnection upgrade costs of future resources.

8.1.2 Base/Intermediate Alternatives

Baseload electricity is the minimum level of electricity demand on the system. Traditionally, baseload electricity demand is met by baseload power plants designed and optimized for continuous running. However, the electricity supply mix is changing with increased intermittent renewable generation. Furthermore, regulations have made new coal plants economically infeasible with significant risk. As such, new coal generation with and without CCS are not part of supply-side resource options in the 2024 IN IRP. Nuclear generation was considered as part of the supply-side resource options for baseload resources.

Intermediate power plants adjust outputs as electricity demand fluctuates. Natural gas combined cycle power plants have become the typical generation resource option for intermediate power plants, and they are included in the 2024 IN IRP.

8.1.2.1 Natural Gas Combined Cycle

Natural gas combined cycle (NGCC) units combine a steam and a gas turbine cycle to generate electricity. In the gas turbine cycle, atmospheric air is pressurized using a compressor, injected with fuel, and ignited to generate high-temperature pressurized gas that expands to drive the turbine and generate electricity. The waste heat from the gas turbine is then used to generate steam to drive a steam turbine to generate additional electricity, increasing generation efficiency.

Modern NGCCs have moderate capital costs, high generating efficiency, relatively low carbon emissions (per MWh) compared to older fossil fuel units, and the ability to follow load over a significant range of operation. These characteristics make the technology desirable for intermediate applications. The Company considered both single shaft (one combustion turbine generator and one steam turbine generator) and multi-shaft (two combustion turbine generators and one steam turbine generator) NGCC configurations to be the best fit as they align with historical operating experience and expected output relative to the overall Company's needs.

NGCCs are modeled in PLEXOS® as a standard dispatchable resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints. Two new NGCC configurations in the model are available for selection, including the H-class turbine single shaft configuration with 420 MW capacity and the H-class turbine multi-shaft configuration with 1,030 MW capacity. These resources are made available in the model with the first operating year of 2031, reflective of the anticipated period required for PJM interconnection request approvals, regulatory approvals, permitting, siting, engineering, and construction.

Figure 27 below shows the installed cost assumptions used for new single shaft and multi-shaft NGCC resources.

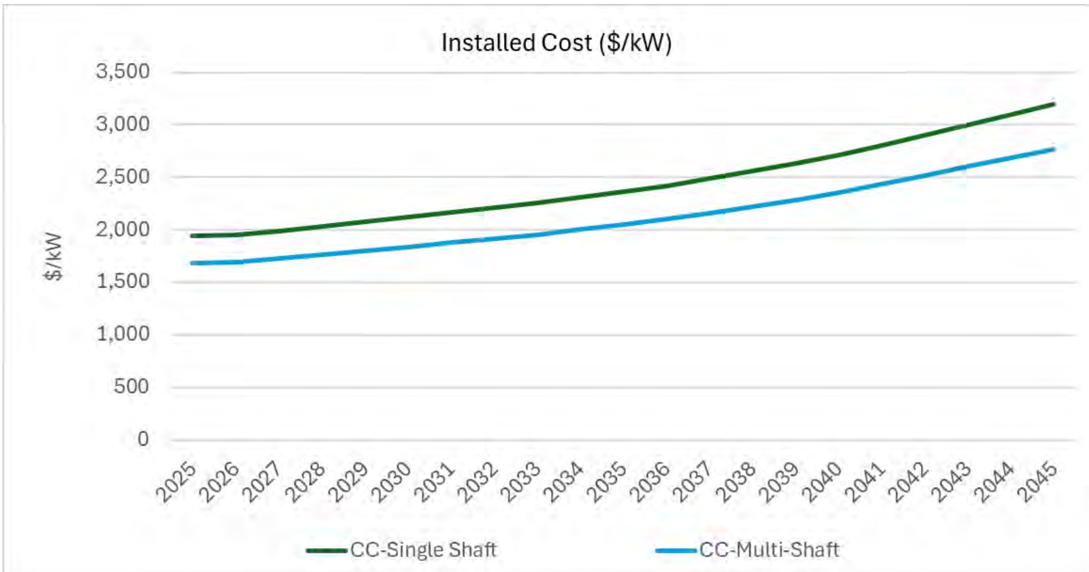

Figure 27. NGCC – Single and Multi-Shaft Installed Costs

Table 18 below shows first year operating and maintenance costs and heat rates modeled for new NGCC.

Table 18. First Year New NGCC Operating Cost and Heat Rate Assumptions

		H-Class Multi-Shaft (1,030 MW)	H-Class Single Shaft (420 MW)
Variable Operations & Maintenance (VOM)	$ / MWh	2.53	3.45
Fixed Operations & Maintenance (FOM)	$ / kW-yr	16.51	19.09
Heat Rate	Btu / kWh	6,370	6,430

In addition to new NGCC resources, three existing NGCC resources were modeled. The first two existing NGCC resources were modeled as proxy power purchase resources with five- and ten-year contract periods. The third existing NGCC resource was modeled based upon acquisition and ownership of an existing resource, assuming 20 years remaining life. These three existing NGCC resources were all made available in the model with a first operating year of 2028, reflective of the anticipated period required for regulatory approvals. The installed cost for existing NGCC resources waw developed with market-based intelligence and was confirmed by the Company's 2024 RFPs. Table 19 below shows the installed cost assumptions used for the existing NGCC resources.

Table 19. First Year Existing NGCC Resource and Operating Costs and Heat Rate Assumptions

		Existing NGCC (5 Year) (900 MW)	Existing NGCC (10 Year) (900 MW)	Existing NGCC (20 Year) (900 MW)
Installed Cost	$/MW-D or $/kW	680 $/MW-D	680 $/MW-D	1,100 $/kW
VOM	$ / MWh	3.502	3.502	3.502
FOM	$ / kW-yr	176.96224	176.96224	16.6121.02
Heat Rate	Btu / kWh	6,989.4	6,989.4	6,989.4

It's important to note that the NGCC technology discussed above can in fact operate on several different fuels with modifications to the NGCC. In recent years, major NGCC manufacturers have refined the combustion characteristics of their respective offerings to effectively combust a wide array of industrial and synthetic fuels – including hydrogen. So called "green" hydrogen[16] produced from electrolysis of water using renewable power has seen increased development over the past few years. Depending upon the exact model, many NGCCs are currently capable of firing hydrogen/natural gas fuel blends ranging up to approximately 30% hydrogen. The major manufacturers continue research and development of new combustion hardware with goals of reaching 100% hydrogen firing in the next several years. Although, the availability and adequacy of "green" hydrogen supply to NGCC facilities must be considered.

8.1.2.2 Cook Relicense

The Cook Nuclear plant is an existing generation resource that I&M owns and operates and provides significant contributions to both capacity and energy requirements for Indiana customers. Currently, the licenses of Cook Units 1 and 2 will expire in Q4 2034 and Q4 2037, respectively. The 2024 IN IRP resource options included a 20-year Subsequent License Renewal (SLR or relicensing) of each unit. For each scenario and sensitivity, the modeling optimized the decision whether to retire or relicense both Cook units, considering economic and reliability impacts.

Costs considered in the relicensing of Cook were based on the best information available at the time IRP inputs were developed. These costs are subject to change in the future as the SLR process proceeds and additional information is obtained. The SLR cost estimates used in the IRP include a $42.5M SLR cost that was based on benchmarking with other nuclear utilities undergoing the same effort. Another component of future costs supporting the SLR is the one-time inspections that will be required after receiving the new license but prior to the subsequent period of extended operation. An estimate of $20M was used based on the experience of a contracted engineering firm. After the

[16]Green hydrogen is made with electrolyzers powered by non-carbon emitting resources. Other types of hydrogen production, for example "blue" hydrogen, are made from reforming methane with CCS of the CO_2 byproduct.

Cook the license renewal is completed, additional capital improvement projects will be required to support 20 additional years of life. One of the major projects will include an expansion of the existing dry cask fuel storage pad. An estimated cost, less an estimated cost reimbursement by the Department of Energy (DOE), is $4.1M for this expansion[17]. This is estimated based on the cost of the initial dry cask storage pad. Finally, plant equipment replacements will be required. The Company completed an internal review of plant systems to identify any end-of-life components that would require replacement to ensure plant reliability for another 20 years. The estimated cost for these projects was $250M, based on experience from projects that had been previously completed. All these cost figures are in 2023 dollars and were included in the 2024 IN IRP modeling. Additional on-going capital costs and fixed operations and maintenance costs are also included in the 2024 IN IRP modeling.

8.1.2.3 Small Modular Reactor

Small modular reactors (SMRs) are a new generation of nuclear fission technology utilizing smaller reactor designs, module factory fabrication and passive safety features. Key features of an SMR include:

- Small physical footprints
- Limited on-site preparation, leading to faster construction time and scalability
- Siting flexibility including sites previously occupied by coal-fired plants
- Passive safety features, allowing the reactor to safely shutdown in an emergency without requiring human interventions

SMR is an alternative resource providing baseload electricity without CO_2 emissions. Its siting flexibility and improved safety features provide a potential benefit of being sited closer to demand centers, reducing transmission investments.

SMR is still in the early stages of development and there remain uncertainties over the cost, performance, and availability of the technology. SMRs are modeled in PLEXOS® as a standard dispatchable resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints. One new SMR configuration with 300 MW of capacity was made available in the model for selection. This resource was initially made available in the model with a first operating year of 2037, reflective of the anticipated period required for PJM interconnection request approvals, regulatory approvals, permitting siting, engineering, and construction.

Figure 28 below shows the assumed installed capital cost of SMR over time.

[17]Assuming 97% reimbursement by DOE

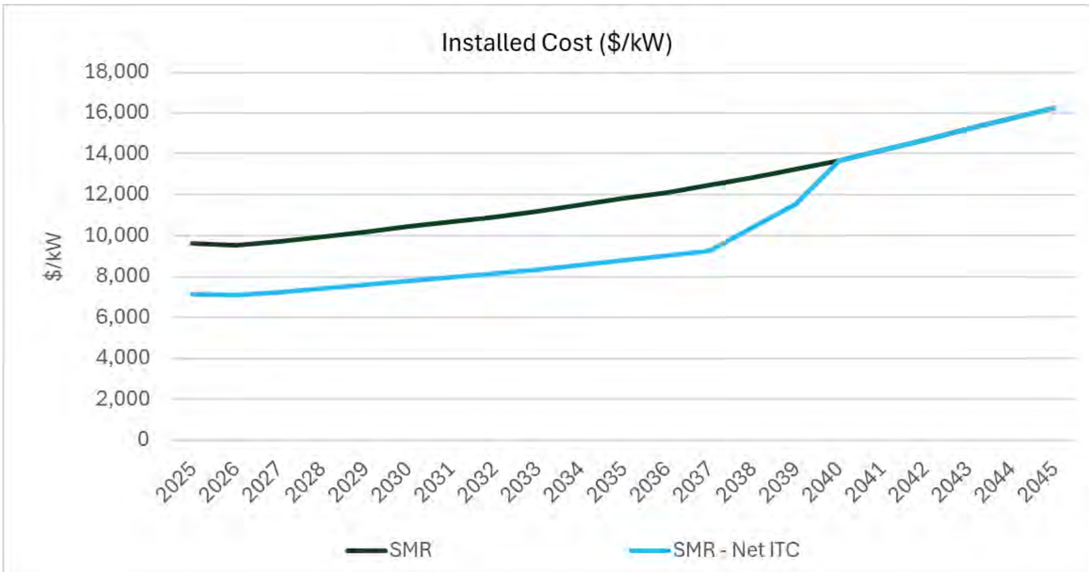

Figure 28. SMR Installed Costs

The first operating year SMR operating costs and heat rate assumptions are shown in Table 20 below.

Table 20. SMR Operating Costs and Heat Rate Assumptions

		SMR (600 MW)
VOM	$ / MWh	4.55
FOM	$ / kW-yr	143.79
Heat Rate	Btu / kWh	10,447

8.1.2.4 Carbon Capture and Sequestration

Carbon capture and sequestration (CCS) technology provides another alternative for producing reliable low-carbon baseload electricity. CO_2 in the flue gas from the combustion of fossil fuels is captured by amine-based solvent in the absorption column and then released from the solvent in a concentrated form in a stripper column. The process requires a significant amount of steam to break the bond between the CO_2 and the solvent, and auxiliary power to run the CO_2 compressor and other mechanical equipment. As such, CCS-equipped power plants have significant heat rate and capacity penalties relative to power plants without CCS.

NGCCs with CCS are modeled in PLEXOS® as a standard dispatchable resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints. One new build NGCC with CCS configuration is available for selection in PLEXOS®, as a 380 MW H-class single shaft, NGCC with 90% CCS. This resource is made available in the model with the first operating year of 2035, reflective of the anticipated period required for PJM interconnection request approvals, regulatory approvals, permitting, siting, engineering, and construction.

The assumption on installed costs for the new build NGCC with CCS is shown in Figure 29.

Figure 29. NGCC with CCS Installed Costs

Table 21 shows first year operating and maintenance costs and heat rates modeled for new NGCC with CCS.

Table 21. NGCC w/ CCS Operating Cost and Heat Rate Assumptions

		NGCC w/ CCS (380 MW)
VOM	$ / MWh	8.50
FOM	$ / kW-yr	40.18
Heat Rate	Btu / kWh	7,120

8.1.3 Peaking Alternatives

Peaking sources have traditionally provided additional generating capacity during demand peaks that typically occur a few hundred hours each year but can occur more or less. Given the low utilization of peaking generators, focus in the past has been on minimizing capital and fixed costs instead of fuel efficiency and other variable costs.

More recently, greater amounts of intermittent renewable generation in the market combined with more extreme weather patterns have necessitated more flexible resources. For example, an unanticipated drop in wind generation during the day will require quick response from other generators to keep supply and demand in balance. A string of extreme cold weather days will require additional generating capacity beyond the typical hours each year traditionally supplied by peak generators. Certain peaking technologies can also provide ancillary services such as frequency response, black start, and inertia that help keep the system reliable. In the 2024 IN IRP, three peaking resources considered are combustion turbines, aeroderivative turbines, and reciprocating engines.

8.1.3.1 Natural Gas Combustion Turbines

A natural gas-fired combustion turbine system (NGCT) uses a compressor to pressurize atmospheric air, which is injected with fuel and ignited to generate high-temperature pressurized gas that expands to drive the turbine and generate electricity. Unlike NGCCs, unused thermal energy is released into the atmosphere via the exhaust gases instead of being recovered. NGCTs are usually expected to start up once a day and operate at full capacity during peak demand hours in the day, making them well suited for a power system with predictable peak patterns.

NGCTs are modeled in PLEXOS® as a standard dispatchable resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints. One new NGCT configuration is available for PLEXOS® to select, the 240MW F-Class unit. This generic resource is made available in the model with a first operating year of 2030, reflective of the anticipated period required for PJM interconnection request approvals, regulatory approvals, permitting, siting, engineering, and construction.

Figure 30 below shows the installed cost assumptions used for the new NGCT resource.

Figure 30. NGCT Installed Costs

Table 22 shows first year operating and maintenance costs and heat rates modeled for new NGCT.

Table 22. NGCT Operating Cost and Heat Rate Assumptions

		F-Class NGCT (240MW)
VOM	$ / MWh	5.98
FOM	$ / kW-yr	9.31
Heat Rate	Btu / kWh	9,910

In addition to new NGCT resources, three existing NGCT resources were modeled. The first two existing NGCT resources were modeled as proxy power purchase resources with five- and ten-year contract periods. The third existing NGCT resource was modeled based upon acquisition and ownership of an existing resource, assuming 20 years remaining life. These three existing NGCT resources were all made available in the model with a first operating year of 2028, reflective of the anticipated period required for regulatory approvals. The installed costs for existing NGCT resources were developed with market-based intelligence and were confirmed by the 2024 RFPs. Table 23 below shows the installed cost assumptions used for the existing NGCT resources.

Table 23. First Year Existing NGCT Resource and Operating Costs and Heat Rate Assumptions

		Existing NGCT (5 Year) (500 MW)	Existing NGCT (10 Year) (500 MW)	Existing NGCT (20 Year) (500 MW)
Installed Cost	$/MW-D or $/kW	493 $/MW-D	493 $/MW-D	644 $/kW
VOM	$ / MWh	1.33	1.33	1.33
FOM	$ / kW-yr	147.85	147.85	22.25
Heat Rate	Btu / kWh	10,888	10,888	10,888

8.1.3.2 Aeroderivative Turbines

Aeroderivative turbine (AD) units are based off aircraft jet engines designs and are modified for use in power generation. Their operating characteristics make them well suited with high renewable penetration as they can quickly respond to significant shifts in supply and demand conditions in the power system. For example, the GE 9E series NGCT requires 30 minutes to start up whereas the GE LM6000 AD unit requires only 5 minutes. This allows AD units to operate at full load even for a small amount of time. In addition, AD units are more efficient in a simple cycle operation than NGCTs for capacity less than 100 MW. However, AD units are relatively more expensive than NGCTs.

AD units are modeled in PLEXOS® in 110 MW units as a standard dispatchable resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints.

These resources are made available in the model with a first operating year of 2031, reflective of the anticipated period required for PJM interconnection request approvals, regulatory approvals, permitting, siting, engineering, and construction.

Figure 31 below shows the installed cost assumptions used for the new AD resource.

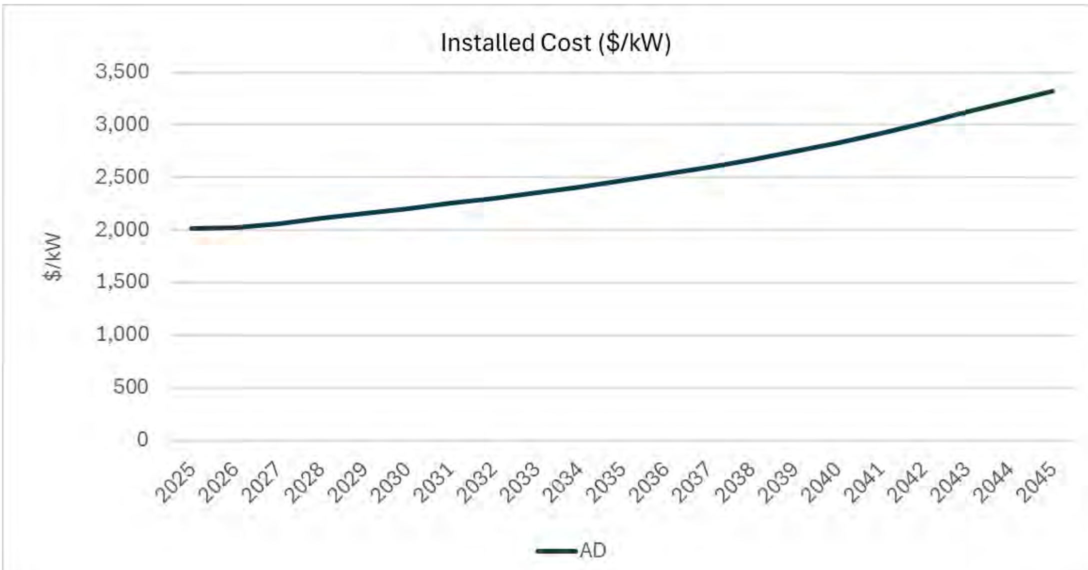

Figure 31. Aeroderivative Turbine Installed Costs

Table 24 shows first year operating and maintenance costs and heat rates used for aeroderivative turbines.

Table 24. Aeroderivative Turbine Operating Cost and Heat Rate Assumptions

		AD (110 MW)
VOM	$ / MWh	6.36
FOM	$ / kW-yr	22.07
Heat Rate	Btu / kWh	9,120

8.1.3.3 Reciprocating Internal Combustion Engine

Like NGCTs, Reciprocating Internal Combustion Engines (RICE) rely on the combustion of air mixed with fuel to generate hot pressurized gases. Unlike NGCTs, the expansion of these gases creates pressure within piston chambers which is used to drive a rotating motion to generate electricity. Multiple RICE units are usually incorporated into a larger generating set for main grid applications.

RICE generating sets can usually start and reach full load in less than five minutes, making them even faster than AD units in responding to system needs. RICE generating sets can also run more efficiently at partial load as individual RICE units within the generating set can be shut down to reduce output while allowing remaining units to run a full load. Unlike NGCTs or ADs, RICE units can be started multiple times in a day without incurring additional maintenance costs. These characteristics make RICE units well suited for power systems that require frequent but short-duration dispatches.

RICE units are modeled in PLEXOS® in 20 MW units as a standard dispatch resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints. These resources are made available in the model with a first operating year of 2031, reflective of the anticipated period required for PJM interconnection request approvals, regulatory approvals, permitting, siting, engineering, and construction.

Figure 32 below shows the installed cost assumptions used for the new RICE resources.

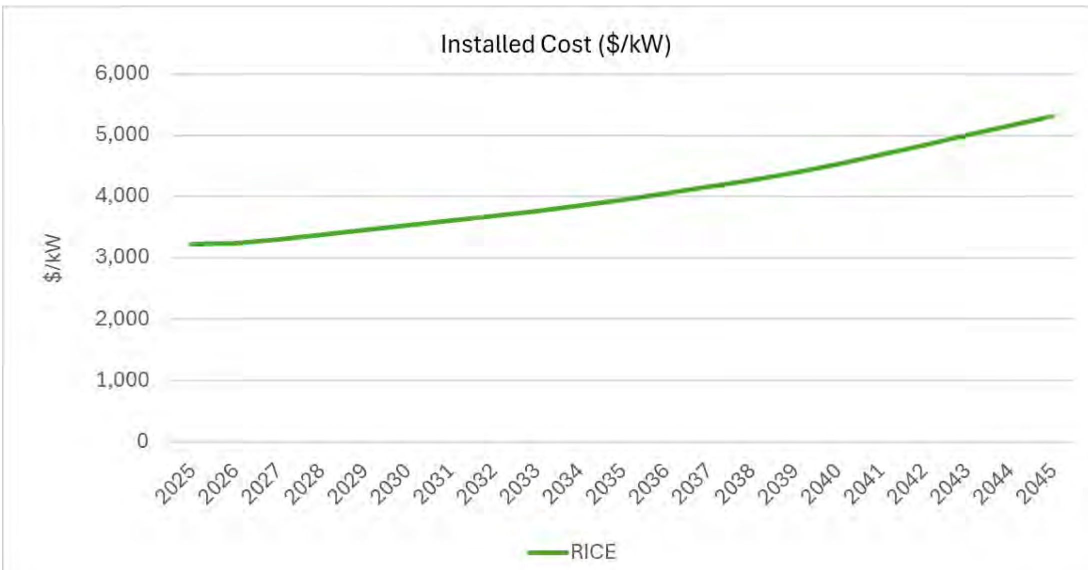

Figure 32. RICE Installed Costs

Table 25 shows first year operating costs and heat assumptions modeled for RICE resources.

Table 25. RICE Operating Cost and Heat Rate Assumptions

		RE (20 MW)
VOM	$ / MWh	7.70
FOM	$ / kW-yr	47.59
Heat Rate	Btu / kWh	8,300

8.1.4 Renewable Alternatives

Renewable generation alternatives such as wind, solar, and hydro, provide an opportunity to deliver affordable clean energy to address future electricity needs when cost effective. These technologies can provide a hedge against future uncertainties in fuel prices, carbon policies, and technology risks as they have zero carbon emissions and zero marginal costs. While these resources provide a reasonable hedge against several uncertainties, their intermittent nature for energy generation adds other uncertainties and variables to recognize in resource planning.

In the 2024 IN IRP, three renewable alternatives considered are onshore wind, utility-scale solar photovoltaic and co-located solar and storage. In addition, the relicensing of two existing hydro facilities is included as a resource option in the 2024 IN IRP. For co-located solar and storage, PLEXOS® can choose to pair utility-scale photovoltaic with a lithium-ion battery where a paired solution is economic. Co-located solar and storage are discussed further in Section 8.1.5.3.

8.1.4.1 Utility-Scale Solar

Solar photovoltaic (solar) uses semiconductor materials surrounded by protective layers to convert sunlight into electricity. The system has a modular structure which allows it to be scaled to meet different levels of energy needs, large or small.

Solar units are modeled in PLEXOS® in 150 MW units as non-dispatchable renewable resources. Utility-scale solar PV is first made available as a resource option in PLEXOS® in 2028, reflective of the anticipated period required for regulatory approvals. They are modeled with a generic hourly production profile representative of the region with an average capacity factor of 23% assuming a single-axis tracking configuration. The capacity and energy of solar units also degrade at 0.5% on an annual basis.

Two types of solar resource were modeled. The first was modeled as proxy power purchase resource with a 15-year contract period and a cost of $85/MWh. The second was modeled based upon resource ownership, assuming a 35-year life. A portion of the 35-year solar resources were eligible for the Energy Community Bonus tax credit and thus had further reduced installed costs.

Figure 33 below shows the installed cost assumptions used for the 35-year solar resource.

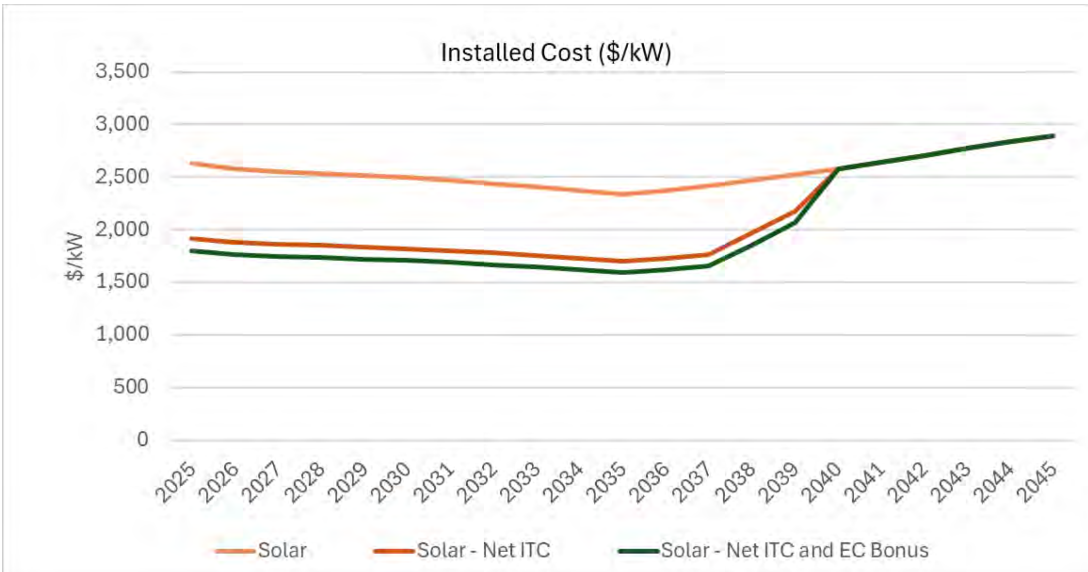

Figure 33. Solar Installed Costs

Table 26 shows the first operating year fixed operations and maintenance cost (FOM).

Table 26. Solar First Year Fixed Operating Costs

		Solar (150 MW)
FOM	$ / kW-yr	9.59

8.1.4.2 Wind

Onshore wind (wind) energy is based on exploiting the air pressure differential across two sides of a rotor blade, causing the rotor blade to spin and generate electricity. Typically, multiple wind turbines are grouped to develop a wind turbine power project which requires only a single connection to the transmission system. Careful site selection and turbine placement within the project is critical as wind velocity varies by geography, and the proximity of the wind farm to a transmission system with available capacity can impact cost. The most critical factors (*i.e.*, wind speed and sustainability) are typically highest in remote locations, requiring the electricity generated from wind resources to be transmitted longer distances to load centers necessitating the build out of high voltage transmission to optimally integrate large additions of wind into the grid. This is considered through the higher network and interconnection costs for wind resources, noted in Section 8.1.1.5.

Wind units are modeled in PLEXOS® in 200 MW units as non-dispatchable renewable resources. Wind is first made available as a resource option in PLEXOS® in 2028, reflective of the anticipated period required for regulatory approvals. They are modeled with a generic hourly production profile representative of the region with an average capacity factor of 33%.

Two types of wind resources were modeled. The first was modeled as proxy power purchase resource with a 15-year contract period and a cost of $86/MWh. The second was modeled based upon resource ownership, assuming a 30-year life.

Figure 34 below shows the installed cost assumptions used for the 30-year wind resource.

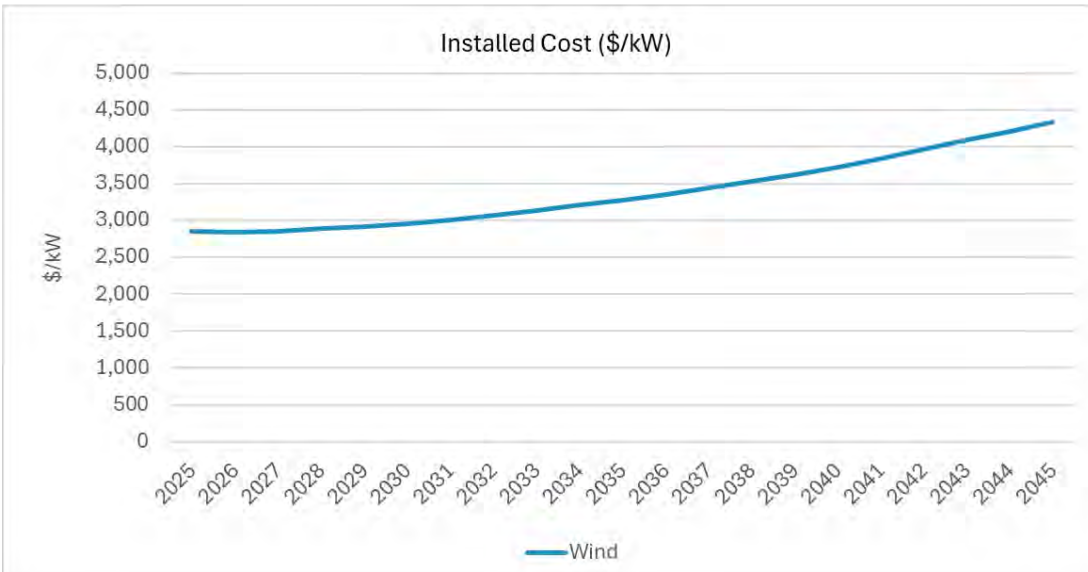

Figure 34. Wind Resources All-in Capital Expenditures

Table 27 shows the first operating year fixed operations and maintenance cost (FOM).

Table 27. Wind First Year Fixed Operating Costs

		Wind (200 MW)
FOM	$ / kW-yr	21.97

8.1.4.3 Hydro Relicense

I&M owns six hydro facilities along the St. Joseph River in northern Indiana and southwest Michigan. Two of the hydro facilities have FERC license expiration dates within the next ten years: the Elkhart Hydroelectric Plant in 2030, and the Mottville Hydroelectric Plant in 2033.

As part of the overall relicensing evaluation, including I&M's IRP analysis, I&M engaged WSP USA, Inc, to conduct a four-phase study of the hydro facilities. The four phases consisted of: Phase 1 Decommissioning, Phase 2 Public Engagement, Phase 3 Socioeconomic Analysis, and Phase 4 Relicense. The scope began with a phased approach to evaluating an updated decommissioning study of the hydro facilities and determining the socio-economic beneficial-cost evaluation for relicensing or decommissioning.

For the Phase 1 study, WSP prepared a decommissioning cost evaluation which included an evaluation of the hydro facilities site against local, state and federal permitting requirements. The updated decommissioning study results were used as an input in the IRP modeling. Phase 2 focused on public engagement. As part of the WSP study, the affected communities and industry representatives were engaged and provided insights into the potential benefits and disadvantages of each decommissioning and relicensing scenario undertaken. Through various outreach activities, such as advertising signs at dams, news releases, fact sheets, websites, public survey, and open house meetings, valuable thoughts and concerns were gained from customers, area residents, and local businesses. The goal was to understand the community's current use of the dams as recreational facilities, their perceived benefits, and potential future benefits, as well as gather key inputs to support socio-economic analysis. I&M's July 9, and 11, 2024 open house meetings each had over 400 attendees.

Phase 3 was the socio-economic evaluation which analyzes the societal benefits of each dam's relicensing and decommissioning (full removal) scenarios for the impacted community. This involves collecting data on the demographics, economic activity, and social and cultural characteristics of the communities that are located upstream, downstream, and adjacent to the dams by identifying and evaluating the potential positive and negative impacts of decommissioning on the affected communities. Societal impacts could include improved water quality, restored fish and wildlife habitat, changes in recreational opportunities, job loss or creation, and changes in tax revenue.

The socio-economic analysis was conducted via a benefit-cost analysis (BCA) framework to evaluate the quantitative societal effects, such as energy revenue, impact on property values, and changes in recreational activity. The alternatives assessed include either relicensing the facilities or completing a decommissioning process and surrendering the license. The specific scenarios evaluated in the assessment included:

- Scenario #1: Relicense with no upgrades: continuation of current operations, without any major investment.
- Scenario #2: Relicense with upgrades: continuation of current operations, including a refurbishment investment to increase the overall efficiency of the plant.
- Scenario #3: Decommissioning (high cost): demolition of the plant and restoration of the site in a high-cost estimate scenario.
- Scenario #4: Decommissioning (low cost): demolition of the plant and restoration of the site in a low-cost estimate scenario.

Additionally, the BCA was supplemented with a qualitative assessment of socio-economic benefits and disadvantages, including dam failure risk, net job change, river network connectivity and implications for low-income communities.

Based on the WSP analysis, decommissioning of either the Elkhart Hydroelectric Plant or the Mottville Hydroelectric Plant results in a benefit-cost ratio (BCR) below 1.0, meaning that the costs exceed the benefits. For both facilities, the scenario with the highest BCR corresponds to Scenario #1 (Relicense without upgrades), however Scenario #2 - Relicense with upgrades, also yielded a positive benefit-cost analysis. Overall, from both a qualitative and cost efficiency perspective, Relicense is concluded to be the alternative with higher benefits.

Phase 4 was an independent review by WSP of an analysis performed by I&M regarding the FERC relicensing of two hydroelectric projects located on the St. Joseph's River.

In developing the IRP, I&M leveraged data from the WSP Phase 1 decommissioning cost evaluation for the Elkhart and Mottville units. This study served as the basis for modeling inputs used to assess the decommissioning of the units. I&M selected the midpoint values. Elkhart also included a decommissioning cost of $243M which is the midpoint of the low and high WSP Phase 1 analysis decommissioning estimates of $107M and $379M respectively. Mottville also included a decommissioning cost of $113M which is the midpoint of the low and high WSP Phase 1 analysis decommissioning estimates of $49M and $177M respectively. For the IRP analysis, costs considered in the relicensing of the Elkhart Hydroelectric Plant include a $1M license renewal cost with additional on-going capital costs and fixed operations and maintenance costs. Costs considered in the relicensing of the Mottville Hydroelectric Plant include a $1M license renewal cost with additional on-going capital costs and fixed operations and maintenance costs. The IRP and WSP analysis will be used as part of the overall and ongoing evaluation of relicensing of these facilities.

8.1.5 Storage Alternatives

8.1.5.1 Utility-Scale Battery Storage

Lithium-ion (Li-ion) batteries store and discharge energy through the movement of lithium ions between a negative and positive electrode, while iron-air batteries use reversible rusting, where oxygen converts iron metal to rust during the discharge state, and then rust is converted back to iron during the charging state. Batteries do not generate additional energy. Instead, they provide capacity during periods of peak energy demand through discharging of energy stored during periods of low energy demand. Accordingly, increased deployment of Li-ion and iron-air batteries in the system can smooth out energy price volatility. Batteries can be operated to arbitrage by charging in low demand or low-price periods and discharge in high demand or high price periods.

Battery alternatives are experiencing rapid growth in deployment in utility-scale storage applications. This reflects advantageous operating characteristics that include high round-trip efficiency for Li-ion batteries, high energy density, low self-discharge and fast response capabilities. The battery alternatives can also respond to dispatch signals within a second, making them well suited for primary frequency regulations, such as providing initial immediate response to deviations in grid frequency driven by sudden demand spikes or supply losses. However, Li-ion batteries have limited cycle life due to degradation, where battery augmentation is required during the project lifetime to maintain performance. Conversely, iron-air batteries will not require routine augmentation, but they are expected to degrade faster than Li-ion batteries, requiring a full repower in the middle of their useful life.

The storage modeling process involves dispatching storage resources against fundamental market prices in PLEXOS® hourly chronological production cost model. The storage generation and charge costs are extracted and used as inputs in the expansion planning optimization. Reductions in capacity expansion fixed costs are used as values for real-time and ancillary services market revenues. Any additional volatility in the day-ahead market is accounted for using a similar optimization framework. For the 2024 IN IRP, the modeling of battery alternatives includes an additional potential value stream available to these resources of $60/kW on average. This is a proxy for value associated with sub-hourly and hourly energy arbitrage and ancillary services. The Company continues to explore methods to recognize additional value streams from fast responding resources like batteries. Battery alternatives are made available in PLEXOS® and are modeled as an energy storage option with a duration of four, six, eight, and 100 hours. Long duration and multi-day storage options were included, consistent with the Settlement Agreement approved by the IURC in Cause No. 45933. Table 28 below shows the storage assumptions used in the 2024 IN IRP.

Table 28. Utility-Scale Storage Assumptions

Technology	Capacity (MW)	Duration (Hr)	Energy (MWh)	Roundtrip Efficiency (%)	Expected Life (Years)
Lithium – Ion	50	4	200	87	20
Lithium – Ion	50	6	300	87	20
Lithium – Ion	50	8	400	87	20
Iron – Air	20	100	2,000	40	20

Li-ion batteries are modeled in PLEXOS® in a configuration of 50 MW and the iron-air battery is made available in a configuration of 20 MW as standard dispatchable resources, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints.

Figure 35 below shows the installed cost assumptions used for the battery resources.

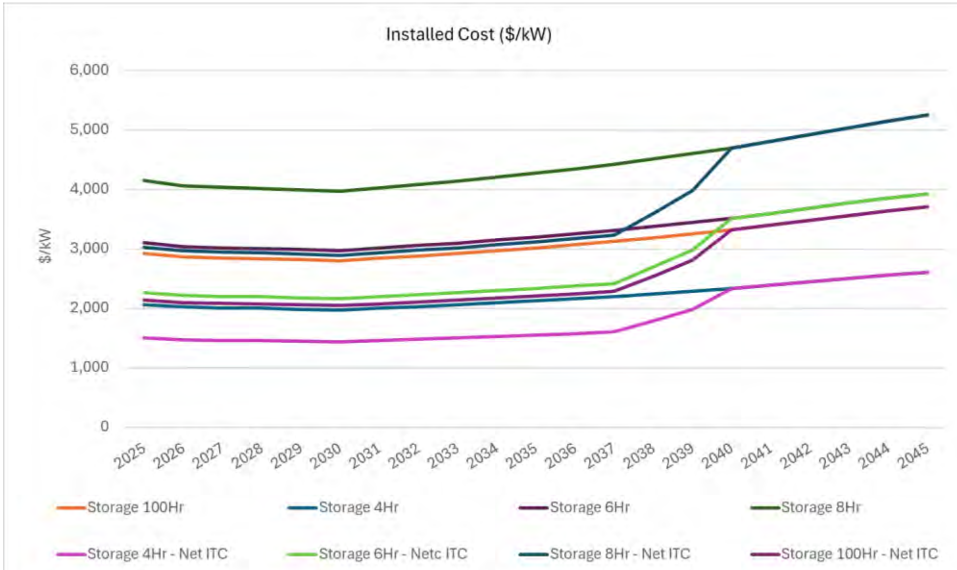

Figure 35. Battery Storage All-in Capital Expenditures

Table 29 shows the first operating year fixed operations and maintenance cost (FOM), and heat rate assumptions.

Table 29. Battery Storage First Year Fixed Operating Cost

		Storage 4-Hr (50 MW)	Storage 6-Hr (50 MW)	Storage 8-Hr (50 MW)	Storage 100-hr (20 MW)
FOM	$ / kW-yr	52.14	79.66	106.21	18.99

See Section 8.1.5.3 below for a discussion of the co-located solar and storage resource included in the 2024 IN IRP.

8.1.5.2 Distribution Sited Storage

The 2024 IN IRP included seven distribution sited battery storage resource options for selection by the PLEXOS® model. The distribution storage resources are dispatched against fundamental market prices in an hourly chronological production cost model and then the generation and charge costs are extracted and placed as inputs into the expansion planning model. These were operated similar to the battery units described in the previous section.

These battery resources represent alternative solutions to traditional distribution projects to address either thermal or reliability issues. The thermal use case can address thermal overloads on distribution substation equipment during peak demand time periods. The reliability use case can address outage impacts to customers throughout the entire year.

Battery storage resources can be placed at stations nearing thermal overload conditions, adding capacity at the station and deferring the need for traditional upgrades. For the thermal use cases, battery storage is restricted from receiving energy revenues in peak months (mid-July to mid-August) but can receive energy revenues in the remaining months.

Battery storage resources can be placed at stations that have historically had reliability issues. For the reliability use cases, 50% of the battery storage capacity is reserved to address potential outages while the remaining 50% can be used in the energy market. The installed cost associated with the battery storage resources will be reduced by the estimated avoided Customer Minutes of Interruption (CMI) savings from improved reliability.

County Road 4

Traditional Project: This project will add 1-25MVA station transformer and 3-12kV feeders to the County Road 4 station. The transformer and feeder additions are driven by the 103% circuit thermal overload and the need for increased capacity and improved reliability to support load growth in the area. It will supply capacity for full customer recovery and planned distribution automation circuit reconfiguration (DACR).

2028: $1.5M
2029: $2.1M

Storage Proposal: I&M will install 3 MW/12MWh battery storage resource along or near end of the County Road 4 circuits to serve an island of customers when the circuit is interrupted. The project addition is driven by the 103% circuit thermal overload and the need for increased capacity and improved reliability to support load growth in the area.

2028: $8M
2029: $10M

<u>Robison Park Station</u>

Traditional Project: This project will add 1-20MVA station transformer, 3-12kV feeders, and 1-138kV circuit switcher to the Robison Park Station. The transformer and feeder additions are driven by the 123% circuit thermal overload and a 91% loading factor on the station transformer. The increased capacity and additional circuits will also improve reliability with additional transfer capabilities and support load growth in the area. It will also supply capacity for full customer recovery and planned DACR.

2027: $250k
2028: $2M
2029: $4.5M

Storage Proposal: I&M will install 3 MW/12MWh battery storage resource at Robison Park station to provide capacity relief to both the Robison Park-Mayhew circuit and the station transformer. The transformer and feeder additions are driven by the 123% Robison Park-Mayhew circuit thermal overload, a 91% loading factor on the station transformer, and the need for increased capacity and improved reliability to support load growth in the area.

2028: $8M
2029: $10M

<u>Colfax Station</u>

Traditional Project: This project will add 1-25MVA station transformer, 1-12kV feeder, and 1-69kV bus tie circuit breaker to the South Bend area Colfax station. The transformer and feeder addition are driven by the 101% thermal overload on the Colfax-School circuit, and the need for increased capacity and improved reliability to support load growth in the area. It will supply capacity for full customer recovery and planned DACR.

2028: $1.5M
2029: $2.1M

Storage Proposal: I&M will install 3 MW/12MWh battery storage resource along or near end of the Colfax-School circuit to serve an island of customers when the circuit is interrupted. The transformer and feeder additions are driven by the 101% thermal overload on the Colfax-School circuit, and the need for increased capacity and improved reliability to support load growth in the area.

2028: $8M
2029: $10M

Summit Station

Traditional Project: This project will add 1-25MVA station transformer, 4-12kV feeders and 1-138kV circuit switcher at a new greenfield station called Flaugh. The transformer and feeder additions are driven by the 101% Summit-Huguenard circuit thermal overload, a 94% loading factor on the station transformer, the need for increased capacity and improved reliability to support load growth in the area.

2026: $500k
2027: $2.5M
2028: $4.5M

Storage Proposal: I&M will install 4 MW/16MWh battery storage resource at the station to provide capacity relief to both the Summit-Huguenard circuit and the Summit station transformer 2. The transformer and feeder additions are driven by the 101% Summit-Huguenard circuit thermal overload, a 94% loading factor on the station transformer, and the need for increased capacity and improved reliability to support load growth in the area.

2027: $8M
2028: $16M

Beech Rd Station

Traditional Project: This project will add 1-25MVA station transformer, 3-12kV feeders and 1-138kV circuit switcher at a new greenfield station called Ash Rd. The transformer and feeder additions are driven by the 2.5MVA planning criteria violation for load at risk between Beech Rd and Whitaker stations, the need for increased capacity and improved reliability to support load growth in the area.

2031: $300k
2032: $4.6M
2033: $3.4M

Storage Proposal: I&M will install 3 MW/12MWh battery storage resource at or near the Cleveland station to provide capacity relief to both the station transformer and to offset base load generation requirements. The transformer and feeder additions are driven by the 2.5MVA planning criteria violation for load at risk between Beech Rd and Cleveland stations, the need for increased capacity and improved reliability to support load growth in the area.

2032: $8M
2033: $10M

Whitaker Station

Traditional Project: I&M is preparing to convert this area of Elkhart from 34.5/69kV supply voltage to address aging infrastructure needs, which requires the Elkhart wastewater plant to convert from 34.5kV to 12kV service. The project will install 500' of new 12kV line and metering and retire a 34.5kV phase over phase switch.

2027: $150K
2028: $150K

Storage Proposal: I&M will install 3 MW/12MWh BESS along or near end of the circuit to serve an island of customers when the circuit is interrupted. The Whitaker-Elk circuit has experienced over 1.63 million CMI in the last 3 years and should see a significant decrease in CMI with the installation of the battery project.

2027: $8M
2028: $10M

Murray Station[18]

Traditional Project: I&M is proposing a station rebuild to address aging station facilities at Murray station. This project installs a 69/12kV, 9.375MVA transformer and 2-12kV circuits on new property next to Murray station; the project also provides DACR and CVR opportunities.

2027: $1.5M
2028: $3.5M

Storage Proposal: Install a 1 MW/4MWh BESS at or near the Murray station to serve customers when the circuit is interrupted. The Murray-Murray circuit has experienced over 1 million CMI in the last 3 years and should see a significant decrease in CMI with the installation of the battery project.

2027: $2M
2028: $4M

[18] This Distributed Sited Storage opportunity was labeled Pleasant – Yoder in the Stakeholder Presentation materials.

8.1.5.3 Co-located Solar and Storage

For co-located solar and storage, PLEXOS® can choose to pair utility-scale photovoltaic with a lithium-ion battery where a paired solution is economic. The 2024 IN IRP included a co-located solar and battery option, available in 200 MW blocks (150MW solar plus 50MW of 4-hour duration battery storage). Figure 36 below shows the installed cost assumptions used for the solar with storage resource.

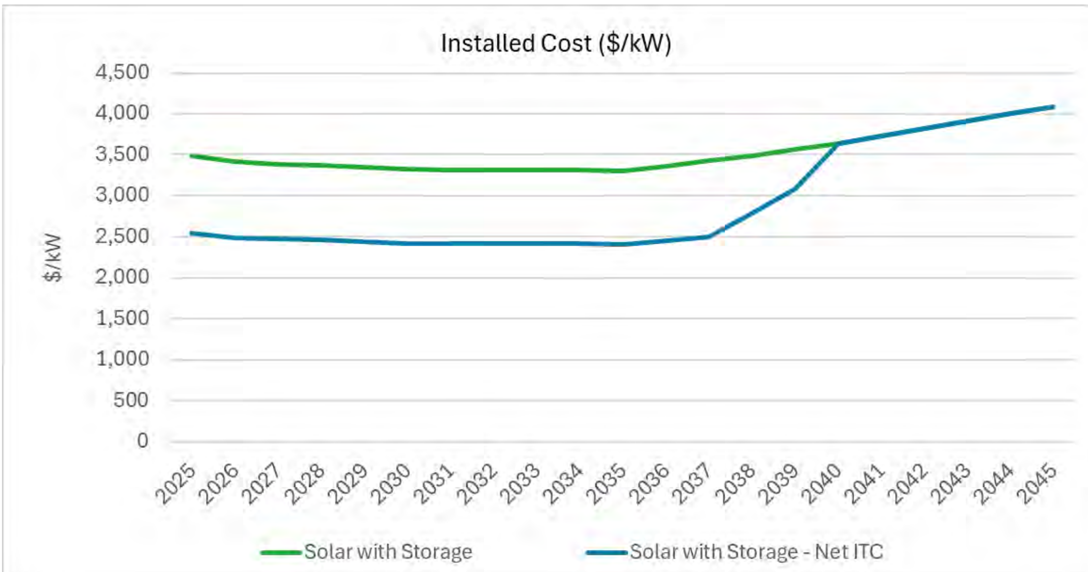

Figure 36. Solar with Storage Installed Costs

Table 30 shows the first operating year fixed operations and maintenance cost (FOM).

Table 30. Solar plus Storage First Year Fixed Operating Costs

		Solar (150MW)
FOM	$ / kW-yr	35.36

8.2 New Demand-Side Resources

As part of the 2024 IN IRP, additional or "incremental" demand-side resources beyond those described in Section 6.5 were identified and modeled based on the 2024 MPS performed by GDS Associates and Brightline Group ("the GDS Team"). Non-income qualified EE, DR, and DER programs were modeled on a comparable economic basis as supply-side programs while income qualified demand-side programs were informed by the MPS and included in the 2024 IN IRP.

8.2.1 Demand-side Management Market Potential Study Overview

To evaluate the potential for future DSM resources in the 2024 IN IRP, I&M utilized the 2024 MPS prepared by the GDS Team for EE, DR, and DER potential. The 2024 MPS provided updated DSM programs, measures, costs and energy and demand savings for a 20-year time horizon which includes I&M's approved DSM plan for 2025, beginning with the 2026 program year. The study included primary market research and a comprehensive review of current programs, historical savings, and projected energy savings opportunities, to develop estimates of technical, economic, and achievable potential. Separate estimates of EE, DR, and DER potential were developed. EECO or CVR was not evaluated in the MPS as I&M had previously conducted an internal analysis for energy and demand savings across all circuits in the I&M Indiana service area.

8.2.2 Modeling Framework and Inputs

The GDS Team used its Excel-based EE, DR and DER planning models to perform all the analyses in the 2024 MPS. These models allow the user to develop forecasts of measure and program costs, participants, kWh and kW savings, and benefit/cost ratios over the planning horizon. These models are transparent and all formulas, model inputs, and model outputs can be viewed by the model user.

As a sensitivity in the 2024 MPS, GDS produced an estimate of potential savings assuming commercial and industrial customers could no longer opt-out of utility-funded electric EE programs. The 2024 IN IRP and associated DSM inputs reflect the current conditions that allow opt-out customers in Indiana.

Avoided energy supply costs are used to assess the value of energy savings. Avoided cost values for electric energy, electric capacity, and avoided Transmission and Distribution (T&D) were provided by I&M as part of an initial data request. Electric energy is based on an annual system marginal cost. For years outside of the avoided cost forecast timeframe, future year avoided costs were escalated by the rate of inflation. These avoided costs are included in Appendix Volume 1 Exhibit F and G.

I&M provided the GDS Team with monthly on and off-peak avoided energy costs. GDS used this data to create 8,760 avoided cost values for each forecast year. GDS then applied these avoided costs to the 8,760 savings from each measure based on assigned end-use load shapes to determine the value of measures that save more energy during peak periods than those that might save during off-peak periods. In addition, the avoided capacity and T&D avoided costs were applied to the estimated coincident peak demand savings for each measure.

8.2.3 Energy Efficiency Measures and Potential

8.2.3.1 Measures Considered

Measure list development during the 2024 MPS was a collaborative effort in which the GDS Team developed draft lists that were shared with I&M and MPS stakeholders. The energy efficiency measure lists were informed by a wide range of sources, including current I&M program offerings, the Indiana Technical Reference Manual (TRM), and commercially viable emerging technologies, among others. The final measure lists ultimately included in the study reflected the source review and considerations from the parties that participated in the measure list review process.

In total, the GDS Team analyzed 353 unique EE measure types for this study. Several measures were included with multiple permutations to account for specific market segments, such as different building types, efficiency levels, and replacement options. In total, GDS developed 2,106 measure permutations for I&M's Indiana service area.

Table 31 below includes the residential, commercial, and industrial market segments and the energy efficiency measures.

Table 31. Electric End-Uses Included in the 2024 MPS

Residential	CC&I	
	Commercial	Industrial[19]
Heating	Interior Lighting	Lighting
Cooling	Exterior Lighting	HVACHVAC
Water Heating	Refrigeration	Machine Drive
Cooking	Space Cooling	Process Heat
Refrigerator	Space Heating	Process Cool / Refrigeration
Freezer	Ventilation	Other Process
Dishwasher	Water Heating	Process – Machine Drive
Clothes Washer	Plug Loads / Office Equipment	Other Facility
Dryer	Cooking	Compressed Air
TV	Other	Water / Wastewater
Light	Whole Building / Behavioral	Process – Agriculture
Miscellaneous		Whole Building / Behavior

8.2.3.2 I&M Demand-side Management Measure Assumptions and Market/Equipment Characteristics

The GDS Team reviewed the assumptions for measure costs, savings and useful lives included in prior I&M DSM plans and updated these assumptions where appropriate. The GDS Team utilized data specific to I&M when it was available and current. I&M evaluation report findings, I&M program planning assumptions, and the Indiana TRM were leveraged to the extent feasible. Additional data sources were only used if these sources either did not address a certain measure or contained outdated information. Additional source documents included the Illinois TRM, Energy Information Administration (EIA), American Council for an Energy-Efficient Economy research reports, the Northwest Power Conservation Council and Regional Technical Forum (Industrial processes), and DOE commercial building reports.

[19] For the industrial sector, the analysis employed a top-down analysis at the end-use level as opposed to a detailed measure analysis. The GDS Team selected this approach to more comprehensively target industrial loads given the myriad of different energy-consuming equipment within industrial facilities.

In addition to measure assumption development, the GDS Team engaged in primary market research for DER measures only to collect customer willingness to participate in program offerings data, across select end-uses and technologies.

8.2.3.3 Electric Energy Efficiency Potential

The amount of available EE is typically described in four sets: technical potential, economic potential, achievable potential, and program potential.

The technical potential encompasses all known efficiency improvements that are possible, regardless of cost, and thus, whether or not it is cost-effective (i.e., all EE measures would be adopted if technically feasible). The logical subset of this pool is the economic potential. In the I&M Indiana jurisdiction, economic potential for EE only includes measures that are cost-effective based on screening with the Utility Cost Test (UCT). In I&M's service territory, the UCT considers electric energy, capacity, and T&D savings as benefits, and utility incentives and direct install equipment expenses as the cost. Consistent with application of economic potential according to the National Action Plan for Energy Efficiency, the measure level economic screening does not consider non-incentive or measure delivery costs (e.g., admin, marketing, evaluation etc.) in determining cost-effectiveness.[20]

Except for the low-income segment of the residential sector, all measures were required to have a UCT benefit-cost ratio greater than 1.0 to be included in economic potential and all subsequent estimates of EE potential. Low-income measures were not required to be cost-effective.

Achievable potential is the amount of cost-effective energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures, the non-measure costs of delivering programs (for administration, marketing, analysis, and Evaluation, Measurement, &Verification (EM&V)), and the capability of programs and administrators to boost program activity over time. Barriers include financial constraints, customer awareness and willingness-to-participate in programs, technical constraints, and other barriers that the "program intervention" is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study evaluated two achievable potential scenarios:

Maximum Achievable Potential (MAP) estimates achievable potential with I&M paying incentives equal to 100% of measure incremental costs and aggressive adoption rates; and
Realistic Achievable Potential (RAP) estimates achievable potential with I&M paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.

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[20] National Action Plan for Energy Efficiency: Understanding Cost-Effectiveness of Energy Efficiency Programs. Note: Non-incentive delivery costs are included in the assessment of program potential and overall DSM budgets for IRP inputs.

Finally, the GDS Team conducted research and analysis to identify areas for I&M to consider for potential improvements to the current program portfolio. Program potential also considers what can or should be accomplished with utility-sponsored programs versus EE savings that happen through alternative interventions. Overall, the GDS Team refined the RAP into the Program Potential scenario based on the following updated factors:

- Incentive levels and structures: Measures within existing I&M programs were modeled within their current framework unless research dictated otherwise;
- Program non-incentive costs (administrative costs); and
- Measure Assignments: In some cases, achievable potential cost-effective measures were reassigned to new program types.

A comparison of the RAP and Program Potential for residential and nonresidential is shown below in Figure 37 and Figure 38. The decrease from RAP to Program Potential in the residential sector is driven by changes in program mapping for certain measures, aligning the income-qualified program spending with historical levels to reduce cross subsidization concerns across customer segments, as well as programs being dropped from the program potential if not cost-effective at the program-level (i.e., after including administrative costs).

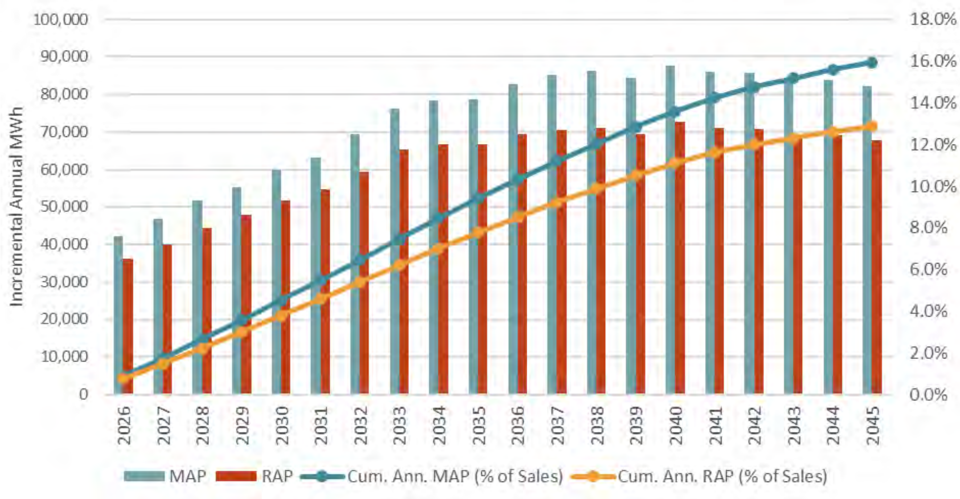

Figure 37. Residential Maximum and Realistic Achievable Potential

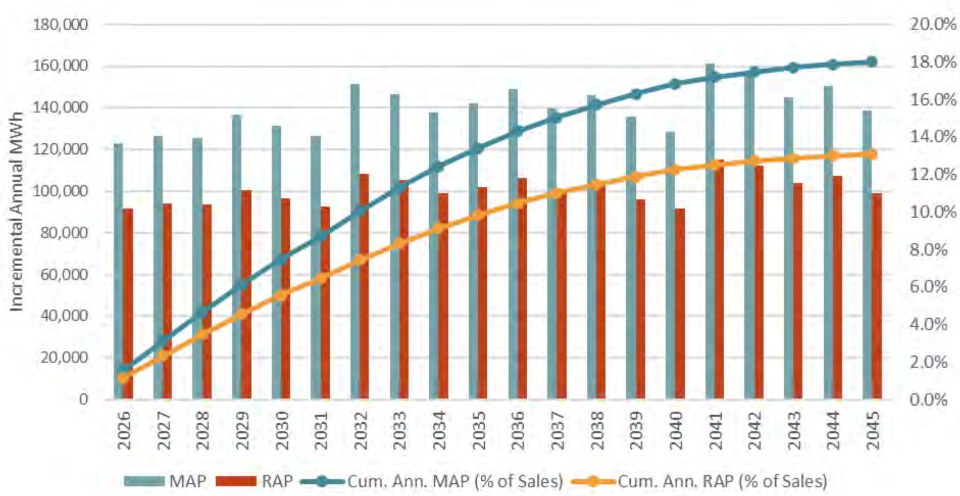

Figure 38. Nonresidential Maximum and Realistic Achievable Potential

8.2.4 Demand Response Potential

DR potential for the I&M Indiana territory was estimated following a similar methodology as the EE analysis. Two achievable technical and economic scenarios (maximum and realistic) were developed for I&M's territories considering the potential for 23 different DR program iterations. Expansions to I&M's existing DR programs were considered, as well as new program opportunities. Utility cost components included program development, implementation, incentive, and evaluation costs. Programs were screened using the UCT and using a threshold of 1.0, considering the performance of the program across the full twenty-year study period. In the 2024 MPS, the MAP scenario represents a 'best practice' estimate of what could be achieved considering I&M customers' likely participation rates and assumes higher levels of incentives for participation. The RAP scenario reflects a realistic scenario estimate based on typical or 'average' participation rates likely to be achieved considering program barriers. Program types that compose the MAP and RAP scenarios are listed in Table 32.

Table 32. DR Potential Study Program Results by Sector

Sector	Program	MAP	RAP
Residential	Connected Thermostat	XX	X
	Time-of-use (TOU) Rate w/o enabling technology	X	X
	Critical Peak Pricing Rate w/o enabling technology	X	X
	Central AC DLC	X	X
	Behavioral	X	X
C&I	Connected Thermostat	XX	X
	DWHDWH DLC	XX	X
	Real Time Pricing (RTP) Rate	X	X
	Critical Peak Pricing Rate w/o enabling technology	X	X
	Time-of-use (TOU) Rate w/o enabling technology	X	X
	Capacity Bidding	X	X
	Curtailable Rate	X	

The RAP results for DR by sector over the MPS horizon are shown in Figure 39.

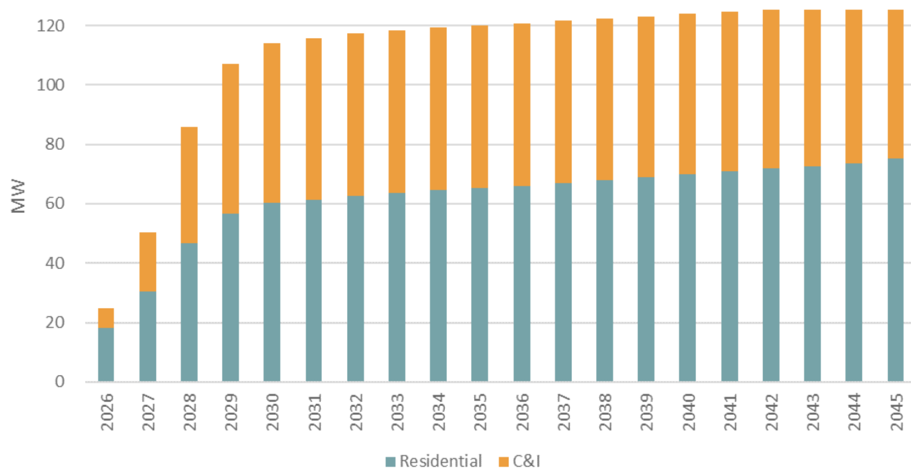

Figure 39. Realistic Achievable Demand Response Potential by Sector – Indiana

8.2.5 Distributed Energy Resources Potential

DER resources were modeled based on residential and non-residential solar and solar paired with battery resources. Potential for both resources was assessed based on premise-level availability to host the DER technology across I&M's territory with economic analysis based on estimated market costs and generation benefits to the end-use customer. To determine the level of customer penetration, I&M estimated adoption forecasts based on Bass diffusion curves, which are a method for determining how new products are adopted in a population. The diffusion curves were informed by existing installed systems, assumed maximum market penetration, and coefficients of innovation and imitation. GDS used I&M's internal customer data to inform quantities of existing solar PV and solar and paired with battery systems active in I&M's Indiana service territory. Using primary research conducted in 2023 with I&M residential and non-residential customers, GDS estimated various adoption levels to calculate scenarios of maximum market penetration. The Bass curve was fitted within these parameters using innovation and imitation coefficients based on state-specific research conducted by NREL.[21] This forecast considered the level of solar and solar paired with battery installations over the 20-year MPS time horizon.

The DER analysis ultimately found all modeled solar and solar paired with battery resources were not cost effective according to the UCT. The UCT was selected as the primary cost-effectiveness screening test for DERs to evaluate from the utility perspective to help determine whether a utility-

[21] Sigrin, B., et al. (2016). *The distributed generation market demand model (dGen): Documentation*. National Renewable Energy Laboratory.

sponsored program incentive intervention is prudent. Ultimately, solar and solar paired with battery technologies in the 2024 IN IRP modeling included achievable potential levels of these incremental DER.

8.3 Future Demand-Side Management Resources

8.3.1 Energy Efficiency Bundles

EE bundles for 2024 IN IRP modeling were developed by the GDS Team using the net present value (NPV) of costs over the lifetime kWh saved for each EE measure. Using the NPV of costs per kWh saved per measure, the GDS Team mapped EE measures into low-cost and high-cost residential RAP bundles, one residential RAP behavioral bundle, one RAP income-qualified bundle, and one Enhanced RAP (combined RAP and MAP) commercial and industrial (C&I) bundle for 2024 IN IRP inputs. These EE bundles were developed based on stakeholder feedback, consistent with the Settlement Agreement approved by the IURC in Cause No. 45933. The GDS Team then mapped the program potential savings from the 2024 MPS into the identified EE bundles for 2024 IN IRP model input. It is important to note that the bundles are not equal in measure counts or overall magnitude of savings.

Two adjustments to the 2024 MPS's program EE potential savings, and one direct adjustment to costs, were necessary prior to inclusion in the 2024 IN IRP. The first adjustment was to provide the program potential savings at the generator level. The 2024 MPS savings are reported at the meter-level. Sector savings were adjusted based on I&M's peak demand line loss factors to convert savings from the meter level up to the generator level.[22]

The second savings adjustment, referred to as a "net to gross" adjustment, is included to align the projections of future EE potential with the embedded efficiency trends already included in the I&M load forecast as discussed in Section 4.6.2. Also discussed in the load forecast section, the sales forecast developed for the 2024 MPS includes any projections of EE beyond prevailing building codes and equipment standards, while the load forecast used for the 2024 IN IRP does include implicit assumptions about future EE. The net to gross adjustment aligns incremental efficiency to the net efficiency already embedded in the 2024 IN IRP load forecast. GDS developed the net to gross adjustment using the measure level net to gross savings ratio determined in the MPS.

The 2024 IN IRP's capacity expansion model does not calculate avoided transmission and distribution (T&D) benefit associated with DSM measures, thus the GDS Team provided I&M with EE and DR costs that have been adjusted to net out the avoided T&D benefit.

[22] I&M's peak demand line loss factors were used for adjusting both energy and demand savings from the customer meter up to generation. The peak demand line loss factor was used a proxy for marginal line loss factors, which have not been studied by I&M.

The GDS Team provided the EE inputs across three different vintage bundles: 2026-2028, 2029-2032, and 2033-2044 to better optimize the value of EE to the system over time periods that align with subsequent I&M planning horizons. The EE MWh and MW impacts for each vintage block provide the cumulative annual lifetime savings. Conversely, because EE program costs are only incurred during the year of measure installation, budgets are only reflected during the identified years in each vintage block. The EE resources provided to I&M for 2024 IN IRP modeling are discussed in the next section. The bundle savings included in modelling can be found in Appendix Volume 1 Exhibit F.

8.3.1.1 Time-Differentiated Savings

The PLEXOS® software views demand-side resources as non-dispatchable "generators" that produce energy similar to non-dispatchable supply-side generators such as wind or solar. Thus, the value of each resource is impacted by the hours of the day and time of the year that it "generates" energy. With their diversity of generation patterns and smaller capacities relative to supply-side resources, DSM resources are appealing options when there is a smaller capacity or energy void. This flexibility helps mitigate the overbuilding of supply-side resources and lessens the amount of capacity and energy required to be purchased from the market. This in turn can reduce energy market risk for both the utility and customers.

In addition to the annual impacts, typical hourly (8,760) shapes for each EE bundle, that reflect the various measures and end-uses reflected in each EE bundle, were provided as inputs for the 2024 IN IRP to assess the value of energy savings on an hourly basis. The GDS Team disaggregated the EE bundle savings based on the same end-use load shapes utilized in the 2024 MPS in order to produce an overall bundle 8,760 savings profile. As a result, the 8,760 shapes are unique for each EE sector and vintage bundle.

8.3.2 Demand Response Inputs

Levels of DR potential for summer peak demand reduction associated with the RAP scenario was provided as inputs to the 2024 IN IRP. The RAP scenario reductions were divided into two bins based on resource type, whether a dispatchable, or callable, DR resource or a fixed DR resource. Time-of-use rate programs make up the only fixed DR resource in RAP. All other programs in the scenarios were dispatchable resources.

Program cost outputs from the 2024 MPS were formatted as required by the 2024 IN IRP into annual program costs for each sector, scenario, and resource type. Program costs were shown in the year of their occurrence and not annualized over the life of the program. Appendix Volume 1 Exhibit F shows the levels of DR potential provided for Dispatchable and Fixed DR programs.

8.3.3 Distributed Energy Resources Inputs

Although the 2024 MPS found no cost-effective achievable potential (under current avoided costs and cost-effectiveness screening parameters) from DERs, the GDS Team performed modeling based on the fact that future DER growth may occur in the I&M Indiana service territory with utility intervention through customer incentives for DER adoption of solar and solar paired with battery. This scenario was modeled based on primary data reported from I&M's customers related to the willingness to adopt DER technologies with two different levels of utility incentive. Forecasted incremental generation, additional to existing capacity for solar and solar paired with battery over the study horizon, is presented in Figure 40 below. This forecast was modeled in all 2024 IN IRP scenarios.

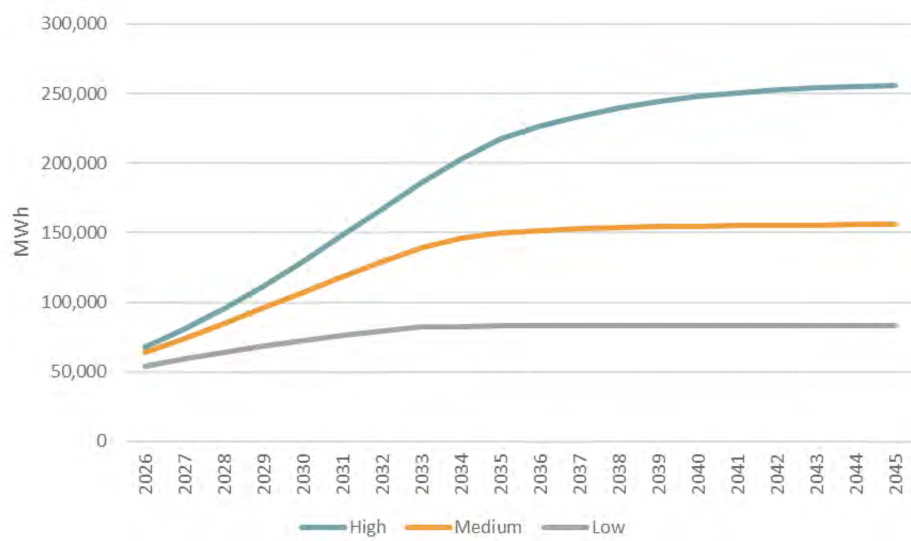

Figure 40. DER Forecasted Generation

8.3.4 Conservation Voltage Reduction (CVR)

The future potential for CVR is based on the number of distribution substations where CVR can be cost effectively deployed and operated in I&M's energy delivery system based upon the forecast CVR potential from the 2021 IRP. No new, incremental distribution substations to the 2021 IRP potential were included in the 2024 IN IRP. The Company performed cost effective analysis for the distribution substation buses (i.e., the electrical point of common connection for a set of distribution circuits, typically a set of three circuits) that do not currently have CVR deployed. The analysis found no new station buses to be cost effective. As a result, only those stations still planned for operation from the 2021 IRP plan were included in the 2024 IN IRP. The total energy and peak demand savings from this CVR potential is estimated and show in Table 33.

Table 33. CVR Energy and Demand Savings Potential

Year	Number of CVR Enabled Substations	Energy Savings (kWh)	Demand Savings (kW)
2025	27	42,820,865	1,080
2026	23	22,818,721	687
2027	7	7,047,878	262
2028	3	2,905,427	114
Total Annual for 2029 through 2044	60	75,592,891	2,143

9 Portfolio Development and Analysis

9.1 Overview

After determining the modeling inputs and key assumptions, the next step in the five-step 2024 IN IRP process is to define and optimize the I&M resource portfolios (see Figure 7). For the 2024 IN IRP, a Base Reference Case, three (3) alternative scenarios, and 11 alternative sensitivities were used to inform the development of a Preferred Portfolio. The Base Reference Case, alternative scenarios, and alternative sensitivities (collectively referred to as Cases) are defined in Sections 9.2 and 9.3 while the portfolio modeling and performance are discussed in Sections 9.4, 9.5, and 9.6. Section 9.7 presents the risk assessment and Section 9.8 identifies I&M's Preferred Portfolio for its Indiana service territory.

9.2 Scenarios

The Base Reference Case reflects the most probable future scenario based on forecast assumptions. To capture uncertainty around possible future market conditions, scenarios reflecting high and low economic growth and a scenario reflecting enhanced environmental regulations were modeled. These scenarios were introduced in Section 5, and are discussed below.

9.2.1 Base Reference Scenario

In the Base Reference Case, major drivers include:

- I&M's long-term energy and demand forecasts increase significantly due to growing customer base;
- Natural gas and energy market prices are increasing in real dollars;
- New resource capital costs which are declining moderately for fossil and wind resources in real dollars and declining significantly for solar and storage resources in real dollars; and
- Short-term resource annual build limits.

The Base Reference Case serves to inform the Company of an optimal portfolio of resources without implementation of the EPA's CAA Section 111(b)(d) Final and Proposed Rules (EPA Section 111(b)(d)). This portfolio serves to provide an important baseline for the Company to evaluate impacts from the inputs and assumptions of the other cases.

9.2.2 High and Low Economic Growth

The High Economic Growth and Low Economic Growth Cases were developed to assess resource selections assuming higher and lower overall economic impacts to key drivers. As noted in Section 4.12, these scenarios assume the HSL load in Indiana's forecast remain constant. Specifically, the following key inputs and assumptions were adjusted to reflect both high and low economic growth:

- Electricity demand reflective of higher or lower economic growth;
- Market prices reflective of higher or lower demand across PJM; and,
- Natural gas prices reflective of higher or lower demand due to economic growth.

Environmental regulations under the High and Low Economic Growth Cases are unchanged from the Base Reference Case.

9.2.3 Enhanced Environmental Regulations

The Enhanced Environmental Regulations (EER) Case reflects existing and proposed regulations under the EPA Section 111(b)(d). Specifically, rules proposed by the EPA in May of 2023 impacting both existing generating units and new generating units were factored into the portfolio modeling for the EER Case. Final rules were issued in April of 2024, impacting only new natural gas resources and existing coal resources. For the EER Case, the following constraints on gas resources not equipped with CCS technology were assumed:

- New NGCT resources: operate at less than 20% annual capacity factor beginning upon selection of the resource.
- New NGCC resources: operate at less than 40% annual capacity factor beginning upon selection of the resource.
- Existing NGCT and NGCC resources: operate at less than 50% annual capacity factor beginning 1/1/2030.

The assumptions above impact Indiana's existing fleet and resource additions.

9.3 Alternative Sensitivities

While alternative scenarios are intended to capture general, broad reaching market impacts, the alternative sensitivities developed for the 2024 IN IRP are intended to capture impacts from specific input and assumption changes. The alternative sensitivities developed for the 2024 IN IRP include:

- Base under EPA Section 111 (b)(d) Requirements;
- Low Carbon: Transition to Objective;
- Low Carbon: Expanded Build Limits;
- Base with High Indiana Load;
- Base with Low Indiana Load;
- Rockport Unit 1 Retires 2025;
- Rockport Unit 1 Retires 2026;
- Exit OVEC ICPA in 2030;
- High Technology Costs;
- Expanded Wind Availability (Base); and
- Expanded Wind Availability (EER).

Each of these sensitivities are described below.

9.3.1 Base under EPA Section 111(b)(d) Requirements

The Base under EPA Section 111(b)(d) Requirements Case is intended to measure the impact that these requirements have on I&M's resource selection and Power Supply Costs. This sensitivity is similar to the EER Case except that it assumes the same commodity prices as in the Base Reference Case. In contrast, the EER Case assumes commodity prices associated with these environmental regulations. The goal of this sensitivity was to compare to the EER Case and understand how EPA Section 111(b)(d) compliance under different commodity price scenarios can impact the resource selection.

9.3.2 Low Carbon: Transition to Objective

The Low Carbon Objective is to annually generate carbon-free energy that meets or exceeds an equivalent level of I&M's Indiana's annual retail load based on its largest commercial and industrial customers energy requirements. This energy requirement represents approximately 75% of Indiana's total energy obligation by 2044. Wind, solar, hydro, and nuclear resources contribute to the Low Carbon Objective. The goal of this sensitivity was to evaluate when the Low Carbon Objective could be achieved using I&M's base modeling inputs and resource build limits. ITC, PTC, and Carbon Capture and Storage Tax Credits made available under IRA 2022 are extended throughout the entire planning horizon. This case and its assumptions were developed based on Stakeholder feedback seeking IRP modeling that would advance and expand clean energy resource development.

9.3.3 Low Carbon: Expanded Build Limits

Similar to the Low Carbon: Transition to Objective sensitivity above, this case and its assumptions were developed based on Stakeholder feedback seeking IRP modeling that would advance and expand clean energy resource development. In this sensitivity, I&M further evaluated the Low Carbon Objective by expanding the build limits for solar and wind resources from the base modeling inputs and resource build limits used in the Low Carbon: Transition to Objective Case. These build limits are noted in Table 34. The Low Carbon: Expanded Build Limits Case is intended to reflect resource selection and Power Supply Costs when the Low Carbon Objective is met throughout the entire planning horizon. ITC, PTC, and Carbon Capture and Storage Tax Credits made available under IRA 2022 are extended throughout the entire planning horizon.

Table 34. Low Carbon: Expanded Build Limits

Resource Type	Annual Build Limit (MW)	Cumulative Build Limit through 2030 (MW)	Cumulative Build Limit Through Planning Horizon (MW)
Wind (15 Year)	1,600	3,400	6,800
Wind (30 Year)	3,200	N/A	
Solar (15 Year)	1,050	2,100	4,800
Solar (35 Year)	1,050	2,550	5,400
Co-located Solar and Storage (4-Hour)	1,050	1,650	1,650

9.3.4 Base with High Indiana Load

The Base with High Indiana Load Case is intended to measure impacts on capacity additions and Power Supply Costs assuming a high-case Indiana load forecast. All other assumptions for this sensitivity are from the Base Reference Case. The approach used to develop high-case Indiana load is described in Section 4.12. The high-case forecast assumed the HSL load in Indiana's forecast remained constant. The goal of this sensitivity is to compare to the High Economic Growth Case and understand how high load growth under different commodity price scenarios can impact the resource selection. This case and its assumptions were developed based on feedback from the Director's Report.

9.3.5 Base with Low Indiana Load

The Base with Low Indiana Load Case is intended to measure impacts on capacity additions and Power Supply Costs assuming a low-case Indiana load forecast. All other assumptions for this sensitivity are from the Base Reference Case. The approach used to develop low-case Indiana load is described in Section 4.12. The low-case forecast assumed the HSL load in Indiana's forecast remained constant. The goal of this sensitivity is to compare the Low Economic Growth Case and understand how low load growth under different commodity price scenarios can impact the resource selection. This case and its assumptions were developed based on feedback from the Director's Report.

9.3.6 Rockport Unit 1 Retires 2025

This sensitivity was conducted in compliance with the Settlement Agreement approved in IURC Cause No. 45546. The Rockport Unit 1 Retires 2025 Case evaluates the impact on resource selection and Power Supply Costs if Rockport Unit 1 retired May 31, 2025, rather than in 2028. All other assumptions for this sensitivity are from the Base Reference Case.

9.3.7 Rockport Unit 1 Retires 2026

This sensitivity was conducted in compliance with the Settlement Agreement approved in IURC Cause No. 45546. The Rockport Unit 1 Retires 2026 Case evaluates the impact on resource selection and Power Supply Costs if Rockport Unit 1 retired May 31, 2026, rather than in 2028. All other assumptions for this sensitivity are from the Base Reference Case.

9.3.8 Exit OVEC ICPA in 2030

This sensitivity was conducted in compliance with the Settlement Agreement approved in IURC Cause No. 45546. I&M is one of 13 Sponsoring Companies that receives power from Ohio Valley Electric Corporation (OVEC) under the Intercompany Power Agreement (ICPA). Under the ICPA, I&M is entitled to 7.85 percent of the annual capacity and energy produced by OVEC and, in return, I&M is responsible for its share of OVEC's costs. The ICPA has been in place since 1953 and has a current expiration date of June 30, 2040. The Exit OVEC ICPA in 2030 Case is intended to evaluate the impact on resource selections and Power Supply Costs assuming I&M exited the ICPA in 2030 rather than 2040. However, the ICPA does not have any provision for early termination without the unanimous consent of all Sponsoring Companies and subsequent FERC approval.

To support this sensitivity, the Company conducted an analysis of its obligations associated with terminating the OVEC ICPA early based on forecasted information from OVEC. This analysis evaluated the following two early termination scenarios:

1. I&M is able to exit the ICPA through an upfront payment towards its proportional share of debt outstanding, with a successful negotiation of early termination with other Sponsoring Companies and subsequent FERC approval.
2. I&M is able to buy out of its energy purchase obligations and proportional share of debt service costs but is unable to obtain the necessary approvals to completely exit the agreement and therefore must continue to fund the ongoing operations of the two OVEC plants.

The costs from scenario 2 were included in the Affordability analysis for this sensitivity. This assessment was based on the information available to I&M and may not represent all costs I&M

would incur in either scenario if the ICPA were terminated early. As stated previously though, the ICPA does not contain an early termination clause.

9.3.9 High Technology Costs

The High Technology Cost Case is intended to measure the impact that higher costs to build or buy new generation has on resource selection and Power Supply Costs. This sensitivity adjusted assumptions used in the Base Reference Case to reflect high technology costs for all technologies, as noted in Appendix Volume 1 Exhibit E. The increases were sourced from NREL ATB and recent market intelligence gained through the 2024 RFPs. The goal of this sensitivity was to compare to the Base Reference Case and understand how higher costs can impact the resource selection.

9.3.10 Expanded Wind Availability (Base)

During the 2024 IN IRP process, I&M received updated market intelligence from its 2024 RFPs that indicated additional wind resources were available through 2030. The Expanded Wind Availability Case is intended to measure the impact that increasing wind build limits has on the Base Reference Case. All inputs and assumptions for this sensitivity are the same as the Base Reference Case except that the cumulative build limit through 2030 for wind resources increased to 1,200 MW. The goal of this sensitivity is to compare to the Base Reference Case and understand how expanded wind availability can impact the resource selection.

9.3.11 Expanded Wind Availability (EER)

During the 2024 IN IRP process, I&M received updated market intelligence from its 2024 RFPs that indicated additional wind resources were available through 2030. The Expanded Wind Availability (EER) Case is intended to measure the impact that increasing wind build limits has on the EER Case. All inputs and assumptions for this sensitivity are the same as the EER Case except that the cumulative build limit through 2030 for wind resources increased to 1,200 MW. The goal of this sensitivity is to compare to the EER Case and understand how expanded wind availability can impact the resource selection.

9.4 Portfolio Development

All the portfolios developed for the 2024 IN IRP start with the Indiana load forecast and a representation of the current portfolio of generating resources, including existing and planned resources and contracts. The difference between the Indiana load forecast and the capacity and energy contribution from the current portfolio reflects the capacity and energy needs to be filled in with the selection of new resources, as discussed in Section 7.

Portfolios to fill capacity and energy needs under the various Cases are developed using the PLEXOS® LT Plan tool licensed through Energy Exemplar. The PLEXOS® software model is widely used in the electric utility industry for resource planning and production cost analyses. The PLEXOS® long-term optimization model, also known as LT Plan, served as the basis for performing the 2024 IN IRP modeling. The PLEXOS® LT Plan model finds the optimal portfolio of future capacity and energy resources, including DSM additions, by minimizing the Net Present Value Revenue Requirement (NPVRR) of the Power Supply Costs over the planning horizon. By minimizing NPVRR, the model will provide optimized portfolios with the lowest Power Supply Costs, while adhering to the Company's constraints.

Optimized portfolios are identified subject to a series of modeling parameters and constraints, to identify a mix of resources that seeks to minimize the aggregate of the following portfolio resource Power Supply Cost components:

- Fixed costs of capacity additions, i.e., carrying charges on incremental capacity additions (based on an I&M-specific, weighted average cost of capital), and fixed O&M;
- Fixed costs of any capacity purchases;
- Program costs of (incremental) DSM alternatives;
- Variable costs associated with Indiana generating units. This includes fuel, start-up, consumables, market replacement cost of emission allowances, and variable O&M costs; and
- A 'netting' of the production revenue earned in the PJM power market from Indiana's generation resource sales and the cost of energy necessary to meet Indiana's load obligation.

PLEXOS® executes the objective function described above while abiding by the following constraints:

- Minimum capacity reserve margins;
- Limited energy market purchases and sales;
- Resource additions (i.e., maximum units built);
- Age and lifetime of power generation facilities;
- Operation constraints, such as ramp rates, minimum up/down times, capacity, heat rates, etc.;
- Fuel burn minimum and maximums; and
- Energy contract parameters such as energy and capacity.

As noted above, energy market purchases and sales as a percent of total energy obligation were limited in the 2024 IN IRP modeling for the Cases. Table 35 below shows energy market purchases and sales limits applied for the Cases. Cases not noted in the table utilized the Base Reference Case energy market purchases and sales limits.

Table 35. Market Sales and Purchases Limits

Years	Base Reference Case	EER, Base under EPA Section 111(b)(d) Requirement, and Expanded Wind Availability (EER) Cases
2025-28	60%	60%
2029-30	50%	50%
2031-33	30%	35%
2034+	20%	25%

The model inputs that comprise the objective function and constraints are considered in the development of an optimal resource portfolio that best fits a utility's capacity and energy needs. The LT Plan reasonably considers the relative load and generation variable and fixed costs that change from plan-to-plan. Likewise, transmission costs are included to the extent that they are associated with new generating capacity or are linked to specific supply alternatives.

9.5 Portfolio Analysis

The Portfolios evaluated for the 2024 IN IRP were developed based on the four (4) scenarios and 11 sensitivities described in detail in Section 9.2 and 9.3 above. This section presents and discusses the resource additions for all the Cases[23].

9.5.1 Base Reference Case Analysis

The Base Reference Case reflects the model's selection of the most economic resource additions using base forecast assumptions.

[23] The IRP modeling inadvertently reflected the Lawrenceburg CPA contract to end in the 2034/35 DY instead of ending in the 2033/34 DY, as noted in Table 11. All Cases were reviewed, and it was confirmed that if the change was reflected, all Cases modeled would still meet the 2034 Target Obligation.

Table 36 below shows resource additions selected in the Base Reference Case.

Table 36. Base Reference Case Cumulative Nameplate Capacity Additions

Year	Nameplate MW								Accredited MW	
	Wind	Solar	Storage	New NGCC	Existing NGCC	New NGCT	Existing NGCT	Nuclear Cook SLR	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

The Base Reference Case includes short-term capacity additions through 2027 until supply-side resources become available in 2028. Solar, wind, storage, and gas resources are selected in 2028 in response to load growth by 2030. Existing NGCCs are selected to meet the capacity and energy obligations beginning in 2028 and increase to a cumulative amount of 3,600 MW by 2030. Existing NGCTs are selected to meet capacity obligation beginning in 2028 and increase to a cumulative amount of 2,000 MW by 2031. DR, EE, DER, CVR increase over time as the capacity and energy obligations increase. Beyond 2031, new NGCCs are built in 2034 and 2036 as they are the most economic option to meet the growing capacity and energy obligations. In addition, the Cook SLR is selected in 2035 and 2038.

Figure 41 shows the accredited capacity results by resource type for the Base Reference Case while the Target Obligation represents the PJM Forecast Pool Requirement (FPR) and the additional 5% capacity contingency.

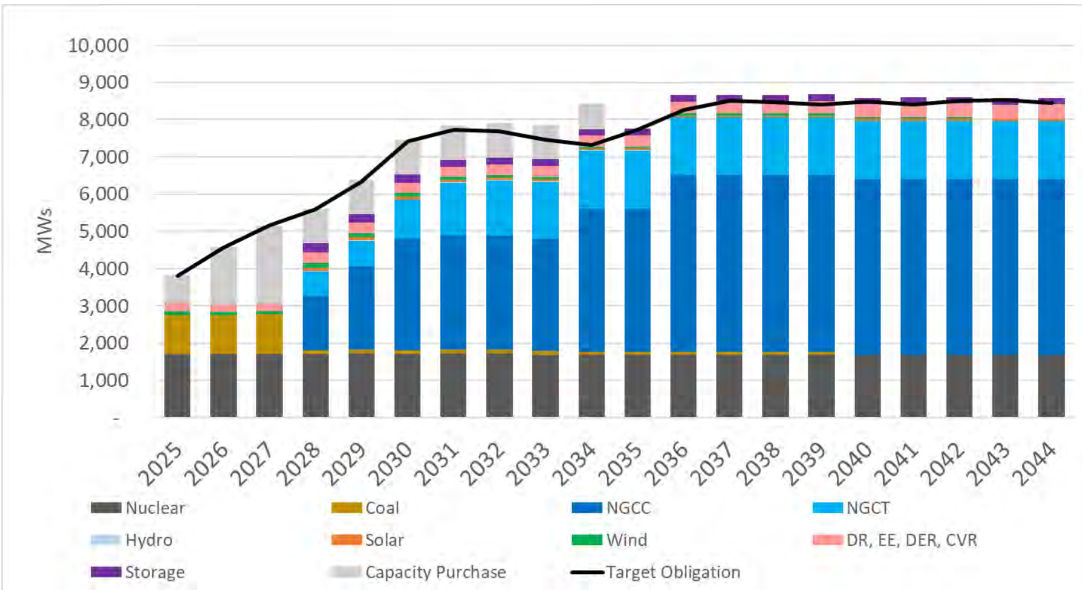

Figure 41. Base Reference Case Accredited Capacity by Resource Type

The accredited capacity for all resources in Figure 41 reflects forecasted ELCCs as described in Section 8.1.1.3. Existing nuclear, NGCC, and NGCT provide nearly all the capacity needs throughout 2044.

Energy results by resource type for the Base Reference Case are shown in Figure 42.

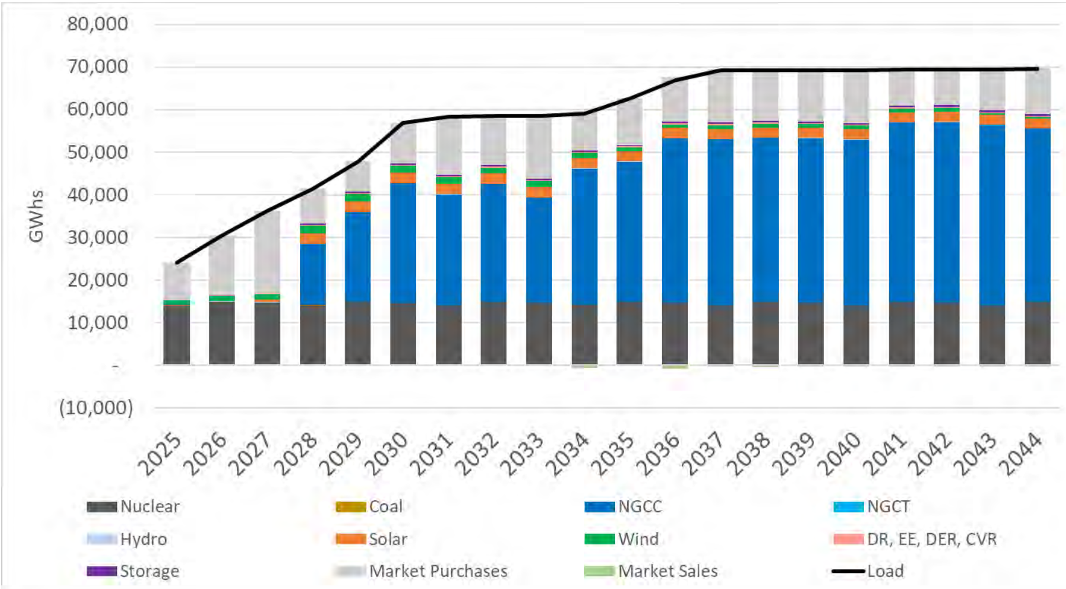

Figure 42. Base Reference Case Energy by Resource Type

Energy from nuclear, NGCC, and market purchases provide most of the energy needs, with renewables and demand-side resources making up a small component of the energy needs. There are minimal energy market sales throughout the planning horizon.

9.5.2 Analysis of Scenarios

9.5.2.1 High and Low Economic Growth

The High and Low Economic Growth Cases were developed with impacts to market-wide load and market commodity prices. The High Economic Growth Case includes load forecasts and commodity prices that are higher than the Base Reference Case. Likewise, the Low Economic Growth Case includes load forecasts and commodity prices that are lower than the Base Reference Case. The High and Low Economic Growth Case forecast assumed the HSL load in Indiana's forecast remained constant as explained in Section 4.12.

Table 37 below shows resource additions included in the High Economic Growth Case.

Table 37. High Economic Growth Case Cumulative Nameplate Capacity Additions

Year	Nameplate MW								Accredited MW	
	Wind	Solar	Storage	New NGCC	Existing NGCC	New NGCT	Existing NGCT	Nuclear Cook SLR	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

The High Economic Growth Case includes short-term capacity additions through 2027 until supply-side resources become available in 2028. Solar, wind, storage, and gas resources are selected in 2028 in response to load growth by 2030. Short-term capacity is still selected in 2028 as no other resources are available to support the capacity needs. Existing NGCCs are selected to meet the capacity and energy obligations beginning in 2028 and increase to a cumulative amount of 3,600 MW by 2031. Existing NGCTs are selected to meet capacity obligation beginning in 2028 and increase to a cumulative amount of 3,500 MW by 2031. DR, EE, DER, CVR increase over time as the capacity and energy obligations increase. Beyond 2031, new NGCCs are built in 2034 and new NGCTs are built in 2042. In addition, the Cook SLR is selected in 2035 and 2038.

Compared to the Base Reference Case, the High Economic Growth Case selects more solar and wind resources, less new NGCC, and more existing and new NGCTs. Additionally, four megawatts of the Distribution Sited Storage resources described in Section 8.1.5.2 are selected. Fewer NGCCs are selected compared to the Base Reference Case due to the higher fuel prices. Alternatively, more NGCTs are selected as these resources are necessary to meet the capacity obligation.

Figure 43 shows the accredited capacity results by resource type for the High Economic Growth Case.

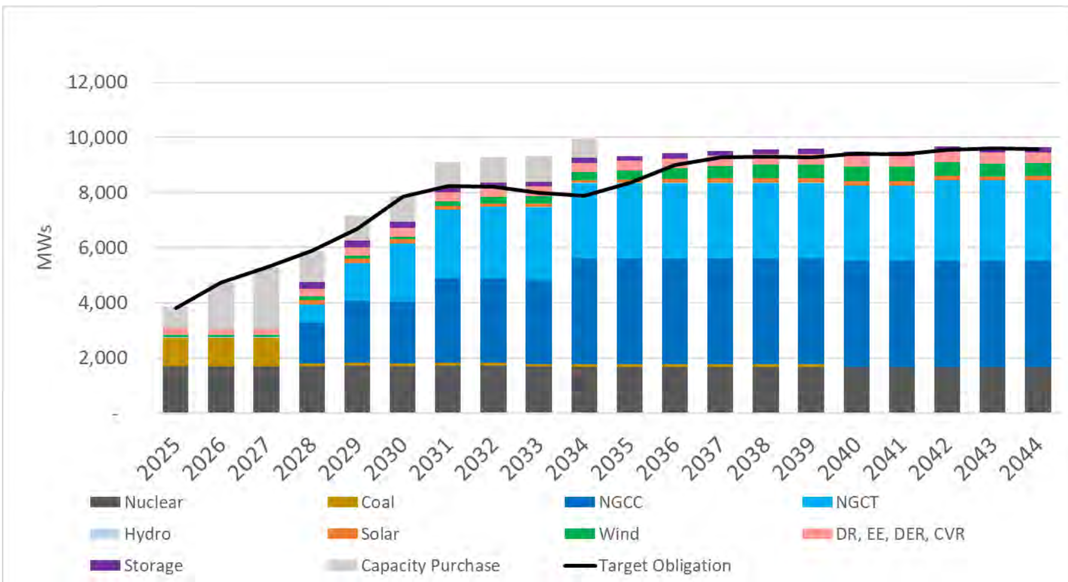

Figure 43. High Economic Growth Case Accredited Capacity by Resource Type

The accredited capacity for all resources reflects forecasted ELCCs as described in Section 8.1.1.3. Existing nuclear, NGCC, and NGCT provide nearly all the capacity needs throughout 2044. Figure 43 shows the increase in accredited capacity compared to the Target Obligation during 2031 to 2035. This is due to capacity additions selected economically to meet the energy obligation during that period while preparing for the subsequent load increase which occurs from 2034 to 2037.

Energy results by resource type for the High Economic Growth Case are shown in Figure 44.

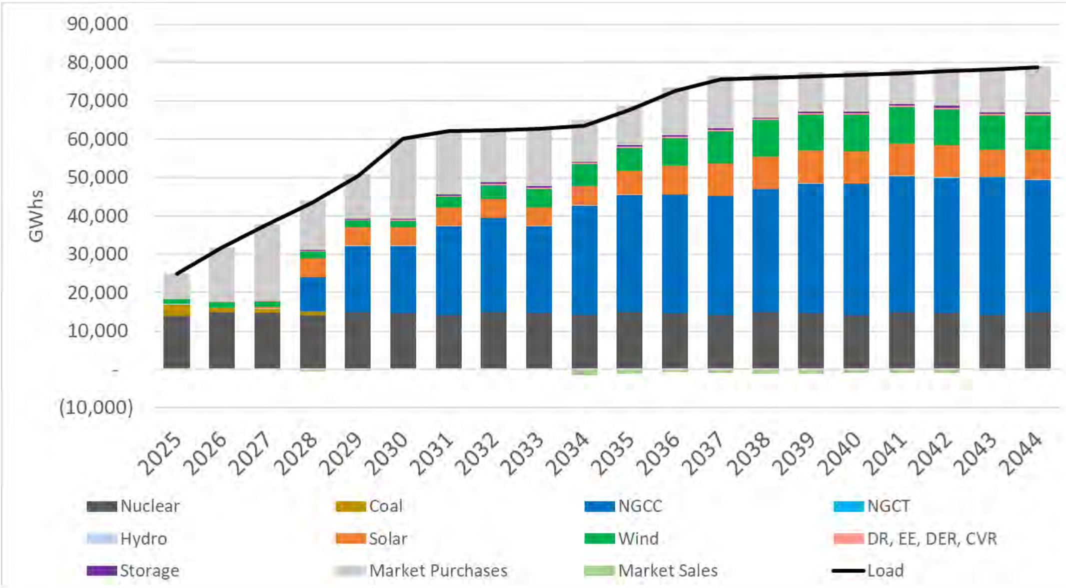

Figure 44. High Economic Growth Case Energy by Resource Type

Energy from nuclear, NGCC, and market purchases provide most of the energy needs, with renewables and demand-side resources making up a small component of the energy needs. There are minimal energy market sales throughout the planning horizon.

Table 38 below shows resource additions included in the Low Economic Growth Case.

Table 38. Low Economic Growth Case Cumulative Nameplate Capacity Additions

Year	Nameplate MW								Accredited MW	
	Wind	Solar	Storage	New NGCC	Existing NGCC	New NGCT	Existing NGCT	Nuclear Cook SLR	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

The Low Economic Growth Case includes short-term capacity additions through 2027 until supply-side resources become available in 2028. Wind and gas resources are selected in 2028 in response to load growth by 2030. Existing NGCCs are selected to meet the capacity and energy obligations beginning in 2028 and increase to a cumulative amount of 3,600 MW by 2030. Existing NGCTs are selected to meet capacity obligation beginning in 2028 and increase to a cumulative amount of 1,500 MW by 2030. DR, EE, DER, CVR increase over time until 2031 when they begin to decrease due to the expiration of some of the resources selected. Beyond 2031, new NGCCs are built in 2034 and 2036 as they are the most economic options to meet the growing capacity and energy obligations. In addition, the Cook SLR is selected in 2035 and 2038.

Compared to the Base Reference Case, the Low Economic Growth Case includes no solar, no storage, and less existing NGCTs. DR, EE, DER, and CVR resources are also significantly less in the Low Economic Growth Case.

Figure 45 shows the accredited capacity results by resource type for the Low Economic Growth Case.

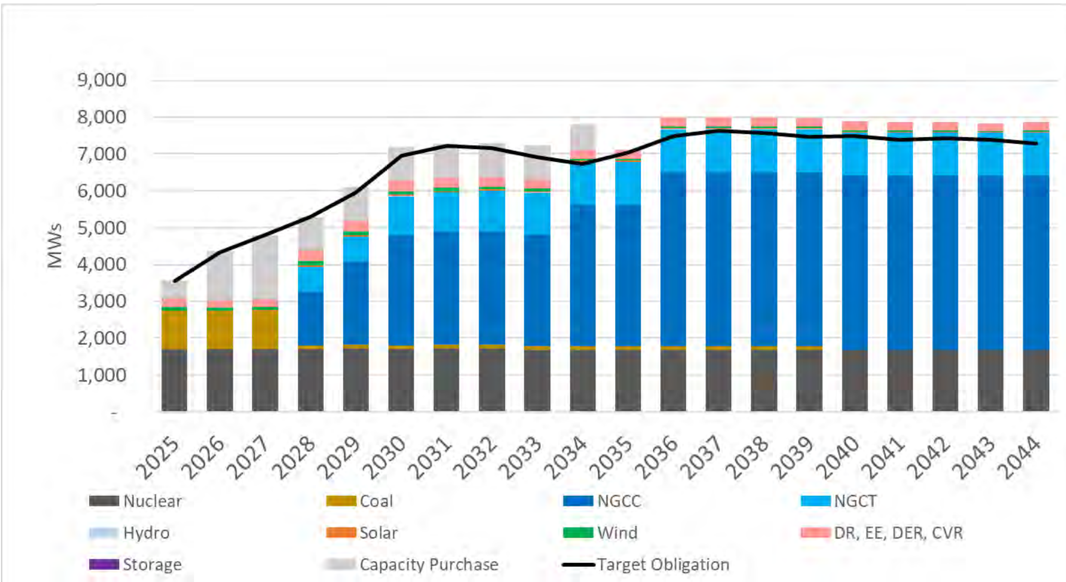

Figure 45. Low Economic Growth Case Accredited Capacity by Resource Type

The accredited capacity for all resources in the figure reflects forecasted ELCCs as described in Section 8.1.1.3. Existing nuclear, NGCC, and NGCT capacity provide nearly all the capacity needs throughout 2044.

Energy results by resource type for the Low Economic Growth Case are shown in Figure 46 below.

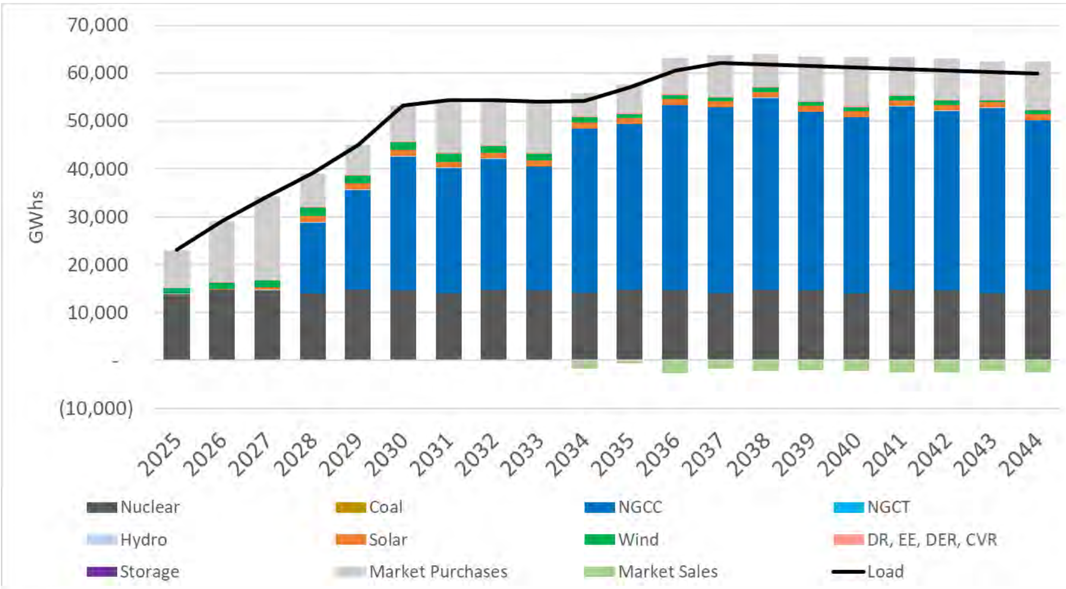

Figure 46. Low Economic Growth Case Energy by Resource Type

Energy from nuclear, NGCC, and energy market purchases provide most of the energy needs, with renewables and demand-side resources making up a small component of the energy needs. There are minimal energy market sales throughout the planning horizon.

Figure 47 below compares the accredited capacity for the Base Reference Case and the High and Low Economic Growth Cases. This comparison is shown for years 2029, 2034, and 2044.

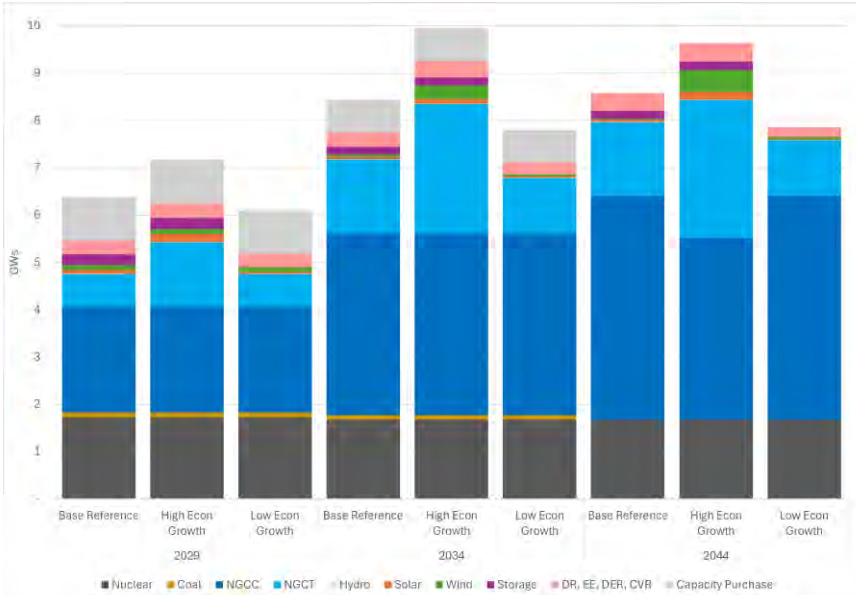

Figure 47. Comparison of Accredited Capacity – Base Reference, High/Low Economic Growth Cases

As can be seen in Figure 47 for 2029, the High Economic Growth Case adds more NGCTs, solar, and wind than the Base Reference Case to meet the higher load assumed by the case. The Low Economic Growth Case reduces solar and selects no storage as compared to the Base Reference Case. For 2034, the High Economic Growth Case adds more NGCT and wind than the Base Reference Case while the Low Economic Growth Case reduces NGCT. By 2044, the High Economic Growth Case reduces NGCC and adds NGCT and wind as compared to the Base Reference Case. The Low Economic Growth Case continues to have lower NGCTs and storage than the Base Reference Case. The Low Economic Growth Case adds less DR, EE, DER, and CVR than the Base Reference Case.

Figure 48 below compares the energy by resource type for the Base Reference Case and the High and Low Economic Growth Cases.

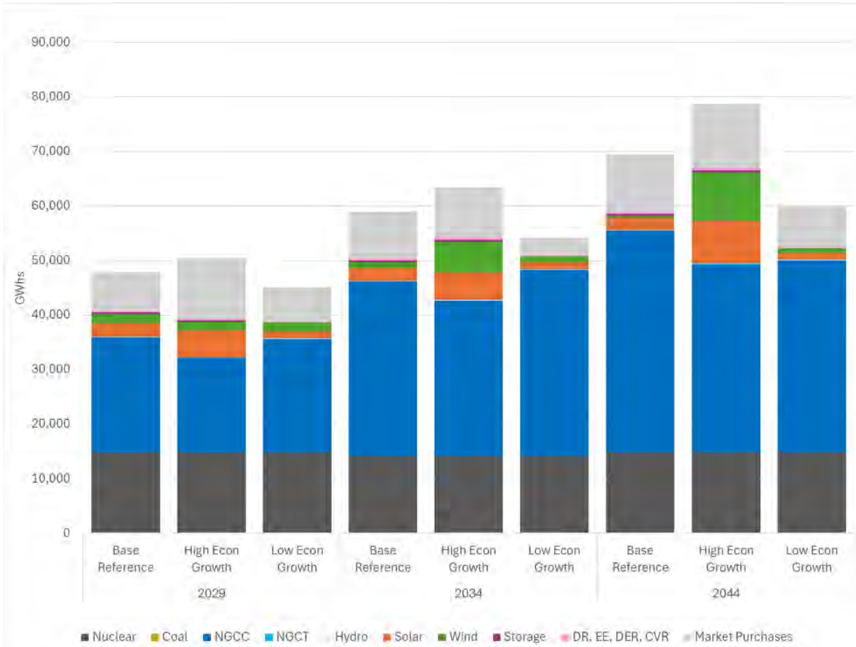

Figure 48. Comparison of Energy – Base Reference, High/Low Economic Growth Cases

As can be seen in Figure 48 for 2029, the High Economic Growth Case includes more energy from solar and market purchases and less energy from NGCC when compared to the Base Reference Case. The Low Economic Growth Case reduces solar energy and market purchases as compared to the Base Reference Case. For 2034 and 2044, the High Economic Growth Case includes more solar and wind energy and less NGCC energy than the Base Reference Case. This is due to the higher natural gas prices assumed in the High Economic Growth Case. The Low Economic Growth Case has less market purchases and less energy from DR, EE, DER, and CVR due to the lower load assumed in this case.

9.5.2.2 Enhanced Environmental Regulations

The EER Case evaluates the most economical solution to meet capacity and energy needs considering the implementation of EPA Section 111(b)(d). Table 39 below shows resource additions included in the EER Case.

Table 39. EER Case Cumulative Nameplate Capacity Additions

Year	Nameplate MW								Accredited MW	
	Wind	Solar	Storage	New NGCC	Existing NGCC	New NGCT	Existing NGCT	Nuclear Cook SLR	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

The EER Case includes short-term capacity additions through 2027 until supply-side resources become available in 2028. Solar, wind, storage, and gas resources are selected in 2028 in response to load growth by 2030. Existing NGCCs are selected to meet the capacity and energy obligations beginning in 2028 and increase to a cumulative amount of 5,400 MW by 2031. Existing NGCTs are selected to meet capacity obligation beginning in 2028 and increase to a cumulative amount of 1,500 MW by 2031. DR, EE, DER, CVR increase over time as the load and energy obligations increase.

Beyond 2031, the Cook SLR is selected in 2035 and 2038. In addition, new NGCTs are selected in 2042 to meet the capacity obligation.

Relative to Base Reference Case, significantly more wind and solar resources are selected in the EER Case. No new NGCCs are selected in the EER Case, although, the total amount of existing NGCC increases to 5,400 MW. The Base Reference Case selects a total cumulative value of 5,660 MW for existing and new NGCCs. Similar amounts of NGCC resources were selected in both cases, but the EER Case selected existing NGCCs instead of new NGCCs due to the lower resource price and the higher capacity factor limitation applied. Existing NGCTs selected in the EER Case are 500 MW less than the Base Reference Case levels. The selection of additional renewable resources and more existing NGCCs compared to the Base Reference Case is due to the capacity factor limitations applied to natural gas resources, as described in Section 9.2.

Figure 49 shows the accredited capacity results by resource type for the EER Case.

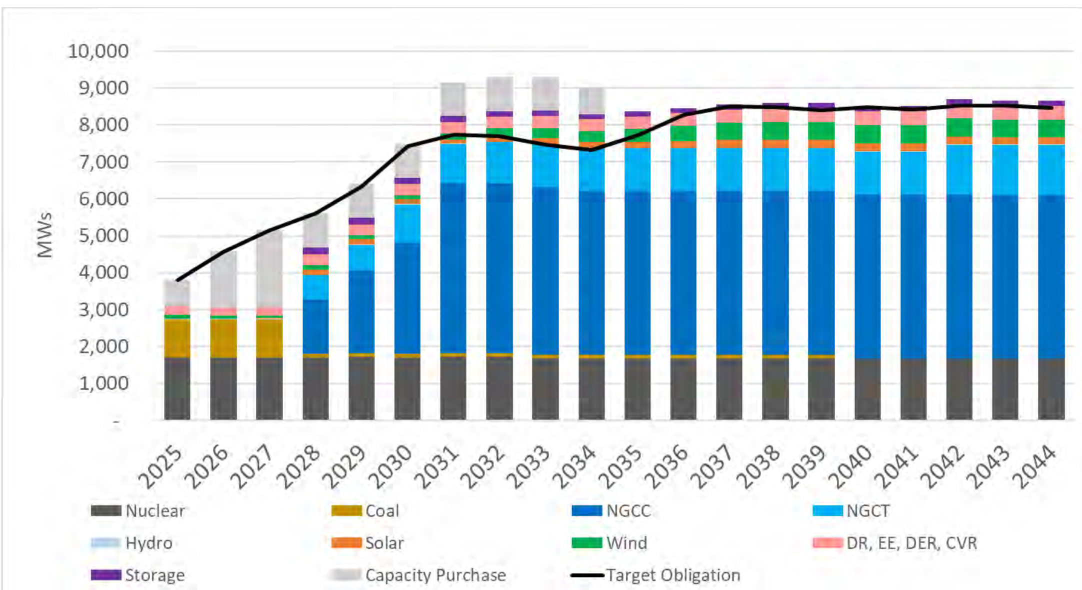

Figure 49. EER Case Accredited Capacity by Resource Type

Nuclear and natural gas resources which have higher accredited capacity values are selected in the EER case and support the majority of the capacity obligation. While nameplate additions of solar and wind are significant, the forecasted ELCCs as described in Section 8.1.1.3 result in lower accredited capacity values for these resources. Figure 49 shows the increase in accredited capacity compared to the Target Obligation during 2031 to 2034. This is due to capacity additions selected economically to meet the energy obligation during that period while preparing for the subsequent load increase which occurs from 2034 to 2037.

Energy results by resource type for the EER Case are shown in Figure 50 below.

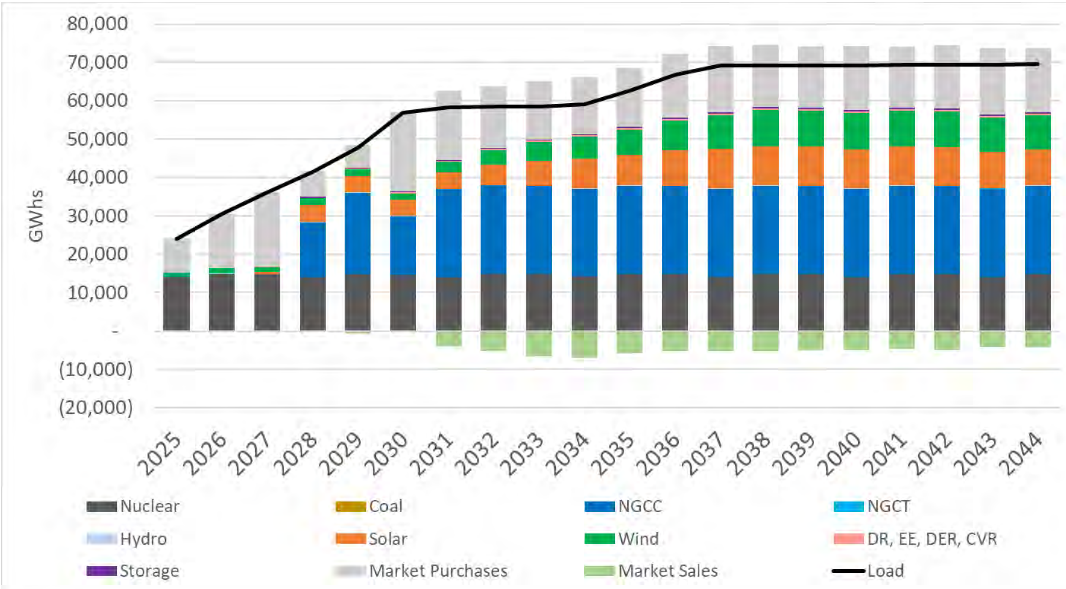

Figure 50. EER Case Energy by Resource Type

Capacity factor limitations result in significantly more energy contributions from wind and solar resources, as shown in Figure 50. The addition of renewable resources results in energy market sales starting in 2031 as renewable energy was generated at times when it was not needed to serve Indiana's load and thus was sold into the market.

9.5.3 Analysis of Sensitivities

9.5.3.1 Base under EPA Section 111(b)(d) Requirements

The Base under EPA Section 111(b)(d) Requirements Case evaluates the most economical solution to meet capacity and energy needs considering the implementation of EPA Section 111(b)(d). Table 40 below shows resource additions included in the Base under EPA Section 111(b)(d) Requirements Case.

Table 40. Base under EPA Section 111(b)(d) Requirements Case Cumulative Nameplate Capacity Additions

Year	Nameplate MW								Accredited MW	
	Wind	Solar	Storage	New NGCC	Existing NGCC	New NGCT	Existing NGCT	Nuclear Cook SLR	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

This portfolio includes short-term capacity additions through 2027 until supply-side resources become available in 2028. Solar, wind, storage, and gas resources are selected in 2028 in response to load growth by 2030. Existing NGCCs are selected to meet the capacity and energy obligations beginning in 2028 and increase to a cumulative amount of 5,400 MW by 2031. Existing NGCTs are selected to meet capacity obligation beginning in 2028 and increase to a cumulative amount of 1,500 MW by 2030. DR, EE, DER, CVR increase over time as the capacity and energy obligations increase. Beyond 2031, the Cook SLR is selected in 2035 and 2038. In addition, new NGCTs are selected in 2042 to meet the capacity obligation.

Figure 51 shows the accredited capacity results by resource type for the Base under EPA Section 111(b)(d) Case.

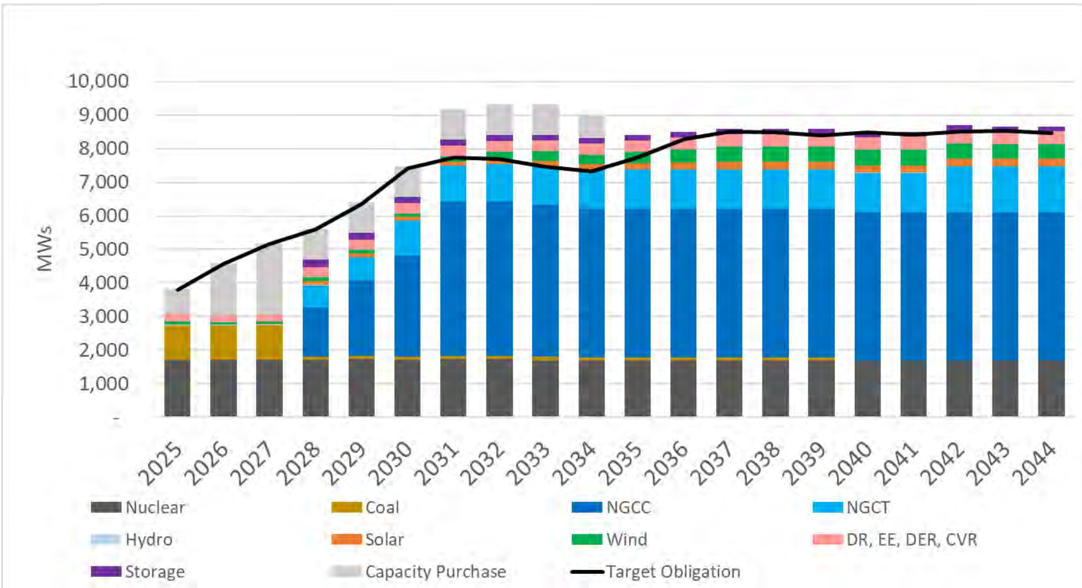

Figure 51. Base under EPA Section 111(b)(d) Requirements Case Accredited Capacity by Resource Type

Nuclear and natural gas resources which have higher accredited capacity values are selected in the Base under EPA Section 111(b)(d) Requirements Case and support the majority of the capacity obligation. While nameplate additions of solar and wind are significant, the forecasted ELCCs as described in Section 8.1.1.3 result in lower accredited capacity values for these resources. Figure 51 shows the increase in accredited capacity compared to the Target Obligation during 2031 to 2034. This is due to capacity additions selected economically to meet the energy obligation during that period while preparing for the subsequent load increase which occurs from 2034 to 2037.

Energy results by resource type for the Base under EPA Section 111(b)(d) Requirements Case are shown in Figure 52 below.

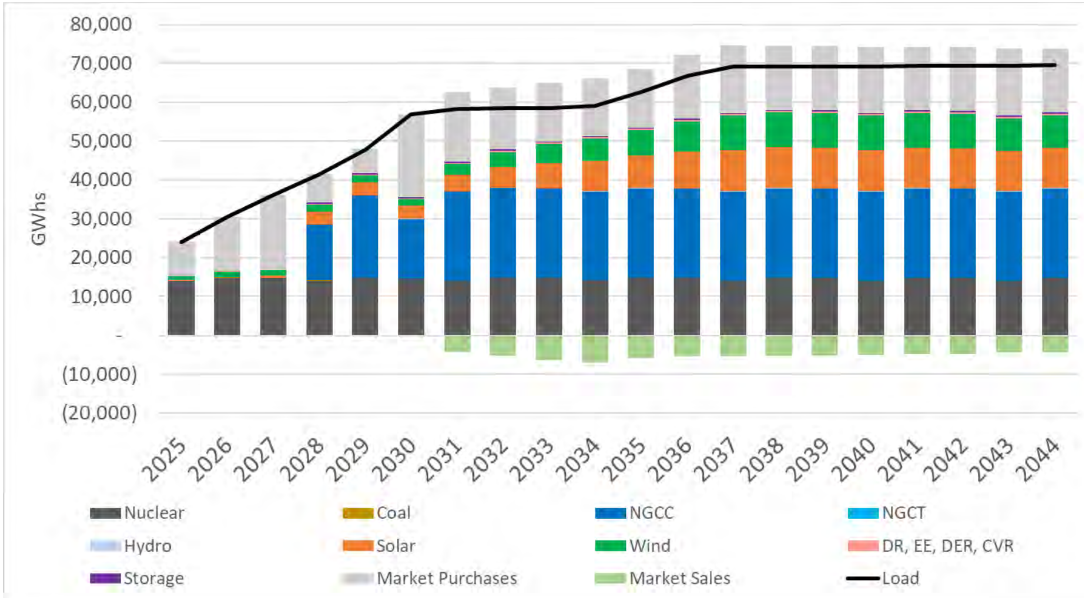

Figure 52. Base under EPA Section 111(b)(d) Requirements Case Energy by Resource Type

The assumed EPA Section 111(b)(d) compliant capacity factor limitations result in significantly more energy contributions from wind and solar resources, as shown in Figure 52. The addition of renewable resources results in energy market sales starting in 2031 as renewable energy was generated at times when it was not needed to serve Indiana's load and thus was sold into the market.

Figure 53 and Figure 54 below compare accredited capacity and energy by resource type for the EER and the Base under EPA Section 111(b)(d) Requirement Cases for years 2029, 2034, and 2044.

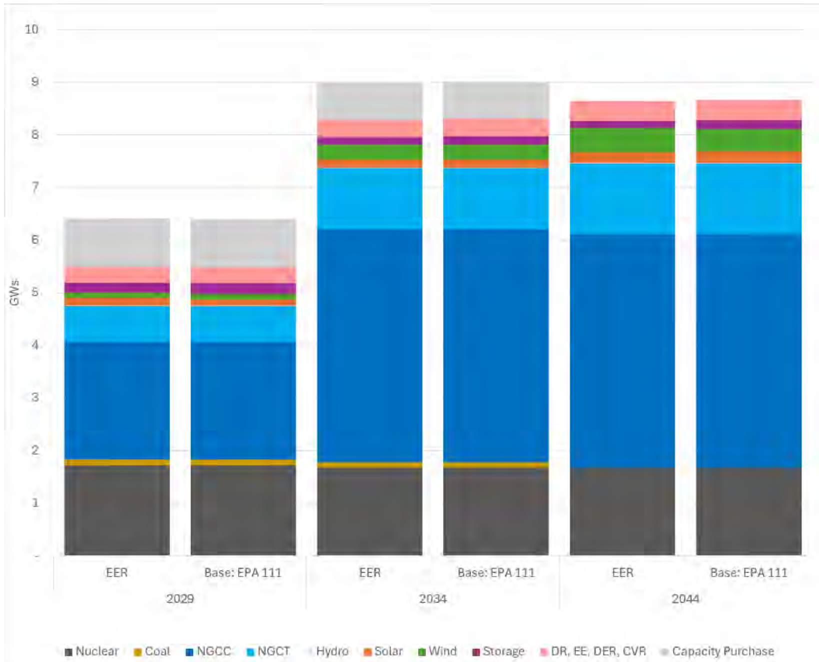

Figure 53. Comparison of Accredited Capacity - EER and Base under EPA Section 111(b)(d) Requirement Cases

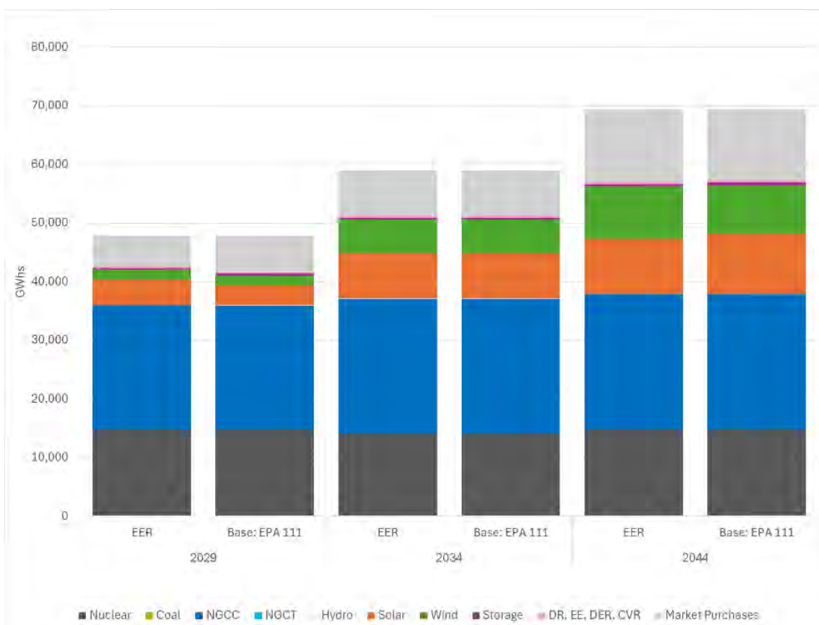

Figure 54. Comparison of Energy - EER and Base under EPA Section 111(b)(d) Requirement Cases

As noted in the figures above, the Base under EPA Section 111(b)(d) Case is substantially similar to the EER Case in all years. These results indicate that the assumed EPA Section 111(b)(d) compliant capacity factor limitations were the main driver of resource selections rather than commodity prices.

9.5.3.2 Low Carbon Cases

The Low Carbon Objective is to annually generate carbon-free energy to serve Indiana retail customers that is equivalent to or exceeds Indiana’s largest commercial and industrial customers energy requirements. The goal of Low Carbon: Transition to Objective Case was to evaluate when the Low Carbon Objective could be achieved using I&M's base modeling inputs and resource build limits. The goal of Low Carbon: Expanded Build Limits Case was to evaluate resource selection and Power Supply Costs associated with meeting the Low Carbon Objective throughout the entire planning horizon. This case and its assumptions were developed based on Stakeholder feedback seeking IRP modeling that would advance and expand clean energy resource development.

Table 41 below shows resource additions included in the Low Carbon: Transition to Objectives Case.

Table 41. Low Carbon: Transition to Objective Case Cumulative Nameplate Capacity Additions

Year	Nameplate MW								Accredited MW	
	Wind	Solar	Storage	New NGCC	Existing NGCC	New NGCT	Existing NGCT	Nuclear Cook SLR & SMR	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	200	1,796	300	0	1,800	0	1,000	0	92	0
2029	400	2,235	300	0	1,800	0	2,000	0	111	0
2030	400	2,224	300	0	2,700	0	2,500	0	121	0
2031	800	2,662	300	0	2,700	0	3,500	0	131	0
2032	1,200	3,845	300	0	2,700	0	3,500	0	149	0
2033	1,600	5,023	300	0	2,700	0	3,500	0	162	0
2034	2,000	6,194	300	0	2,700	0	3,500	0	173	0
2035	2,600	7,360	300	0	2,700	0	3,500	888	185	0
2036	3,200	8,968	450	0	2,700	230	3,500	888	197	0
2037	3,400	10,269	500	0	2,700	230	3,500	1,488	205	0
2038	3,400	10,217	500	0	2,700	230	3,500	2,780	211	0
2039	3,400	10,164	500	0	2,700	230	3,500	2,780	217	0
2040	3,400	10,261	500	0	2,700	230	3,500	2,780	223	0
2041	3,400	10,208	500	0	2,700	230	3,500	2,780	227	0
2042	3,400	10,155	500	0	2,700	230	3,500	2,780	230	0
2043	3,200	9,548	500	0	2,700	230	3,500	3,080	233	0
2044	3,000	9,359	500	0	2,700	230	3,500	3,080	235	0

The Low Carbon: Transition to Objective Case includes short-term capacity additions through 2027 until supply-side resources become available in 2028. Solar, wind, storage, and gas resources are selected in 2028 in response to load growth by 2030. The Low Carbon Objective is achieved in 2038, as significant solar and wind resources are added, with a total of 10,217 MW of solar and 3,400 MW of wind by 2038. Existing NGCT and NGCC additions still play a significant role in the portfolio, with a total of 3,500 MW and 2,700 MW selected by 2044, respectively. However, new NGCCs are not selected and only 230 MW of new NGCTs are selected. A significant addition to the portfolio is the selection of 600 MW of SMR capacity in 2037 and 300 MW in 2038. In addition, the Cook SLR is selected in 2035 and 2038.

Figure 55 shows the accredited capacity results by resource type for the Low Carbon: Transition to Objective Case.

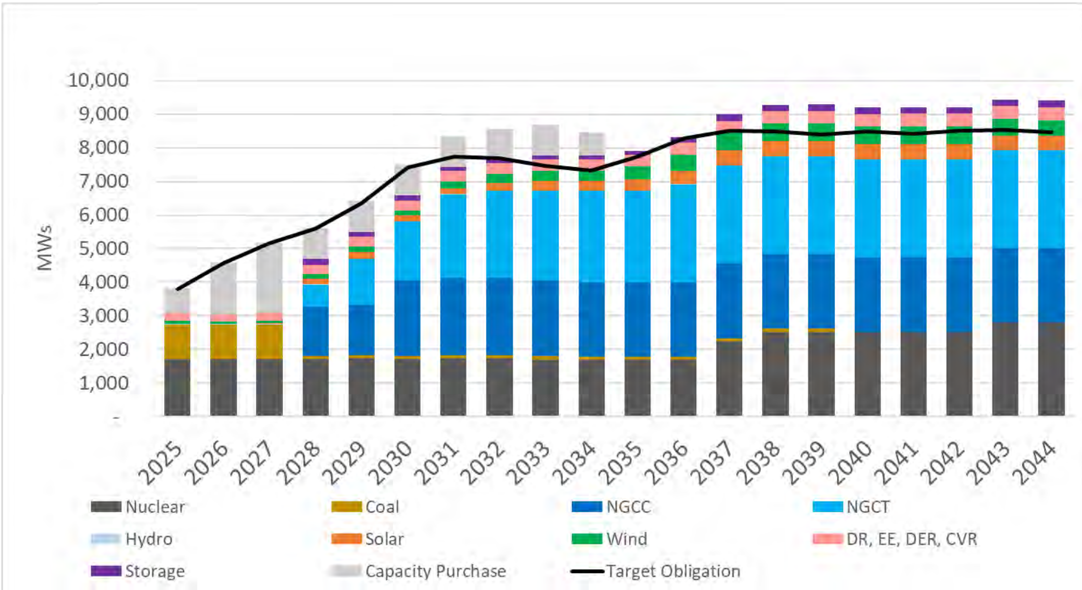

Figure 55. Low Carbon: Transition to Objective Case Accredited Capacity by Resource Type

Although significantly more wind and solar resources are added, nuclear and natural gas resources continue to support the majority of the capacity obligation. The forecasted ELCCs for wind and solar resources result in lower accredited capacity. Figure 55 shows the increase in accredited capacity compared to the Target Obligation during 2031 to 2034. This is due to capacity additions selected economically to meet the energy obligation during that period while preparing for the subsequent load increase which occurs from 2034 to 2037. In 2037, SMR’s are selected to support the Low Carbon Objective, causing the total accredited capacity to be higher than the Target Obligation for the remainder of the planning horizon.

Energy results by resource type for the Low Carbon: Transition to Objective Case are shown in Figure 56.

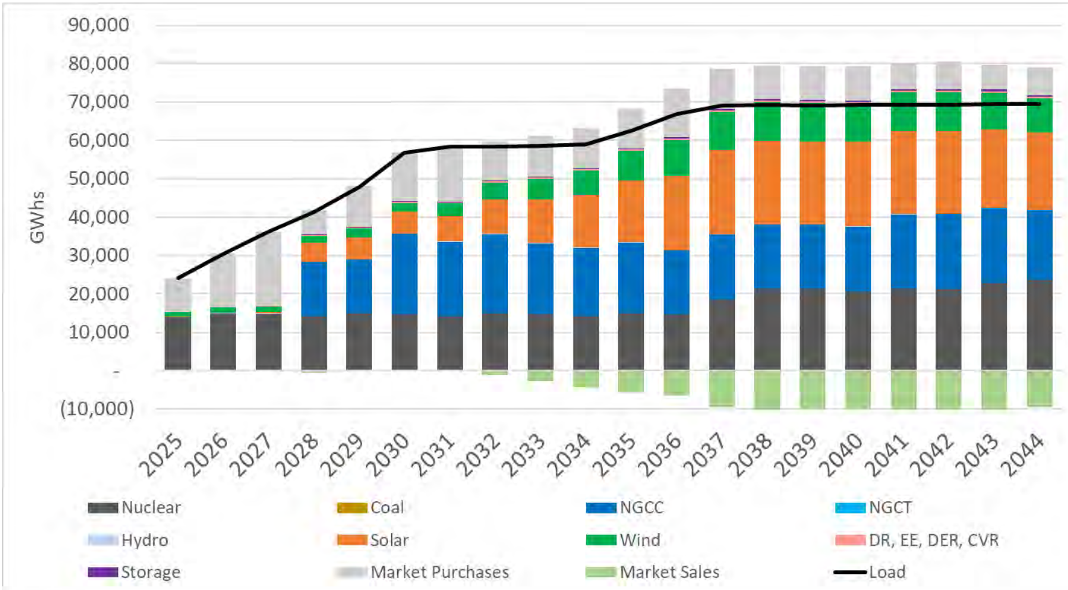

Figure 56. Low Carbon: Transition to Objective Case Portfolio Energy by Resource Type

Starting in 2028, carbon-free resources begin to provide a significant portion of the energy supply while natural gas resources contribute less energy over the planning horizon. As noted above, the Low Carbon Objective is achieved by 2038. The significant addition of renewable resources results in energy market sales starting in 2032 as renewable energy was generated at times when it was not needed to serve Indiana's load and thus was sold into the market. SMRs selected in 2037 contribute to the Low Carbon Objective.

Table 42 below shows resource additions included in the Low Carbon: Expanded Build Limits Case.

Table 42. Low Carbon: Expanded Build Limits Case Cumulative Nameplate Capacity Additions

Year	Nameplate MW								Accredited MW	
	Wind	Solar	Storage	New NGCC	Existing NGCC	New NGCT	Existing NGCT	Nuclear Cook SLR & SMR	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

The Low Carbon: Expanded Build Limits Case includes short-term capacity additions through 2027 until supply-side resources become available in 2028. Solar, wind, storage, and gas resources are selected in 2028 in response to load growth by 2030. Significant solar and wind resources are added to meet the Low Carbon Objective, with a total of 8,394 MW of solar and 6,200 MW of wind by 2038. This case selects more wind and less solar when compared to the Low Carbon: Transition to Objective Case. The Low Carbon: Expanded Build Limits Case also selects less existing NGCCs and more existing NGCTs when compared to the Low Carbon: Transition to Objectives Case. A significant addition to the portfolio is the selection of 300 MW of SMR capacity in 2037 and 300 MW in 2038. In addition, the Cook SLR is selected in 2035 and 2038.

Figure 57 shows the accredited capacity results by resource type for the Low Carbon: Expanded Build Limits Case.

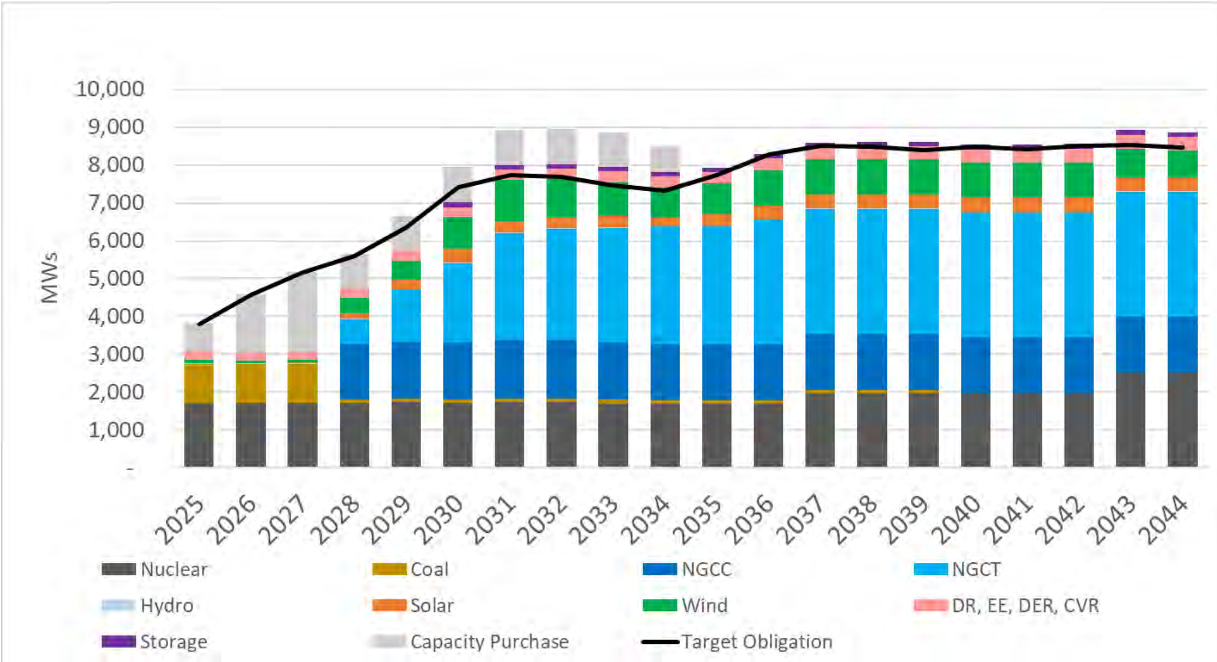

Figure 57. Low Carbon: Expanded Build Limits Case Accredited Capacity by Resource Type

Although significantly more wind and solar resources are added, nuclear and natural gas resources continue to support the majority of the capacity obligation. The forecasted ELCCs for wind and solar resources result in lower accredited capacity. Figure 57 shows the increase in accredited capacity compared to the Target Obligation during 2030 to 2034. This is due to capacity additions selected economically to meet the energy obligation during that period while preparing for the subsequent load increase which occurs from 2034 to 2037. In 2037, SMR's are selected to support the Low Carbon Objective, increasing the nuclear accredited capacity throughout the remainder of the planning horizon.

Energy results by resource type for the Low Carbon: Expanded Build Limits are shown in Figure 58.

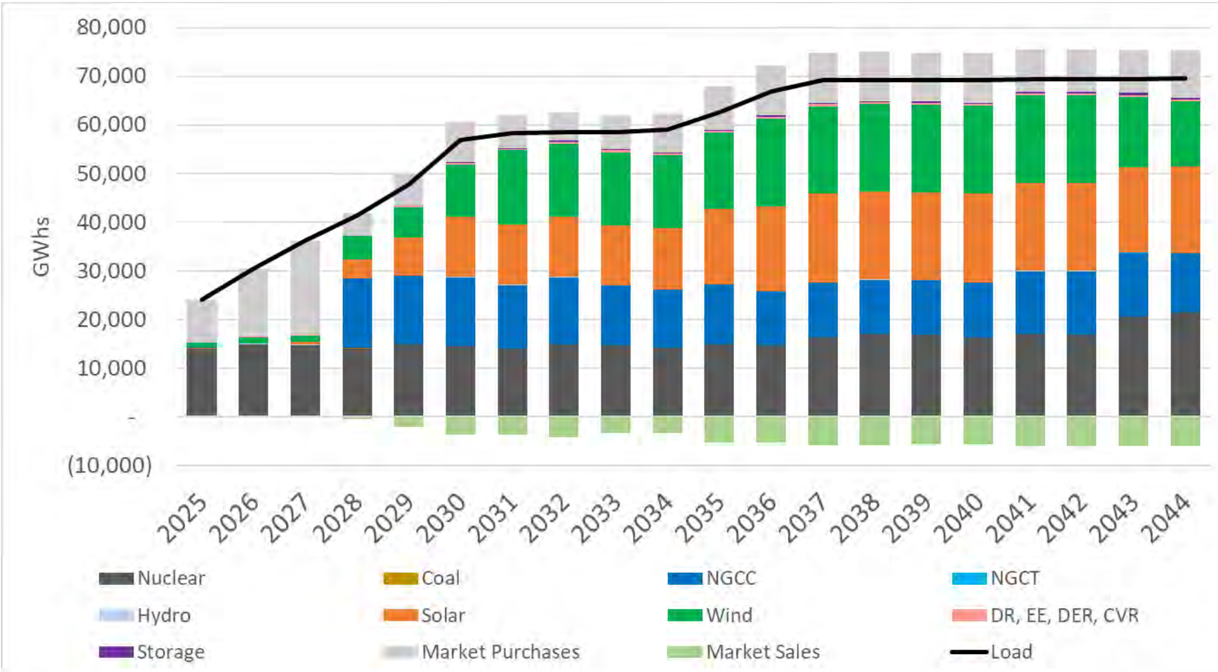

Figure 58. Low Carbon: Expanded Build Limits Case Portfolio Energy by Resource Type

Starting in 2028, carbon-free resources begin to provide a significant portion of the energy supply while natural gas resources contribute less energy over the planning horizon. The Low Carbon Objective is achieved throughout the planning horizon. The significant addition of renewable resources results in energy market sales starting in 2029 as renewable energy was generated at times when it was not needed to serve Indiana's load and thus was sold into the market. SMRs selected in 2037 contribute to the Low Carbon Objective.

Figure 59 below compares the accredited capacity for the Base Reference Case Portfolio and the Low Carbon Cases. This comparison is shown for years 2029, 2034, and 2044.

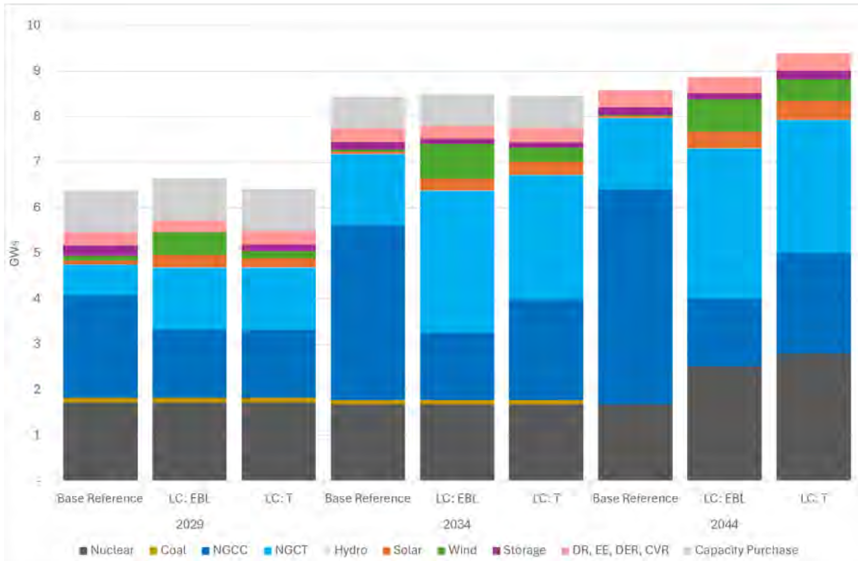

Figure 59. Comparison of Accredited Capacity - Base Reference and Low Carbon Cases

As seen in Figure 59, the Low Carbon Cases show significant increases in wind and solar capacity when compared to the Base Reference Case. Both cases select a similar amount of natural gas resources when comparing to the Base Reference Case, although NGCC capacity is replaced more economic NGCT capacity through 2044 as less NGCCs are required to support the energy obligation. The increases are more prominent in the Low Carbon: Expanded Build Limits Case due to the expansion of build limits allowing the model to select more carbon-free resources. Both Low Carbon Cases show an increase in nuclear capacity by 2044 due to the selection of SMR resources.

Figure 60 below compares the energy by resource type for the Base Reference Case and the Low Carbon Cases.

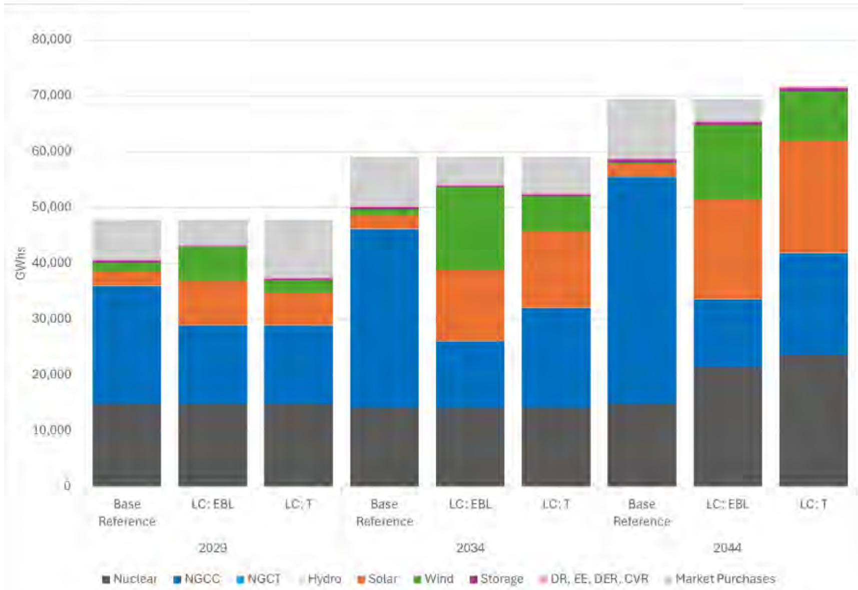

Figure 60. Comparison of Energy – Base Reference and Low Carbon Cases

Both Low Carbon Cases show increased generation from wind and solar resources when comparing to the Base Reference Case. The Low Carbon: Expanded Build Limits Case shows more generation from wind compared to the Low Carbon: Transition to Objective Case throughout the planning horizon due to the expansion of wind build limits. The increase in carbon-free generation offsets reductions in NGCC generation for all years as compared to the Base Reference Case. The SMRs in 2037 for both Low Carbon Cases contribute additional nuclear generation as compared to the Base Reference Case.

Significantly more resources are selected in the Low Carbon Cases as compared to the Base Reference Case. The Base Reference Case selects 10.7 GW of nameplate capacity over the planning horizon while the Low Carbon Cases both select over 22 GW of nameplate capacity to meet the Low Carbon Objective. Overall, the two Low Carbon Cases selected the most nameplate capacity additions of any of the 2024 IN IRP cases, which can be noted in Appendix Volume 1 Exhibit C. The significant addition of resources leads to increased costs, which will be discussed in Section 9.6.

9.5.3.3 Base with High and Low Indiana Load

The Base with High and Low Indiana Load Cases are intended to measure impacts on portfolio resource selections and Power Supply Costs assuming a high- or low- case Indiana load forecast. The high- and low-case forecast assumed the HSL load in Indiana's forecast remained constant.

Table 43 shows the resource additions for the Base with High Indiana Load Case.

Table 43. Base with High Indiana Load Case Cumulative Nameplate Capacity Additions

Year	Nameplate MW								Accredited MW	
	Wind	Solar	Storage	New NGCC	Existing NGCC	New NGCT	Existing NGCT	Nuclear Cook SLR	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

The Base with High Indiana Load Case includes short-term capacity additions through 2027 until supply-side resources become available in 2028. Solar, wind, storage, and gas resources are selected in 2028 in response to load growth by 2030. Short-term capacity is still selected in 2028 as no other resources are available to support the capacity needs. Existing NGCCs are selected to meet the capacity and energy obligations beginning in 2028 and increase to a cumulative amount of 3,600 MW by 2030. Existing NGCTs are selected to meet the capacity obligation beginning in 2028 and increase to a cumulative amount of 3,000 MW by 2031. Beyond 2031, new NGCCs are built in 2034 and 2036 and new NGCTs are built in 2042 and 2043. In addition, the Cook SLR is selected in 2035 and 2038.

Figure 61 shows the accredited capacity results by resource type for the Base with High Indiana Load Case.

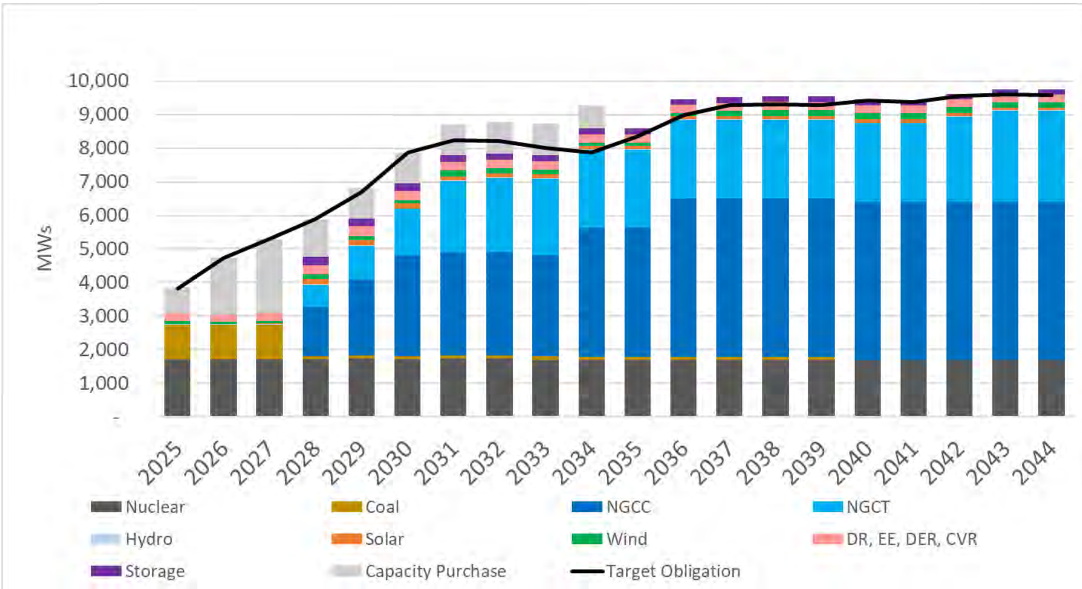

Figure 61. Base with High Indiana Load Case Accredited Capacity by Resource Type

Existing nuclear, NGCC, and NGCT support the majority capacity needs throughout 2044. Figure 61 shows the increase in accredited capacity compared to the Target Obligation from 2031 to 2034. This is due to capacity additions selected economically to meet the energy obligation during that period while preparing for the subsequent load increases which occurs from 2034 to 2037.

Energy results by resource type for the Base with High Indiana Load Case are shown in Figure 62.

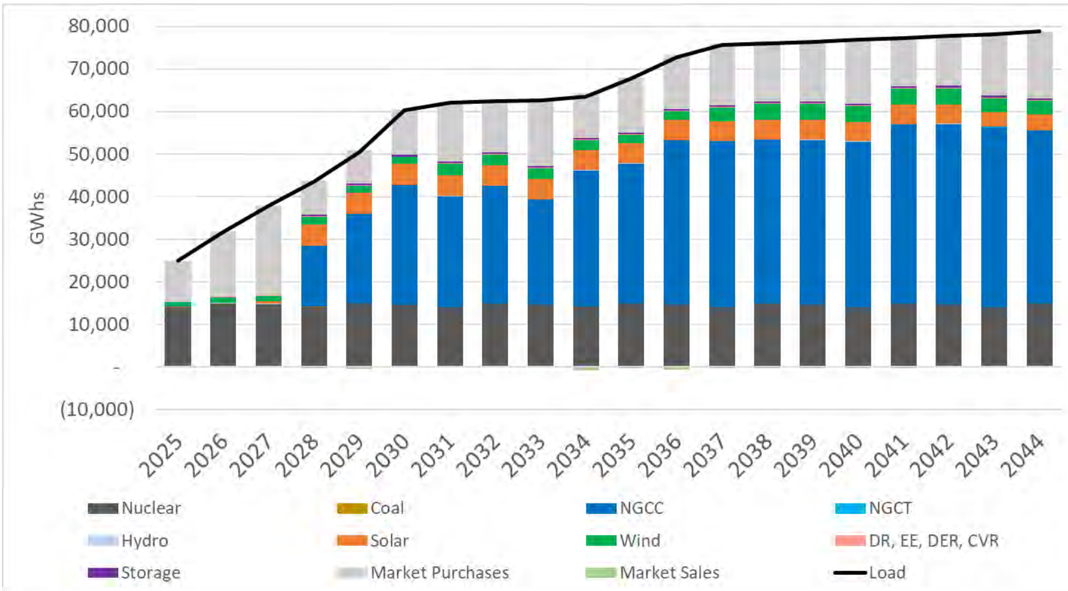

Figure 62. High Indiana Load Case Portfolio Energy by Resource Type

Energy from nuclear, NGCC, and market purchases provide most of the energy needs, with renewables and demand-side resources making up a small component of the energy needs. There are minimal market sales throughout the planning horizon.

Figure 63 below compares the accredited capacity by resource type for the High Economic Growth and Base with High Indiana Load Cases. This comparison is shown for years 2029, 2034, and 2044.

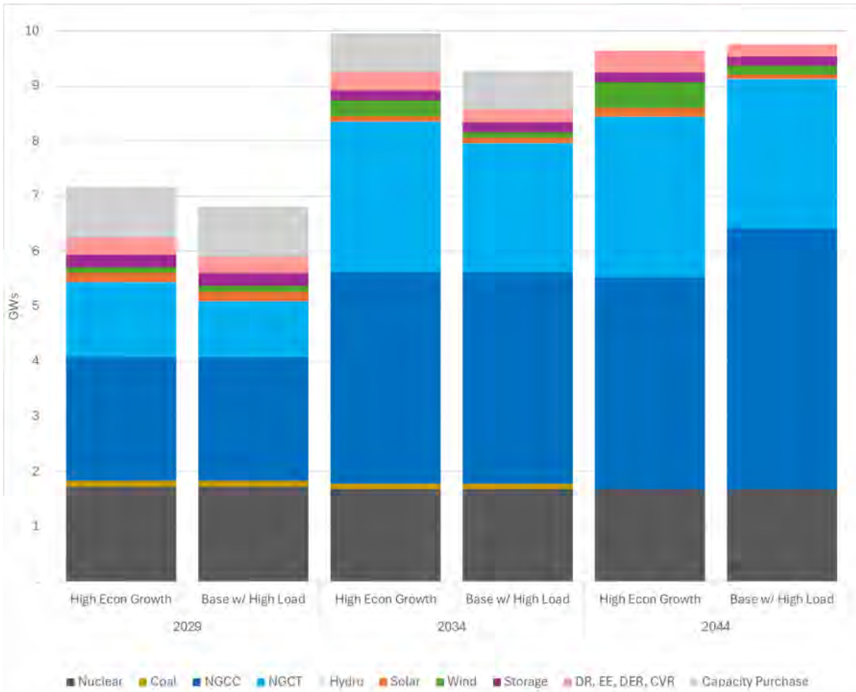

Figure 63. Comparison of Accredited Capacity – High Economic Growth and Base with High Indiana Load Cases

As seen in Figure 63, the Base with High Indiana Load Case results in less accredited capacity from NGCT compared to the High Economic Growth Case over the planning horizon. In 2029 and 2034, the Base with High Indiana Load Case selects less resources compared to the High Economic Growth Case while still meeting the capacity needs. In 2044, the Base with High Indiana Load Case selects more NGCCs to support the capacity and energy needs as compared to the High Economic Growth Case.

Figure 64 below compares energy by resource type for the High Economic Growth and Base with High Indiana Load Cases. This comparison is shown for years 2029, 2034, and 2044.

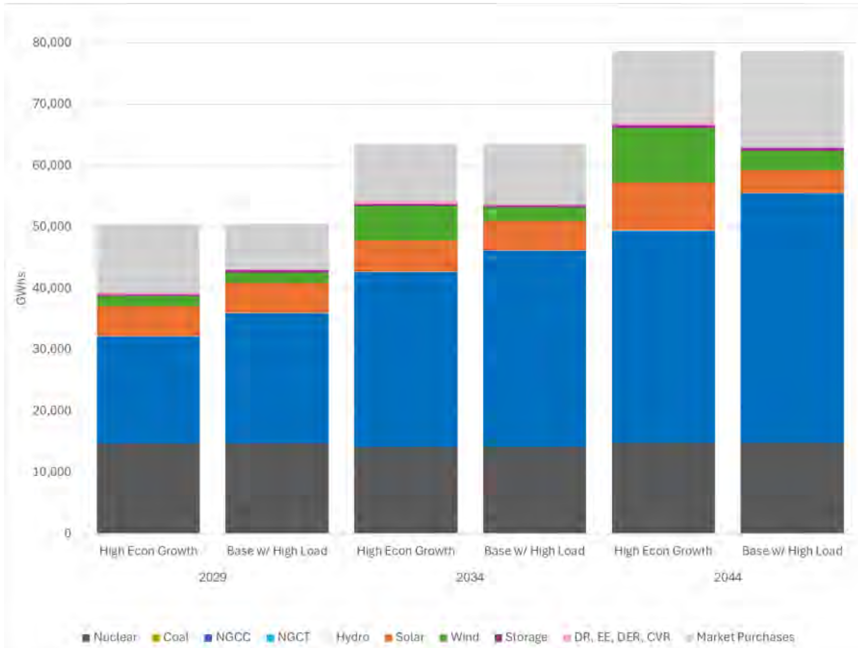

Figure 64. Comparison of Energy - High Economic Growth and Base with High Indiana Load Cases

Over the planning horizon, NGCCs provide more energy in the Base with High Indiana Load Case as compared to the High Economic Growth Case. This is due to the lower natural gas prices assumed in the Base with High Indiana Load Case, incentivizing the NGCCs to dispatch at higher capacity factors and generate more energy.

Table 44 shows the resource additions for the Base with Low Indiana Load Case.

Table 44. Base with Low Indiana Load Case Cumulative Nameplate Capacity Additions

Year	Nameplate MW								Accredited MW	
	Wind	Solar	Storage	New NGCC	Existing NGCC	New NGCT	Existing NGCT	Nuclear Cook SLR	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

The Base with Low Indiana Load Case includes short-term capacity additions through 2027 until supply-side resources become available in 2028. Wind and gas resources are selected in 2028 in response to load growth by 2030. Existing NGCCs are selected to meet the capacity and energy obligations beginning in 2028 and increase to a cumulative amount of 3,600 MW by 2030. Existing NGCTs are selected to meet capacity obligation beginning in 2028 and increase to a cumulative amount of 2,000 MW by 2031. DR, EE, DER, CVR increase over time until 2031 when they begin to decrease due to the expiration of some of the resources selected. Beyond 2031, new NGCCs are built in 2034 to meet the load growth as NGCCs are the most economic options to meet the growing capacity and energy obligations. In addition, the Cook SLR is selected in 2035 and 2038.

Figure 65 shows the accredited capacity results by resource type for the Base with Low Indiana Load Case.

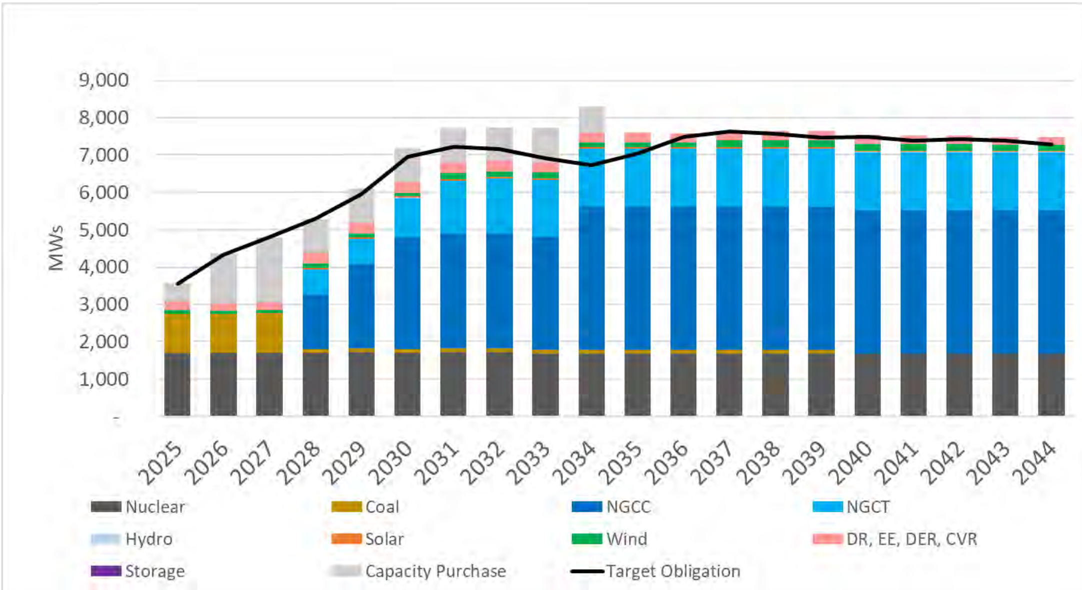

Figure 65. Base with Low Indiana Load Case Accredited Capacity by Resource Type

Existing nuclear, NGCC, and NGCT support the majority of the capacity needs throughout 2044. Figure 65 shows the increase in accredited capacity compared to the Target Obligation during 2031 to 2035. This is due to capacity additions selected economically to meet the energy obligation during that period while preparing for the subsequent load increase which occurs from 2034 to 2037.

Energy results by resource type for the Base with Low Indiana Load Case are show in Figure 66.

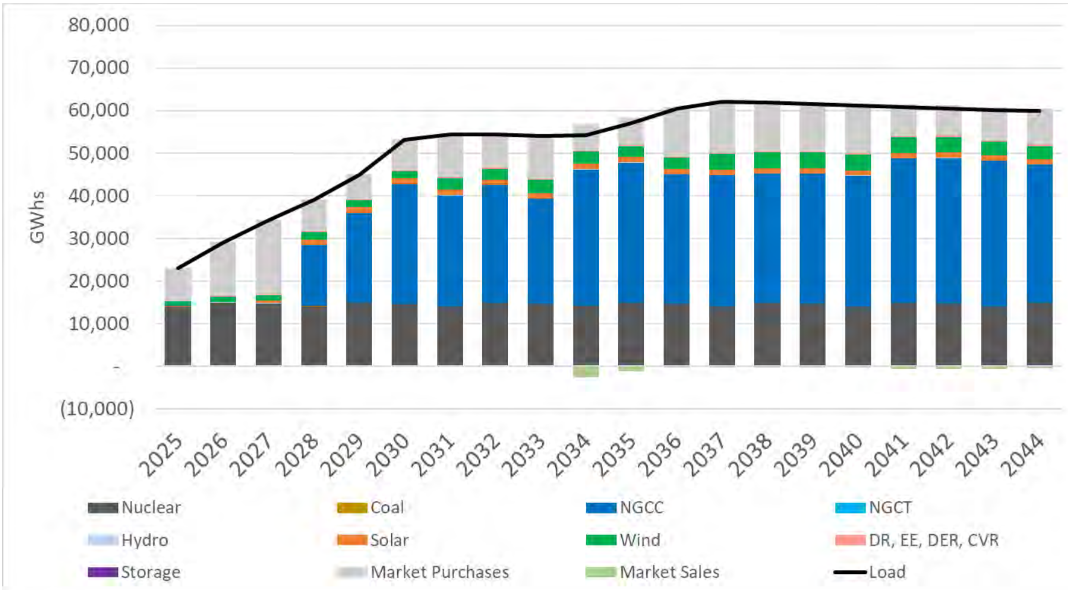

Figure 66. Low Indiana Load Case Portfolio Energy by Resource Type

Energy from nuclear, NGCC, and market purchases provide most of the energy needs, with renewables and demand-side resources making up a small component of the energy needs. There are minimal market sales throughout the planning horizon.

Figure 67 below compares the accredited capacity by resource type for the Low Economic Growth and Base with Low Indiana Load Cases. This comparison is shown for years 2029, 2034, and 2044.

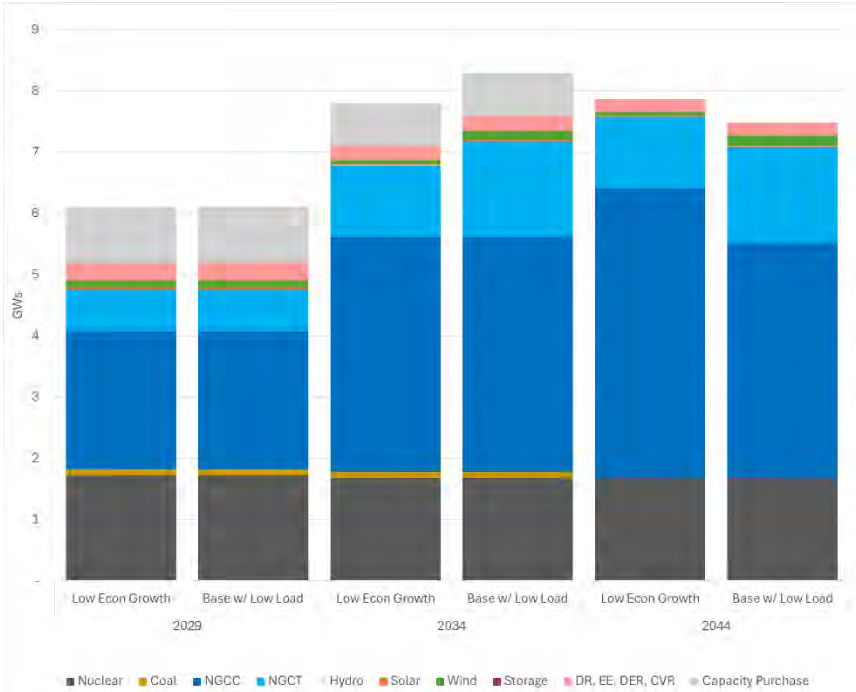

Figure 67. Comparison of Accredited Capacity - Low Economic Growth and Base with Low Indiana Load Cases

As seen in Figure 67, the Base under Low Indiana Load and the Low Economic Growth Case align in 2029 but show differences in 2034 and 2044. In 2034, the Base with Low Indiana Load Case has more accredited capacity from NGCTs and wind as compared to the Low Economic Growth Case. In 2044, the Base with Low Indiana Load Case has less NGCCs but more NGCTs.

Figure 68 below compares energy by resource type for the Low Economic Growth and Base with Low Indiana Load Cases. This comparison is shown for years 2029, 2034, and 2044.

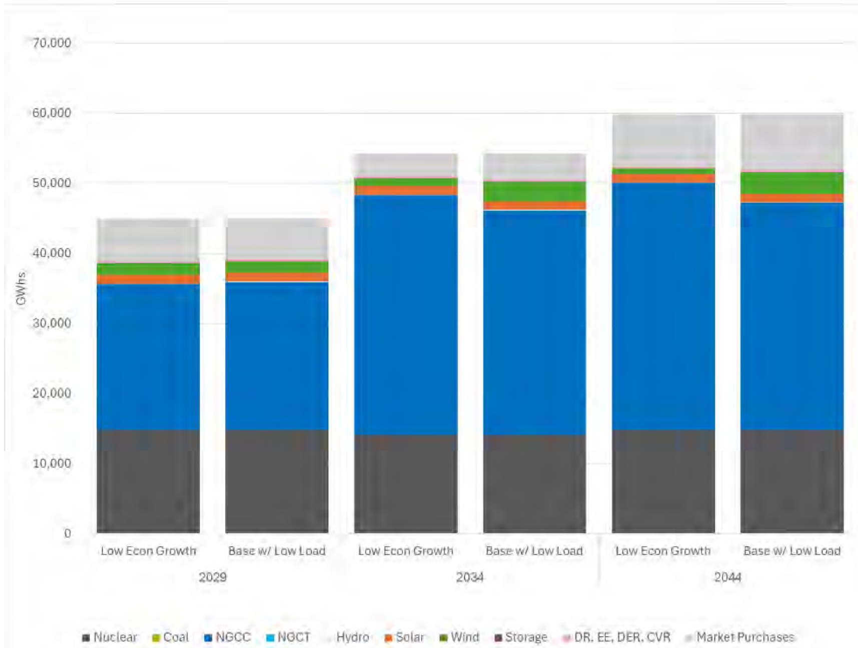

Figure 68. Comparison of Energy - Low Economic Growth and Base under Low Indiana Load Cases

Similar to the comparison of accredited capacity, Figure 68 shows the Base with Low Indiana Load and the Low Economic Growth Case align in 2029 but show differences in 2034 and 2044. The primary difference is the NGCC energy. In 2034 and 2044, less NGCC energy is generated due to the higher natural gas prices assumed in the Base with Low Indiana Load Case as compared to the Low Economic Growth Case. The energy deficit is replaced by energy generated by wind resources.

9.5.3.4 Rockport Unit 1 Retires Early

The two Rockport Unit 1 early retirement cases were developed in compliance pursuant to the Settlement Agreement approved in IURC Cause No. 45546. The Rockport Unit 1 Retires 2025 Case assumes the retirement of Rockport Unit 1 on May 31, 2025, rather than 2028, while the Rockport Unit 1 Retires 2026 Case assumes retirement on May 31, 2026.

Table 45 below shows resource additions included in the Rockport Unit 1 Retires in 2025 Case.

Table 45. Rockport Unit 1 Retires 2025 Case Cumulative Nameplate Capacity Additions

Year	Nameplate MW								Accredited MW	
	Wind	Solar	Storage	New NGCC	Existing NGCC	New NGCT	Existing NGCT	Nuclear (Includes Cook SLR & SMR)	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

The Rockport Unit 1 Retires 2025 Case includes larger amounts of short-term capacity additions through 2027 as compared to the Base Reference Case to account for the capacity deficit caused by Rockport's early retirement. Beginning in 2028 and continuing for the remainder of the planning horizon, the selected resources align with those in the Base Reference Case.

Table 46 below shows resource additions included in the Rockport Unit 1 Retires 2026 Case.

Table 46. Rockport Unit 1 Retires 2026 Case Nameplate Capacity Additions

Year	Nameplate MW								Accredited MW	
	Wind	Solar	Storage	New NGCC	Existing NGCC	New NGCT	Existing NGCT	Nuclear (Includes Cook SLR & SMR)	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

The Rockport Unit 1 Retires 2026 Case includes larger amounts of short-term capacity additions through 2027 as compared to the Base Reference Case to account for the capacity deficit caused by Rockport's early retirement. Beginning in 2028 and continuing for the remainder of the planning horizon, the selected resources align with those in the Base Reference Case.

Figure 69, Figure 70, Figure 71, and Figure 72 represent the Rockport Unit 1 Retires 2025 and 2026 Cases accredited capacity and energy results by resource type. As noted above, results align with those of the Base Reference Case beginning in 2028 and continuing for the remainder of the planning horizon.

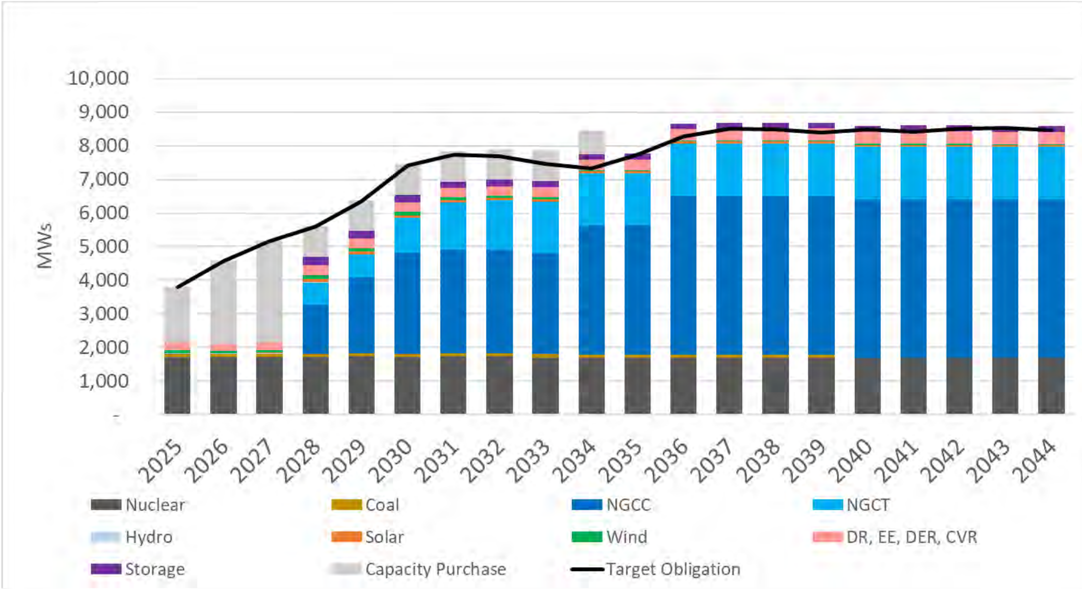

Figure 69. Rockport Unit 1 Retires 2025 Case Accredited Capacity by Resource Type

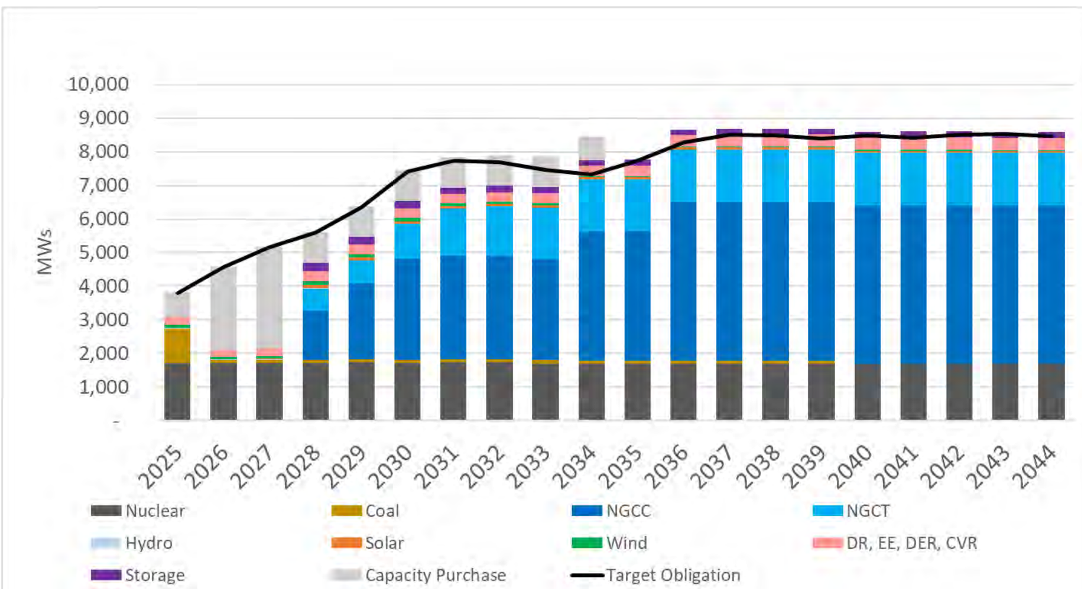

Figure 70. Rockport Unit 1 Retires 2026 Case Accredited Capacity by Resource Type

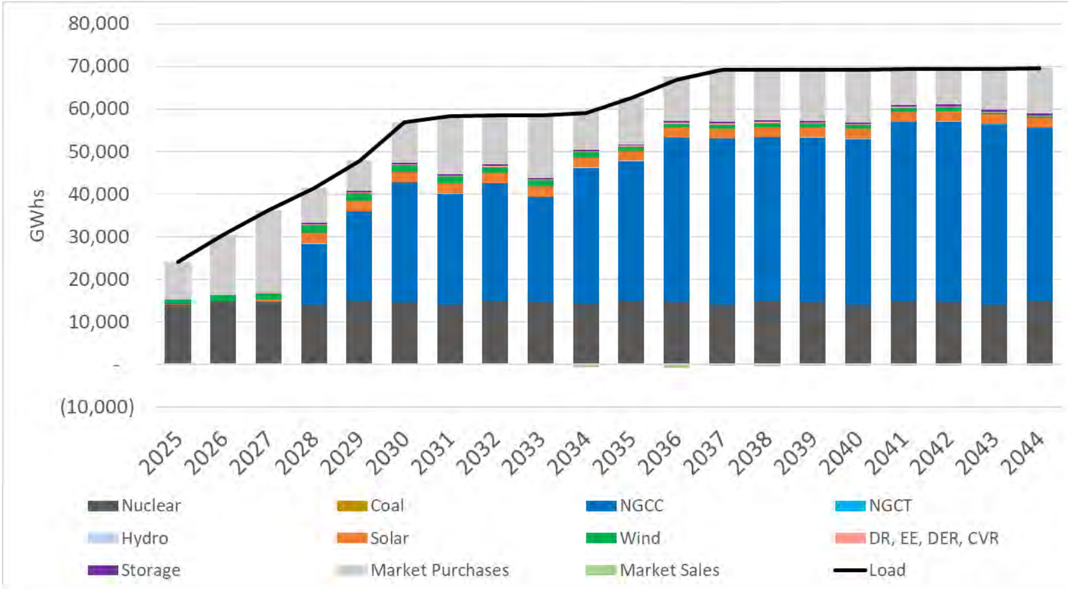

Figure 71. Rockport Unit 1 Retires 2025 Case Energy by Resource Type

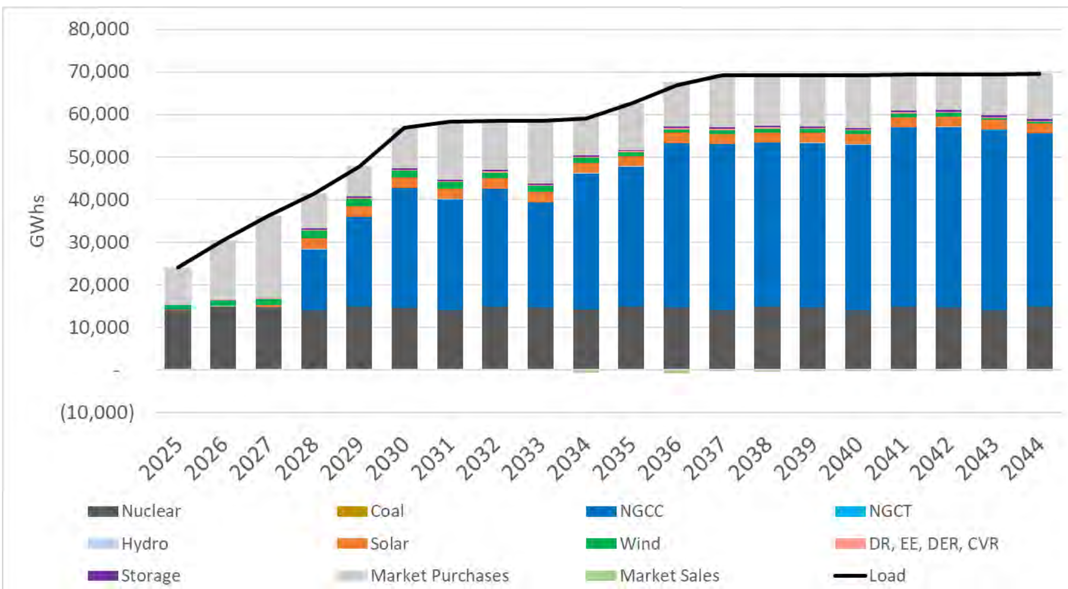

Figure 72. Rockport Unit 1 Retires 2026 Case Energy by Resource Type

9.5.3.5 Exit OVEC ICPA in 2030

The Exit OVEC ICPA in 2030 Case was developed in compliance with the Settlement Agreement approved in IURC Cause No. 45546.

Table 47 shows the resource additions included in the Exit OVEC ICPA in 2030 Case.

Table 47. Exit OVEC ICPA in 2030 Case Cumulative Nameplate Capacity Additions

Year	Nameplate MW								Accredited MW	
	Wind	Solar	Storage	New NGCC	Existing NGCC	New NGCT	Existing NGCT	Nuclear Cook SLR	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

The Exit OVEC ICPA in 2030 Case selects resources substantially similar to the Base Reference Case with the exception of increased selection of demand-side resources. Additional demand-side resources were selected to support the capacity deficit caused by exiting the OVEC ICPA. As will be discussed in Section 9.6, the Affordability analysis metrics for this case resulted in an NPVRR $100 million higher than the Base Reference Case, due to the estimated cost of exiting the OVEC ICPA in 2030.

Figure 73 and Figure 74 show the accredited capacity and energy results by resource type for the Exit OVEC ICPA in 2030 Case. As noted above, results in these figures are substantially similar to those of the Base Reference Case.

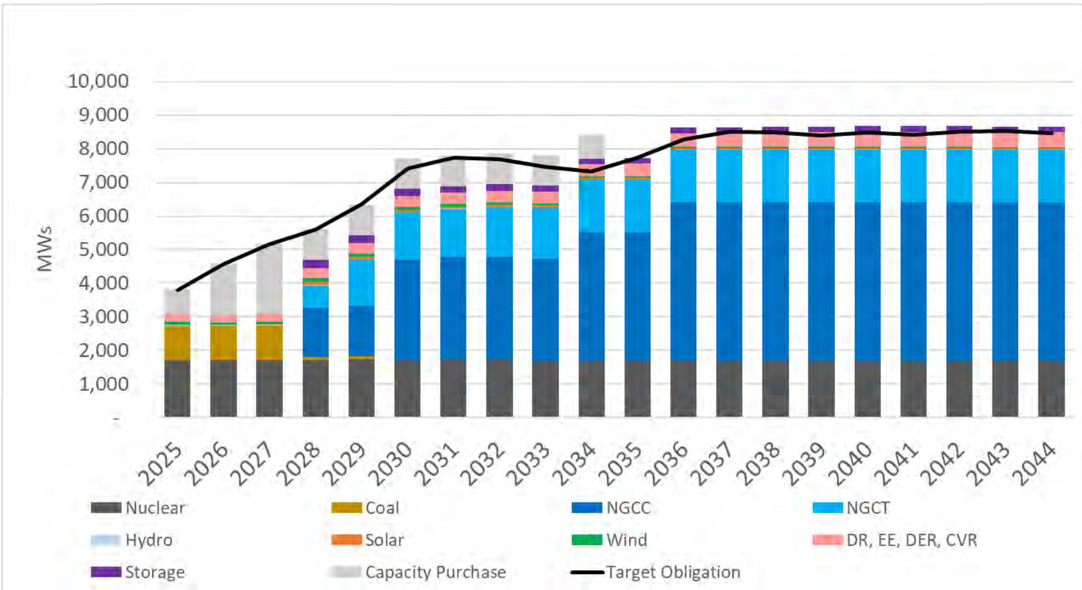

Figure 73. Exit OVEC ICPA in 2030 Case Accredited Capacity by Resource Type

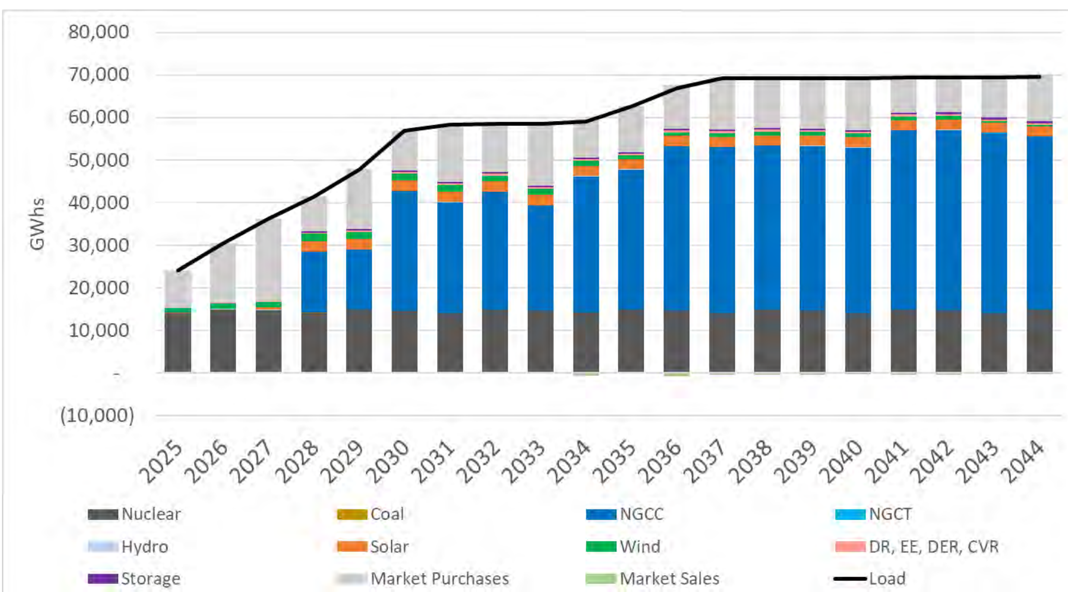

Figure 74. Exit OVEC ICPA in 2030 Case Energy by Resource Type

9.5.3.6 High Technology Costs

The High Technology Costs Case is intended to measure the impact on resource selections and Power Supply Costs assuming higher resource costs.

Table 48 shows the resource additions included in the High Technology Costs Case.

Table 48. High Technology Costs Case Cumulative Nameplate Capacity Additions

Year	Nameplate MW								Accredited MW	
	Wind	Solar	Storage	New NGCC	Existing NGCC	New NGCT	Existing NGCT	Nuclear (Includes Cook SLR & SMR)	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

The resources selected for the High Technology Cost Case are identical to those selected in the Base Reference Case, indicating the capacity and energy needs are the main driver for the selection of resources.

Figure 75 and Figure 76 show the accredited capacity and energy results by resource type for the High Technology Cost Case. As noted above, results align with those of the Base Reference Case for the entire planning horizon.

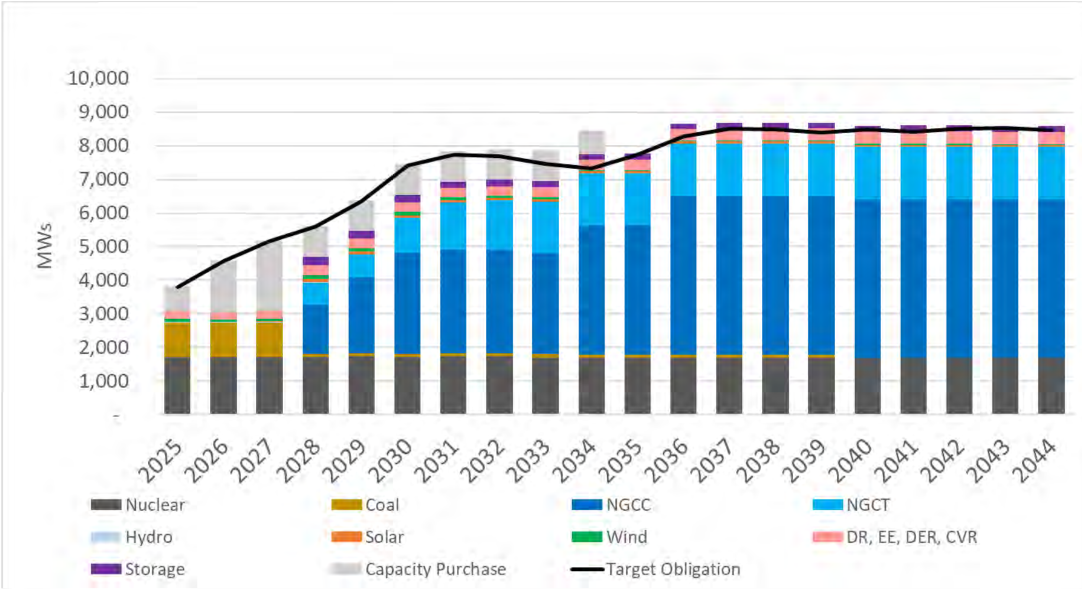

Figure 75. High Technology Costs Case Accredited Capacity by Resource Type

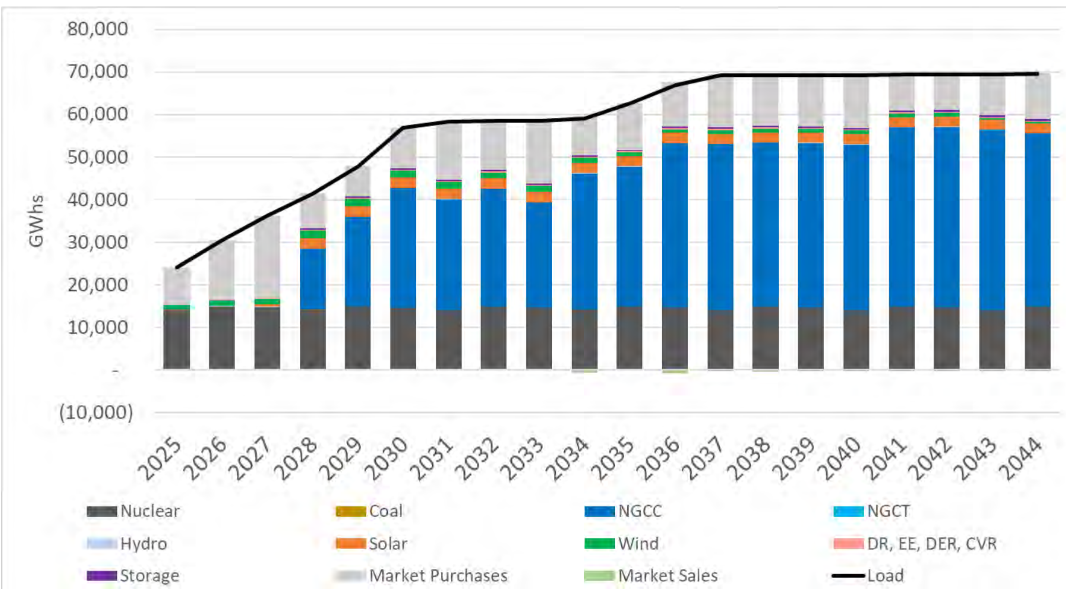

Figure 76. High Technology Costs Case Energy by Resource Type

9.5.3.7 Expanded Wind Availability

I&M developed two (2) Expanded Wind Availability sensitivities to reflect updated market intelligence received through I&M's 2024 RFPs related to additional market availability of wind resources through 2030. The Expanded Wind Availability (Base) Case uses Base Reference Case assumptions, while the Expanded Wind Availability (EER) Case uses EER Case assumptions.

Table 49 below shows resource additions included in the Expanded Wind Availability (Base) Case.

Table 49. Expanded Wind Availability (Base) Case Cumulative Nameplate Capacity Additions

Year	Nameplate MW								Accredited MW	
	Wind	Solar	Storage	New NGCC	Existing NGCC	New NGCT	Existing NGCT	Nuclear Cook SLR	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

The Expanded Wind Availability (Base) Case includes short-term capacity additions through 2027 until supply-side resources become available in 2028. In 2028, all 1,200 MW of wind made available to the model was selected, reducing the amount of solar and storage selected compared to the Base Reference Case. These results indicate that wind resources are more economic compared to solar and storage resources. The same amount of existing and new NGCCs and NGCTs are selected as compared to the Base Reference Case. In addition, the Cook SLR is selected in 2035 and 2038.

Figure 77 shows the accredited capacity results by resource type for the Expanded Wind Availability (Base) Case.

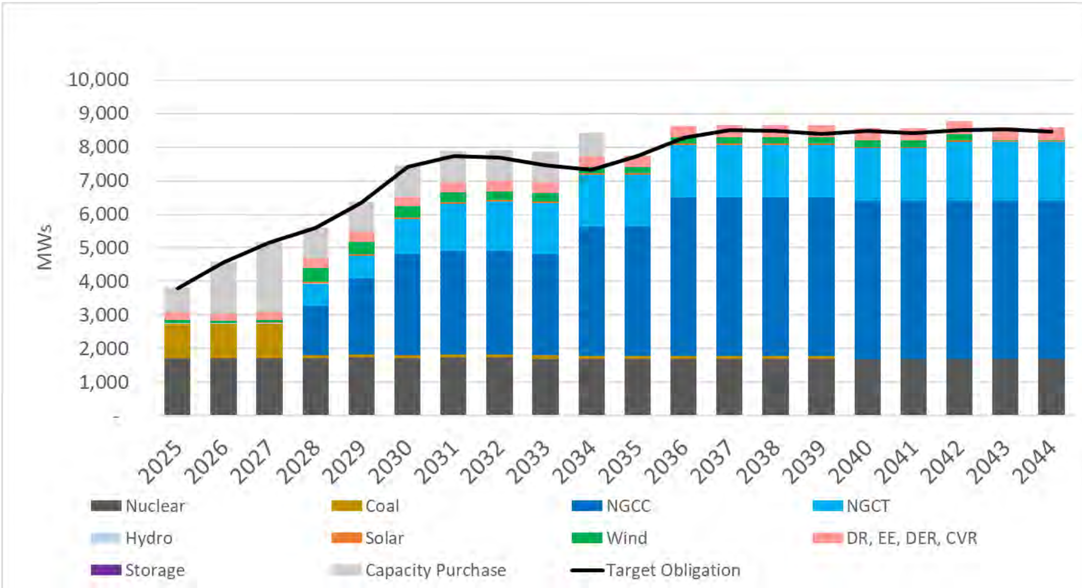

Figure 77. Expanded Wind Availability (Base) Case Accredited Capacity by Resource Type

The accredited capacity values for all resources in Figure 77 reflect forecasted ELCCs as described in Section 8.1.1.3. Existing nuclear, NGCC, and NGCT support the majority of the capacity needs throughout 2044. While nameplate additions of wind are significant, the forecasted ELCCs result in lower accredited capacity for these resources.

Energy results by resource type for the Expanded Wind Availability (Base) Case are shown in Figure 78.

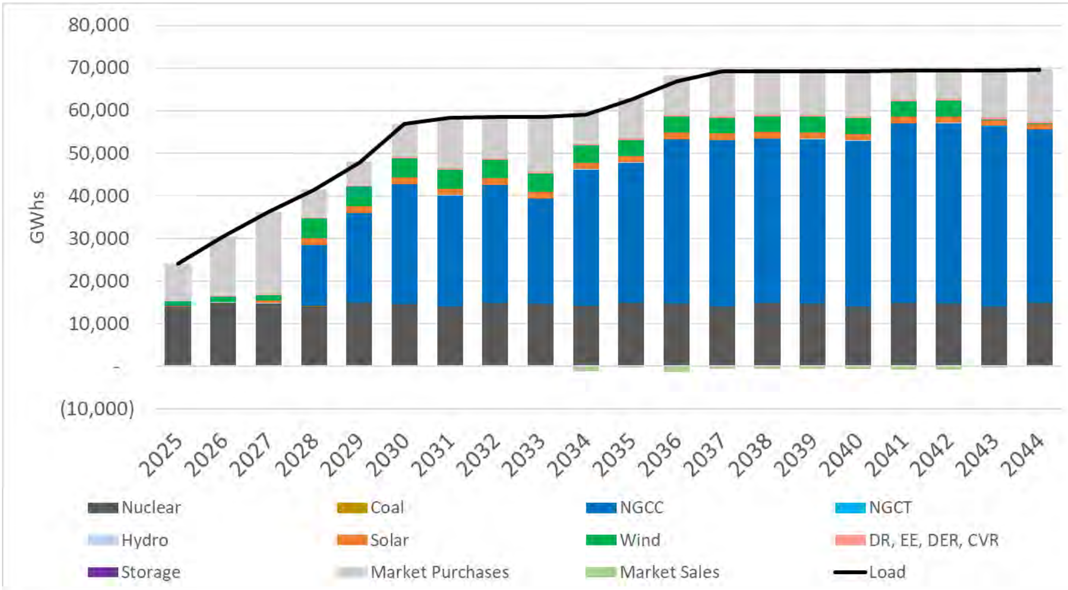

Figure 78. Expanded Wind Availability (Base) Case Energy by Resource Type

Energy from nuclear, NGCC, and market purchases provide most of the energy needs, with renewables and demand-side resources making up a small component of the energy needs. Wind provides more energy as compared to the Base Reference Case. There are minimal market sales throughout the planning horizon.

Figure 79 below compares accredited capacity by resource type for the Base Reference and the Expanded Wind Availability (Base) Cases while Figure 80 compares the energy by resource type. This comparison is shown for years 2029, 2034, and 2044.

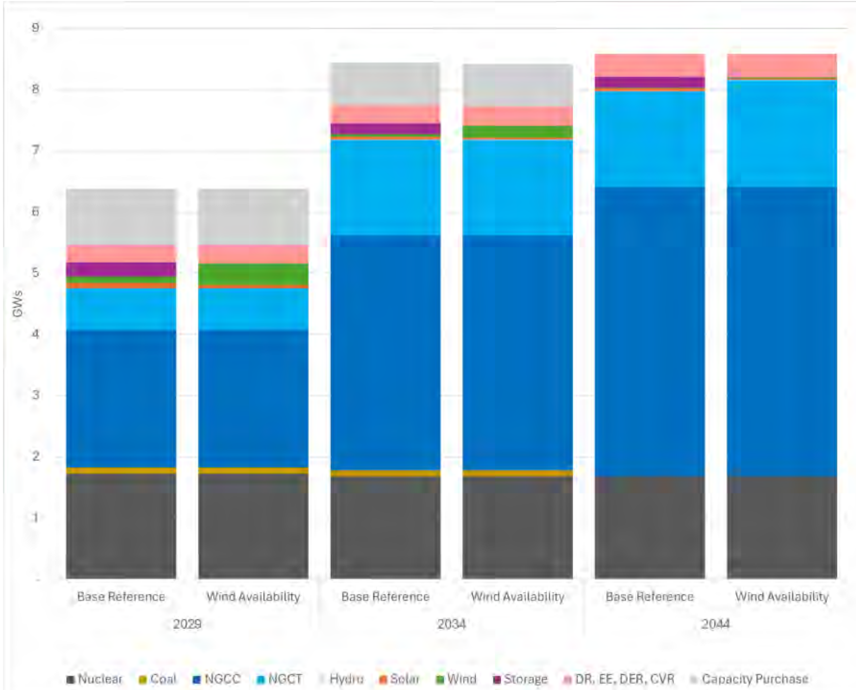

Figure 79. Comparison of Accredited Capacity - Base Reference and Expanded Wind Availability (Base)

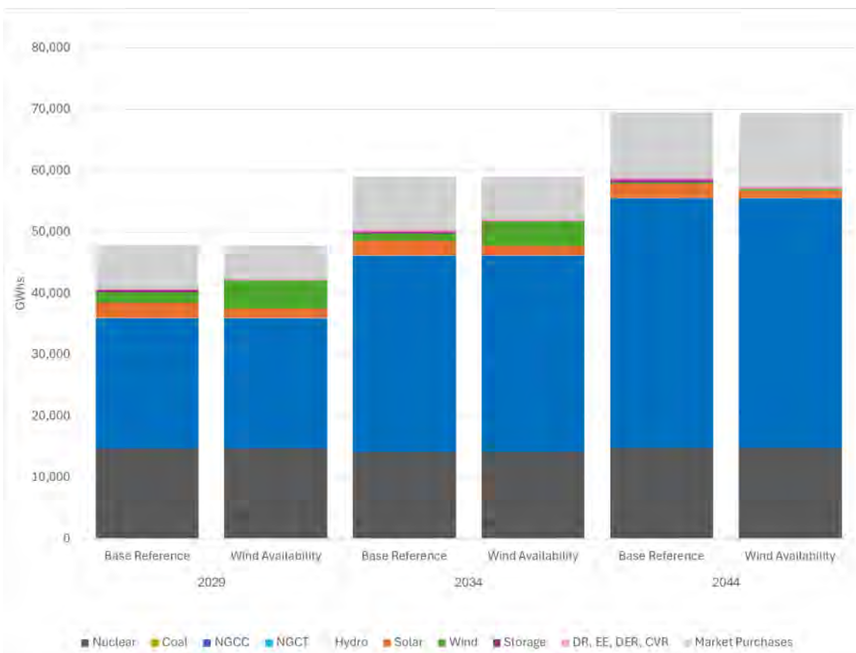

Figure 80. Comparison of Energy - Base Reference and Expanded Wind Availability (Base)

As demonstrated in the figures above, the Expanded Wind Availability (Base) Case is substantially similar to the Base Reference Case, with the exception of more wind resources in 2029 and 2034.

Table 50 below shows resource additions included in the Expanded Wind Availability (EER) Case.

Table 50. Expanded Wind Availability (EER) Case Cumulative Nameplate Capacity Additions

Year	Nameplate MW								Accredited MW	
	Wind	Solar	Storage	New NGCC	Existing NGCC	New NGCT	Existing NGCT	Nuclear (Includes Cook SLR & SMR)	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

The Expanded Wind Availability (EER) Case includes short-term capacity additions through 2027 until supply-side resources become available in 2028. In 2028, 1,000 MW of wind was selected, reducing the amount of solar and storage selected compared to the Base Reference Case. These results indicate that wind resources are more economic compared to solar and storage resources. The same amount of existing and new NGCCs and NGCTs are selected as compared to the EER Case. In addition, the Cook SLR is selected in 2035 and 2038.

Figure 81 shows the accredited capacity results by resource type for the Expanded Wind Availability (EER) Case.

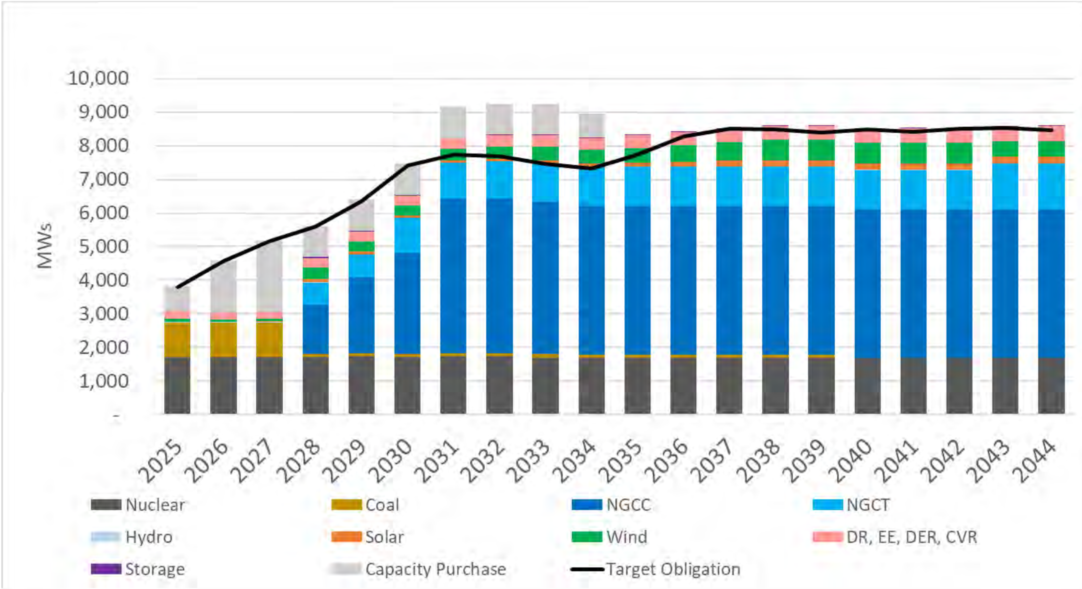

Figure 81. Expanded Wind Availability (EER) Case Accredited Capacity by Resource Type

Nuclear and natural gas resources which have higher accredited capacity support the majority of the capacity obligation. While nameplate additions of solar and wind are significant, the forecasted ELCCs as described in Section 8.1.1.3 result in lower accredited capacity values for these resources. Figure 81 shows the increase in accredited capacity compared to the Target Obligation during 2031 to 2034. This is due to capacity additions selected economically to meet the energy obligation during that period while preparing for the subsequent load increase which occurs from 2034 to 2037.

Energy results by resource type for the Expanded Wind Availability (EER) Case are shown in Figure 82.

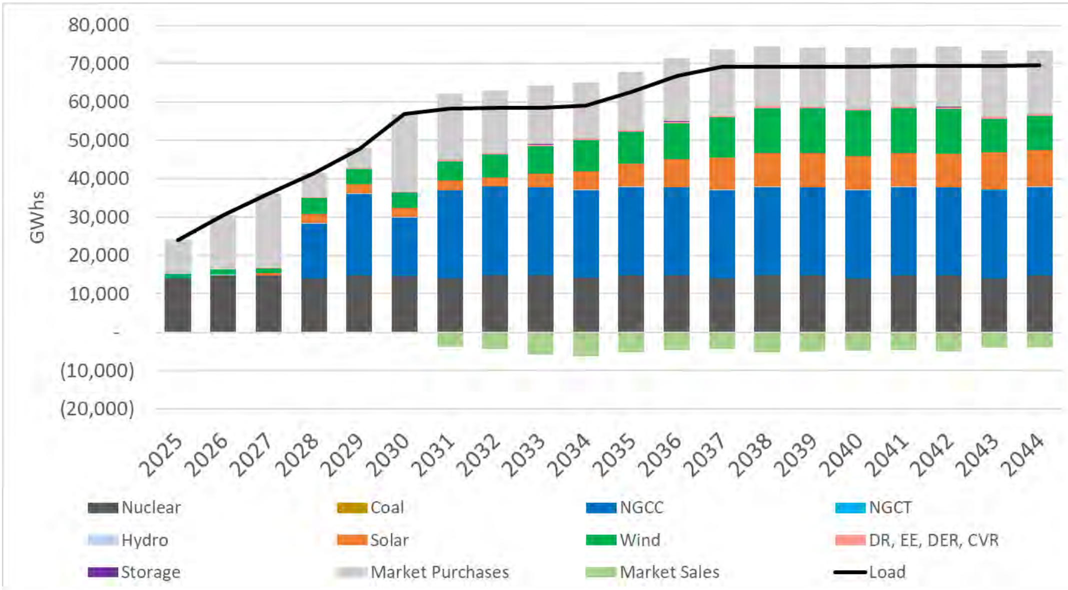

Figure 82. Expanded Wind Availability (EER) Case Energy by Resource Type

The assumed EPA Section 111(b)(d) capacity factor limitations result in significantly more energy contributions from wind and solar resources. The addition of renewable resources results in energy market sales starting in 2031 as renewable energy was generated at times when it was not needed to serve Indiana's load and thus was sold into the market.

Figure 83 below compares accredited capacity by resource type for the EER and the Expanded Wind Availability (EER) Cases while Figure 84 compares the energy by resource type. This comparison is shown for years 2029, 2034, and 2044.

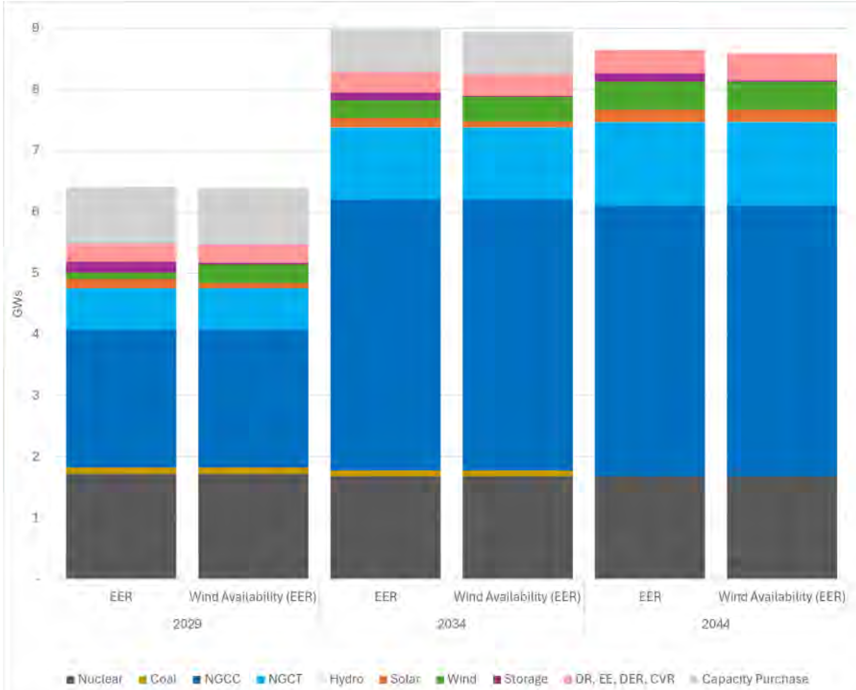

Figure 83. Comparison of Accredited Capacity - EER and Expanded Wind Availability (EER) Cases

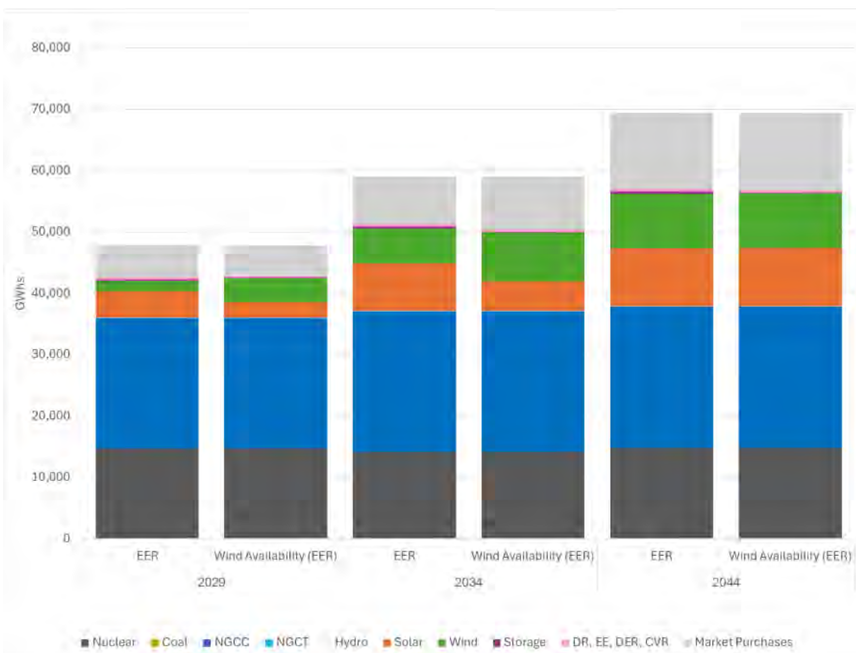

Figure 84. Comparison of Energy - EER and Expanded Wind Availability (EER) Cases

As can be noted in the figures above, the Expanded Wind Availability (EER) Case is substantially similar to the EER Case, with the exception of more wind resources in 2029 and 2034.

9.6 Portfolio Performance Indicators

The 2024 IN IRP Portfolio Performance Indicator metrics align with the Five Pillars of Indiana energy policy consisting of Reliability, Affordability, Resiliency, Stability, and Environmental Sustainability. The definitions for each of the pillars supporting the metrics are provided in Section 2.3. Portfolio metrics for each of the pillars are described below.

9.6.1 Reliability

The objective for Reliability is to consider reliance on the energy market for purchase and sales and to maintain capacity reserve margin. Three performance indicators were selected to measure progress towards maintaining Reliability. The performance indicators for Reliability along with associated metrics are summarized in Table 51.

Table 51. Reliability Performance Indicators

Performance Indicator	Metric Description
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.

As a member of PJM, the Company can leverage low-cost market energy for the benefits of its customers. Under normal conditions, this is of high value to ensure access to reliable and low-cost energy. Energy markets, however, include risks both in a reliance on this resource for purchases and sales during periods of high volatility. Measuring the total portion of customer energy served by the market, or conversely, the reliance on market energy sales in periods of excess generation will provide insight to potential market risks of each portfolio.

Energy market risk was measured using portfolio reliance on market purchases and sales to balance generation with customer load. Performance metrics considered for market risk include the 10- and 20-year NPVs of the associated purchases and sales and the percentage of total Indiana demand (in MWh) purchased or sold over the same 10- and 20-year intervals. Table 52 shows each portfolio's performance under the energy market risk metrics.

Table 52. Reliability Market Metrics Analysis

Portfolio	Market Purchases				Market Sales			
	NPV of Market Purchases ($B)		MWhs % of Total Demand		NPV of Market Sales ($B)		MWhs % of Total Demand	
	10-years	20-years	10-years	20-years	10-years	20-years	10-years	20-years
Base Reference	$2.63	$4.27	27%	22%	$0.01	$0.07	0%	0%
High Economic Growth	$4.04	$6.57	30%	23%	$0.08	$0.30	0%	1%
Low Economic Growth	$1.77	$2.54	24%	19%	$0.03	$0.24	0%	2%
Enhanced Environmental Regulations	$3.12	$5.46	31%	28%	$0.55	$1.41	4%	6%
Base under EPA Section 111(b)(d) Requirements	$3.09	$5.47	31%	28%	$0.50	$1.36	4%	6%
Low Carbon: Expanded Build Limits	$2.10	$3.63	22%	18%	$0.44	$1.36	4%	6%
Low Carbon: Transition to Objective	$2.70	$4.10	27%	20%	$0.19	$1.69	2%	8%
Base with High Indiana Load	$2.83	$4.91	28%	23%	$0.04	$0.07	0%	0%
Base with Low Indiana Load	$2.13	$3.57	24%	20%	$0.06	$0.13	1%	1%
Exit OVEC ICPA in 2030	$2.77	$4.40	28%	22%	$0.01	$0.07	0%	0%
Rockport Unit 1 Retires 2025	$2.64	$4.28	27%	22%	$0.01	$0.07	0%	0%
Rockport Unit 1 Retires 2026	$2.63	$4.27	27%	22%	$0.01	$0.07	0%	0%
Expanded Wind Availability (Base)	$2.40	$3.91	25%	20%	$0.03	$0.12	0%	1%
Expanded Wind Availability (EER)	$3.07	$5.36	31%	27%	$0.47	$1.27	4%	5%
High Technology Costs	$2.63	$4.27	27%	22%	$0.01	$0.07	0%	0%

The Cases with the largest market purchase NPVs are the High Economic Growth, Base with High Indiana Load, Enhanced Environmental Regulations, Base under EPA Section 111(b)(d) Requirements, and Expanded Wind Availability (EER) Cases. High market purchase NPVs for the High Economic Growth and Base with High Indiana Load Cases are driven by higher load forecast assumptions resulting in more energy market purchases. The three cases that included the assumed EPA Section 111(b)(d) compliant capacity factor limitations (EER, Base Under EPA Section 111(b)(d), and Expanded Wind Availability (EER)) resulted in higher market purchase NPVs due to the lower generation produced from the natural gas resources and the intermittency of renewable generation. Cases with high levels of renewable energy also have larger market sales NPVs, as energy was generated by renewables in times when it was not needed to serve Indiana's load. That excess renewable energy was sold to the market. This is demonstrated in the Low Carbon Cases and the three cases that included the assumed EPA Section 111(b)(d) compliant capacity factor limitations. These cases have the largest 20-year market sales NPVs.

By measuring planning reserves performance, the Company can evaluate the exposure of different resource portfolios towards meeting planning PJM's FPR. Table 53 shows each portfolio's performance under the planning reserve margin metrics.

Table 53. Reliability Reserve Margins

Portfolio	Planning Reserve Margins – Average of Annual (%)	
	10-years	20-years
Base Reference	-0.7%	-3.4%
High Economic Growth	3.9%	-0.7%
Low Economic Growth	-0.3%	-1.5%
Enhanced Environmental Regulations	5.3%	-0.3%
Base under EPA Section 111(b)(d) Requirements	5.5%	-0.2%
Low Carbon: Expanded Build Limits	4.5%	-0.8%
Low Carbon: Transition to Objective	2.0%	0.5%
Base with High Indiana Load	0.8%	-2.6%
Base with Low Indiana Load	2.3%	-1.9%
Exit OVEC ICPA in 2030	-0.6%	-3.2%
Rockport Unit 1 Retires 2025	-0.7%	-3.4%
Rockport Unit 1 Retires 2026	-0.6%	-3.4%
Expanded Wind Availability (Base)	-0.6%	-3.4%
Expanded Wind Availability (EER)	5.1%	-0.6%
High Technology Costs	-0.7%	-3.4%

The average annual Planning Reserve Margin metric should be compared to the target values of -3% and -5.5% for the 10- and 20-year period, respectively. These target values represent the average PJM FPR and the capacity contingency over the specified period. In the 10-year period, the average annual Planning Reserves values range from -0.7% to 5.5%. All Portfolios add capacity over the Target Obligation during this period to prepare for load growth beginning in 2034. In addition, resources are added to meet the energy obligation during the 10-year period. In the 20-year period, the average annual Planning Reserves values range from -3.4% to 0.5%.

The Low Carbon Cases and the three cases that included the assumed EPA Section 111(b)(d) compliant capacity factor limitations (EER, Base Under EPA Section 111(b)(d), and Expanded Wind Availability (EER)) had the highest average annual Planning Reserves. The Low Carbon Cases had higher annual Planning Reserves due to the additional resources selected to meet the Low Carbon Objective modeled in these cases. The cases that had the assumed capacity factor limitations had higher annual Planning Reserves due to the selection of additional resources to meet the energy obligation. All cases meet the forecasted PJM load obligation.

9.6.2 Affordability

The objective of Affordability is to maintain focus on costs to customers and the resilience of Cases to changing market conditions. Affordability metrics utilized are for the generation component Power Supply Costs only and do not represent final costs which will apply to customers. Power Supply Costs represent the annualized capital associated with resources selected, operation and maintenance (O&M) costs, fuel costs, environmental costs, net purchases and sales of energy and capacity, property and income taxes, and the return on capital. The performance indicators for Affordability along with associated metrics are summarized in Table 54.

Table 54. Affordability Performance Indicators

Performance Indicator	Metric Description
Near-Term Rate Impacts (CAGR)	7-year Compound Annual Growth Rate (CAGR) of Annual Power Supply Costs. Lower values are better.
Net Present Value Revenue Requirement (NPVRR)	Portfolio 20-year NPVRR of Power Supply Costs. Lower values are better.
Portfolio Resilience	Range of Portfolio NPVRR (Power Supply Costs) dispatched across all Cases. Lower values are better.

The Affordability metrics above measure each portfolio's ability to provide low-cost capacity and energy in the short- and long-term while meeting the constraints applied for each Case. Both short- and long-term metrics are intended to demonstrate anticipated costs that will impact I&M and its commercial, industrial, and residential customers. As these financial metrics indicate a crucial component of the costs being incurred, lower values for each indicate better portfolio performance under the Affordability Pillar.

Portfolio Resilience was measured for Candidate Portfolios selected for stochastic risk analysis that will be described in Section 9.7. Portfolio Resilience, measured as the difference between the 10th

and 90th percentile NPVRRs obtained from stochastic risk analysis, indicates the financial impact that economic uncertainties could have on Candidate Portfolios. Lower values are preferred, as this indicates a lower variability of expected customer costs across a wide range of long-term market conditions. These results are presented in Section 9.8.

Table 55 provides Affordability metrics for each portfolio developed.

Table 55. Affordability Metrics Analysis

Portfolio	Short Term	Long Term
	7-yr CAGR Power Supply (%)	NPVRR ($B)
	2024-2031	2025-2044
Base Reference	-0.5%	$32.0
High Economic Growth	1.6%	$39.3
Low Economic Growth	-2.3%	$25.7
Enhanced Environmental Regulations	0.7%	$33.2
Base under EPA Section 111(b)(d) Requirements	0.7%	$33.3
Low Carbon: Expanded Build Limits	4.5%	$41.4
Low Carbon: Transition to Objective	1.3%	$39.9
Base with High Indiana Load	-0.1%	$34.9
Base with Low Indiana Load	-0.7%	$28.3
Exit OVEC ICPA in 2030	-0.4%	$32.1
Rockport Unit 1 Retires 2025	-0.5%	$32.6
Rockport Unit 1 Retires 2026	-0.5%	$32.4
Expanded Wind Availability (Base)	-0.5%	$31.8
Expanded Wind Availability (EER)	0.5%	$32.8
High Technology Costs	0.7%	$34.8

Over the seven-year period, the variation in the expected growth of customer rates is driven by the differences in short-term resource additions across the Cases. As expected, the Low Economic

Growth and Base with Low Indiana Load Cases both show the lowest seven-year growth rates at -2.3% and -0.7%, respectively. These low values are driven by the Cases selecting less resources to serve the lower load compared to the other cases. The Base Reference Case has the next lowest seven-year growth rate along with the Cases that select similar resources to that case. Alternatively, the Low Carbon Cases have the highest seven-year growth rates. These high values are driven by the selection of a significant amount of carbon-free resources in the same seven-year period. The High Economic Growth Case has a high seven-year growth rate driven by this case selecting more resources to serve the higher load compared to the other cases. The High Technology Cost Case also has a higher seven-year growth rate due to the elevated resource cost assumption included in this case. The three cases that included the assumed EPA Section 111(b)(d) compliant capacity factor limitations (EER, Base Under EPA Section 111(b)(d), and Expanded Wind Availability (EER)) had similar seven-year growth rates at 0.5% to 0.7%, indicating moderate short-term growth as compared to other Cases.

The portfolios with the lowest NPVRRs include the cases closely aligned with the Base Reference Case as well as the Expanded Wind Availability Cases. These cases had NPVRRs ranging between \$31.8B to \$32.8B. Similar to the short-term affordability metrics, the Low Economic Growth and Base with Low Indiana Load Cases both show the lowest NPVRRs at \$25.7B and \$28.3B, respectively. The High Economic Growth, Base with High Indiana Load, Low Carbon: Transition to Objective, and the High Technology Cost Cases have the highest NPVRRs ranging from \$34.8B to \$41.4B. Specifically, the Low Carbon Cases had the highest NPVRRs indicating the cost impact of the Low Carbon Objective.

9.6.3 Resiliency

The objective of Resiliency is to evaluate and measure diversity of resources and fleet dispatchability. The performance indicators for Resiliency along with associated metrics are summarized in Table 56.

Table 56. Resiliency Performance Indicators

Performance Indicator	Metric Description
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.

I&M is interested in selecting a diverse set of resources as a method for maintaining Resiliency for its customers and in evaluating the role that new and innovative technologies can play to help customers reach their goals. This performance indicator will allow the Company to assess the overall diversity within portfolios considered. The diversity index is based on the Shannon-Weiner Diversity Index that considers the number of different types of resources and their respective contributions to the portfolio total with respect to capacity and energy. The change in the diversity index for each portfolio over time provides a view of how portfolio diversity changes over time. This metric is an improvement from the 2021 I&M IRP as it considers the respective contributions of each resource, in addition to the number of different types of resources. Whereas the 2021 I&M IRP only considered the number of unique generations and fuel types in its diversity metrics.

Table 57 shows the percent change in the portfolio diversity index from 2025 over the 10- and 20-year period.

Table 57. Resiliency/ Reliability Metrics Analysis

Portfolio	Resource Diversity			
	Capacity (%)		Energy (%)	
	10-years	20-years	10-years	20-years
Base Reference	31%	19%	173%	139%
High Economic Growth	41%	43%	71%	79%
Low Economic Growth	18%	5%	161%	154%
Enhanced Environmental Regulations	35%	37%	306%	325%
Base under EPA Section 111(b)(d) Requirements	36%	38%	281%	299%
Low Carbon: Expanded Build Limits	56%	52%	317%	311%
Low Carbon: Transition to Objective	53%	54%	302%	304%
Base with High Indiana Load	34%	25%	208%	189%
Base with Low Indiana Load	24%	19%	170%	172%
Exit OVEC ICPA in 2030	27%	21%	177%	142%
Rockport Unit 1 Retires 2025	80%	64%	183%	148%
Rockport Unit 1 Retires 2026	31%	19%	173%	139%
Expanded Wind Availability (Base)	28%	12%	188%	114%
Expanded Wind Availability (EER)	31%	34%	296%	318%
High Technology Costs	31%	19%	173%	139%

The portfolios that show the largest increase in resource diversity are the Low Carbon Cases. This is due to the significant number of renewable resources in addition to the SMRs selected in these cases. The EER and Expanded Wind Availability (EER) Cases also show a significant increase in diversity over 20 years. The Rockport Unit 1 Retires 2025 Case has a large increase in diversity because the starting point for the change measurement, 2025, has a lower diversity score without Rockport Unit 1 included in the capacity or energy positions. Cases with lower changes in diversity over time are the portfolios based on Base Reference Case assumptions.

9.6.4 (Grid) Stability

I&M's selected Grid Stability metric is designed to evaluate and measure the dispatchability of resources selected in each of the Cases. Fleet Resiliency was evaluated and measured by dispatchable capacity as a percentage of peak load. This metric also supports the Resiliency Pillar.

Table 58 summarizes dispatchable capacity as a percent of total nameplate capacity for each portfolio modeled.

Table 58. Grid Stability/Resiliency Metrics Analysis

Portfolio	Fleet Resiliency: Dispatchable Capacity (%)	
	10-years	20-years
Base Reference	90%	97%
High Economic Growth	96%	97%
Low Economic Growth	89%	97%
Enhanced Environmental Regulations	95%	95%
Base under EPA Section 111(b)(d) Requirements	96%	96%
Low Carbon: Expanded Build Limits	87%	88%
Low Carbon: Transition to Objective	91%	95%
Base with High Indiana Load	92%	98%
Base with Low Indiana Load	92%	96%
Exit OVEC ICPA in 2030	90%	97%
Rockport Unit 1 Retires 2025	84%	95%
Rockport Unit 1 Retires 2026	86%	95%
Expanded Wind Availability (Base)	86%	93%
Expanded Wind Availability (EER)	92%	92%
High Technology Costs	90%	97%

All portfolios show high levels of Fleet Resilience as measured by dispatchable capacity as a percentage of peak load. This is due to the level of natural gas resources selected in each Case in addition to the relicensing of Cook Units 1 and 2.

9.6.5 Environmental Sustainability

The objective of Environmental Sustainability is to evaluate and measure environmental sustainability benefits and compliance costs. The performance indicators for Environmental Sustainability along with associated metrics are summarized in Table 59.

Table 59. Environmental Sustainability Performance Indicators

Performance Indicator	Metric Description
Emissions Change	CO_2, NOx, and 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 the Affordability Pillar above

I&M is interested in understanding how each portfolio's resource selections will impact Environmental Sustainability as measured by emissions reduction. Environmental performance is measured by quantifying the percentage change from the 2005 baseline levels of carbon dioxide (CO2), nitrogen oxide (NOx), and sulfur dioxide (SO2). The Company understands that environmental sustainability can come at a cost and will additionally consider NPVRR under the Affordability objective when discussing the Environmental Sustainability objective.

Table 60 shows the percentage reduction in emissions from 2005 for each of the modeled portfolios.

Table 60. Environmental Stability Metrics Analysis

Portfolio	Emissions Analysis: % Change from 2005 Baseline					
	% Change CO_2		% Change NOx		% Change SO_2	
	2034	2044	2034	2044	2034	2044
Base Reference	-39%	-24%	-94%	-93%	-100%	-100%
High Economic Growth	-46%	-34%	-95%	-93%	-100%	-100%
Low Economic Growth	-35%	-35%	-93%	-94%	-100%	-100%
Enhanced Environmental Regulations	-56%	-55%	-95%	-95%	-100%	-100%
Base under EPA Section 111(b)(d) Requirements	-56%	-55%	-95%	-95%	-100%	-100%
Low Carbon: Expanded Build Limits	-77%	-77%	-97%	-97%	-100%	-100%
Low Carbon: Transition to Objective	-65%	-65%	-96%	-96%	-100%	-100%
Base with High Indiana Load	-39%	-24%	-94%	-93%	-100%	-100%
Base with Low Indiana Load	-39%	-39%	-94%	-94%	-100%	-100%
Exit OVEC ICPA in 2030	-39%	-24%	-94%	-93%	-100%	-100%
Rockport Unit 1 Retires 2025	-39%	-24%	-94%	-93%	-100%	-100%
Rockport Unit 1 Retires 2026	-39%	-24%	-94%	-93%	-100%	-100%
Expanded Wind Availability (Base)	-39%	-24%	-94%	-93%	-100%	-100%
Expanded Wind Availability (EER)	-56%	-55%	-95%	-95%	-100%	-100%
High Technology Costs	-39%	-24%	-94%	-93%	-100%	-100%

The Low Carbon Cases resulted in the highest reduction in CO_2 compared to the other Cases modeled. Although, as noted in Section 9.6.2, these cases resulted in significantly higher NPVRRs as compared to the other Cases modeled. The three cases that included the assumed EPA Section 111(b)(d) compliant capacity factor limitations (EER, Base Under EPA Section 111(b)(d), and Expanded Wind Availability (EER)) provided the second highest reduction in CO_2 compared to the other Cases at 55% reduction by 2044. The remaining portfolios have similar levels of CO_2 reduction and are between 24% and 39% by 2044. All portfolios have similar levels of NOx and SO_2 reduction.

The 2024 IN IRP emissions analysis assumes Scope 1 CO_2 emissions[24]. It also conservatively assumes that all selected resources are owned by I&M. Actual emissions reduction results could be less depending on the ownership structure of future resources.

9.7 Risk Assessment

Stochastic analyses were performed for a subset of the Cases modeled (Candidate Portfolios) for the purpose of assessing portfolio risk. The results of the stochastic analyses were used to develop probability distributions around key metrics used in the Portfolio Performance Indicator matrix. Uncertainty implied from these probability distributions were added to the Portfolio Performance Indicator matrix for Candidate Portfolios to allow for the comparison of performance and financial risk across the portfolios.

9.7.1 Stochastic Modeling Approach

Stochastic modeling was used for the risk analysis of the Candidate Portfolios. The risk analysis involved the definition of risk in the form of probability distributions around key uncertainty variables, which include load, natural gas prices, and market power prices. The stochastic simulation used the Monte Carlo method to generate 100 unique samples for each uncertain variable (load, natural gas prices, and energy market prices). These samples were designed to maintain cross-variable correlations, ensuring that relationships between these factors were accurately represented. The 100 samples formed a complete probability distribution capturing the full range of possible outcomes. To maintain temporal consistency, the model preserved key statistical properties of historical data, including trend, seasonal patterns, and serial correlation. The 100 sets of input variables were run through PLEXOS®'s chronological dispatch model for each portfolio to create 100 sets of key output variables. Key output variables include Power Supply Costs, generation by resource, and energy market purchases and sales. The 100 sets of output results converted to probability distributions for key output variables. The resulting distributions for each output variable described risk around that key output variable.

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[24] U.S. Environmental Protection Agency. (n.d.). *Scope 1 and Scope 2 inventory guidance*. Retrieved from https://www.epa.gov/climateleadership/scope-1-and-scope-2-inventory-guidance#:~:text=Scope%201%20emissions%20are%20direct,boilers%2C%20furnaces%2C%20vehicles

9.7.2 Load Stochastics

I&M's Indiana load was forecasted under high and low load cases as described in Section 4.12. Uncertainty implied by these cases were converted to hourly standard deviations, which were used to develop input probability distributions from which the stochastic Monte Carlo simulations could sample. Figure 85 below shows the monthly load simulation results for 10%, 25%, 75%, and 90% based on a log normal cumulative probability distribution.

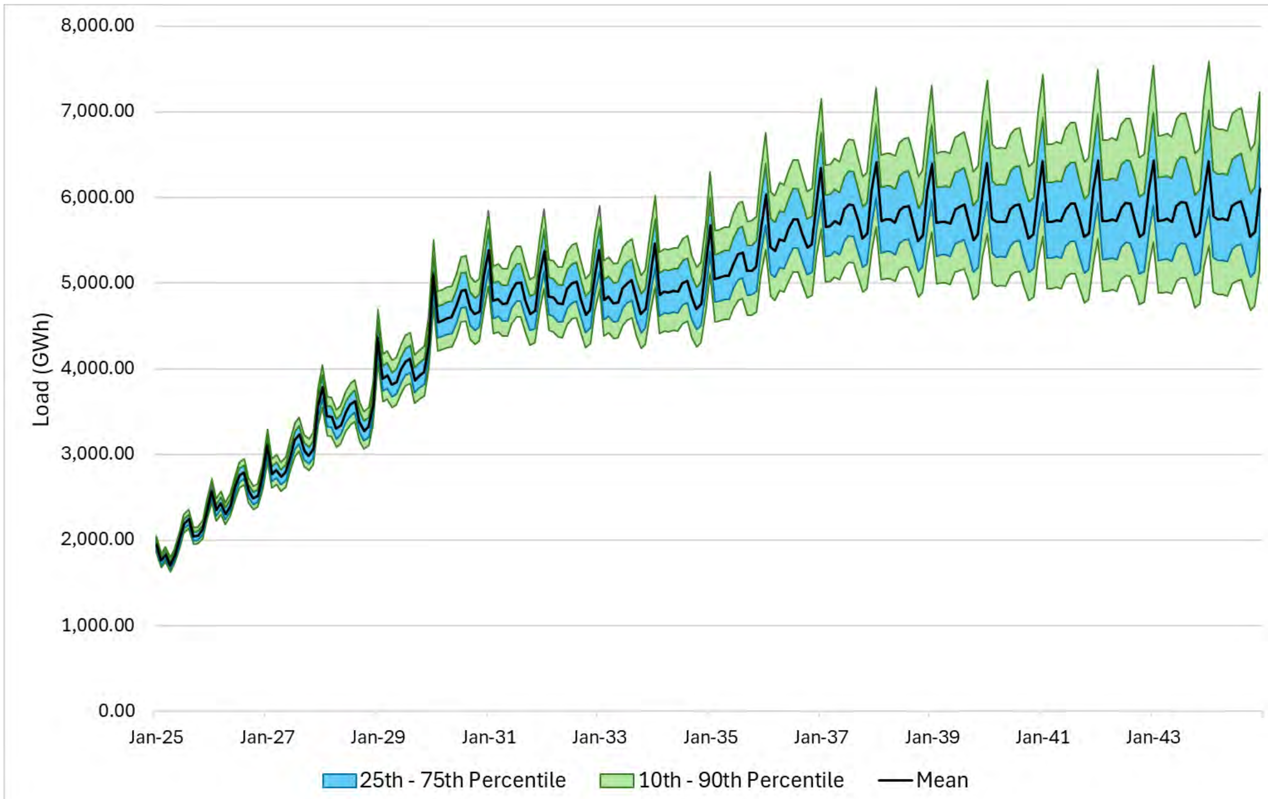

Figure 85. Monthly Load Stochastic Results

9.7.3 Natural Gas Price Stochastics

Natural gas prices were forecasted under high and low cases as described in Section 5.2. Uncertainty implied by these cases were converted to monthly standard deviations for natural gas prices, which were used to develop input probability distributions from which the stochastic Monte Carlo simulations could sample assuming a log normal distribution. Figure 86 below shows the natural gas price simulation results for 10%, 25%, 75%, and 90% based on a log normal cumulative probability distribution.

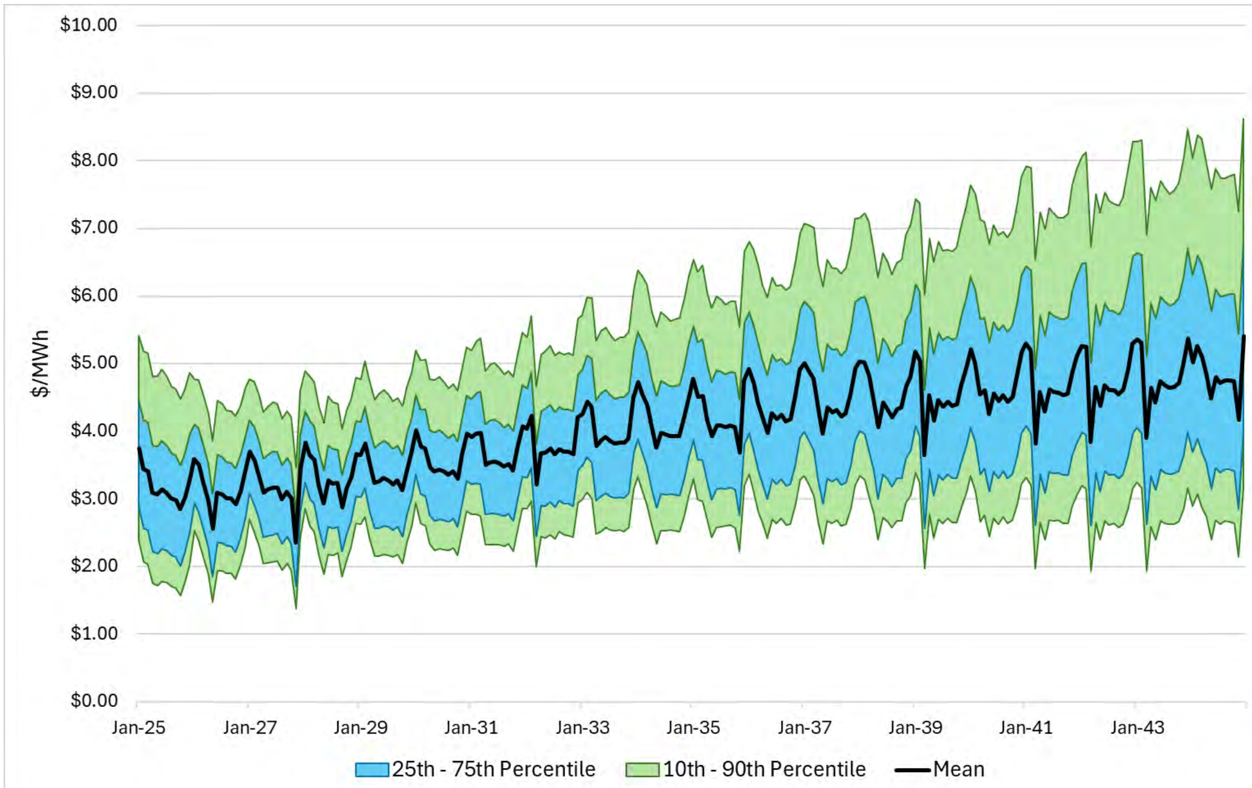

Figure 86. Natural Gas Price Stochastics Results

9.7.4 Market Energy Prices

Market energy prices were forecasted under high and low cases as described in Section 5.5. Uncertainty implied by these cases was converted to hourly standard deviations for market energy prices, which were used to develop input probability distributions from which the stochastic Monte Carlo simulations could sample assuming a lognormal distribution. Figure 87 below shows the market energy price simulation results for 10%, 25%, 75%, and 90% based on a log normal cumulative probability distribution.

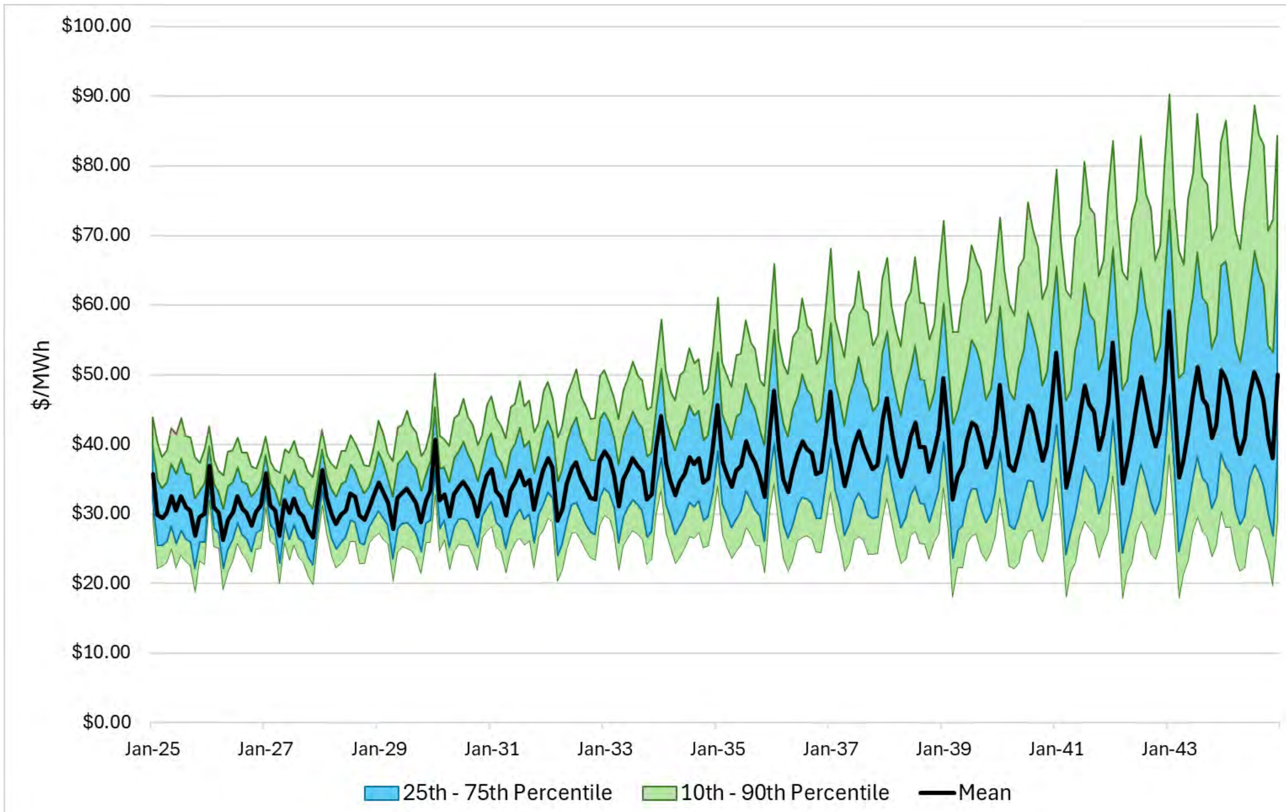

Figure 87. Energy Market Prices Stochastic Results

9.8 Identification of Preferred Portfolio

The identification of the Preferred Portfolio is informed from the results of the Candidate Portfolios and how they performed against the IRP Objectives consistent with the Five Pillars. The Preferred Portfolio, which is a product of complex analysis, planning judgement, and a balanced assessment of the Portfolio Performance Indicator, is discussed in Section 9.8.3.

As an integral step in the 2024 IN IRP process, I&M selected three Candidate Portfolios for Risk Analysis in Step 4 of the 2024 IN IRP Process (see Figure 7). Each of the Candidate Portfolios represents a potential strategic resource planning decision, with different benefits quantified within the Portfolio Performance Indicators. The goal is to identify resulting Candidate Portfolios that represent a variety of strategic alternatives for further analysis. The group of selected Candidate Portfolios then advance to the 2024 IN IRP Step 5: Compare Results & Identify Preferred Portfolio (see Figure 7) where they are analyzed to develop comparative measures (metrics) for presentation in the Portfolio Performance Indicator matrix.

The Candidate Portfolios selected for further analysis are:

- Base Reference
- Low Carbon: Transition to Objective
- Expanded Wind Availability (EER)

The remainder of this section discusses the Candidate Portfolios Performance Indicator metrics, risk analysis performed on the Candidate Portfolios, a comparison of the risk analysis results for the Candidate Portfolios, the selection of the Preferred Portfolio, and the performance indicator metrics of the Preferred Portfolio.

9.8.1 Candidate Portfolio Performance Indicator Metrics

Portfolio Performance Indicator Metrics for the three (3) Candidate Portfolios are summarized in Table 61 and Table 62.

Table 61. Candidate Portfolios Performance Indicator Metrics

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% 2044: -24%	2034: -94% 2044: -93%	2034: -100% 2044: -100%
Low Carbon: Transition	1.3%	$39.9	$9.8	2034: -65% 2044: -65%	2034: -96% 2044: -96%	2034: -100% 2044: -100%
Expanded Wind Availability (EER)	0.5%	$32.8	$11.4	2034: -56% 2044: -55%	2034: -95% 2044: -95%	2034: -100% 2044: -100%

Table 62. Candidate Portfolios Performance Indicator Metrics

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%) 20 Years: $4.3B (22%)	10 Years: $0.0B (0.1%) 20 Years: $0.1B (0.3%)	10 Years: -0.7% 20 Years: -3.4%	Capacity: 31% | 19% Energy: 173% | 139%	10 Years: 90% 20 Years: 97%
Low Carbon: Transition	10 Years: $2.7B (27%) 20 Years: $4.1B (20%)	10 Years: $0.2B (1.6%) 20 Years: $1.7B (7.7%)	10 Years: 2.0% 20 Years: 0.5%	Capacity: 53% | 54% Energy: 302% | 304%	10 Years: 91% 20 Years: 95%
Expanded Wind Availability (EER)	10 Years: $3.1B (31%) 20 Years: $5.4B (27%)	10 Years: $0.5B (3.5%) 20 Years: $1.3B (5.2%)	10 Years: 5.1% 20 Years: -0.6%	Capacity: 31% | 34% Energy: 296% | 318%	10 Years: 92% 20 Years: 92%

The Base Reference Case was selected as a Candidate Portfolio because it functions as an important comparison point for the other Candidate Portfolios and ultimately the Preferred Portfolio. In addition, it was one of the lowest cost portfolios with an NPVRR of $32B. Although, this case had a much lower amount of carbon-free resources selected as compared to several of the other cases, resulting in lower resource diversity metric results and lower CO_2 emissions reductions.

The Low Carbon: Transition to Objective Case was selected as a Candidate Portfolio due to its high Reliability, Resiliency, and Environmental Sustainability results. Compared to the Base Reference Case, this case selected significantly more carbon-free resources, including 600 MW of SMRs in 2037 which then increases to a cumulative amount of 1,200 MW by 2044. These resource additions resulted in significantly higher resource diversity metric results. Additionally, these carbon-free resources led to significant reductions in CO_2 emissions compared to the Base Reference Case. Although, this case was one of the highest cost portfolios with an NPVRR of $39.9B, which is $7.9B more than the NPVRR of the Base Reference Case.

Finally, the Expanded Wind Availability (EER) Case was selected as a Candidate Portfolio due to its favorable positioning for potential future environmental regulation, and its high Reliability, Resiliency, and Environmental Sustainability results. Similar to the Low Carbon: Transition to Objective Case, this case selected significantly more carbon-free resources compared to the Base Reference Case. These resource additions resulted in significantly higher resource diversity metric results and improved reductions in CO_2 emissions compared to the Base Reference Case. These high results are achieved at a much lower cost compared to the Low Carbon: Transition to Objective Case and only $0.8B more than the NPVRR of the Base Reference Case.

Figure 88 below highlights the benefits of each Candidate Portfolio according to the Portfolio Performance Indicator Matrix results.

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 ✓

Figure 88. Overview of Candidate Portfolio Performance

The capacity and energy profiles were compared between each of the three Candidates Portfolios. Figure 89 below compares the accredited capacity by resource type while Figure 90 compares the energy by resource type for the Candidate Portfolios.

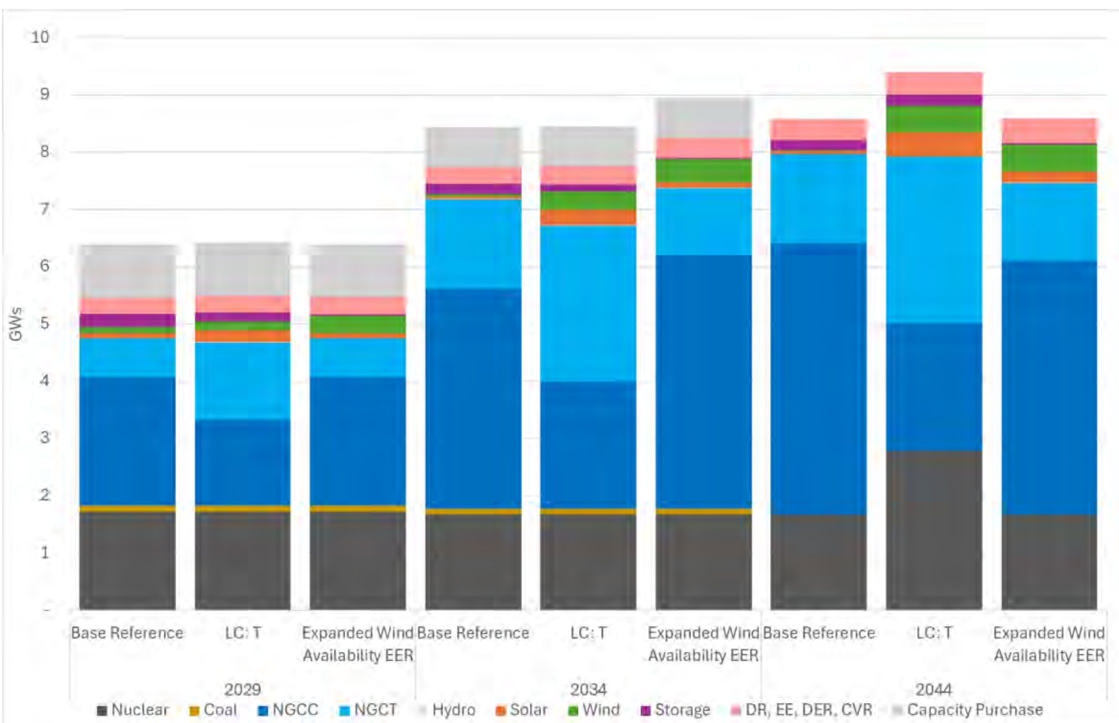

Figure 89. Candidate Portfolios Accredited Capacity by Resource Type

Throughout the planning horizon, all Candidate Portfolios rely primarily on natural gas resources, whether NGCCs or NGCTs, to support the capacity need. In 2034 and 2044, the Low Carbon: Transition to Objective and Expanded Wind Availability (EER) Cases have more accredited capacity from renewables as compared to the Base Reference Case. Although, the amount of accredited capacity from renewables is lower in comparison to the accredited capacity provided by natural gas and nuclear facilities.

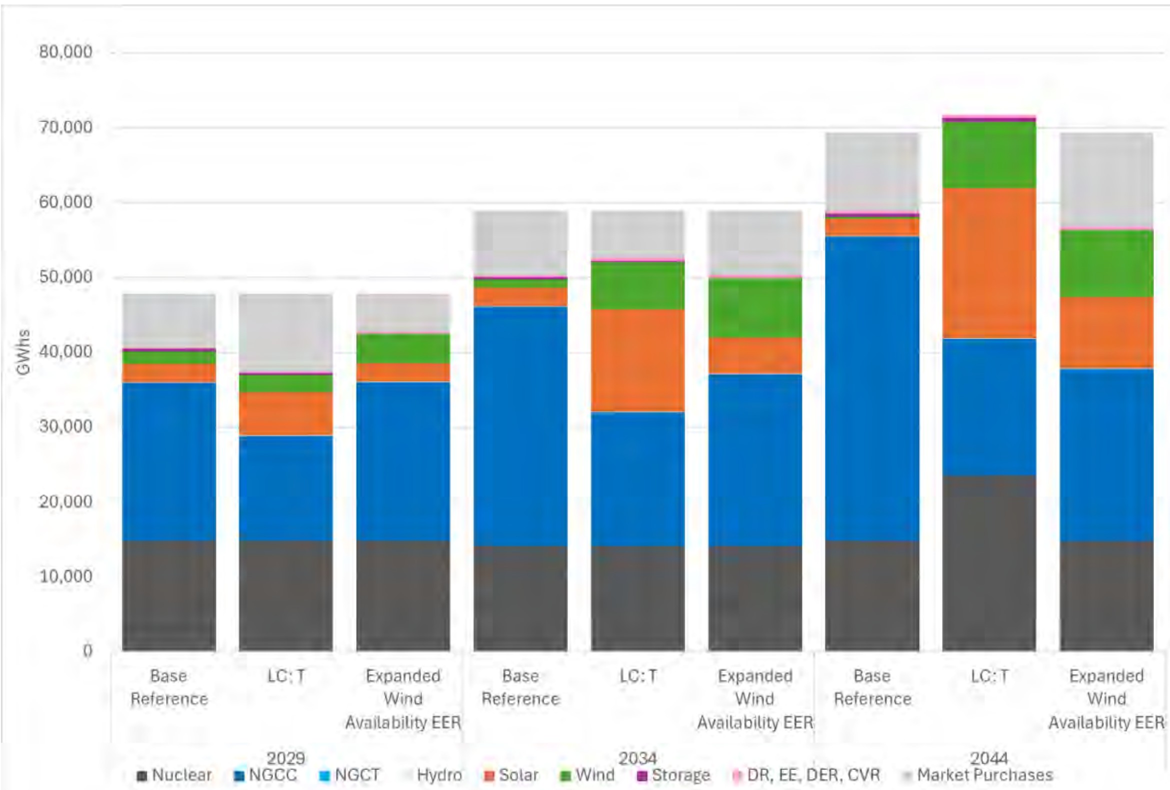

Figure 90. Candidate Portfolios Energy by Resource Type

While all Candidate Portfolios relied primarily on natural gas to support the capacity need, the energy generated varied by resource type between the three cases. The Base Reference Case relied more heavily on NGCCs to support the energy need, while the Expanded Wind Availability (EER) and Low Carbon: Transition to Objective Cases had more energy generated from renewable resources. In 2044, the Low Carbon: Transition to Objective Case had increased energy generated from nuclear facilities, due to the addition of SMRs. As noted in Table 62, both the Expanded Wind Availability (EER) and Low Carbon: Transition to Objective Cases had much higher energy diversity values when compared to the Base Reference Case.

9.8.2 Candidate Portfolio Risk Analysis

The risk analysis performed on Candidate Portfolios includes the development of output probability distributions around total Power Supply Costs (in the form of NPVs), energy market purchases as a percentage of load, and energy market sales as a percentage of load.

9.8.2.1 Portfolio NPV Risk

Probability distributions for Power Supply Costs NPVs were developed for the risk analysis. Figure 91 compares portfolio NPVs for the 10%, 25%, 75%, and 90% values with a box and whisker plot.

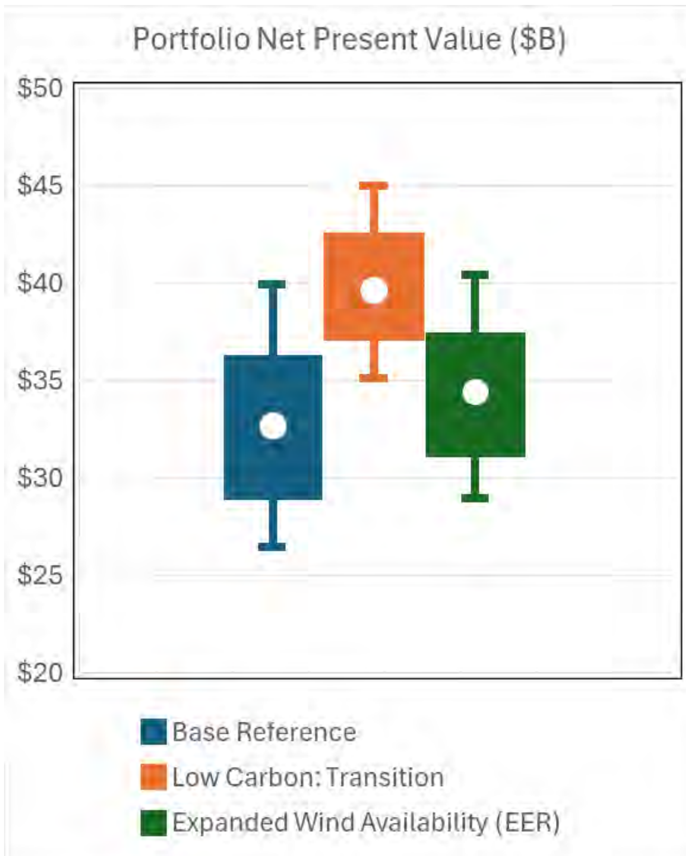

Figure 91. Candidate Portfolios NPV

The lower whisker on the plot represents the 10th percentile while the upper whisker represents the 90th percentile. The lower portion of the box on the plot represents the 25th percentile while the upper portion of the box represents the 75th percentile. The white dot represents the mean NPV for each of the Candidate Portfolios. A smaller range between the 10th and the 90th percentile indicates less variability in NPV and therefore less future cost risk.

As can be seen in Figure 91, the Low Carbon: Transition to Objective Case has the highest mean NPV, the Base Reference Case has the lowest mean NPV, and the Expanded Wind Availability (EER) Case has a mean NPV slightly higher than the Base Reference Case. These mean NPV values from the risk analysis align closely with the NPV values from the deterministic Affordability analysis results noted in Table 61.

The Base Reference Case has a larger range between the 10th and 90th percentile, indicating more NPV variability and cost risk. The Low Carbon: Transition to Objective Case has the smaller range between the 10th and 90th percentile but has a much higher mean NPV compared to the other Candidate Portfolios. The Expanded Wind Availability (EER) Case has a smaller range compared to the Base Reference Case, indicating less variability and cost risk.

9.8.2.2 Energy Market Purchase Risk

Energy market purchase variability is an important factor to understand. Significant reliance on energy market purchases can expose a portfolio to significant market price risk if future market energy prices are higher than forecasted. Probability distributions for energy market purchases as a percentage of load were developed for the risk analysis. Specifically, for each Candidate Portfolio, purchases as a percentage of load were averaged across the planning horizon. Figure 92 compares the 20-year average portfolio purchases as a percentage of load for the 10%, 25%, 75%, and 90% values on a box and whisker plot.

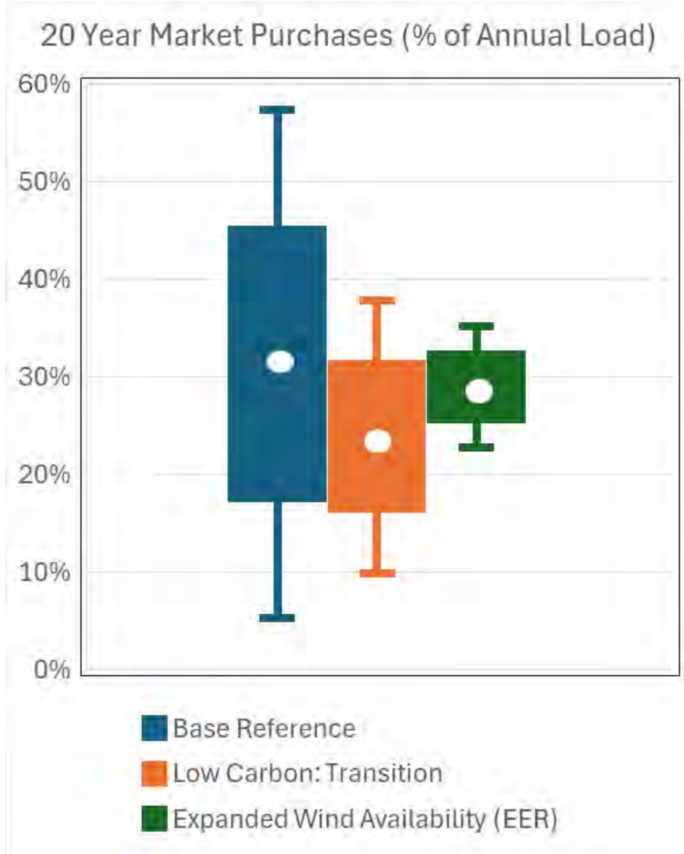

Figure 92. Candidate Portfolios Purchases as a Percent of Annual Load

The lower whisker on the plot represents the 10th percentile while the upper whisker represents the 90th percentile. The lower portion of the box on the plot represents the 25th percentile while the upper portion of the box represents the 75th percentile. The white dot represents the mean market purchases as a percent of annual load for each of the Candidate Portfolios. A smaller range between the 10th and the 90th percentile indicates less variability in market purchase as a percent of annual load and therefore less future energy market purchase risk.

As can be seen in Figure 92, the Base Reference Case has the highest range of market purchase variability, while the Expanded Wind Availability (EER) Case has the lowest range. This is a result of the assumed 50% annual capacity factor limitations applied to the existing NGCCs in the Expanded Wind Availability Case (EER) to comply with EPA Section 111(b)(d) requirements. As a result of this limitation, existing NGCCs dispatched at an annual capacity factor of 50% in almost all samples for all years. Therefore, for samples that reflect favorable economic conditions (i.e. high market prices or low gas prices), the existing NGCC will still dispatch at a maximum annual capacity factor of 50% due to the limitation. This is the reason for the narrow variability displayed between the mean and the bottom whisker for the Expanded Wind Availability (EER) Case. On the contrary, for samples that reflect highly unfavorable economic conditions (i.e. low market prices or high gas prices), the existing NGCC will operate at a less than 50% annual capacity factor, but the variability will not be as high as the Base Reference Case because the generation is reduced from a lower mean in the Expanded Wind Availability (EER) Case compared to the Base Reference Case. This is the reason for the narrow variability displayed between the mean and the top whisker for the Expanded Wind Availability (EER) Case. The Low Carbon: Transition to Objective Case had less energy market purchase variability compared to the Base Reference Case. This is due to the lower amount of NGCCs in the Low Carbon: Transition to Objective Case as compared to the Base Reference Case. As noted above, energy market purchases are impacted significantly by NGCC dispatch, thus a case with less NGCCs will have less energy market purchase variability.

9.8.2.3 Energy Market Sales Risk

Conversely to energy market purchase risk, energy market sales risk becomes important if future market prices were to fall lower than forecasted. Significant reliance on energy market sales for low portfolio costs can expose a portfolio to significant market price risk. Probability distributions for energy market sales as a percentage of annual load were developed for the risk analysis. Specifically, for each Candidate Portfolio, energy market sales as a percentage of annual load were averaged across a 20-year period (2025 through 2044). Figure 93 compares the 20-year average portfolio energy market sales as a percentage of load for the 10%, 25%, 75%, and 90% values on a box and whisker plot.

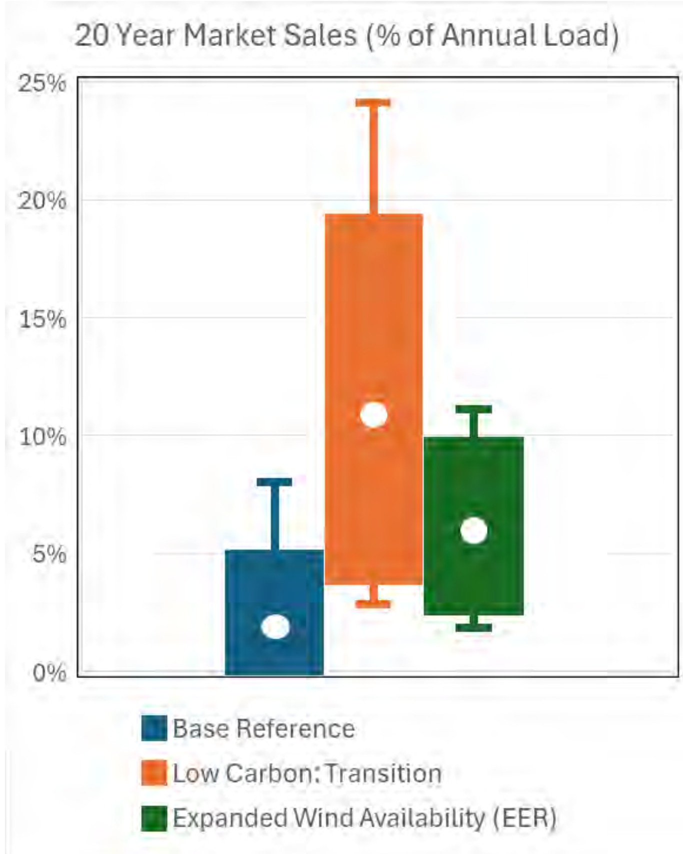

Figure 93. Candidate Portfolios Sales % of Annual Load

The lower whisker on the plot represents the 10th percentile while the upper whisker represents the 90th percentile. The lower portion of the box on the plot represents the 25th percentile while the upper portion of the box represents the 75th percentile. The white dot represents the mean market sales as a percent of annual load for each of the Candidate Portfolios. A smaller range between the 10th and the 90th percentile indicates less variability in market sales as a percent of annual load and therefore less future energy market sales risk.

As can be seen in Figure 93, the Low Carbon: Transition to Objective Case has the highest range of energy market sales variability, with the Base Reference Case and the Expanded Wind Availability (EER) Cases having less variability. The energy market sales variability is driven by the amount of renewable resources within a portfolio. As noted in Section 9.6.1, the intermittency of renewable generation led to excess energy that was sold into the energy market. The Low Carbon: Transition to Objective Case had the most amount of renewable resources compared to the other Candidate Portfolios, resulting in the highest range of energy market sales variability.

9.8.3 Selection of Preferred Portfolio

The Preferred Portfolio was informed by the results of the Candidate Portfolios discussed earlier in this section.

9.8.3.1 Preferred Portfolio Strategy and Modeling

The Preferred Portfolio supports a balanced consideration of Indiana's Five Pillars of energy policy and provides a planning basis for the Company's near-term plan, 2025 through 2030, and long-term indicative plan, 2031 through 2044. The Preferred Portfolio was primarily based on modifications to the Expanded Wind Availability (EER) Candidate Portfolio. This case was selected as the basis for the Preferred Portfolio for the following reasons:

- The case better positions I&M for compliance with existing and future Greenhouse Gas regulations based on the current and proposed EPA Section 111(b)(d) rules, and the potential for regulations to occur in some form during the planning horizon. This is discussed in Section 9.3.
- The case leverages a mix of resource types that support reliability and stability, while increasing resource diversity and expanding the renewable and clean energy portfolio, as discussed in Section 9.7.
- The case leverages existing natural gas resources which allows I&M to better manage the remaining life of its generation portfolio and associated risks, mitigates the impact of development risks associated with new generation, and lowers the additionality impacts of natural gas on I&M's customers and the PJM system.
- The case resulted in less variability in future cost risks as compared to the Base Reference Case in the risk analysis results, discussed in Section 9.8.2.1.
- The case reflects up to date market conditions on resource availability based on results from the four (4) separate RFPs issued in 2024.

In addition, the Preferred Portfolio leverages cost savings opportunities and other benefits associated with redevelopment of the Rockport site with future NGCTs and SMR technology. Specifically, the Preferred Portfolio included the following resource additions planned for the Rockport site:

- New NGCTs in 2030, reflecting 690 MW of nameplate capacity. These new NGCTs reflect estimated cost reductions of approximately 15% compared to the generic new NGCT resource price, as discussed in Section 8.1.3.1. These cost reductions were included to reflect the cost savings associated with the reuse of the Rockport interconnection, existing facilities, and the opportunity to leverage favorable equipment pricing associated with AEP multi-unit supply chain opportunities.

- SMRs in 2036 and 2037, reflecting a total 600 MW of nameplate capacity. These SMRs reflect estimated cost reductions of approximately 30% compared to the generic SMR resource price, as discussed in Section 8.1.2.3. These cost reductions were included to reflect the cost savings associated with the reuse of the Rockport interconnection and existing facilities, energy community bonus ITCs, federal grant opportunities, customer participation, and leveraging fast follower savings opportunities. The Rockport facility qualifies as an energy community under the IRA 2022. As an initial step, in January, 2024 I&M entered into a grant funding partnership seeking grants from the U.S. Department of Energy (DOE) to support the Early Site Permit process at the Rockport site[25]. Through the DOE's Generation III+ Small Modular Reactor Program, and grant funding partnership with the Tennessee Valley Authority (TVA) and GE Hitachi Nuclear Energy, I&M is seeking $50 million to begin the early stages of SMR development at the Rockport site.

The redevelopment opportunity at the Rockport site is further supported by PJM's Capacity Interconnection Rights (CIR) Transfer Process[26]. On January 31, 2025, PJM proposed a new process for transferring CIRs from deactivating to new replacement generation resources. This Replacement Generation Interconnection Process, separate but parallel to PJM's clustered cycle process, uses "first ready, first served" principles to address resource adequacy concerns. If approved by FERC, PJM's proposal would support an expedited process for reusing I&M's existing interconnection rights at the Rockport site for future generation resource development.

Demand-side resources were also adjusted in the Preferred Portfolio to better reflect what is realistically achievable for the various options and further balance customer affordability, portfolio cost-effectiveness and customer familiarity and acceptance. The Demand Response (DR) Residential and Commercial & Industrial (C&I) resources for both Direct Load Control (DLC) and Rates were set in the Preferred Portfolio near existing DR program forecast RAP levels. While less than the original RAP, continuing to offer the same DR programs mitigates customer confusion, aligns with customer preferences according to programs they already participate in, and manages program cost impacts by reducing the number of like-kind program offerings. Furthermore, the average portfolio cost effectiveness score for the Preferred Portfolio DR programs improves by 12.5% from the average score for the original RAP portfolio of programs from the MPS. Similar to DR, the high-cost residential bundle was excluded from the Preferred Portfolio to better manage EE program costs, portfolio cost effectiveness, and customer affordability. The MPS portfolio cost effectiveness score improves by approximately 15% with the high-cost residential bundle not included. The Conservation Voltage Reduction (CVR) resource was reduced in the Preferred

[25] American Electric Power. (2025). *AEP Seeking Grants to Assist with Advanced Nuclear Site Exploration in Indiana and Virginia*. Retrieved from https://www.aep.com/news/stories/view/9974/

[26] Federal Energy Regulatory Commission. (2025). *Docket No. ER25-1128-000: Proposed tariff amendments for replacement generation interconnection service*. Retrieved from https://elibrary.ferc.gov/eLibrary/

Portfolio to reflect an updated outlook for resource cost effectiveness and distribution system operational considerations.

These three adjustments were included in the Expanded Wind Availability (EER) Case and the model was re-optimized in PLEXOS®. The following changes to the resource selections from the Expanded Wind Availability (EER) Case occurred as a result of the adjustments described above:

- In 2031, 900 MW less of existing NGCC was selected.
- The timing of 500 MW of existing NGCT was shifted from 2030 to 2031.
- Beginning in 2032, up to 299 MW more solar was selected through 2034. Starting in 2037, up to 1,603 MW less solar was selected.
- Similar amounts of DR, EE, DER, CVR were selected through 2031 with less DR, EE, DER, CVR selected through 2044.

Table 63 shows the capacity additions for the Preferred Portfolio while the accredited capacity by resource type is shown in Figure 94.

Table 63. Preferred Portfolio Cumulative Nameplate Capacity Additions

Year	Nameplate MW								Accredited MW	
	Wind	Solar	Storage	New NGCC	Existing NGCC	New NGCT	Existing NGCT	Nuclear Cook SLR & SMR	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

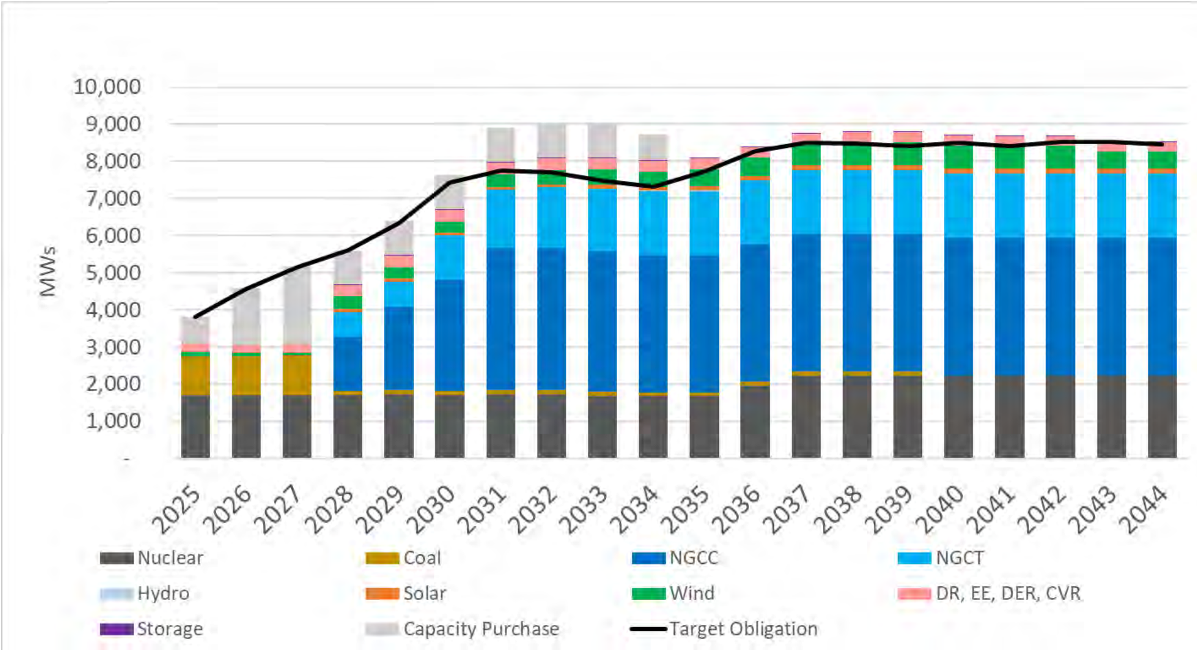

Figure 94. Preferred Portfolio Accredited Capacity by Resource Type

The Preferred Portfolio reflects a diverse mix of resources. Wind, solar, storage, existing NGCCs, and NGCTs are all selected in the first year of availability to meet capacity and energy obligations. Substantial amounts of these resources are selected over the planning horizon, consistent with the Expanded Wind Availability (EER) Case. As noted previously, 690 MW of new NGCTs were included in 2030, and 300 MW of SMR was included in both 2036 and 2037 (600 MW total), reflecting new resource additions located at the Rockport site. The resources at the Rockport site add new capacity to PJM's and I&M's system. The Cook SLR is selected in 2035 and 2038, consistent with all other Cases modeled. Cook, SMRs, and other natural gas resources with higher accredited capacity values support most of the Target Obligation, as can be seen in Figure 94. Wind and solar have lower accredited capacity values, as defined by PJM and noted in Section 8.1.1.3. The increase in accredited capacity compared to the Target Obligation during 2031 to 2034[27] is due to capacity additions selected economically to meet the energy obligation during that period while preparing for the subsequent load increase which occurs from 2034 to 2037, consistent with many of the Cases modeled. Though not shown in the Table 63 above, the Preferred Portfolio also includes relicensing of the Elkhart and Mottville Hydro resources in 2030 and 2033, respectively.

[27] The IRP modeling inadvertently reflected the Lawrenceburg CPA contract to end in the 2034/35 DY instead of ending in the 2033/34 DY, as noted in Table 11. The Preferred Portfolio was reviewed, and it was confirmed that if the change was reflected, the Preferred Portfolio would still meet the 2034 Target Obligation.

Figure 95 shows energy by resource type for the Preferred Portfolio.

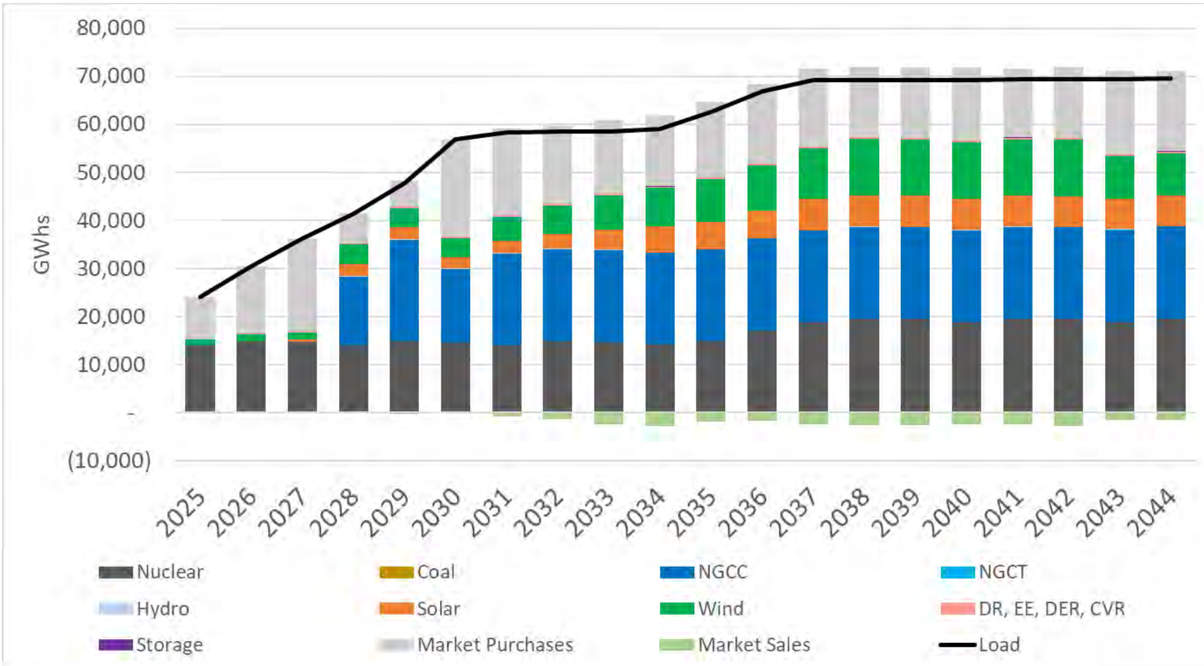

Figure 95. Preferred Portfolio Energy by Resource Type

In the first three years as energy needs increase, the Preferred Portfolio includes energy market purchases until resources are made available for selection in 2028. When resources become available in 2028, NGCC and nuclear resources provide the majority of the energy. In 2030, the energy generated from NGCC reduces due to the assumed EPA Section 111(b)(d) compliant capacity factor limitations for existing NGCC facilities, as discussed in Section 9.3. After 2030, wind and solar begin to generate more energy as the nameplate capacity of those resources increases. While wind and solar provided minimal accredited capacity to support the Target Obligation as seen in Figure 94, these resources provide approximately 25% of the energy generated from 2034 to 2044. Additionally, starting in 2036 when the first SMR is selected, nuclear resources provide approximately 28% of the energy generated through 2044.

9.8.3.2 Preferred Portfolio Results Comparison

Figure 96 compares the Preferred Portfolio's accredited capacity values by resource type and Figure 97 compares the Preferred Portfolio's energy by resource type those of the Candidate Portfolios.

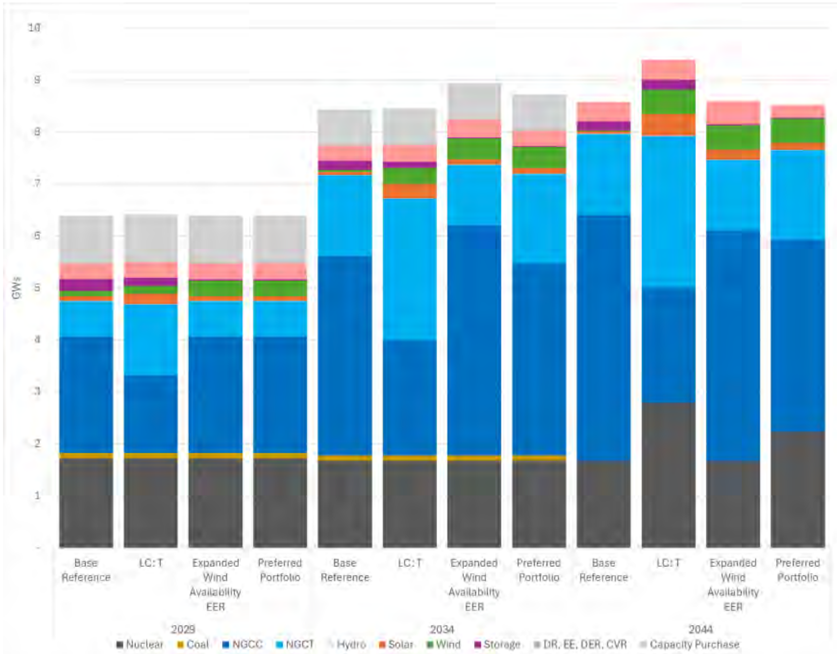

Figure 96. Preferred Portfolio and Candidate Portfolios Accredited Capacity by Resource Type

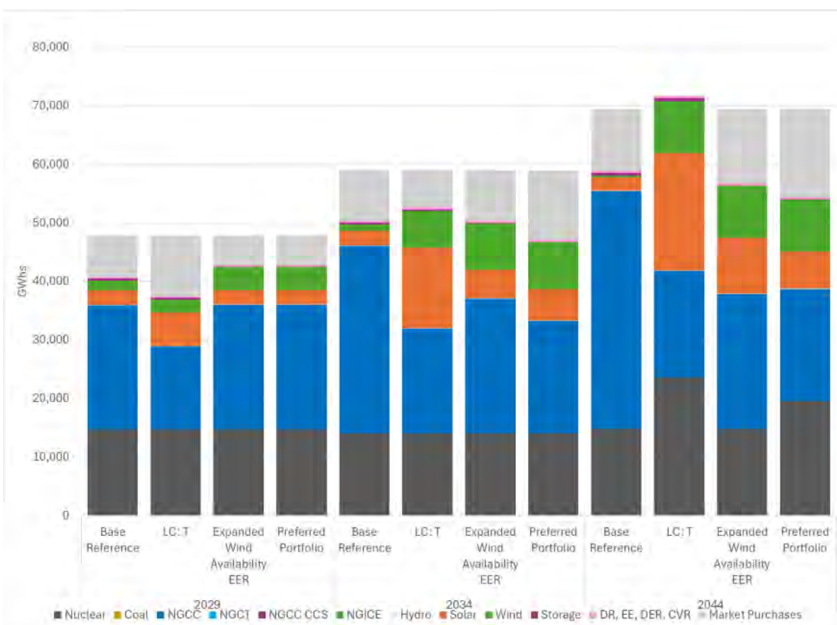

Figure 97. Preferred Portfolio and Candidate Portfolios Energy by Resource Type

In 2029, the Preferred Portfolio's accredited capacity values are similar to those of the Candidate Portfolios. All the portfolios select similar amounts of natural gas resources to support the capacity need. The energy values for the Preferred Portfolio are similar to those of the Expanded Wind Availability (EER) and Base Reference Cases, with NGCCs and nuclear providing the majority of the generation. The Low Carbon: Transition to Objective Case has substantial NGCC capacity, although less than the other portfolios, resulting in more energy market purchases.

In 2034, the Preferred Portfolio's accredited capacity and energy values begin to differ from the Candidate Portfolios, although, all portfolios are still reliant on similar levels of natural gas resources to support the capacity need. The wind and solar accredited capacity values have increased compared to the Base Reference Case and align more closely to the values in the Low Carbon: Transition to Objective and the Expanded Wind Availability (EER) Cases. The energy values for the Preferred Portfolio also align more closely with the Low Carbon: Transition to Objective and the Expanded Wind Availability (EER) Cases as wind and solar resources begin to provide more of the energy while NGCCs provide less.

In 2044, all portfolios still rely on similar levels of natural gas resources to support the capacity need with between seven (7) and eight (8) GW of accredited capacity provided from NGCCs or NGCTs. As noted previously, significant natural gas resource selection was a consistent theme amongst all Cases modeled in this IRP. The Preferred Portfolio's accredited capacity and energy values are similar to those of the Expanded Wind Availability (EER) Case, although there are some differences. The primary differences are the increase in nuclear accredited capacity and energy and the reduction in NGCC energy. These differences are due to the reduction of the NGCC with the addition of the Rockport NGCTs and SMRs, discussed earlier in this section.

9.8.3.3 Preferred Portfolio Risk Analysis

The same risk analysis completed on the Candidate Portfolios was also performed on the Preferred Portfolio. This allowed I&M to compare and contrast the relative risks associated with the four portfolios. Overall, the Preferred Portfolio performed well across the range of risks analyzed and when compared to the Candidate Portfolios, reflected a balanced plan that incorporates many of the favorable features of the other Candidate Portfolios. Figure 98 compares the Preferred Portfolio NPVs for the 10%, 25%, 75%, and 90% values to the Candidate Portfolios with a box and whisker plot.

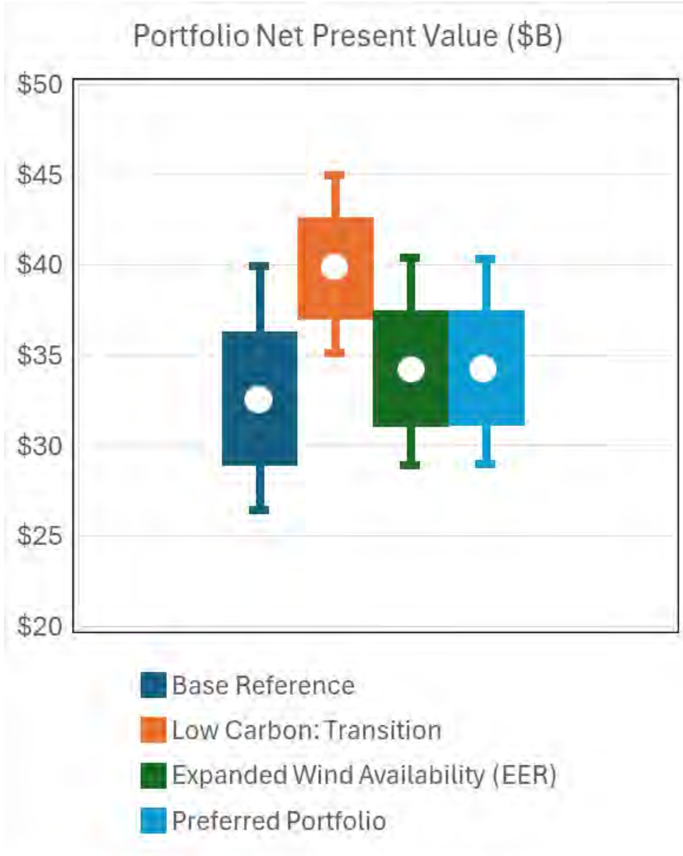

Figure 98. Preferred Portfolio and Candidate Portfolios NPV

The comparison above indicates that the Preferred Portfolio's NPV variability results are between those of the Base Reference and the Low Carbon: Transition to Objective Cases. The Preferred Portfolio's NPV variability is similar to the Expanded Wind Availability (EER) Case variability, although slightly less. As noted in Section 9.8.2.1, while the Low Carbon: Transition to Objective Case has a lower NPV variability, its mean NPV is much higher compared to the other Candidate Portfolios, and ultimately the Preferred Portfolio. These results indicate the Preferred Portfolio's improved NPV variability compared to the Expanded Wind Availability (EER) Case and the overall balance it provides when comparing the NPV variability to the NPV mean.

Figure 99 compares the Preferred Portfolio's 20-year average energy market purchases as a percentage of load for 10%, 25%, 75%, and 90% values on a box and whisker plot to those of the Candidate Portfolios.

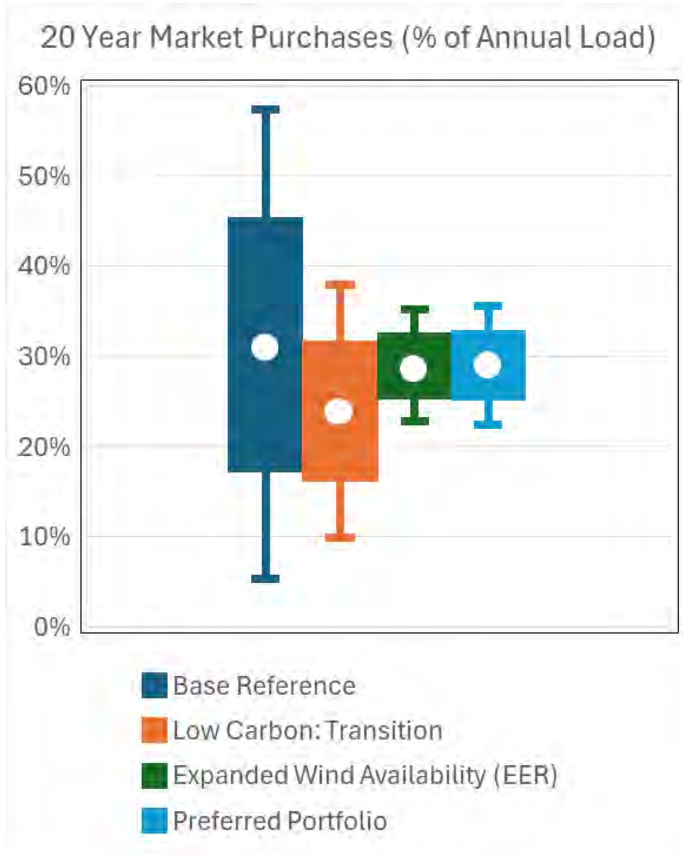

Figure 99. Preferred Portfolio and Candidate Portfolios Market Purchases % of Annual Load

The comparison above indicates that the Preferred Portfolio's energy market purchase variability falls between the results of the Candidate Portfolios, has a narrow range of energy market purchase variability and is similar to the Expanded Wind Availability (EER) Case. The Base Reference and Low Carbon: Transition to Objective Cases have substantially higher energy market purchase variability. The Preferred Portfolio's lower variability of energy market purchases is driven largely by the assumed capacity factor limitations applied to the existing NGCCs. Because of this limitation, existing NGCCs in the Preferred Portfolio are almost always economic for up to 50% of the hours of a year, resulting in existing NGCCs in the Preferred Portfolio dispatching at exactly 50% for most years in the risk analysis. Energy market purchases are impacted significantly by NGCC dispatch, and NGCC dispatch is consistent across various natural gas price and market price scenarios, energy market purchases are also consistent from year to year in the risk analysis. As a result, energy market purchase variability in the risk analysis is low in the Preferred Portfolio.

Figure 100 compares the Preferred Portfolio's 20-year average energy market sales as a percentage of load for 10%, 25%, 75%, and 90% values on a box and whisker plot to those of the Candidate Portfolios.

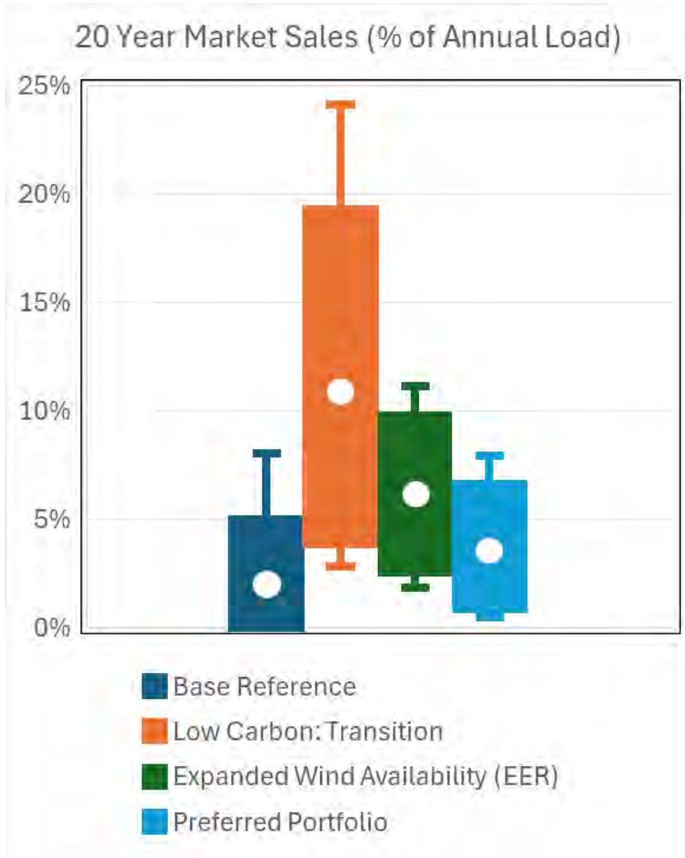

Figure 100. Preferred Portfolio and Candidate Portfolios Sales as % of Annual Load

The results above demonstrate that Preferred Portfolio performs very well when considering energy market sales volatility compared to the other Candidate Portfolios. As discussed in Section 9.8.2.3, the energy market sales variability is largely driven by the amount of renewable resources within a portfolio. As a result, the Low Carbon: Transition to Objective Case has significantly higher risk and variability. The Expanded Wind Availability (EER) Case also had higher risk and more variability due primarily to having more solar resources over the planning horizon. While the Base Reference case had greater variability but potentially less risk, primarily due to having fewer renewable resources over the planning horizon.

The risk analysis was completed on the Preferred Portfolio prior to finalizing the portfolio. The risk analysis supported the Preferred Portfolio and provided insight into how the portfolio would perform under a variety of uncertain futures.

9.8.3.4 Preferred Portfolio Performance Indicators

As discussed previously in Section 2.3, I&M developed a set of Portfolio Performance Indicators aligned with the Five Pillars of Indiana energy policy that were used to further assess and compare the Preferred Portfolio against the Candidate Portfolios. Table 64 and Table 65 compare the Preferred Portfolio's Performance Indicator metrics to those of the Candidate Portfolios.

Table 64. Affordability and Environmental Sustainability 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% 2044: -24%	2034: -94% 2044: -93%	2034: -100% 2044: -100%
Low Carbon: Transition	1.3%	$39.9	$9.8	2034: -65% 2044: -65%	2034: -96% 2044: -96%	2034: -100% 2044: -100%
Expanded Wind Availability (EER)	0.5%	$32.8	$11.4	2034: -56% 2044: -55%	2034: -95% 2044: -95%	2034: -100% 2044: -100%
Preferred Portfolio	0.4%	$33.1	$11.4	2034: -63% 2044: -63%	2034: -96% 2044: -96%	2034: -100% 2044: -100%

Table 65. Reliability, Resiliency, and Grid Stability 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%) 20 Years: $4.3B (22%)	10 Years: $0.0B (0.1%) 20 Years: $0.1B (0.3%)	10 Years: -0.7% 20 Years: -3.4%	Capacity: 31% | 19% Energy: 173% | 139%	10 Years: 90% 20 Years: 97%
Low Carbon: Transition	10 Years: $2.7B (27%) 20 Years: $4.1B (20%)	10 Years: $0.2B (1.6%) 20 Years: $1.7B (7.7%)	10 Years: 2.0% 20 Years: 0.5%	Capacity: 53% | 54% Energy: 302% | 304%	10 Years: 91% 20 Years: 95%
Expanded Wind Availability (EER)	10 Years: $3.1B (31%) 20 Years: $5.4B (27%)	10 Years: $0.5B (3.5%) 20 Years: $1.3B (5.2%)	10 Years: 5.1% 20 Years: -0.6%	Capacity: 31% | 34% Energy: 296% | 318%	10 Years: 92% 20 Years: 92%
Preferred Portfolio	10 Years: $3.1B (31%) 20 Years: $5.3B (27%)	10 Years: $0.2B (1.3%) 20 Years: $0.5B (2.3%)	10 Years: 4.2% 20 Years: -0.6%	Capacity: 39% | 35% Energy: 299% | 299%	10 Years: 91% 20 Years: 93%

As shown in Table 64 and Table 65 above, the Preferred Portfolio performs very well across the range of Portfolio Performance Indicators when compared to the Candidate Portfolios resulting in a balanced plan that supports I&M's IRP Objectives and Indiana's Five Pillars.

Affordability:

When considering the Affordability Pillar, the Preferred Portfolio results were toward the lower (more favorable) end of the range compared to the other Candidate Portfolios. The main driver influencing the relative results was related to the amount of nameplate capacity additions and composition of resources selected in each portfolio. The Base Reference Case performed best relative to the affordability metrics used to evaluate short-term and long-term Power Supply Costs due to selecting significantly less nameplate capacity additions, relying most heavily on natural gas resources and selecting the least amount of renewable resources. While the Low Carbon: Transition to Objective Case performed best relative to portfolio resilience, it had the highest short-term and long-term Power Supply Cost metrics due to selecting significantly more nameplate capacity additions. The Preferred Portfolio represents a balanced resource plan that leverages the affordability benefits of natural gas resources while continuing to expand I&M's portfolio of clean energy resources, resulting in moderate short-term growth rate, an NPVRR close to that of the Base Reference Case, and improved portfolio resilience.

Environmental Sustainability:

When considering the Environmental Sustainability Pillar, the Preferred Portfolio supports similar or more favorable CO_2, NOx, and SO_2 emissions reductions as compared to the Candidate Portfolios when dispatching the natural gas resources under the assumed EPA Section 111(b)(d) compliant capacity factor limitations. When specifically comparing to the Expanded Wind Availability (EER) Case, the Preferred Portfolio benefits from the new NGCT and SMR additions at the Rockport site to enable further reduction of CO_2 and NOx emissions. The Low Carbon: Transition to Objective Case does provide more favorable CO_2, NOx, and SO_2 emissions reductions, but this case is $6.8B more expensive than the Preferred Portfolio.

Reliability and Resiliency:

For the Reliability Pillar, I&M evaluated energy market risk and planning reserve margin. Overall, the Preferred Portfolio represents a balanced resource plan that supports future reliability for I&M's customers. The Preferred Portfolio and Candidate Portfolio Cases each require relatively high levels of market energy purchases due to Indiana's significant growth in forecasted energy requirements, with the Preferred Portfolio and the Expanded Wind Availability (EER) Case having higher energy market purchase risk due to the assumed EPA Section 111(b)(d) compliant capacity factor limitations for natural gas resources. The Preferred Portfolio performs very well with respect to energy market sales risk when comparing against the Expanded Wind Availability (EER) and the Low Carbon: Transition to Objective Cases. As discussed in previous sections, cases with high levels of renewable energy also had higher market sales risk. The Expanded Wind Availability (EER) and the Low Carbon: Transition to Objective Cases had higher market sales risk due to the increased amount of solar resources in these cases as compared to the Preferred Portfolio. In addition, the Preferred Portfolio performs well achieving I&M's planning reserve margin target, but as noted earlier in this section, the 10-year results are higher than average due to capacity additions selected economically to meet the energy obligation during that period while preparing for the subsequent load increase which occurs from 2034 to 2037.

Resource diversity was used to evaluate the Reliability and Resiliency Pillars. The Preferred Portfolio significantly enhances resource diversity for I&M's customers, achieving a higher capacity and energy diversity metric compared to the Base Reference Case, with similar results to the Expanded Wind Availability (EER) Case. The Low Carbon: Transition to Objective Case does provide higher capacity diversity metric results, but as noted previously, this case is $6.8B more expensive than the Preferred Portfolio.

Grid Stability and Resiliency:

Finally, fleet resiliency was used to evaluate the Grid Stability and Resiliency Pillars. All Candidate Portfolios showed high levels of fleet resilience as measured by dispatchable capacity as a percentage of nameplate capacity. The Preferred Portfolio provided over 90% of dispatchable capacity as compared to the company peak demand, supporting future Grid Stability and Resiliency for I&M's customers.

10 Conclusion and Short-Term Action Plan

The Company's 2024 IN IRP is the result of a Public Advisory Process and extensive modeling that evaluated numerous scenarios and sensitivities using the best available industry and market intelligence available at the time to inform resource assumptions. I&M's IRP Objectives and Portfolio Performance Indicators were designed to align with Indiana's Five Pillars of energy policy. The Preferred Portfolio represents a balanced consideration of the Five Pillars and an all-of-the-above resource plan to meet the future energy and capacity needs of I&M's Indiana retail customers and will be used as a guide for the resource decisions I&M undertakes as its business transforms in the future to serve the unprecedented load growth forecasted. The Preferred Portfolio leverages key opportunities to significantly expand I&M's resource diversity, taking advantage of existing and new generation resources, to support ongoing safety, reliability, and resiliency of the grid. The Preferred Portfolio also positions I&M to significantly expand clean energy resources and prepare for potential future environmental regulation, thereby supporting an environmentally sustainable future. Collectively, the benefits of the Preferred Portfolio support I&M's IRP Objectives while mitigating potential cost risks to customers in the event future market conditions change.

Steps that I&M has taken, or will take, as part of its Short-term Action Plan include:

DSM Programs: Continue the planning and regulatory actions necessary to implement an ongoing cost-effective portfolio of DSM programs in Indiana consistent with this IRP.

Rockport Retirement: Continue to take the steps necessary to support a transition of the Rockport Coal facility, including proceeding with necessary actions to support the ongoing development and commissioning of new resources from I&M's 2022 and 2023 All-Source RFPs that have been approved by the Commission to replace Rockport.

Near Term Capacity Needs: Use bilateral capacity purchases to obtain the capacity needed for future PJM Delivery Years that cannot be met through long-term resources.

2024 Competitive Procurement Activities: Complete selection of resources from the 2024 RFP and other competitive procurement activities undertaken by I&M that reflect the market conditions at the time the procurement activities are conducted. Seek approval of resources that are reasonably consistent with the Preferred Portfolio resource selections.

Rockport CT: Complete competitive procurement process, secure 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 Competitive Procurement Activities: Continue to issue future generation RFPs or utilize other competitive procurement methods, as necessary, to meet I&M's capacity and energy needs.

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 opportunities reflected in the Preferred Portfolio.

Adjust for the Future: Adjust this action plan and future IRPs to reflect changing circumstances, as necessary.

Since the Company's last IRP, I&M accomplishments towards the 2021 Short-Term Action Plan include:

- Complied with the modeling and other IRP-related commitments as set forth in the Settlement Agreements in Cause Nos. 45546 and 45933.
- Conducted All-Source RFPs in 2022 and 2023 to acquire the generation resources necessary to replace the energy and capacity needs associated with the Rockport retirement obligation in December 2028. The Commission approved the related resources in Cause Nos. 45868, 45869, 46083, 46085, and 46088.
- The Company completed an updated Market Potential Study in 2024 assessing the potential for future energy efficiency (EE), demand response (DR) and distributed energy resources (DER) resources.
- The Company issued four RFPs in September 2024 targeting approximately 4,000 MW of solar, wind, storage, thermal and supplemental capacity resources.
- The Company has notified PJM of its intention to continue as a Fixed Resource Requirement (FRR) entity through the 2025/2026 PJM Delivery Year ending May 31, 2026.
- The Company continues to monitor and support PJM's Capacity Interconnection Rights (CIR) Transfer Efficiency proposal that would support an expedited process for reusing I&M's existing interconnection rights at the Rockport site for future generation resource development.

Appendix Volume 1

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Appendix Volume 2

Load Forecast Model Equations and Statistical Test Results

Appendix Volume 3

Appendix Volume 4

Public Advisory Process